C 5933

ANNUAL REPORT OF UNIT OPERATIONS - FORM 24

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
SFN 54260 (09-2004)

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MINERAL RESOURCES

For Year 2023 ~~2024~~

PLEASE READ INSTRUCTIONS BEFORE FILLING OUT FORM.
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Field	Unitized Pool	Unit	
DICKINSON	LODGEPOLE	DICKINSON LODGEPOLE UNIT	
		Current OOIP Estimate	Cumulative Oil Production
		Bbls	7682515 Bbls

Operator	Telephone Number
SCOUT ENERGY MANAGMENT LLC	(469) 485-3122

Address	City	State	Zip Code
13800 MONTFORT DRIVE	DALLAS	TX	75240

YEAR 2023 PRODUCTION / INJECTION

Oil Produced (Bbls)	Gas Produced (MCF)	Water Produced (Bbls)	GOR (SCF/Bbl)	Injection Volume	Make-Up Water Produced (Bbls)
91016	23399	496067	0	1244779 Bbls 0 MCF	0

YEAR 2023 WELL COUNT

Producing Wells	Injection Wells	Shut-In Wells	Temporarily Abandoned Wells	SWD Wells	Water Supply Wells
2	2	0	1	0	0

YEAR 2023 RESERVOIR PRESSURE DATA (Report 3 most representative bottom hole pressures from more than one well, if possible.)

Datum (Feet Below S.L.)	Date Of Test	Well Name and Number	Well File Number	Extrapolated Reservoir Pressure (PSIG)

YEAR 2023 OPERATIONS

Producers Drilled	Injectors Drilled	Injectors Converted	Wells Shut-in	Wells TA	SWD Wells		Water Supply Wells	
					Drilled	Converted	Drilled	Converted
0	0	0	0	1	0	0	0	0

YEAR 2024 PROPOSED OPERATIONS

Producing Wells To Be Drilled	Injection Wells To Be Drilled	Injection Wells To Be Converted	Wells To Be Plugged	Wells To Be TA	SWD Wells To Be		Water Supply Wells To Be	
					Drilled	Converted	Drilled	Converted
0	0	0	0	0	0	0	0	0

YEAR 2023 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PERFORMED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description

YEAR 2024 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PROPOSED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description

Comments

No major workovers or artificial changes made in 2023. No major workovers or artificial lift changes planned for 2024.

Signature	Printed Name	Title	Date
[signature]	Mikey Pham	Regulatory Analyst	March 13, 2024

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ANNUAL REPORT OF UNIT OPERATIONS - FORM 24

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
SFN 54260 (09-2004)

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N.D. INDUSTRIAL COMMISSION

For Year: 2022

PLEASE READ INSTRUCTIONS BEFORE FILLING OUT FORM.
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Field	Unitized Pool	Unit	
DICKINSON	LODGEPOLE	DICKINSON LODGEPOLE UNIT	
		Current OOIP Estimate: Bbls	Cumulative Oil Production: 7591499 Bbls

Operator	Telephone Number
SCOUT ENERGY MANAGMENT LLC	(469) 485-3122

Address	City	State	Zip Code
13800 MONTFORT DRIVE, SUITE 100	DALLAS	TX	75240

YEAR 2022 PRODUCTION / INJECTION

Oil Produced (Bbls)	Gas Produced (MCF)	Water Produced (Bbls)	GOR (SCF/Bbl)	Injection Volume	Make-Up Water Produced (Bbls)
98989	45334	364409	0	858515 Bbls 0 MCF	0

YEAR 2022 WELL COUNT

Producing Wells	Injection Wells	Shut-In Wells	Temporarily Abandoned Wells	SWD Wells	Water Supply Wells
2	2	0	1	0	0

YEAR 2022 RESERVOIR PRESSURE DATA (Report 3 most representative bottom hole pressures from more than one well, if possible.)

Datum (Feet Below S.L.)	Date Of Test	Well Name and Number	Well File Number	Extrapolated Reservoir Pressure (PSIG)

YEAR 2022 OPERATIONS

Producers Drilled	Injectors Drilled	Injectors Converted	Wells Shut-in	Wells TA	SWD Wells Drilled	SWD Wells Converted	Water Supply Wells Drilled	Water Supply Wells Converted
0	0	0	0	0	0	0	0	0

YEAR 2023 PROPOSED OPERATIONS

Producing Wells To Be Drilled	Injection Wells To Be Drilled	Injection Wells To Be Converted	Wells To Be Plugged	Wells To Be TA	SWD Wells To Be Drilled	SWD Wells To Be Converted	Water Supply Wells To Be Drilled	Water Supply Wells To Be Converted
0	0	0	0	0	0	0	0	0

YEAR 2022 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PERFORMED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
Dickinson-Lodgepole Unit 74	13447	Plugback. Reduce perforated section to 10' to improve waterflood

YEAR 2023 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PROPOSED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description

Comments
No major workovers or artificial lift changes planned for 2023.

Signature	Printed Name	Title	Date
[signature]	Mikey Pham	Regulatory Tech	March 9, 2023

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ANNUAL REPORT OF UNIT OPERATIONS - FORM 24

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
SFN 54260 (09-2004)

For Year
2021

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Field	Unitized Pool	Unit	
		DICKINSON LODGEPOLE UNIT	
DICKINSON	LODGEPOLE	Current OOIP Estimate: Bbls	Cumulative Oil Production: 7492510 Bbls

Operator	Telephone Number
SCOUT ENERGY MANAGEMENT LLC	(972) 590-6353

Address	City	State	Zip Code
13800 Montfort Road, Suite 100	DALLAS	TX	75240

YEAR 2021 PRODUCTION / INJECTION

Oil Produced (Bbls)	Gas Produced (MCF)	Water Produced (Bbls)	GOR (SCF/Bbl)	Injection Volume	Make-Up Water Produced (Bbls)
88969	50073	352056		840314 Bbls 0 MCF	0

YEAR 2021 WELL COUNT

Producing Wells	Injection Wells	Shut-In Wells	Temporarily Abandoned Wells	SWD Wells	Water Supply Wells
2	2	0	1	0	0

YEAR 2021 RESERVOIR PRESSURE DATA (Report 3 most representative bottom hole pressures from more than one well, if possible.)

Datum (Feet Below S.L.)	Date Of Test	Well Name and Number	Well File Number	Extrapolated Reservoir Pressure (PSIG)

YEAR 2021 OPERATIONS

Producers Drilled	Injectors Drilled	Injectors Converted	Wells Shut-in	Wells TA	SWD Wells Drilled	SWD Wells Converted	Water Supply Wells Drilled	Water Supply Wells Converted
0	0	0	0	0	0	0	0	0

YEAR 2022 PROPOSED OPERATIONS

Producing Wells To Be Drilled	Injection Wells To Be Drilled	Injection Wells To Be Converted	Wells To Be Plugged	Wells To Be TA	SWD Wells To Be Drilled	SWD Wells To Be Converted	Water Supply Wells To Be Drilled	Water Supply Wells To Be Converted

YEAR 2021 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PERFORMED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
Dickinson-Lodgepole Unit 75	13514	Plugback. Reduce perforated section to 10' to improve waterflood

YEAR 2022 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PROPOSED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
Dickinson-Lodgepole Unit 74	13447	Plugback. Reduce perforated section to 10' to improve waterflood

Comments

Signature	Printed Name	Title	Date
Sharon Sequera	Sharon Sequera	Senior Regulatory Analyst	March 29, 2022

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ANNUAL REPORT OF UNIT OPERATIONS - FORM 24

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
SFN 54260 (09-2004)

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ND Oil & Gas Division

For Year 2020

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Field	Unitized Pool	Unit	
Dickinson	Lodgepole	Dickinson Lodgepole	
		Current OOIP Estimate: Bbls	Cumulative Oil Production: 7403541 Bbls

Operator	Telephone Number
Scout Energy Management LLC	(972) 277-1397

Address	City	State	Zip Code
13800 Montfort Drive, Suite 100	Dallas	TX	75240

YEAR 2020 PRODUCTION / INJECTION

Oil Produced (Bbls)	Gas Produced (MCF)	Water Produced (Bbls)	GOR (SCF/Bbl)	Injection Volume		Make-Up Water Produced (Bbls)
39726	22740	485800		1148702	Bbls	0
				0	MCF	

YEAR 2020 WELL COUNT

Producing Wells	Injection Wells	Shut-In Wells	Temporarily Abandoned Wells	SWD Wells	Water Supply Wells
2	2	0	0	0	1

YEAR 2020 RESERVOIR PRESSURE DATA (Report 3 most representative bottom hole pressures from more than one well, if possible.)

Datum (Feet Below S.L.)	Date Of Test	Well Name and Number	Well File Number	Extrapolated Reservoir Pressure (PSIG)

YEAR 2020 OPERATIONS

Producers Drilled	Injectors Drilled	Injectors Converted	Wells Shut-in	Wells TA	SWD Wells Drilled	SWD Wells Converted	Water Supply Wells Drilled	Water Supply Wells Converted
0	0	0	0	1	0	0	0	0

YEAR 2021 PROPOSED OPERATIONS

Producing Wells To Be Drilled	Injection Wells To Be Drilled	Injection Wells To Be Converted	Wells To Be Plugged	Wells To Be TA	SWD Wells To Be Drilled	SWD Wells To Be Converted	Water Supply Wells To Be Drilled	Water Supply Wells To Be Converted
0	0	0	0	0	0	0	0	0

YEAR 2020 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PERFORMED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
N/A		

YEAR 2021 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PROPOSED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
Dickinson Lodgepole Unit 75	13514	Plug back - reduce perforated section to 10' to improve waterflood

Comments

No major workovers or artificial lift changes in 2020.
Plugback on the Dickinson Lodgepole Unit 75. Reduce perforated section to 10' to improve waterflood performance in 2021.

Signature	Printed Name	Title	Date
Sheronda Greenwood	Sheronda Greenwood	Regulatory Analyst	June 2, 2021

ANNUAL REPORT OF UNIT OPERATIONS - FORM 24

1. This report is to be filed annually, by April 1, for the preceding calendar year.

2. The unit, field, unitized pool, operator, well names and numbers, and file numbers shall coincide with the official records on file with the Commission.

3. All oil volumes shall be reported as barrels (42 gallons), corrected to 14.73 psia and 60 degrees F. All other liquid volumes shall be reported as barrels (42 gallons). All liquid volumes shall be rounded to the nearest full barrel. All gas volumes shall be reported as MCF and corrected to 14.73 psia and 60 degrees F.

4. The "Current OOIP Estimate" shall be the most recently updated figure.

5. The "Cumulative Oil Production" shall be from the effective date of the unit.

6. Well status' shall coincide with the official definitions of the Commission.

7. The datum used for reservoir pressure measurements shall coincide with the respective field order.

8. The original of this report shall be filed with the Industrial Commission of North Dakota, Oil and Gas Division, 600 East Boulevard, Dept. 405, Bismarck, ND 58505-0840.

Case 5933

ANNUAL REPORT OF UNIT OPERATIONS - FORM 24

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
SFN 54260 (09-2004)

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ND Oil & Gas Division

For Year
2019

PLEASE READ INSTRUCTIONS BEFORE FILLING OUT FORM.
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Field	Unitized Pool	Unit	
Dickinson	Lodgepole	Dickinson Lodgepole	
		Current OOIP Estimate	Cumulative Oil Production
		Bbls	7363815 Bbls

Operator	Telephone Number
Scout Energy Management LLC	(972) 277-1397

Address	City	State	Zip Code
13800 Montfort Drive, Suite 100	Dallas	TX	75240

YEAR 2019 PRODUCTION / INJECTION

Oil Produced (Bbls)	Gas Produced (MCF)	Water Produced (Bbls)	GOR (SCF/Bbl)	Injection Volume	Make-Up Water Produced (Bbls)
27572	7405	133073		524346 Bbls 0 MCF	0

YEAR 2019 WELL COUNT

Producing Wells	Injection Wells	Shut-In Wells	Temporarily Abandoned Wells	SWD Wells	Water Supply Wells
2	2	0	0	0	1

YEAR 2019 RESERVOIR PRESSURE DATA (Report 3 most representative bottom hole pressures from more than one well, if possible.)

Datum (Feet Below S.L.)	Date Of Test	Well Name and Number	Well File Number	Extrapolated Reservoir Pressure (PSIG)

YEAR 2019 OPERATIONS

Producers Drilled	Injectors Drilled	Injectors Converted	Wells Shut-in	Wells TA	SWD Wells Drilled	SWD Wells Converted	Water Supply Wells Drilled	Water Supply Wells Converted
0	0	0	0	0	0	0	0	0

YEAR 2020 PROPOSED OPERATIONS

Producing Wells To Be Drilled	Injection Wells To Be Drilled	Injection Wells To Be Converted	Wells To Be Plugged	Wells To Be TA	SWD Wells To Be Drilled	SWD Wells To Be Converted	Water Supply Wells To Be Drilled	Water Supply Wells To Be Converted
0	0	0	0	1	0	0	0	0

YEAR 2019 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PERFORMED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description

YEAR 2020 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PROPOSED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description

Comments

Signature	Printed Name	Title	Date
Sheronda Greenwood	Sheronda Greenwood	Regulatory Analyst	May 12, 2021

ANNUAL REPORT OF UNIT OPERATIONS - FORM 24

1. This report is to be filed annually, by April 1, for the preceding calendar year.
2. The unit, field, unitized pool, operator, well names and numbers, and file numbers shall coincide with the official records on file with the Commission.
3. All oil volumes shall be reported as barrels (42 gallons), corrected to 14.73 psia and 60 degrees F. All other liquid volumes shall be reported as barrels (42 gallons). All liquid volumes shall be rounded to the nearest full barrel. All gas volumes shall be reported as MCF and corrected to 14.73 psia and 60 degrees F.
4. The "Current OOIP Estimate" shall be the most recently updated figure.
5. The "Cumulative Oil Production" shall be from the effective date of the unit.
6. Well status' shall coincide with the official definitions of the Commission.
7. The datum used for reservoir pressure measurements shall coincide with the respective field order.
8. The original of this report shall be filed with the Industrial Commission of North Dakota, Oil and Gas Division, 600 East Boulevard, Dept. 405, Bismarck, ND 58505-0840.

ANNUAL REPORT OF UNIT OPERATIONS - FORM 24

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
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For Year
2018

Case 5933

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Field	Unitized Pool	Unit	
Dickinson	Lodgepole	Dickinson Lodgepole	
		Current OOIP Estimate: Bbls	Cumulative Oil Production: 7,338,470 Bbls

Operator	Telephone Number
Scout Energy Management LLC	(972) 588-4798

Address	City	State	Zip Code
4901 LBJ Freeway, Suite 300	Dallas	TX	75244

YEAR 2018 PRODUCTION / INJECTION

Oil Produced (Bbls)	Gas Produced (MCF)	Water Produced (Bbls)	GOR (SCF/Bbl)	Injection Volume	Make-Up Water Produced (Bbls)
36,295	15,304	155,196		272,137 Bbls	
				0 MCF	

YEAR 2018 WELL COUNT

Producing Wells	Injection Wells	Shut-In Wells	Temporarily Abandoned Wells	SWD Wells	Water Supply Wells
2	2	0	0	0	1

YEAR RESERVOIR PRESSURE DATA (Report 3 most representative bottom hole pressures from more than one well, if possible.)

Datum (Feet Below S.L.)	Date Of Test	Well Name and Number	Well File Number	Extrapolated Reservoir Pressure (PSIG)

YEAR 2018 OPERATIONS

Producers Drilled	Injectors Drilled	Injectors Converted	Wells Shut-in	Wells TA	SWD Wells		Water Supply Wells	
					Drilled	Converted	Drilled	Converted
0	0	0	0	0	0	0	0	0

YEAR 2019 PROPOSED OPERATIONS

Producing Wells To Be Drilled	Injection Wells To Be Drilled	Injection Wells To Be Converted	Wells To Be Plugged	Wells To Be TA	SWD Wells To Be		Water Supply Wells To Be	
					Drilled	Converted	Drilled	Converted
0	0	0	0	1	0	0	0	0

YEAR 2018 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PERFORMED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description

YEAR 2019 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PROPOSED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
Dickinson Lodgepole Unit 62	7078	Temporarily abandon

Comments

Signature	Printed Name	Title	Date
Sherri Daley	Sherri Daley	Regulatory Specialist	March 5, 2019

ANNUAL REPORT OF UNIT OPERATIONS - FORM 24

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
SFN 54260 (09-2004)

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ND OIL & GAS DIVISION

For Year: **2017**

Case 5933

PLEASE READ INSTRUCTIONS BEFORE FILLING OUT FORM.
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Unit: **Dickinson Lodgepole**			
Field: **Dickinson**	Unitized Pool: **Lodgepole**	Current OOIP Estimate: **12,900,000 Bbls**	Cumulative Oil Production: **7,282,697 Bbls**
Operator: **ConocoPhillips Company**			Telephone Number: **(281) 206-5362**
Address: **600 N. Dairy Ashford**	City: **Houston**	State: **TX**	Zip Code: **77079**

YEAR 2017 PRODUCTION / INJECTION

Oil Produced (Bbls)	Gas Produced (MCF)	Water Produced (Bbls)	GOR (SCF/Bbl)	Injection Volume	Make-Up Water Produced (Bbls)
22,212	13,763	155,130	619	314,087 Bbls	
				MCF	

YEAR 2017 WELL COUNT

Producing Wells	Injection Wells	Shut-In Wells	Temporarily Abandoned Wells	SWD Wells	Water Supply Wells
2	2	0	0	0	1

YEAR RESERVOIR PRESSURE DATA (Report 3 most representative bottom hole pressures from more than one well, if possible.)

Datum (Feet Below S.L.)	Date Of Test	Well Name and Number	Well File Number	Extrapolated Reservoir Pressure (PSIG)
7,271	7/15/1996	DLU 83	13598	3648
	6/16/2003	DLU 79	13447	3992
	11/11/1999	DLU 75	13519	3890

YEAR 17 OPERATIONS

Producers Drilled	Injectors Drilled	Injectors Converted	Wells Shut-in	Wells TA	SWD Wells Drilled	SWD Wells Converted	Water Supply Wells Drilled	Water Supply Wells Converted
0	0	0	0	0	0	0	0	0

YEAR 2018 PROPOSED OPERATIONS

Producing Wells To Be Drilled	Injection Wells To Be Drilled	Injection Wells To Be Converted	Wells To Be Plugged	Wells To Be TA	SWD Wells To Be Drilled	SWD Wells To Be Converted	Water Supply Wells To Be Drilled	Water Supply Wells To Be Converted
0	0	0	0	0	0	0	0	0

YEAR 2017 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PERFORMED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
West Dickinson UN 362	14414	Repaired a tubing leak and returned the well to pumping

YEAR 2018 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PROPOSED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description

Comments
COP transferred operatorship to Scout Energy eff: 8/1/2017

Signature	Printed Name	Title	Date
[signature]	Donna Williams	Regulatory	3/14/18

ANNUAL REPORT OF UNIT OPERATIONS - FORM 24

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
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For Year
2016

Case 5933

PLEASE READ INSTRUCTIONS BEFORE FILLING OUT FORM.
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Field	Unitized Pool	Unit	
Dickinson	Lodgepole	Dickinson Lodgepole	
		Current OOIP Estimate: 12,900,000 Bbls	Cumulative Oil Production: 7,260,485 Bbls

Operator	Telephone Number
ConocoPhillips Company	(281) 206-5362

Address	City	State	Zip Code
600 N. Dairy Ashford	Houston	TX	77079

YEAR 2016 PRODUCTION / INJECTION

Oil Produced (Bbls)	Gas Produced (MCF)	Water Produced (Bbls)	GOR (SCF/Bbl)	Injection Volume	Make-Up Water Produced (Bbls)
29,594	15,737	169,270	531	470,881 Bbls	
				MCF	

YEAR 2016 WELL COUNT

Producing Wells	Injection Wells	Shut-In Wells	Temporarily Abandoned Wells	SWD Wells	Water Supply Wells
2	2	0	0	0	1

YEAR RESERVOIR PRESSURE DATA (Report 3 most representative bottom hole pressures from more than one well, if possible.)

Datum (Feet Below S.L.)	Date Of Test	Well Name and Number	Well File Number	Extrapolated Reservoir Pressure (PSIG)
7,271	7/15/1996	DLU 83	13598	3648
	6/16/2003	DLU 79	13447	3992
	11/11/1999	DLU 75	13519	3890

YEAR 2016 OPERATIONS

Producers Drilled	Injectors Drilled	Injectors Converted	Wells Shut-in	Wells TA	SWD Wells Drilled	SWD Wells Converted	Water Supply Wells Drilled	Water Supply Wells Converted
0	0	0	0	0	0	0	0	0

YEAR 2017 PROPOSED OPERATIONS

Producing Wells To Be Drilled	Injection Wells To Be Drilled	Injection Wells To Be Converted	Wells To Be Plugged	Wells To Be TA	SWD Wells To Be Drilled	SWD Wells To Be Converted	Water Supply Wells To Be Drilled	Water Supply Wells To Be Converted
0	0	0	0	0	0	0	0	0

YEAR 2016 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PERFORMED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description

YEAR 2017 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PROPOSED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description

Comments

Signature	Printed Name	Title	Date
	Donna Williams	Sr. Regulatory Advisor	February 20, 2017

ANNUAL REPORT OF UNIT OPERATIONS - FORM 24

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
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ND Oil & Gas Division

For Year
2015

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Field	Unitized Pool	Unit	
Dickinson	**Lodgepole**	**Dickinson Lodgepole**	
		Current OOIP Estimate	Cumulative Oil Production
		12900000 Bbls	**7230891 Bbls**

Operator	Telephone Number
ConocoPhillips Company	**(281) 206-5362**

Address	City	State	Zip Code
600 N. Dairy Ashford; P10-03-3030	**Houston**	**Tx**	**77079**

YEAR 2015 PRODUCTION / INJECTION

Oil Produced (Bbls)	Gas Produced (MCF)	Water Produced (Bbls)	GOR (SCF/Bbl)	Injection Volume		Make-Up Water Produced (Bbls)
37428	**21882**	**267880**	**584**	**672130**	**Bbls**	**84924**
					MCF	

YEAR 2015 WELL COUNT

Producing Wells	Injection Wells	Shut-In Wells	Temporarily Abandoned Wells	SWD Wells	Water Supply Wells
2	**2**	**0**	**0**	**0**	**1**

YEAR 2015 RESERVOIR PRESSURE DATA (Report 3 most representative bottom hole pressures from more than one well, if possible.)

Datum (Feet Below S.L.)	Date Of Test	Well Name and Number	Well File Number	Extrapolated Reservoir Pressure (PSIG)
7271	**07/15/96**	**DLU 83**	**13598**	**3648**
	06/16/03	**DLU 79**	**13447**	**3992**
	11/11/99	**DLU 75**	**13519**	**3890**

YEAR 2015 OPERATIONS

Producers Drilled	Injectors Drilled	Injectors Converted	Wells Shut-in	Wells TA	SWD Wells		Water Supply Wells	
					Drilled	Converted	Drilled	Converted
0	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

YEAR 2016 PROPOSED OPERATIONS

Producing Wells To Be Drilled	Injection Wells To Be Drilled	Injection Wells To Be Converted	Wells To Be Plugged	Wells To Be TA	SWD Wells To Be		Water Supply Wells To Be	
					Drilled	Converted	Drilled	Converted
0	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

YEAR 2015 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PERFORMED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
N/A		

YEAR 2015 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PROPOSED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
N/A		

Comments
Some make up water is supplied by produced water from Encore HR 1-4

Signature	Printed Name	Title	Date
[signature]	**Donna Williams**	**Sr. Regulatory Advisor**	**February 10, 2016**

ANNUAL REPORT OF UNIT OPERATIONS - FORM 24

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
SFN 54260 (09-2004)

For Year
2013

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Field	Unitized Pool	Unit	
Dickinson	Lodgepole	Dickinson Lodgepole	
		Current OOIP Estimate: 12,900,000 Bbls	Cumulative Oil Production: 7,144,764 Bbls

Operator	Telephone Number
ConocoPhillips Company	281-206-5362

Address	City	State	Zip Code
600 N. Dairy Ashford; P10-03-3030	Houston	TX	77079

YEAR 2013 PRODUCTION / INJECTION

Oil Produced (Bbls)	Gas Produced (MCF)	Water Produced (Bbls)	GOR (SCF/Bbl)	Injection Volume	Make-Up Water Produced (Bbls)
52,764	32,802	445,346	621	530,270 Bbls / MCF	84,924

YEAR 2013 WELL COUNT

Producing Wells	Injection Wells	Shut-In Wells	Temporarily Abandoned Wells	SWD Wells	Water Supply Wells
2	2	0	0	0	1

YEAR 2013 RESERVOIR PRESSURE DATA (Report 3 most representative bottom hole pressures from more than one well, if possible.)

Datum (Feet Below S.L.)	Date Of Test	Well Name and Number	Well File Number	Extrapolated Reservoir Pressure (PSIG)
7,271	7/15/1996	DLU 83	13598	3648
	6/16/2003	DLU 79	13447	3992
	11/11/1999	DLU 75	13519	3890

YEAR 2013 OPERATIONS

Producers Drilled	Injectors Drilled	Injectors Converted	Wells Shut-in	Wells TA	SWD Wells Drilled	SWD Wells Converted	Water Supply Wells Drilled	Water Supply Wells Converted
0	0	0	0	0	0	0	0	0

YEAR 2014 PROPOSED OPERATIONS

Producing Wells To Be Drilled	Injection Wells To Be Drilled	Injection Wells To Be Converted	Wells To Be Plugged	Wells To Be TA	SWD Wells To Be Drilled	SWD Wells To Be Converted	Water Supply Wells To Be Drilled	Water Supply Wells To Be Converted
0	0	0	0	0	0	0	0	0

YEAR 2013 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PERFORMED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description

YEAR 2014 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PROPOSED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description

Comments
Some make up water is supplied by produced water from Encore HR 1-4

Signature	Printed Name	Title	Date
[signature]	Donna Williams	Sr. Regulatory Advisor	June 2, 2014

ANNUAL REPORT OF UNIT OPERATIONS - FORM 24

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
SFN 54260 (09-2004)

MAR 2013
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ND OIL & GAS
DIVISION

For Year
2012

Case 5933

PLEASE READ INSTRUCTIONS BEFORE FILLING OUT FORM.
PLEASE SUBMIT THE ORIGINAL.

Field	Unitized Pool	Unit	
		Dickinson Lodgepole	
Dickinson	Lodgepole	Current OOIP Estimate: 12,900,000 Bbls	Cumulative Oil Production: 7,094,871 Bbls

Operator	Telephone Number
ConocoPhillips Company	432-688-6943

Address	City	State	Zip Code
P.O. Box 51810	Midland	Tx	79710

YEAR 2012 PRODUCTION / INJECTION

Oil Produced (Bbls)	Gas Produced (MCF)	Water Produced (Bbls)	GOR (SCF/Bbl)	Injection Volume		Make-Up Water Produced (Bbls)
				0	Bbls	
67,985	38,801	451,965	617	790,825	MCF	338,860

YEAR 2012 WELL COUNT

Producing Wells	Injection Wells	Shut-In Wells	Temporarily Abandoned Wells	SWD Wells	Water Supply Wells
2	2	0	0	0	1

YEAR 2012 RESERVOIR PRESSURE DATA (Report 3 most representative bottom hole pressures from more than one well, if possible.)

Datum (Feet Below S.L.)	Date Of Test	Well Name and Number	Well File Number	Extrapolated Reservoir Pressure (PSIG)
7,271	7/15/1996	DLU 83	13598	3648
	6/16/2003	DLU 79	13447	3992
	11/11/1999	DLU 75	13519	3890

YEAR 2012 OPERATIONS

Producers Drilled	Injectors Drilled	Injectors Converted	Wells Shut-in	Wells TA	SWD Wells Drilled	SWD Wells Converted	Water Supply Wells Drilled	Water Supply Wells Converted
0	0	0	0	0	0	0	0	0

YEAR 2013 PROPOSED OPERATIONS

Producing Wells To Be Drilled	Injection Wells To Be Drilled	Injection Wells To Be Converted	Wells To Be Plugged	Wells To Be TA	SWD Wells To Be Drilled	SWD Wells To Be Converted	Water Supply Wells To Be Drilled	Water Supply Wells To Be Converted
0	0	0	0	0	0	0	0	0

YEAR 2012 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PERFORMED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description

YEAR 2013 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PROPOSED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description

Comments
Some make up water is supplied by produced water from Encore HR 1-4

Signature	Printed Name	Title	Date
	Donna Williams	Sr. Regulatory Advisor	March 19, 2013

ANNUAL REPORT OF UNIT OPERATIONS - FORM 24

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
SFN 54260 (09-2004)

For Year
2011

Case 5933

FEB 2012 RECEIVED ND OIL & GAS DIVISION

PLEASE READ INSTRUCTIONS BEFORE FILLING OUT FORM.
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Unit Name			
		Dickinson Lodgepole	
Field	Unitized Pool	Current OOIP Estimate	Cumulative Oil Production
Dickinson	Lodgepole	12,900,000 Bbls	7,032,094 Bbls

Operator	Telephone Number
ConocoPhillips Company	432-688-6943

Address	City	State	Zip Code
P.O. Box 51810	Midland	Tx	79710

YEAR 2011 PRODUCTION / INJECTION

Oil Produced (Bbls)	Gas Produced (MCF)	Water Produced (Bbls)	GOR (SCF/Bbl)	Injection Volume		Make-Up Water Produced (Bbls)
				495,080	Bbls	
57,539	36,242	328,231	630	0	MCF	166,849

YEAR 2011 WELL COUNT

Producing Wells	Injection Wells	Shut-In Wells	Temporarily Abandoned Wells	SWD Wells	Water Supply Wells
2	2	0	0	0	1

YEAR 2011 RESERVOIR PRESSURE DATA (Report 3 most representative bottom hole pressures from more than one well, if possible.)

Datum (Feet Below S.L.)	Date Of Test	Well Name and Number	Well File Number	Extrapolated Reservoir Pressure (PSIG)
7,271	7/15/1996	DLU 83	13598	3648
	6/16/2003	DLU 79	13447	3992
	11/11/1999	DLU 75	13519	3890

YEAR 2011 OPERATIONS

Producers Drilled	Injectors Drilled	Injectors Converted	Wells Shut-in	Wells TA	SWD Wells		Water Supply Wells	
					Drilled	Converted	Drilled	Converted
0	0	0	0	0	0	0	0	0

YEAR 2012 PROPOSED OPERATIONS

Producing Wells To Be Drilled	Injection Wells To Be Drilled	Injection Wells To Be Converted	Wells To Be Plugged	Wells To Be TA	SWD Wells To Be		Water Supply Wells To Be	
					Drilled	Converted	Drilled	Converted
0	0	0	0	0	0	0	0	0

YEAR 2011 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PERFORMED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description

YEAR 2012 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PROPOSED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description

Comments

Some make up water is supplied by produced water from Encore HR 1-4

Signature	Printed Name	Title	Date
	Donna Williams	Sr. Regulatory Advisor	February 22, 2012

ANNUAL REPORT OF UNIT OPERATIONS - FORM 20

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
SFN _________ (09-2004)

MAY 2011 RECEIVED ND OIL & GAS DIVISION

For Year
2010

Case 5933

PLEASE READ INSTRUCTIONS BEFORE FILLING OUT FORM.
PLEASE SUBMIT THE ORIGINAL.

Unit: Dickinson Lodgepole			
Field: Dickinson	Unitized Pool: Lodgepole	Current OOIP Estimate: 12,900,000 Bbls	Cumulative Oil Production: 6,990,540 Bbls
Operator: ConocoPhillips Company			Telephone Number: 432-688-6943
Address: P.O. Box 51810	City: Midland	State: Tx	Zip Code: 79710

YEAR 2010 PRODUCTION / INJECTION

Oil Produced (Bbls)	Gas Produced (MCF)	Water Produced (Bbls)	GOR (SCF/Bbl)	Injection Volume	Make-Up Water Produced (Bbls)
72,418	45,061	460,571	621	655,155 Bbls / 0 MCF	194,584

YEAR 2010 WELL COUNT

Producing Wells	Injection Wells	Shut-In Wells	Temporarily Abandoned Wells	SWD Wells	Water Supply Wells
2	2	0	0	0	1

YEAR 2010 RESERVOIR PRESSURE DATA (Report 3 most representative bottom hole pressures from more than one well, if possible.)

Datum (Feet Below S.L.)	Date Of Test	Well Name and Number	Well File Number	Extrapolated Reservoir Pressure (PSIG)
7,271	7/15/1996	DLU 83	13598	3648
	6/16/2003	DLU 79	13447	3992
	11/11/1999	DLU 75	13519	3890

YEAR 2010 OPERATIONS

Producers Drilled	Injectors Drilled	Injectors Converted	Wells Shut-in	Wells TA	SWD Wells Drilled	SWD Wells Converted	Water Supply Wells Drilled	Water Supply Wells Converted
0	0	0	0	0	0	0	0	0

YEAR 2011 PROPOSED OPERATIONS

Producing Wells To Be Drilled	Injection Wells To Be Drilled	Injection Wells To Be Converted	Wells To Be Plugged	Wells To Be TA	SWD Wells To Be Drilled	SWD Wells To Be Converted	Water Supply Wells To Be Drilled	Water Supply Wells To Be Converted
0	0	0	0	0	0	0	0	0

YEAR 2010 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PERFORMED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description

YEAR 2011 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PROPOSED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description

Comments
Some make-up water is supplied by produced water from Encore HR 1-4

Signature	Printed Name	Title	Date
[signature]	Donna Williams	Sr. Regulatory Advisor	May 16, 2011

ANNUAL REPORT OF UNIT OPERATIONS - FORM 24

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
SFN ________ (09-2004)

RECEIVED ND OIL & GAS DIVISION

Case 5933

For Year
2009

PLEASE READ INSTRUCTIONS BEFORE FILLING OUT FORM.
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Unit		
Dickinson Lodgepole		
Field Dickinson	**Unitized Pool** Lodgepole	
Current OOIP Estimate 12,900,000 Bbls	**Cumulative Oil Production** 2,711,975 Bbls	

Operator	Telephone Number
ConocoPhillips Company	432-688-6943

Address	City	State	Zip Code
P.O. Box 51810	Midland	Tx	79710

YEAR 2009 PRODUCTION / INJECTION

Oil Produced (Bbls)	Gas Produced (MCF)	Water Produced (Bbls)	GOR (SCF/Bbl)	Injection Volume	Make-Up Water Produced (Bbls)
77,994	47,022	401,905	603	659,548 Bbls / MCF	257,643

YEAR WELL COUNT

Producing Wells	Injection Wells	Shut-In Wells	Temporarily Abandoned Wells	SWD Wells	Water Supply Wells
2	2	0	0	0	1

YEAR 2009 RESERVOIR PRESSURE DATA (Report 3 most representative bottom hole pressures from more than one well, if possible.)

Datum (Feet Below S.L.)	Date Of Test	Well Name and Number	Well File Number	Extrapolated Reservoir Pressure (PSIG)
7,271	7/15/1996	DLU 83	13598	3648
	6/16/2003	DLU 79	13447	3992
	11/11/1999	DLU 75	13519	3890

YEAR 2009 OPERATIONS

Producers Drilled	Injectors Drilled	Injectors Converted	Wells Shut-in	Wells TA	SWD Wells		Water Supply Wells	
					Drilled	Converted	Drilled	Converted
0	0	0	0	0	0	0	0	0

YEAR 2010 PROPOSED OPERATIONS

Producing Wells To Be Drilled	Injection Wells To Be Drilled	Injection Wells To Be Converted	Wells To Be Plugged	Wells To Be TA	SWD Wells To Be		Water Supply Wells To Be	
					Drilled	Converted	Drilled	Converted
0	0	0	0	0	0	0	0	0

YEAR 2009 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PERFORMED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
DLU 83	13598	Repaired tubing leak

YEAR 2010 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PROPOSED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
DLU 79	13447	Install IPC tubing downhole
DLU 83	13598	Install IPC tubing downhole

Comments

Some make-up water is supplied by produced water from Encore HR 1-4.

Signature	Printed Name	Title	Date
	Donna Williams	Sr. Regulatory Specialist	March 9, 2010

ANNUAL REPORT OF UNIT OPERATIONS - FORM 24

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
SFN _________ (09-2004)

For Year **2008**

Case 5933

PLEASE READ INSTRUCTIONS BEFORE FILLING OUT FORM.
PLEASE SUBMIT THE ORIGINAL.

Field	Unitized Pool	Unit	
Dickinson	**Lodgepole**	**Dickinson Lodgepole**	
		Current OOIP Estimate: **12,900,000 Bbls**	Cumulative Oil Production: **2,633,981 Bbls**

Operator	Telephone Number
ConocoPhillips Company	**432-688-6913**

Address	City	State	Zip Code
P.O. Box 51810	**Midland**	**TX**	**79710**

YEAR 2008 PRODUCTION / INJECTION

Oil Produced (Bbls)	Gas Produced (MCF)	Water Produced (Bbls)	GOR (SCF/Bbl)	Injection Volume	Make-Up Water Produced (Bbls)
84,206	**50,266**	**439,990**	**597**	**760,039 Bbls** / **MCF**	**320,049**

YEAR 2008 WELL COUNT

Producing Wells	Injection Wells	Shut-In Wells	Temporarily Abandoned Wells	SWD Wells	Water Supply Wells
2	**2**	**0**	**0**	**0**	**1**

YEAR 2008 RESERVOIR PRESSURE DATA (Report 3 most representative bottom hole pressures from more than one well, if possible.)

Datum (Feet Below S.L.)	Date Of Test	Well Name and Number	Well File Number	Extrapolated Reservoir Pressure (PSIG)
7,271	**7/15/1996**	**DLU 83**	**13598**	**3648**
	6/16/2003	**DLU 79**	**13447**	**3992**
	11/11/1999	**DLU 75**	**13519**	**3890**

YEAR 2008 OPERATIONS

Producers Drilled	Injectors Drilled	Injectors Converted	Wells Shut-in	Wells TA	SWD Wells		Water Supply Wells	
					Drilled	Converted	Drilled	Converted
0	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

YEAR 2009 PROPOSED OPERATIONS

Producing Wells To Be Drilled	Injection Wells To Be Drilled	Injection Wells To Be Converted	Wells To Be Plugged	Wells To Be TA	SWD Wells To Be		Water Supply Wells To Be	
					Drilled	Converted	Drilled	Converted
0	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

YEAR MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PERFORMED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
DLU #79	**13447**	**Installed Fiberlined Tubing and new packer**

YEAR MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PROPOSED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description

Comments

Signature	Printed Name	Title	Date
Justin C. Firkins	**Justin C. Firkins**	**Regulatory Specialist**	**March 5, 2008**

ANNUAL REPORT OF UNIT OPERATIONS - FORM 24

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
SFN _________ (09-2004)

12345678910111213141516171819202122232425262728293031
JUL 2008
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ND OIL & GAS
DIVISION

For Year
2007

Case 5933

PLEASE READ INSTRUCTIONS BEFORE FILLING OUT FORM.
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Unit			
Dickinson Lodgepole			
Field	**Unitized Pool**	**Current OOIP Estimate**	**Cumulative Oil Production**
Dickinson	Lodgepole	12,900,000 Bbls	2,549,775 Bbls

Operator	Telephone Number
ConocoPhillips Company	432-688-6913

Address	City	State	Zip Code
PO Box 51810	Midland	TX	79710

YEAR 2007 PRODUCTION / INJECTION

Oil Produced (Bbls)	Gas Produced (MCF)	Water Produced (Bbls)	GOR (SCF/Bbl)	Injection Volume	Make-Up Water Produced (Bbls)
98,231	60,860	458,850	620	757,097 Bbls MCF	298,247

YEAR 2007 WELL COUNT

Producing Wells	Injection Wells	Shut-In Wells	Temporarily Abandoned Wells	SWD Wells	Water Supply Wells
2	2	0	0	0	1

YEAR 2007 RESERVOIR PRESSURE DATA (Report 3 most representative bottom hole pressures from more than one well, if possible.)

Datum (Feet Below S.L.)	Date Of Test	Well Name and Number	Well File Number	Extrapolated Reservoir Pressure (PSIG)
7,271	7/15/1996	DLU 83	13598	3648
	6/16/2003	DLU 74	13447	3992
	11/11/1999	DLU 75	13514	3890

YEAR 2007 OPERATIONS

Producers Drilled	Injectors Drilled	Injectors Converted	Wells Shut-in	Wells TA	SWD Wells		Water Supply Wells	
					Drilled	Converted	Drilled	Converted
0	0	0	0	0	0	0	0	0

YEAR 2008 PROPOSED OPERATIONS

Producing Wells To Be Drilled	Injection Wells To Be Drilled	Injection Wells To Be Converted	Wells To Be Plugged	Wells To Be TA	SWD Wells To Be		Water Supply Wells To Be	
					Drilled	Converted	Drilled	Converted
0	0	0	0	0	0	0	0	0

YEAR MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PERFORMED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
DLU #79	13554	Repaired Tubing Leak

YEAR MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PROPOSED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
DLU #74	13447	Install fiberlined tubing

Comments

Signature	Printed Name	Title	Date
Justin C Firkins	Justin C. Firkins	Regulatory Specialist	July 8, 2008

ANNUAL REPORT OF UNIT OPERATIONS - FORM 24

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
(03-2001)

Case 5933

For Year
2006

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ND OIL & GAS DIVISION

PLEASE READ INSTRUCTIONS BEFORE FILLING OUT FORM.
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Field	Unitized Pool	Unit	
Dickinson	Lodgepole	Dickinson Lodgepole	
		Current OOIP Estimate: 12900000 Bbls	Cumulative Oil Production: 2451544 Bbls
Operator: ConocoPhillips Company			Telephone Number:
Address:	City:	State: TX	Zip Code:

YEAR 2006 PRODUCTION / INJECTION

Oil Produced (Bbls)	Gas Produced (MCF)	Water Produced (Bbls)	GOR (SCF/Bbl)	Injection Volume	Make-Up Water Produced (Bbls)
108388	65993	436915	609	798333 Bbls 0 MCF	361148

YEAR 2006 WELL COUNT

Producing Wells	Injection Wells	Shut-In Wells	Temporarily Abandoned Wells	SWD Wells	Water Supply Wells
2	2	0	0	0	1

YEAR 2006 RESERVOIR PRESSURE DATA (Report 3 most representative bottom hole pressures from more than one well, if possible.)

Datum (Feet Below S.L.)	Date Of Test	Well Name and Number	Well File Number	Extrapolated Reservoir Pressure (PSIG)
7271	07/15/96	DLU 83	13598	3648
	06/16/03	DLU 74	13447	3992
	11/11/99	DLU 75	13514	3890

YEAR 2006 OPERATIONS

Producers Drilled	Injectors Drilled	Injectors Converted	Wells Shut-in	Wells TA	SWD Wells		Water Supply Wells	
					Drilled	Converted	Drilled	Converted
0	0	0	0	0	0	0	0	0

YEAR 2007 PROPOSED OPERATIONS

Producing Wells To Be Drilled	Injection Wells To Be Drilled	Injection Wells To Be Converted	Wells To Be Plugged	Wells To Be TA	SWD Wells To Be		Water Supply Wells To Be	
					Drilled	Converted	Drilled	Converted
0	0	0	0	0	0	0	0	0

YEAR 2006 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PERFORMED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
DLU 74	13447	None
DLU 75	13514	None
DLU 79	13554	None
DLU 83	13598	None

YEAR 2006 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PROPOSED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
None		

Comments

Signature	Printed Name	Title	Date
Justin C Firkins	Justin C. Firkins	Regulatory Technician	02/13/2007

ANNUAL REPORT OF UNIT OPERATIONS - FORM 24

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
(03-2001)

Case 5933

MAY 2006
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ND OIL & GAS
DIVISION

For Year ~~2005~~ 2006

PLEASE READ INSTRUCTIONS BEFORE FILLING OUT FORM.
PLEASE SUBMIT THE ORIGINAL.

Field	Unitized Pool	Unit	
Dickinson	Lodgepole	Dickinson Lodgepole	
		Current OOIP Estimate: 12900000 Bbls	Cumulative Oil Production: 2343156 Bbls

Operator	Telephone Number
ConocoPhillips Company	(832) 486-2297

Address	City	State	Zip Code
P. O. Box 2197, 3W6104	Houston	TX	77272-2197

YEAR 2005 PRODUCTION / INJECTION

Oil Produced (Bbls)	Gas Produced (MCF)	Water Produced (Bbls)	GOR (SCF/Bbl)	Injection Volume		Make-Up Water Produced (Bbls)
116033	65852	422087	566	738122	Bbls	316035
				0	MCF	

YEAR 2005 WELL COUNT

Producing Wells	Injection Wells	Shut-In Wells	Temporarily Abandoned Wells	SWD Wells	Water Supply Wells
2	2	0	0	0	1

YEAR 2005 RESERVOIR PRESSURE DATA (Report 3 most representative bottom hole pressures from more than one well, if possible.)

Datum (Feet Below S.L.)	Date Of Test	Well Name and Number	Well File Number	Extrapolated Reservoir Pressure (PSIG)
7271	07/15/96	DLU 83	13598	3648
	06/16/03	DLU 74	13447	3992
	11/11/99	DLU 75	13514	3890

YEAR 2005 OPERATIONS

Producers Drilled	Injectors Drilled	Injectors Converted	Wells Shut-in	Wells TA	SWD Wells Drilled	SWD Wells Converted	Water Supply Wells Drilled	Water Supply Wells Converted
0	0	0	0	0	0	0	0	0

YEAR 2006 PROPOSED OPERATIONS

Producing Wells To Be Drilled	Injection Wells To Be Drilled	Injection Wells To Be Converted	Wells To Be Plugged	Wells To Be TA	SWD Wells To Be Drilled	SWD Wells To Be Converted	Water Supply Wells To Be Drilled	Water Supply Wells To Be Converted
0	0	0	0	0	0	0	0	0

YEAR 2005 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PERFORMED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
DLU 74	13447	None
DLU 75	13514	None
DLU 79	13554	None
DLU 83	13598	None

YEAR 2006 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PROPOSED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
None		

Comments

Signature	Printed Name	Title	Date
Amy Lasche'	Amy Lasche'	Sr. Regulatory Specialist	May 22, 2006

Oil and Gas Division

Lynn D. Helms - Director   Bruce E. Hicks - Assistant Director

Department of Mineral Resources

Lynn D. Helms - Director

North Dakota Industrial Commission

www.oilgas.nd.gov

May 3, 2006   Case 5933

Ms. Amy Lasche'
ConocoPhillips Company
P.O. Box 2197, 3W6104
Houston, TX 77272-2197

RE: ANNUAL REPORT OF UNIT OPERATIONS – FORM 24
Dickinson-Lodgepole Unit
Duck Creek-Lodgepole Unit
West Dickinson-Lodgepole Unit

Dear Ms. Lasche':

The Annual Report of Unit Operations – Form 24 is due annually on March 31 for all units. To date, this report has not been submitted for the above captioned units. At this time, please submit the 2005 Annual Report of Unit Operations – Form 24 for each of the captioned units.

If you have any questions, do not hesitate to contact me.

Sincerely,

David J. McCusker

David J. McCusker
Petroleum Engineer

5933

ANNUAL REPORT OF UNIT OPERATIONS - FORM 24

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
(03-2001)

MAY 2005
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ND OIL & GAS
DIVISION

For Year 2004 ~~2005~~

PLEASE READ INSTRUCTIONS BEFORE FILLING OUT FORM.
PLEASE SUBMIT THE ORIGINAL.

Unit		
Dickinson Lodgepole		

Field	Unitized Pool	Current OOIP Estimate	Cumulative Oil Production
Dickinson	Lodgepole	12900000 Bbls	2227123 Bbls

Operator	Telephone Number
ConocoPhillips Company	(832) 486-2297

Address	City	State	Zip Code
P. O. Box 2197, 3W6104	Houston	TX	77272-2197

YEAR 2004 PRODUCTION / INJECTION

Oil Produced (Bbls)	Gas Produced (MCF)	Water Produced (Bbls)	GOR (SCF/Bbl)	Injection Volume	Make-Up Water Produced (Bbls)
134765	77168	501135	573	679048 Bbls 0 MCF	177913

YEAR 2004 WELL COUNT

Producing Wells	Injection Wells	Shut-In Wells	Temporarily Abandoned Wells	SWD Wells	Water Supply Wells
2	2	0	0	0	1

YEAR 2004 RESERVOIR PRESSURE DATA (Report 3 most representative bottom hole pressures from more than one well, if possible.)

Datum (Feet Below S.L.)	Date Of Test	Well Name and Number	Well File Number	Extrapolated Reservoir Pressure (PSIG)
7271	07/15/96	DLU 83	13598	3648
	06/16/03	DLU 74	13447	3992
	11/11/99	DLU 75	13514	3890

YEAR 2004 OPERATIONS

Producers Drilled	Injectors Drilled	Injectors Converted	Wells Shut-in	Wells TA	SWD Wells Drilled	SWD Wells Converted	Water Supply Wells Drilled	Water Supply Wells Converted
0	0	0	0	0	0	0	0	0

YEAR 2005 PROPOSED OPERATIONS

Producing Wells To Be Drilled	Injection Wells To Be Drilled	Injection Wells To Be Converted	Wells To Be Plugged	Wells To Be TA	SWD Wells To Be Drilled	SWD Wells To Be Converted	Water Supply Wells To Be Drilled	Water Supply Wells To Be Converted
0	0	0	0	0	0	0	0	0

YEAR 2004 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PERFORMED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
DLU 74	13447	None
DLU 75	13514	None
DLU 79	13554	None
DLU 83	13598	None

YEAR 2005 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PROPOSED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
None		

Comments

Last BHP taken 6/03.

Signature	Printed Name	Title	Date
Amy Lasche'	Amy Lasche'	Sr. Regulatory Rep.	May 16, 2005

5933

For Year
2003

ANNUAL REPORT OF UNIT OPERATIONS - FORM 14

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
(03-2001)

JUN 2004 RECEIVED ND OIL & GAS DIVISION

PLEASE READ INSTRUCTIONS BEFORE FILLING OUT FORM.
PLEASE SUBMIT THE ORIGINAL.

Unit	
Dickinson Lodgepole	

Field	Unitized Pool	Current OOIP Estimate	Cumulative Oil Production
Dickinson	Lodgepole	12900000 Bbls	2092358 Bbls

Operator	Telephone Number
ConocoPhillips Company	(832) 486-2297

Address	City	State	Zip Code
P. O. Box 2197, 3W6104	Houston	TX	77272-2197

YEAR 2003 PRODUCTION / INJECTION

Oil Produced (Bbls)	Gas Produced (MCF)	Water Produced (Bbls)	GOR (SCF/Bbl)	Injection Volume		Make-Up Water Produced (Bbls)
				775973	Bbls	
167984	102101	520966	608	0	MCF	255007

YEAR 2003 WELL COUNT

Producing Wells	Injection Wells	Shut-In Wells	Temporarily Abandoned Wells	SWD Wells	Water Supply Wells
2	2	0	0	0	1

YEAR 2003 RESERVOIR PRESSURE DATA (Report 3 most representative bottom hole pressures from more than one well, if possible)

Datum (Feet Below S.L.)	Date Of Test	Well Name and Number	Well File Number	Extrapolated Reservoir Pressure (PSIG)
7271	07/15/96	DLU 83	13598	3648
	12/29/97	DLU 74	13447	3700
	11/11/99	DLU 75	13514	3890

YEAR 2003 OPERATIONS

Producers Drilled	Injectors Drilled	Injectors Converted	Wells Shut-in	Wells TA	SWD Wells		Water Supply Wells	
					Drilled	Converted	Drilled	Converted
0	0	0	0	0	0	0	0	0

YEAR 2004 PROPOSED OPERATIONS

Producing Wells To Be Drilled	Injection Wells To Be Drilled	Injection Wells To Be Converted	Wells To Be Plugged	Wells To Be TA	SWD Wells To Be		Water Supply Wells To Be	
					Drilled	Converted	Drilled	Converted
0	0	0	0	0	0	0	0	0

YEAR 2003 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PERFORMED (Attach additional pages if necessary)

Well Name and Number	Well File Number	Brief Description
DLU 74	13447	None
DLU 75	13514	None
DLU 79	13554	None
DLU 83	13598	None

YEAR 2003 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PROPOSED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
None		

Comments

*No BHP's taken since 1999

Signature	Printed Name	Title	Date
Amy Lasche	Amy Lasche'	Sr. Regulatory Rep.	May 27, 2004

ANNUAL REPORT OF UNIT OPERATIONS - FORM 24

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
(03-2001)

For Year: 2002

#5933

MAY 2003 RECEIVED ND OIL & GAS DIVISION

PLEASE READ INSTRUCTIONS BEFORE FILLING OUT FORM.
PLEASE SUBMIT THE ORIGINAL.

Unit	Dickinson Lodgepole
Field	Dickinson
Unitized Pool	Lodgepole
Current OOIP Estimate	12900000 Bbls
Cumulative Oil Production	1924374 Bbls
Operator	ConocoPhillips Company
Telephone Number	(806) 275-3411
Address	P.O. Box 358
City	Borger
State	TX
Zip Code	79008-0358

YEAR 2002 PRODUCTION / INJECTION

Oil Produced (Bbls)	Gas Produced (MCF)	Water Produced (Bbls)	GOR (SCF/Bbl)	Injection Volume		Make-Up Water Produced (Bbls)
231374	128240	654068	554	1083645	Bbls	429577
				0	MCF	

YEAR 2002 WELL COUNT

Producing Wells	Injection Wells	Shut-In Wells	Temporarily Abandoned Wells	SWD Wells	Water Supply Wells
2	2	0	0	0	1

YEAR 2002 RESERVOIR PRESSURE DATA (Report 3 most representative bottom hole pressures from more than one well, if possible.)

Datum (Feet Below S.L.)	Date Of Test	Well Name and Number	Well File Number	Extrapolated Reservoir Pressure (PSIG)
7271	07/15/96	DLU 83	13598	3648
	12/29/97	DLU 74	13447	3700
	11/11/99	DLU 75	13514	3890

YEAR 2002 OPERATIONS

Producers Drilled	Injectors Drilled	Injectors Converted	Wells Shut-in	Wells TA	SWD Wells Drilled	SWD Wells Converted	Water Supply Wells Drilled	Water Supply Wells Converted
0	0	0	0	0	0	0	0	0

YEAR 2003 PROPOSED OPERATIONS

Producing Wells To Be Drilled	Injection Wells To Be Drilled	Injection Wells To Be Converted	Wells To Be Plugged	Wells To Be TA	SWD Wells To Be Drilled	SWD Wells To Be Converted	Water Supply Wells To Be Drilled	Water Supply Wells To Be Converted
0	0	0	0	0	0	0	0	0

YEAR 2002 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PERFORMED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
DLU 74	13447	None
DLU 75	13514	None
DLU 79	13554	None
DLU 83	13598	None

YEAR 2002 MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PROPOSED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
None		

Comments
*No BHP's taken since 1999

Signature	Printed Name	Title	Date
JRReno	J.R. Reno	Operations Manager	May 9, 2003

ANNUAL REPORT OF UNIT OPERATIONS - FORM 24

INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
(03-2001)

#5933

For Year
2001

FEB 2002 RECEIVED ND OIL & GAS DIVISION

PLEASE READ INSTRUCTIONS BEFORE FILLING OUT FORM.
PLEASE SUBMIT THE ORIGINAL.

Field	Unitized Pool	Unit	
Dickinson	Lodgepole	Dickinson Lodgepole	
		Current OOIP Estimate	**Cumulative Oil Production**
		12,900,000 Bbls	1,693,000 Bbls

Operator	Telephone Number
Conoco Inc.	(915) 686-5400

Address	City	State	Zip Code
10 Desta Drive, Suite 100W	Midland	TX	79705

YEAR PRODUCTION / INJECTION

Oil Produced (Bbls)	Gas Produced (MCF)	Water Produced (Bbls)	GOR (SCF/Bbl)	Injection Volume		Make-Up Water Produced (Bbls)
				892,145	Bbls	
268,041	148,265	591,835	553	0	MCF	300,310

YEAR WELL COUNT

Producing Wells	Injection Wells	Shut-in Wells	Temporarily Abandoned Wells	SWD Wells	Water Supply Wells
2	2	0	0	0	1

YEAR RESERVOIR PRESSURE DATA (Report 3 most representative bottom hole pressures from more than on well, if possible.)

Datum (Feet Below S.L.)	Date Of Test	Well Name and Number	Well File Number	Extrapolated Reservoir Pressure (PSIG)
7,271	7/15/1996	DLU 83	13598	3648
	12/29/1997	DLU 74	13447	3700
	11/11/1999	DLU 75	13514	3890

YEAR OPERATIONS

Producers Drilled	Injectors Drilled	Injectors Converted	Wells Shut-in	Wells TA	SWD Wells		Water Supply Wells	
					Drilled	Converted	Drilled	Converted
0	0	0	0	0	0	0	0	0

YEAR PROPOSED OPERATIONS

Producing Wells To Be Drilled	Injection Wells To Be Drilled	Injection Wells To Be Converted	Wells To Be Plugged	Wells To Be TA	SWD Wells To Be		Water Supply Wells To Be	
					Drilled	Converted	Drilled	Converted
0	0	0	0	0	0	0	0	0

YEAR MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PERFORMED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description
DLU 74	13447	None
DLU 75	13514	None
DLU 79	13554	None
DLU 83	13598	None

YEAR MAJOR WORKOVERS OR ARTIFICIAL LIFT CHANGES PROPOSED (Attach additional pages if necessary.)

Well Name and Number	Well File Number	Brief Description

Comments
No BHP's taken since 1999.

Signature	Printed Name	Title	Date
Roy A. Burgess	Roy A. Burgess	Sr. Staff Engineer	2/6/02

BEFORE THE INDUSTRIAL COMMISSION

OF THE STATE OF NORTH DAKOTA

CASE NO. 5933
ORDER NO. 6893

IN THE MATTER OF A HEARING CALLED ON A MOTION OF THE COMMISSION TO CONSIDER THE PETITION OF CONOCO INC. FOR AN ORDER PROVIDING FOR THE UNITIZED MANAGEMENT, OPERATION, AND FURTHER DEVELOPMENT OF THE DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION; VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE.

ORDER OF THE COMMISSION

On June 16, 1994, the Industrial Commission issued Order No. 6861 in this case. Two interested parties have asked the Commission to reconsider its decision. Placid Oil Company and the Andrea Singer Pollack Revokable Trust (hereafter "the Trust") have filed petitions for reconsideration. On July 18, 1994, Conoco Inc. filed a response to the petitions. On July 21st the Trust filed a reply to Conoco. Accompanying the Trust's reply are a number of journal articles discussing the use of 3D seismic data.

In their submissions, Placid and the Trust set forth the reasons why they believe the Commission erred in granting Conoco's request to unitize the Dickinson-Lodgepole Unit Area. The Commission has studied each of Placid's and the Trust's arguments and reviewed the record of the case. The Commission believes that its decision in Order No. 6861 is the fairest interpretation of the evidence. It declines, therefore, to withdraw or stay Order No. 6861, or to reopen the record to take additional evidence. The petitions are denied. Our reasoning follows.

The Trust argues that Findings 14 and 16 in Order No. 6861 are wrong because the Trust used not only seismic interpretation to delineate the productive boundaries of the reservoir but also well data, and that Finding 17 is wrong because seismic interpretation can identify a reservoir's productive boundaries. Findings 14 and 16 refer to the specific location of the productive reservoir, and the Commission reaffirms that the Trust interpreted, and testified that it interpreted, only seismic data to specifically identify the location of the boundaries of the productive reservoir. The Commission was persuaded by Conoco's witness that seismic data is an unreliable method to locate the Dickinson-Lodgepole reservoir boundary primarily because there is little velocity contrast between the productive and nonproductive Lodgepole. Furthermore, seismic data requires interpretation before it can be applied and Placid and the Trust merely submitted maps based on their seismic interpretations and did not submit the raw seismic data. The interpretative nature and unreliability of seismic data to delineate the boundaries of the productive reservoir is shown by the dissimilarity in the maps Placid and the Trust prepared using the same seismic data.

Placid, like the Trust, argues that Findings 16 and 17 are erroneous. It believes Finding 16 is wrong, asserting that Placid did introduce seismic information to identify the productive reservoir. Perhaps Finding 16 should have been written more clearly, for Placid (and the Trust) seems to misunderstand it. Finding 16 states that the Commission did not receive evidence sufficient to prove that seismic data can successfully identify the productive reservoir. The evidence accepted by the Commission was just the opposite, as expressed in Finding 17. Placid believes that Finding 17 is inconsistent with the basis upon which Conoco proposed the unit. Placid's argument misinterprets the word "mound" to be synonymous with "reservoir." The Commission, however, uses the word "mound" to include not only the reservoir quality rock, but also any associated deposition found around the perimeter of the reservoir quality rock.

Placid challenges Finding 24 and its conclusion that the allocation of the unit is fair. Placid did not propose what it believes would be a fair allocation. More importantly, the allocation is based on Conoco's interpretation of the geology and it is that interpretation that the Commission has found to be more reliable than Placid and the Trust's.

The Trust argues in Paragraph 7 of its petition as well as in its reply to Conoco, that the Commission erred in relying on characteristics of the Fryburg Interval to locate the boundaries of the Lodgepole Pool reservoir. In particular, the Trust states that the Fryburg map is based on only two additional wells and that it has nothing to locate its western edge. The map has three additional wells and the Frenzel 79 and Walton 84 wells provide data points to help identify the western edge. The Trust states that use of the Fryburg map is inappropriate because the Fryburg thickens to the northeast. No evidence was presented to show this. The Trust claims Conoco's Fryburg map is unreliable because had it been prepared in another way it would have a different result. The Trust could have prepared a Fryburg map using the method it believes appropriate. It didn't, and to state as a fact what that method would have produced is speculative.

The Trust argues that Findings 19 and 20 "are totally without basis." Placid also challenges Findings 19 and 20, as well as Finding 18. Conoco adequately explained the relationship between the Fryburg Interval and the Lodgepole Pool and how data from the Filipi No. 76 can aid in locating the eastern boundary of the productive reservoir. We will not repeat Conoco's arguments, which we found persuasive.

The Trust argues that Finding 22 "is essentially irrelevant" and Placid says Finding 22 is unsupported. While a volumetric calculation is not definitive in locating a reservoir, it can confirm geologic interpretations and the volumetric calculation here confirms Conoco's interpretation. Its use in this way was supported by testimony from Conoco.

The Trust asks that Conoco's 3D seismic data be produced and made part of the record. This is a red herring. Since seismic data cannot identify the productive reservoir there is no purpose in requiring Conoco to produce it for consideration in this case. The Trust, in its reply brief, states that the Wyoming Conservation Commission used only seismic data to delineate the edge of a reservoir in the Little Missouri Field. The Trust does not support this assertion with a copy of the Wyoming order or the case record, nor does it explain whether the characteristics of Wyoming's Little Missouri Field are similar with those of the Dickinson-Lodgepole Field or even the Williston Basin. The Trust also refers to a use of seismic in Saskatchewan but again fails to supply documentation to support its assertion.

The Trust submitted with its reply brief copies of a number of journal articles concerning the use of 3D seismic. There is no evidence that the areas discussed in the articles bear any similarity to the characteristics of the Dickinson-Lodgepole Pool. Without such evidence the articles are unhelpful, if not irrelevant. Furthermore, there is no reason why these articles could not have been submitted into evidence at the hearing. The Commission declines to reopen the case to make these part of the record.

Placid argues that the Commission erred by failing to set forth equitable terms for development outside the unit. Existing spacing outside the unit remains in effect and any adjustments to that spacing were not properly before the Commission in this case.

Dated this 3rd day of August, 1994.

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA

/s/ Edward T. Schafer, Governor

/s/ Heidi Heitkamp, Attorney General

/s/ Sarah Vogel, Commissioner of Agriculture

STATE OF NORTH DAKOTA | IN DISTRICT COURT

COUNTY OF STARK | SOUTHWEST JUDICIAL DISTRICT

Andrea Singer Pollack Revocable Trust, Andrea Singer Pollack, Trustee,

Appellant,

v.

The Industrial Commission of the State of North Dakota, Conoco, Inc., and all other persons having an interest in the Dickinson-Lodgepole Unit,

Appellees.

Civil No. 94C-283

Copy
FINHL

. . . .

Industrial Commission's Reply Brief and
Response to Motion to Produce

State of North Dakota
Heidi Heitkamp
Attorney General

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Assistant Attorney General
Office of Attorney General
State Office Building
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Bismarck, North Dakota 58505
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Attorneys for the Appellees

TABLE OF CONTENTS

I. History of the Case

1. The Dickinson-Lodgepole Pool was discovered in February of 1993 with the drilling and completion of the Dickinson State No. 74 well in Section 32, Township 140 North, Range 96 West. TR. 125-26 (Zorn Test.).

2. The productive pool is relatively small, comprising not much more than about two sections of land. See Tabs 7, 35 of Record. The pool lies within a unique formation, that is, it is a pronounced mound feature. Tr. 45-50 (Hyrkas Test.)

3. After the discovery well, five more wells were drilled by Conoco in or near the Dickinson-Lodgepole Pool. Three wells were completed as producers, the Kadrmas No. 75 well, the Frenzel No. 79 well, and the State A No. 83 well. The non-producing wells, the Filipi No. 76 and the Walton No. 84, were plugged and abandoned. TR. 126-28 (Zorn Test.).

4. By October of 1993 Conoco concluded that the reservoir pressure would quickly drop and the productivity of the field would be damaged if some form of pressure maintenance were not undertaken. Id. at 133, 140-41. Conoco reduced production to prevent reservoir pressure from falling too quickly. Id. at 134, 136. Conoco also recognized that a secondary recovery program was needed to ensure that the field was efficiently developed. Id. at 135-36.

5. Conoco estimates that a secondary recovery project would extend life of the field from 12.3 years to 17.3 years and recover

an additional 2.48 million barrels of oil. It also estimates that an additional $9 million would be earned by working interest owners as a result of secondary recovery and that payments to royalty owners would increase by $2.6 million. Id. at 142, 145-46.

6. Conoco then began working with the other 13 working interest owners in the area to put together a plan of unitization. Id. at 10-13, 25. The plan of unitization was eventually ratified by six working interest owners. Id. at 26. Other than Conoco, these working interest owners each owned less than 1% of the unit. Id. at 26. Conoco's interest is about 73%. Id. at 30. Conoco next sought ratification by mineral owners. Of the 102 royalty interest owners in the pool, 48 ratified the plan. Id. at 27. Conoco, besides being a working interest owner, also owns a royalty interest in the pool, which amounts to about 4%. Id. at 36. About 86% of the royalty owners and about 76% of the working interest owners ratified the plan of unitization. TR. 14 (Turner Test.).

7. In April of 1994 Conoco filed its application with the Industrial Commission requesting approval of the plan of unitization. Tab 1 of Record.

8. The unit proposed by Conoco included 1,436 acres. TR. 19 (Turner Test.). The unit is within at least a part of six different sections of land and is divided into nine different tracts. A visual depiction of the unit is at tabs 7 and 35 of the Record. A description of the mineral owners and working interest

owners in each of the nine tracts is set forth at tabs 38 and 41 of the Record.

9. Two days before the hearing, the Andrea Singer Pollack Revocable Trust (hereafter "the Trust") filed a response to Conoco's petition. Tab 30 of Record. The response stated that while unitization is necessary for effective and economic recovery of hydrocarbons in the pool, Conoco's proposal is not equitable to all working and royalty interest owners.

10. A hearing on Conoco's application was held on June 8, 1994. Appearing to resist Conoco's application were Placid Oil Co. as well as the Trust.

11. Placid's interest in the area of unitization is in the S½ of section 30 the N½ of section 31, that is, on the NW side of the unit. TR. 180 (Bressler Test.); Tab 38 of Record. The Trust's interest lies in the S½ of the section 31, that is, on the west side of the unit. Tab 38 of Record.

12. Placid and the Trust believe the area should be unitized, but objected to Conoco's application on the ground that the boundaries of the unit, as proposed by Conoco, do not accurately reflect the productive boundaries of the pool. TR. 178 (Bressler Test.); TR. 247 (Preston Test.).

13. At the hearing, Conoco, Placid, and the Trust presented witnesses and exhibits in support of their positions. Placid and the Trust argued that the boundaries of the unit should be redrawn. If they were to be redrawn, Placid and the Trust would receive a greater allocation of the unit production and Conoco would receive

a lesser amount. Placid and the Trust also argued that Conoco had in its possession evidence that it did not present at the hearing but should have been presented because it would shed more light on the boundaries of the pool. That evidence is 3D seismic data.

14. Conoco submitted testimony and exhibits supporting its view of the boundaries of the productive pool. It responded to the request for production of its 3D seismic data by presenting evidence that 3D seismic would not assist in delineating the boundaries of the pool. Conoco stated that 3D seismic is useful only as an exploration tool and not as a tool to delineate the boundaries of the Dickinson-Lodgepole Pool.

15. After the hearing, on June 15, 1994, Conoco submitted a reply to the Trust's pre-hearing "Response" to Conoco's application. Tab 99 of Record.

16. On June 16, 1994, the Industrial Commission issued its Order. Tab 100 of Record. The Commission found Conoco's view about the usefulness of 3D seismic and on the pool boundaries to be more credible than Placid's and the Trust's view. Therefore, it granted the application.

17. The Trust and Placid then filed Petitions for Reconsideration. Tabs 101 and 102 of Record. On July 18 Conoco filed a response. Tab 104 of Record. On July 21 the Trust filed a reply to Conoco's response. Tab 105 of Record. Attached to the Trust's reply were a number of journal articles discussing the use of seismic data. Tab 106 of Record. None of these articles were offered at the hearing.

18. The Commission had intended to make its decision on the Petitions for Reconsideration on July 21, the day on which it received the Trust's reply. Because of the Trust's submission, the Commission delayed its decision on the Petitions for Reconsideration to give it an opportunity to study the Trust's reply. Tab 107 of Record.

19. On August 3, 1994, the Commission issued its Order denying the Petitions for Reconsideration. Tab 108 of Record. The Order responded to the arguments raised by Placid and the Trust in their Petitions for Reconsideration. It also declined to reopen the hearing record to allow the journal articles submitted by the Trust to become part of the record.

20. The Trust appealed the Commission's decision. Tab 109 of Record. Placid did not appeal.

II. Discussion

A. Standard of the Review.

"The court is to sustain the Commission's order 'if the Commission has regularly pursued its authority and its findings and conclusions are sustained by the law and by substantial and credible evidence.'" Hanson v. Industrial Commission, 466 N.W.2d 587, 590 (N.D. 1991). This substantial evidence test is not difficult to meet. There need only be evidence in the record that a reasonable mind would accept as adequate to support the order. Id. The evidence needed to support the order need not rise to the standard of "the greater weight of the evidence" or to the standard of a "preponderance of the evidence." Id.

The substantial evidence test is more easily met than the typical standard of review of administrative decisions. Id. Greater deference is given by courts to the Industrial Commission's decisions. Id. Because of the technical nature of the Commission's work, its decisions are "entitled to respect and appreciable deference." Id. at 591. See also Montana-Dakota Utilities Company v. Public Service Commission, 413 N.W.2d 308, 312 (N.D. 1987).

B. The Non-production of Conoco's 3D Seismic Data.

Conoco has in its possession the raw data of the 3D seismic work done in the area. Conoco did not rely upon this information in putting together the plan of unitization or in presenting its evidence. The Trust argues that the 3D data could have helped to accurately locate the boundaries of the pool, and because Conoco did not produce the data, the adverse inference rule of Colgate-Palmolive Co. v. Dorgan, 225 N.W.2d 278, 281 (N.D. 1974), applies.

The adverse inference rule for non-production of evidence may no longer exist. "[T]he availability of modern discovery and other disclosure procedures serves to diminish both the justification and the need for the inference." 2 McCormick on Evidence 186-87 (4th ed. 1992). In light of modern procedural rules for discovery, the court in Jones v. Otis Elevator Co., 861 F.2d 655, 659 n.4 (11th Cir. 1988), questioned the continued need for such inferences. For the same reason the Fifth Circuit Court of Appeals referred to the similar "uncalled-witness rule" as "an anachronism" and an "archaism." Herbert v. Wall-Mart Stores, Inc., 911 F.2d 1044, 1048, 1049 (5th Cir. 1990). In Jenkins v. Bierschenk, 333 F.2d 421, 425 (8th Cir. 1964), the court affirmed the trial court's refusal to draw the inference for non-production of the defendant's son in part because "[n]o discovery procedure as to [the son] was employed."

Discovery in administrative proceeding can be as comprehensive as that available in judicial proceedings. Upon a showing of good cause, the Commission had authority to allow the Trust to undertake discovery, including interrogatories, depositions, and requests for production. N.D.C.C. § 28-32-09(4)(5). The Trust could also have asked the Commission to itself subpoena the 3D seismic data for use at the hearing, which the Commission had authority to do upon a showing by the Trust of "general relevance and reasonable scope of the evidence sought." N.D.C.C. § 28-32-09(2).

The Trust did not invoke the discovery provisions of chapter 28-32. Thus, it is questionable whether the adverse inference rule applies. The Trust knew Conoco would not present the 3D data at the hearing, as it stated in its pre-hearing brief. Tab 30 of Record, Brief at 3. Thus, responsibility for non-production does not fall entirely on Conoco. The Trust should not benefit from a circumstance which it may have been able to avoid by using the procedural tools at its disposal.[1] See Berger v. State Highway Commissioner, 394 N.W.2d 678, 684-85 (N.D. 1986).

Even if the adverse inference rule applies, courts "often counsel caution" in its application. 2 McCormick on Evidence 186 (4th ed. 1992). E.g. Jenkins v. Bierschenk, 333 F.2d at 425. This is because the rule creates evidence from non-evidence. Some courts decline to apply the rule because it calls for speculation about what the non-produced evidence may show. E.g. Oliphant v. Snyder, 147 S.E.2d 122, 126 (Va. 1966). Other courts state that all that can be inferred is that the non-produced evidence would not have been helpful to the party possessing it, and not that it would have been adverse. E.g. United States v. Busic, 587 F.2d 577, 586 (3rd Cir.), cert. dismissed 98 S. Ct. 1631 (1978).

Assuming, however, that the inference applies, it is "open always to explanation by circumstances which make some other hypothesis a more natural one than the party's fear of exposure." 2 Wigmore on Evidence 192 (Chadbourn rev. 1979). It is clear that this seismic data has commercial value. TR. 209-10 (Bressler Test.). Had Conoco made the data a matter of public record, Conoco would have lost the competitive advantage of being the only operator in the area with this information.

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[1]The Trust states that in its pre-hearing brief it "challenged the Commission to order the production of 3D seismic data." Trust Brief at 14. We are not clear what is meant by "challenging" the Commission and what its legal significance is for the purposes of this appeal, but what is clear is that in its pre-hearing brief the Trust did not request the Commission to order production of the 3D seismic, all it did was state that "the Industrial Commission can force its disclosure." Tab 30 of Record, Brief at 3.

More fundamentally, Conoco explained that the 3D seismic data was not produced because it would not be helpful in delineating the boundaries of the productive pool and, therefore, in determining what land should be included within the unit. Two Conoco witnesses supported this proposition. Jerry Hyrkas stated that seismic is "not a good tool at all for the defining reservoir boundaries." TR. 61 (Hyrkas Test.). See also id. at TR. 111-13, 118. Hyrkas is a senior geoscientist with Conoco. Id. at 44. Another Conoco witness, Greg Mohl, also testified that 3D seismic has limited usefulness in detecting pool boundaries. Mohl, a senior geophysicist with Conoco, has BA, MA, and PhD degrees in geology. TR. 258 (Mohl Test.). He has worked with seismic for 7 years. Id. at 268. He has taught "several short courses" on a number of seismic related subjects and he works on seismic projects every day. Id. at 259. Mohl testified that the use of seismic is "totally inappropriate" for delineating the boundaries of the Dickinson-Logdepole Pool and the area to include within the unit. Id. at 260, 269. He supported his conclusions with an extensive discussion of the matter. Id. at 260-269.

Mohl set forth three reasons why 3D seismic data would not be of material use. The first concerns the physical properties of the Lodgepole. Mohl noted that although Placid and the Trust assert the usefulness of 3D data in other areas of the Williston basin and the country, neither discussed the physical properties of the Lodgepole and whether its characteristics allow for an accurate interpretation of seismic. Id. at 260. To support his view that the Lodgepole's physical properties would not support accurate use of seismic, Mohl compared the sonic log of the Kadrmas well, which is in the productive pool, with the sonic log of the Frenzel well, which did not penetrate the productive pool. Id. at 261-62. Mohl found that the velocity contrast between the productive and the non-productive pool to be "seismically invisible." Id. at 263.

Mohl's second concern about using seismic dealt with seismic wave theory. Id. at 264-67. When seismic waves interact with the edge of a pool they interact with "in effect, the seismic blind spot." Id. at 265. The resolution of 3D seismic is insufficient to pick where a productive pool begins and where it ends. The third reason Mohl found to reject the use of seismic to select land to include within a unit, is its highly interpretative nature. "Without exception this has been highly interpretive. It's very sensitive to the individual rock properties. It's also sensitive to the acquisition parameters of the seismic data and the processing of the seismic data. . . . The bottom line is that work of this nature is very good for exploration. It can give you a general shape for, for what you're looking at and point you in the right directions." Id. at 268.

The uncertain nature of seismic data is proven by maps submitted by Placid and the Trust. Each used the same 2D seismic information to prepare the maps. TR. 233, 240 (Gomez Test.). While the trust describes the results as "strikingly similar," Trust Brief at 21, the Commission found them to be distinctly different. Tab 100 of Record at ¶ 15. They differ in six ways, the first two of which are they are particularly significant. (The maps are shown side by side on page 4 of the Trust's "Supplemental Record.")

1. The Trust's map depicts a "saddle" in the middle of the pool. A "saddle" is a thinning of the productive zone. TR. 203 (Bressler Test.). Placid's map does not show a "saddle."

2. The Trust shows a high to the west of the Kadrmas well (and thus smack in the middle of the only tract in which the Trust owns an interest). Placid shows the high to be located much farther to the east, straddling sections 31 and 32.

3. The Trust shows the pool extending farther to the southwest than does Placid.

4. Placid shows the pool extending farther to the north and northwest than does the Trust.

5. Placid shows the pool extending farther to the east than does the Trust.

6. The Trust's contour lines east of the State No. 74 well are drawn much more sharply than are Placid's contour lines.

Using the same seismic data, Placid and the Trust drew distinctly different maps, thus exemplifying the limits of seismic data to determine the boundaries of a productive pool.

While Placid and the Trust presented witnesses that disagreed with Hyrkas and Mohl, the substantial evidence test is satisfied. There is in the record, evidence a reasonable mind would accept as adequate to support the Commission's conclusion that 3D seismic is not useful to locate the pool boundaries. Because of its technical nature the court is to give the conclusion deference and is not to substitute its "judgment for that of the expert." Haugland v.

Spaeth, 476 N.W.2d 692, 695 (N.D. 1991). In summary, Conoco's non-production of the 3D seismic data is explained and the adverse inference rule does not apply.

This dispute among the experts is not unlike what occurred in Hanson v. Industrial Commission where the Supreme Court reviewed conflicting expert testimony. The court ruled that since there was relevant evidence that a reasonable mind might accept, the Commission's conclusion based on that evidence would not be overturned. "The possibility of drawing two inconsistent conclusions from the evidence does not prevent the findings from being supported by substantial evidence." Hanson v. Industrial Commission, 466 N.W.2d 587, 592 (N.D. 1991).

The Trust asks the court to go outside the hearing record to draw the adverse inference. It wants the court to review journal articles the Trust attached to its second brief in support of its petition for reconsideration. Tab 106 of Record. In its order denying the petition the Commission stated:

> "The Trust submitted with its reply brief copies of a number of journal articles concerning the use of 3D seismic. There is no evidence that the areas discussed in the articles bear any similarity to the characteristics of the Dickinson-Lodgepole Pool. Without such evidence the articles are unhelpful, if not irrelevant. Furthermore, there is no reason why these articles could not have been submitted into evidence at the hearing. The Commission declines to reopen the case to make these part of the record."

Tab 108 of Record at 3.

The Trust has gone further outside the record by filing with the court certain documents in its "supplemental record," including an affidavit of someone who did not appear at the hearing and exhibits and an administrative order from a Wyoming case. None of these matters were submitted for the Commission's review before, during, or after the hearing.

The court, however, may "consider only the record which was before the [agency], the transcript of the formal hearing, and any evidence presented at the hearing." Hayden v. North Dakota Workers Compensation Bureau, 447 N.W.2d 489, 497 (N.D. 1989). See also N.D.C.C. § 28-32-19; Lipp v. Job Service North Dakota, 468 N.W.2d 133, 134 (N.D. 1991); Smith v. North Dakota Workers Compensation Bureau, 447 N.W.2d 250, 256-57 (N.D. 1989). In Knutson v. North Dakota Workmens Compensation Bureau, 120 N.W.2d 880 (N.D. 1963), the district court increased the Bureau's award to a claimant and in doing so reviewed new evidence. Since the award was not based on the record before the Bureau, id. at 882, and since the Bureau "had no opportunity to pass on such additional evidence," id. at 883, the district court was reversed.

There is a statutory procedure by which evidence not presented at a hearing can be presented. This is set forth in N.D.C.C. § 28-32-07. The Trust did not comply with this procedure. It merely submitted the journal articles. Tab 106 of Record.

There is no procedure by which a party to an appeal from an administrative decision can petition the court for an order requesting that another party produce evidence. The court has no jurisdiction to enter what is in effect a discovery order. The court, in this case, is an appellate court. Its decision is confined to the record produced below, and that record is closed.

The Trust relies upon N.D.C.C. § 28-32-18 as authority for the court to grant its motion to compel production of the 3D seismic. That section allows the court to grant an application to <u>offer</u> additional evidence, upon a showing that the evidence is relevant and material and there was good cause for the failure to offer it at the hearing. The Trust's motion, however, does not seek leave to offer evidence, it seeks discovery of evidence. Nothing in section 28-32-18 allows the court to grant a motion ordering another party to produce evidence.

C. <u>The Boundaries of the Pool</u>.

The Trust argues that the configuration of the unit as proposed by Conoco and approved by the Commission is in error. In particular, the Trust believes the unit's eastern boundary is located too far to the east in section 32.

The Trust argues that because Conoco has a greater interest in tract 1 of the unit, which is in section 32, than it does in tract 2, it "has a vested interest in pushing the boundary eastward as much as possible." Trust Brief at 19. There is a bit of irony in such a statement, for the Trust's only interest in the unit is on the west side of the unit. If the unit's eastern boundary were moved farther to the west, as the Trust advocates, the Trust would receive a greater allocation of unit production.[2]

The Trust argues that the unit is inequitable because of the way in which the productive pool is configured. The Commission in its two orders made a number of findings related to this question. Tabs 100, 108 of Record. The Trust raises several challenges to these findings. Trust Brief at 20-26. It is concerned with such matters as the location of the oil/water contact, the use of Conoco's reservoir modeling study in determining allocation of unit production, the accuracy of the porosity and oil saturation factors in Conoco's volumetric calculation, and the usefulness of using information from the Fryburg Interval to help understand characteristics of the Lodgepole.

The essence of the Trust's argument on these points is that its witnesses should be believed rather than Conoco's. But it does not explain <u>why</u> its witnesses are more credible than Conoco's and <u>why</u> the Commission acted unreasonably in agreeing with Conoco's interpretation of the geology. For example, although the Trust questions the unit allocation in light of Conoco's reservoir model, Trust Brief at 24, Conoco explained the matter in detail. TR. 289-292 (Zorn Test.). Also, the Trust's challenge to the use of information from the Fryburg Interval, Trust Brief at 22-23, is

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[2]Similarly with Placid. Its only interest lies in tracts 2 and 3 which are on the northwest side of the unit. It sponsored an interpretation of the geology that would have moved the unit boundaries farther to the northwest. TR. 172-73 (Bressler Test.). Tab 81 of Record.

turned back by evidence of Conoco's expert. TR. 51-56. (Hyrkas Test.).

As the Supreme Court recently stated in reviewing an agency decision. "This court exercises restraint when it reviews the findings of an administrative agency, we do not substitute our judgment for that of the agency." Samdahl v. North Dakota Department of Transportation Director, 518 N.W.2d 714, 716 (N.D. 1994). "Findings of fact are not clearly erroneous merely because we may have viewed the facts differently if we had been the trier of fact." Bye v. Mack, 519 N.W.2d 302, 305 (N.D. 1994). Other than repeatedly expressing its opinion that its experts were right and Conoco's were wrong, the Trust presents no basis to overturn the Commission's understanding of the evidence.

During the Commission's first meeting at which it considered the case, Attorney General Heitkamp asked Governor Schafer: "Ed, do you have any insights on this having sat through the hearing?" Trust's Supp. Record at 30. The Governor responded:

> You asked for an observation from being there. I thought Conoco's presentations were real professional and real clear to me, not knowing much about it, it is very logical. The other two [Placid and the Trust] seem to be a little more 'seat of the pants' or 'shoot from the hip,' or whatever you want to call it.

Id. at 32. The Attorney General then commented: "That observation is very valuable because if you felt watching this that the credible evidence really was on the side of Conoco, that is an important observation." Id. at 33.

III. Conclusion

The Trust's motion to produce should be denied. There is no authority allowing the court to issue the order requested, the seismic data sought is not material, and the Trust neglected to use methods available to it to procure the data. A party should not wait until the appeal to compile its factual case.

The Commission's decision to approve the Dickinson-Lodgepole Unit should be upheld. The substantial evidence test has been met. It is reasonable for the Commission to have accepted Conoco's evidence over the Trust's.

Dated this 2d day of December, 1994.

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BEFORE THE INDUSTRIAL COMMISSION

OF THE STATE OF NORTH DAKOTA

CASE NO. 5933
ORDER NO. 6880

IN THE MATTER OF A HEARING CALLED ON A MOTION OF THE COMMISSION TO CONSIDER THE PETITION OF CONOCO INC. FOR AN ORDER PROVIDING FOR THE UNITIZED MANAGEMENT, OPERATION, AND FURTHER DEVELOPMENT OF THE DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION; VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE.

ORDER OF THE COMMISSION

BY THE COMMISSION:

Pursuant to legal notice this cause came on for hearing at 9:00 a.m. on the 8th day of June, 1994, in Bismarck, North Dakota, before an examiner appointed by the Industrial Commission of North Dakota, hereinafter referred to as the "Commission."

NOW, on this 21st day of July, 1994, the Commission, a quorum being present, having considered the testimony adduced and the exhibits received at said hearing, and being fully advised in the premises,

FINDS:

(1) That due public notice having been given as required by law, the Commission has jurisdiction of this cause and the subject matter thereof.

(2) The Commission entered its Order No. 6861 on June 16, 1994, which order approved the Plan of Unitization for the Dickinson-Lodgepole Unit.

(3) Subsequently, Placid and Andrea Singer Pollack Revocable Trust ("ASPRT") filed with the Commission petitions for reconsideration of this matter. Conoco was given the opportunity and submitted a reply brief regarding the allegations in said petitions.

(4) Now, on this date, ASPRT filed with the Commission a response to Conoco's brief.

(5) That this matter should be continued for forty-five (45) days to afford Conoco and Placid the opportunity to respond to ASPRT's second submission. Also, to allow time for the Commission to consider ASPRT's second submission as well as Conoco's and Placid's response.

(6) That the Director is authorized to sign this order.

IT IS THEREFORE ORDERED:

(1) That this matter shall be continued for forty-five (45) days or until further order of the Commission.

Dated this 21st day of July, 1994.

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA

By the Director, on behalf of the Commission.

/s/ Wesley D. Norton, Director

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JUL 1994

July 18, 1994

VIA FACSIMILE

Mr. Charles Carvell
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NDIC CASE NO. 5933 - PETITION OF CONOCO INC. FOR UNITIZED MANAGEMENT, OPERATION AND FURTHER DEVELOPMENT OF DICKINSON-LODGEPOLE UNIT AREA, ET AL.

Dear Charles:

Please find enclosed herewith the CONSOLIDATED RESPONSE OF CONOCO INC. TO "PETITION FOR RECONSIDERATION BY PLACID OIL COMPANY" AND "PETITION FOR RECONSIDERATION BY ANDREA SINGER POLLACK REVOCABLE TRUST".

Should you have any further questions, please advise.

Sincerely,

LBender

LAWRENCE BENDER

LB/leo
Enclosure
cc: Mr. Wesley Norton - *Via U.S. Mail*
Mr. Bruce Hicks - *Via U.S. Mail*
Mr. John Morrison - *Via U.S. Mail*
Mr. Robert Wefald - *Via U.S. Mail*
Mr. Jim Turner - *Via U.S. Mail*
Mr. Paul Schulz - *Via U.S. Mail*

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

IN THE MATTER OF THE PETITION OF CONOCO INC. FOR AN ORDER PROVIDING FOR THE UNITIZED MANAGEMENT, OPERATION, AND FURTHER DEVELOPMENT OF THE DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION; VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE.

CONSOLIDATED RESPONSE OF CONOCO INC. TO "PETITION FOR RECONSIDERATION BY PLACID OIL COMPANY" AND "PETITION FOR RECONSIDERATION BY ANDREA SINGER POLLACK REVOCABLE TRUST"

On June 16, 1994 the North Dakota Industrial Commission ("Commission") entered Order No. 6861 in Case No. 5933. Order No. 6861 granted the application of Conoco Inc. ("Conoco") in the above-captioned matter for the establishment of the Dickinson-Lodgepole Unit in Stark County, North Dakota. On June 30, 1994 and July 1, 1994, Placid Oil Company ("Placid") and the Andrea Singer Pollack Revocable Trust ("ASPRT"), respectively, filed petitions for reconsideration. Placid and ASPRT both allege that the Commission erred in approving the application of Conoco in Case No. 5933.

The record, however, clearly demonstrates that Conoco presented substantial credible evidence to establish that the plan of unitization for the Dickinson-Lodgepole Unit is fair, reasonable and equitable and will result in the greater ultimate recovery of oil and gas from the pool in a manner which will prevent waste, protect correlative rights and prevent the drilling of unnecessary wells.

I. CONTRARY TO PLACID'S CONTENTIONS, COMMISSION ORDER NO. 6861 IS FULLY SUPPORTED BY THE EVIDENCE.

A. Neither Placid nor ASPRT Introduced Seismic Data.

Placid first contends that "certain findings of fact made by the Commission are not supported by the evidence in the record." Placid's Petition at 2. Specifically, Placid points to FINDING NO. 16 which provides that "Placid and ASPRT believe that seismic information can be used to identify the reservoir boundaries, although no evidence was introduced into the record to support identification of the productive portion of the mound using seismic information". Order No. 6861 at 3. Placid argues that FINDING NO. 16 is not supported by the evidence because Placid introduced Exhibit No. 4 which "consists of a synthetic seismic line recreated from the well logs." Placid's Petition at 2.

Contrary to Placid's contention, a synthetic seismic line is not seismic information derived from seismic data. As Conoco's expert geophysicist, Mr. Greg Mohl, testified, a synthetic seismic line is not actual seismic data. Rather, it is a theoretical extrapolation of data derived from well logs. Further, as Placid's witness, Mr. Steve Bressler, testified, Placid did not introduce actual seismic data into evidence because such data was deemed proprietary. As such, Placid and ASPRT merely submitted maps based on seismic interpretations. Accordingly, FINDING NO. 16 is fully supported by the evidence in the record -- "no evidence was introduced into the record to support identification of the productive portion of the mound <u>using seismic information</u>." Order No. 6861 at 3.

Also without merit is Placid's argument that FINDING NO. 17 is "directly contrary to the entire basis upon which Conoco has proposed its unit." Placid's Petition at 2 - 3. Instead, the testimony of Conoco's expert, Mr. Greg Mohl, was that seismic was not an effective tool for identifying the boundaries of the Dickinson-Lodgepole reservoir because there was very little velocity contrast between productive and nonproductive Lodgepole. As such, it is impossible to differentiate between productive and nonproductive Lodgepole using seismic. The use of seismic had absolutely no bearing on the porosity, permeability and other reservoir conditions throughout the mound feature. Since FINDING NO. 17 deals exclusively with seismic and has absolutely nothing to do with porosity, permeability or other reservoir conditions, it is simply a specious argument for Placid to contend that FINDING NO. 17 "is directly contrary to the entire basis upon which Conoco has proposed its unit."

B. <u>The Plan of Unitization for the Dickinson-Lodgepole Pool is Fair, Reasonable and Equitable.</u>

Equally, without merit is Placid's argument that Conoco's plan of unitization for the Dickinson-Lodgepole Pool is not fair, reasonable and equitable. Placid's Petition at 3. Placid argues that FINDING NO. 24 is a conclusion "wholly unsupported by any findings of fact" or evidence in the record. <u>Id</u>. Placid further argues that Conoco's equity formula is not fair and equitable because "Conoco's Exhibit No. 13 allocates ten feet of net pay to the State A No. 83 well which cannot be justified by the evidence in the record." Id. Placid's argument ignores the evidence in the record.

On cross examination, Conoco's expert geologic witness, Mr. Jerry Hyrkas, witness for Conoco, testified that Conoco originally placed the top of the oil/water transition zone at -9818 feet in the State A No. 83 well. At no time did Mr. Hyrkas or any other Conoco witness testify that the oil/water contact was located at -9818 feet. The distinction is crucial because an oil/water contact is the point at which the water saturation goes to 100% whereas an oil/water transition zone is a broad interval over which the water saturation gradually increases to 100%. Since the State A No. 83 has a transition zone not an oil/water contact at -9818 feet, Placid's arguments that Conoco's plan of unitization is not equitable is also without merit.

The record also reflects that both Placid and ASPRT agreed to the oil/water contact interpretation utilized by Conoco in preparing Exhibit No. 13. Since any estimate of water saturation in rock such as the Lodgepole is very interpretative, the decision reached by unanimous consent of all the working interest owners, including Placid and ASPRT, was a fair and reasonable interpretation of the data. While Conoco prepared Exhibit No. 13 based upon what was agreed to by Placid and ASPRT at hearing, Placid presented a new interpretation completely ignoring the decision of the working interest owners which it previously supported.[1]

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[1] As later confirmed by Placid's Mr. Steve Bressler and ASPRT's Mr. Kevin Preston, Conoco's recommendation for inclusion of a transition zone in the reservoir did not receive the necessary votes to be approved by the working interest owner committee. The working interest owners agreed to adopt an oil/water contact which was midway between Conoco's transition zone and the tilted oil/water contact supported by Placid.

Finally, Placid suggest that because the fact that Conoco has 100% working interest in tract 4, Conoco attempted to benefit tract 4 by unfairly treating tracts 3 and 6 where Placid has an interest. The reverse logic also holds true. Placid has zero interest in every tract but tracts 3 and 6. As such, it is in Placid's best interest to downgrade any tract but 3 or 6. On the other hand, it should be noted that the record reflects that Conoco is the largest working interest owner in both tracts 3 and 6. The record also reflects, that 99.55067% of the royalty owners in tract 3 and 100% of the royalty owners in tract 6 have ratified the Unit Agreement and support Conoco's plan of unitization. Clearly, an overwhelming majority of the royalty owners in and under tracts 3 and 6 do not agree with Placid's conclusions that Conoco's plan of unitization for the Dickinson-Lodgepole Pool is not fair and equitable.

C. **<u>The Fryburg Interval is a Useful Tool in Determining the Lodgepole Pool Boundaries</u>.**

Also, without merit is Placid's argument that the Commission's findings in paragraphs 18 through 20 are not supported by the evidence. Placid's Petition at 5. According to Placid, the lack of mound in the Filipi 76 and Frenzel 79 wells invalidates the use of those wells in developing the relationship between Fryburg structure and mound thickness. <u>Id</u>. To the contrary, the quadratic mathematical relationship that Conoco developed (Conoco's Exhibit No. 10) requires that no mound be present where the thickness of non-mound rocks exceeds 1095 feet. Therefore, the lack of mound between the base of the Lodgepole

quadratic eqn $\rightarrow Ax^2 + Bxy + Cy^2 + Ex + Dy + F = 0$
contains no higher than squares (i.e. x^2)

Formation and the top of the Fryburg zone in the Filipi 76 and Frenzel 79 wells provides important validation of Conoco's interpretation.[2]

Furthermore, as the Commission noted in FINDING NO. 23, "Conoco's net pay isopach map is the most credible map presented." Order No. 6861 at 4. Presumably, the Commission made such a finding because the Fryburg map offered by Conoco was the least interpretive of all the maps offered into evidence in this case. The Fryburg map offered by Conoco includes more well data than any of the other map offered into evidence in Case No. 5933. Conoco's Fryburg map was based on information from two wells in the middle of the reservoir (the DHSU 37 and the DHSU 33), as well as one well to the northeast (the DHSU 20). Furthermore, the Fryburg structure is geographically defined on four sides. Taking the geographic center of the reservoir at the DHSU 37 well, the Fryburg is defined by the Frenzel 79 on the northwest, the Walton 84 on the southwest, the State A 83 on the southeast, and the Filipi 76 on the northeast. Based on the evidence in the record, the Commission was justified in finding that "the Fryburg interval can be a useful method to assist in determining the boundaries of the Lodgepole Pool reservoir." Order No. 6861 at 4.

D. The Well Location Rules for the Dickinson-Lodgepole Unit Provide for Orderly Development of the Pool.

Finally, Placid contends that the Commission erred by failing to address the issue of well location rules outside the unit boundary. More specifically, Placid states that "the Commission has failed to address whether 320-acre spacing is still applicable in the

[2] It is important to note that on cross examination ASPRT's geologic witness also supported use of the Fryburg structure in determining mound thickness concerning the existence of the saddle between the State 74 and Kadrmas 75 wells.

remainder of Section 30 or where additional wells drilled to the Dickinson-Lodgepole pool may be located within the remainder of Section 30". Placid's Petition at 5 - 6. Further, Placid contends that their correlative rights will only be protected if it is allowed to drill a well 660 feet from the south line and 660 feet from the east line of Section 30 (effectively on the boundary line of the unit).

Placid makes this contention in spite of the undisputed testimony of Conoco's expert land witness, Mr. Jim Turner. Mr. Jim Turner testified that Conoco would not protest an otherwise legal location drilled outside of the unit boundary in Section 30 and the creation of a non-standard 320-acre spacing unit consisting of only 310 acres. Moreover, Mr. Turner testified that Placid was advised in February 1994 that if it desired to drill a well in Section 30, it should "send us [Conoco] an AFE" and Conoco would evaluate the proposal. More than six months have elapsed since Conoco advised Placid to send an AFE for a well in Section 30. Placid has yet to make proposal to Conoco for the drilling of a well in Section 30. Since Conoco is the largest working interest owner in the Southeast Quarter of Section 30, it is logical to assume the if Placid had intended to drill a well in the Southeast Quarter of Section 30 as they alleged at the hearing and in their petition, Placid would have approached Conoco and made a drilling proposal.

II. CONTRARY TO ASPRT'S CONTENTIONS, THE FINDINGS OF COMMISSION ORDER NO. 6861 ARE NOT "CLEARLY ERRONEOUS"OR TOTALLY WITHOUT BASIS."

ASPRT requests that the Commission "reconsider and stay" Order No. 6861 arguing that certain findings of the Commission are either "clearly erroneous" or "totally without basis." ASPRT's Petition at 1 - 4. In making its arguments, ASPRT either provides no support for its arguments or entirely ignores the evidence in the record.

ASPRT objects to FINDING NOS. 9 and 10 "because they include more tracts than are necessary under the area justified by the ASPRT net isopach map." Id. at 2. Also, ASPRT objects to FINDING NOS. 8, 10, 24 and 26 because they purport to find that the proposed unit protects correlative rights and is fair, reasonable and equitable." Id. ASPRT provides absolutely no support for its conclusion other than the bald statement that FINDING NOS. 8, 10, 24 and 26 "are not justified based on the evidence and should be reconsidered and charged." Id.

In concluding that FINDING NOS. 8, 10, 24 and 26 are not justified, ASPRT ignores the testimony of Conoco's geological witness, Mr. Jerry Hyrkas. Mr. Hyrkas testified that a determination of what tracts to include in the unit were based on the net pay isopach map approved by a vote of the working interest owners using the voting procedure that was established at the first working owners' meeting. It is absurd for ASPRT to argue that the Commission's findings are clearly erroneous and not supported by the record merely because ASPRT presented evidence to the contrary. It is well settled that the Commission, as an administrative agency, is the fact finder and as such has discretion in determining the credibility of witnesses and the weight to be accorded the evidence presented. 2 Am Jur 2d Admin. Law § 363 (1994). It is clear that the Commission exercised that authority and found that Conoco's net pay isopach map was the most credible map presented. Order No. 6861 at 4.

ASPRT also claims FINDING NOS. 14 and 16 are clearly erroneous and not supported by the record because ASPRT used well data in conjunction with seismic data for defining the reservoir edge. Id at 2. Presumably, ASPRT alleges that the Commission committed error by not giving greater weight to the evidence submitted by ASPRT. As set forth above, the Commission has discretion in deciding which evidence to accept and how much weight should be accorded that evidence. Moreover, the record reflects that Conoco and not ASPRT presented the most reliable data for defining the reservoir boundaries. ASPRT's own witness, Mr. Kevin Preston, testified that Conoco's map honored all the data.

Reviewing the data, it is clear that only one point can be exactly defined as the edge of the reservoir — the edge between the Frenzel No. 79 vertical and sidetrack holes. Since ASPRT refused to recognize the relationship between the Fryburg structure and mound thickness, ASPRT was left to define the remaining reservoir limits based on seismic data. As testified by ASPRT's expert, Mr. Ernie Gomez, ASPRT used the same seismic data as Placid in preparing its maps. Even a cursory review of the maps submitted by ASPRT and Placid reveals the highly interpretive nature of seismic mapped reservoir limits. Therefore, ASPRT's and Placid's own exhibits confirm the highly interpretative nature of seismic and its unreliability for use in defining unit boundaries.

ASPRT further argues that FINDING NO. 17 is clearly erroneous and contends that industry experience supports the use of seismic for defining reservoir boundaries. Id. at 2 - 3. Conoco's expert witness, Mr. Greg Mohl, testified that defining oil accumulations and precise reservoir boundaries based on actual seismic data is theoretical and speculative. Coupled with the physical properties associated with the Lodgepole formation, it is simply unrealistic to suggest that actual seismic is a definitive tool which the Commission should recognize as a method for delineating reservoir boundaries for unitization purposes. Certainly, ASPRT is correct that the industry finds seismic a helpful tool in the exploration of other reservoirs and in other areas having more favorable rock properties. Such favorable conditions, however, do not apply to the Lodgepole. Since no one, including Conoco, has found another productive Lodgepole mound using seismic, it is simply premature to say that the use of seismic is a proven tool in the Lodgepole to define reservoir edges.

ASPRT also argues that FINDING NO. 22 is "essentially irrelevant." Id. at 4. ASPRT correctly states that volumetric calculations are estimates based on geologic interpretations. Good geologic interpretations, however, should yield volumetric calculations that match well with the material balance. ASPRT's Mr. Kevin Preston, agreed that Conoco's material balance estimate of 18.25 million barrels of oil was a very accurate estimate of the original oil in place. Since Conoco's volumetric calculation more closely matches the material balance estimate than that of ASPRT, the Commission did not error in adopting Conoco's geologic interpretation rather than ASPRT's geologic interpretation.

Finally, ASPRT argues that FINDING NO. 23 is "clearly erroneous and not supported by a fair interpretation of the evidence." Id. Once again without pointing to any evidence to support the same, ASPRT states that its net isopach map is the most credible. Id. As outlined above, Conoco's isopach map incorporated the most reliable data of all the maps presented. Moreover, Conoco introduced evidence in the record showing that it was the only working interest owner to hold an interest in all nine tracts. Since Conoco is the only working interest owner with an interest in every tract in the unit, Conoco is in the unique position of having the greatest incentive to protect the rights of all owners of interest in each of those tracts.

Furthermore, overlays of maps prepared by ASPRT, Placid, Phillips, and Conoco (which were presented at the working interest owners' meetings), introduced into the record by Conoco, indicate that Conoco's map is the most reasonable and credible interpretation of the reservoir limits. Because Conoco presented the most reasonable and credible depiction of the Dickinson-Lodgepole Pool, it secured the support of more than 76% of the working interest owners and more than 86% of the royalty owners for its Plan of Unitization. The Commission, therefore, did not err and was justified in finding that Conoco's net pay isopach map was the most credible map presented.

CONCLUSION

For all the foregoing reasons, Placid's and ASPRT's petitions for reconsideration should be denied.

DATED this 18th day of July, 1994.

PEARCE & DURICK

By L Bender
LAWRENCE BENDER
Attorneys for Applicant, Conoco Inc.
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CERTIFICATE OF SERVICE

I, the undersigned, hereby certify that a true and correct copy of the following document:

CONSOLIDATED RESPONSE OF CONOCO INC. TO "PETITION FOR RECONSIDERATION BY PLACID OIL COMPANY" AND "PETITION FOR RECONSIDERATION BY ANDREA SINGER POLLACK REVOCABLE TRUST"

was on the 11 day of July, 1994 served by placing the same in the United States mail, postage prepaid, properly addressed to the following:

Mr. John W. Morrison, Jr.
Attorney at Law
400 E. Broadway, Suite 600
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Mr. Robert Wefald
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Bismarck, ND 58502-0001

LAWRENCE BENDER

BEFORE THE INDUSTRIAL COMMISSION

OF THE STATE OF NORTH DAKOTA

CASE NO. 5933
ORDER NO. 6861

IN THE MATTER OF A HEARING CALLED ON A MOTION OF THE COMMISSION TO CONSIDER THE PETITION OF CONOCO INC. FOR AN ORDER PROVIDING FOR THE UNITIZED MANAGEMENT, OPERATION, AND FURTHER DEVELOPMENT OF THE DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION; VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE.

ORDER OF THE COMMISSION

BY THE COMMISSION:

Pursuant to legal notice this cause came on for hearing at 9:00 a.m. on the 8th day of June, 1994, in Bismarck, North Dakota, before an examiner appointed by the Industrial Commission of North Dakota, hereinafter referred to as the "Commission."

NOW, on this 16th day of June, 1994, the Commission, a quorum being present, having considered the testimony adduced and the exhibits received at said hearing, and being fully advised in the premises,

FINDS:

(1) That an application was filed with the Commission by Conoco, Inc., for an order approving the unitized management, operation and further development of a portion of the Dickinson-Lodgepole source of supply of oil and gas located in Stark County, North Dakota, and for an order approving a plan of operation providing for the injection of water and/or other substances into the common source of supply; as a part of said application and attached to it was a plan of unitization consisting of a Unit Agreement

and Unit Operating Agreement; such application was filed in accordance with Sections 38-08-09.1 through 38-08-09.16 of the North Dakota Century Code ("NDCC").

(2) That the notice of filing of the application and petition and the time and place of hearing thereof was regularly given in all respects as by law required, and that more than 45 days prior to the hearing, Conoco, Inc., as the applicant, did give notice of the time and place of said hearing and did mail, postage prepaid, a copy of the application and the proposed plan of unitization to each affected person owning an interest of record in the unit outline at such person's last known post office address, and that the applicant did, more than 45 days prior to the hearing file with the Commission engineering, geological and other technical exhibits to be used and which were used at said hearing, and that the notice so given did specify that such material was filed with the Commission; that due public notice having been given, as required by law, the Commission has jurisdiction of this cause and the subject matter.

(3) That the plan of unitization proposed by the applicant consists of a Unit Agreement for the development and operation of the Dickinson-Lodgepole Unit in the county of Stark, state of North Dakota, together with a Unit Operating Agreement.

(4) That the unitized management, operation and further development of a common source of supply of oil and gas or portion thereof is reasonably necessary in order to effectively carry on a water injection and pressure maintenance project calculated to substantially increase the ultimate recovery of oil and gas from the common source of supply.

(5) That one or more unitized methods of operation as applied to such common source of supply or portion thereof are feasible, will prevent waste and will with reasonable probability result in the increased recovery of substantially more oil and gas from the common source of supply than would otherwise be recovered.

(6) That the estimated additional cost, if any, of conducting such operations will not exceed the value of the additional oil and gas so recovered.

(7) That such unitization and the adoption of one or more unitized methods of operation is for the common good and will result in the general advantage of the owners of the oil and gas rights within the common source of supply of portions thereof directly affected.

(8) That the unitization and unitized operation of the common source of supply described herein, upon the terms and conditions set forth in the Unit Agreement and Unit Operating Agreement, is fair, reasonable, equitable. Furthermore, the terms and conditions are necessary or proper to protect, safeguard, and adjust the respective rights and obligations of the persons affected including royalty owners, owners of overriding royalties, oil and gas payments, carried interests, mortgagees, lien claimants, and others, as well as the lessees.

(9) That the area proposed to be included within the unit area of the Dickinson-Lodgepole Unit is as follows:

TOWNSHIP 140 NORTH, RANGE 96 WEST, 5TH PM
ALL OF SECTION 31, THE S/2 S/2 SW/4 OF SECTION 29, THE SE/4 SE/4 SE/4 OF SECTION 30, THE W/2, THE W/2 W/2 SE/4, THE W/2 SW/4 NE/4 AND THE SW/4 NW/4 NE/4 OF SECTION 32,

TOWNSHIP 139 NORTH, RANGE 96 WEST, 5TH PM
THE N/2 OF SECTION 5 AND THE N/2 AND SE/4 OF LOT 1, THE N/2 OF LOT 2 AND THE NE/4 OF LOT 3 OF SECTION 6.

ALL IN STARK COUNTY AND COMPRISING 1436.45 ACRES; MORE OR LESS.

(10) That the unit area as described in paragraph (9) hereof and in the application and plan of unitization constitutes a common source of supply, and the evidence established that the area to be so included within the unit area is of such size and shape as may be reasonably required for the successful and efficient conduct of the unitized method or method of operation for which the unit is created, and that the conduct thereof will have no adverse effect upon the remainder of such common source of supply. Provided, however, that injection wells and new wells drilled in the unit area for production or injection purposes should be located an adequate distance from the unit boundary in order to fully protect correlative rights.

(11) That all working interest owners agree, that to increase the ultimate recovery of oil and gas from the pool and to prevent waste, the Dickinson-Lodgepole Pool should be unitized.

(12) That Placid Oil Company ("Placid") and Andrea Singer Pollack Revocable Trust ("ASPRT") each have an interest in the proposed Dickinson-Lodgepole Unit, Stark County, North Dakota.

(13) That both Placid and ASPRT object to Conoco's definition of the boundaries of the Lodgepole Pool reservoir. That definition is depicted on Conoco's net pay isopach map, Conoco Exhibit 13.

(14) That Placid and ASPRT each used identical seismic information, along with well data, to construct their own net pay isopach maps, ASPRT Exhibit 7 and Placid Exhibit 9. The reservoir boundary on each map, however, was based only upon seismic information.

(15) That Placid's net pay isopach map does not feature a "saddle", or a structural low, within the mound as depicted by Conoco and ASPRT, although evidence within Placid's own exhibits (e.g. Placid Exhibit 7) indicates that said saddle exists.

(16) That Placid and ASPRT believe that seismic information can be used to identify the reservoir boundaries, although no evidence was introduced into the record to support identification of the productive portion of the mound using seismic information.

(17) That testimony by Conoco indicates that seismic information is a highly interpretive exploration tool with which general structure of a feature can be estimated, but from which reservoir quality and the fluids it contains cannot be detected. Therefore, the productive portion of the Lodgepole mound cannot be determined by seismic information.

(18) That the Fryburg Interval has regional dip to the north across the Dickinson Field and evidence presented to the Commission indicates that the Fryburg interval will be deposited abnormally high, in comparison to said regional dip, because a mound has grown beneath it.

(19) That the structure of the Fryburg Interval can be a useful method to assist in determining the boundaries of the Lodgepole Pool reservoir.

(20) That the Filipi No. 76 well located in the SW NE of Section 32, Township 140 North, Range 96 West, Stark County, North Dakota, penetrated the Fryburg Interval abnormally high, although the mound was not developed under said well, suggesting that the mound edge is nearby.

(21) That Placid and ASPRT agree with Conoco's material balance calculation with which Conoco calculated an original oil in place of 18,250,000 barrels of oil in the Dickinson-Lodgepole reservoir.

(22) That Conoco's volumetric calculation of original oil in place is approximately 6% above the material balance calculation. ASPRT's volumetric calculation of original oil in place is approximately 12% below the calculated material balance calculation. Conoco's volumetric calculation of original oil in place is more in agreement with the material balance calculation. Therefore, the location of the eastern boundary of the reservoir is as asserted by Conoco.

(23) That Conoco's net pay isopach map is the most credible map presented.

(24) That the plan of unitization filed with the application and included in the record as Exhibits 5 and 6, contains fair, reasonable, and equitable provisions for:

(a) The efficient, unitized management and control of the further development and operation of the unit area for the recovery of oil and gas from the common source of supply affected.

(b) The division of interest or formula for the apportionment and allocation of the unit product among the tracts within the unit area is fair, equitable and reasonable.

(c) The manner in which the unit and the further development and operation of the unit area shall or may be financed and the basis, terms and conditions upon which cost and expense thereof shall be apportioned among and assessed against the tracts and interest made chargeable therewith, including a detailed accounting procedure governing all charges and credits incident to such operation, and makes reasonable provision for carrying or otherwise financing lessees who are unable to promptly meet their financial obligations in connection with the unit.

(d) The procedure and basis upon which wells, equipment, and other properties of the several lessees within the unit area are to be taken over and used for unit operations, including the method of arriving at the compensation therefor, or of otherwise proportionately equalizing or adjusting the investment of the several lessees in the project as of the effective date of unit operation.

(e) The creation of an operating committee to have general overall management and control of the unit and the conduct of its business and affairs and the operations carried on by it, together with the creation or designation of such other subcommittees, boards or offices to function under authority of the operating committee as may be necessary, proper or convenient in the efficient management of the unit, defining the powers and duties of all such committees, boards or officers, and prescribing their tenure and time and method for their selection.

(f) The time when the plan of unitization shall become and be effective.

(g) The time when and conditions under which and the method by which the unit shall be or may be dissolved and its affairs wound up.

(25) That the plan of unitization has been signed, ratified or approved by lessees and royalty owners owning in excess of the 70% required percentage interest in and to the unit area, as provided by NDCC Section 38-08-09.5.

(26) That such Unit Agreement and the Unit Operating Agreement are in the public interest, are protective of correlative rights and are reasonably necessary to increase ultimate recovery and to prevent waste of oil and gas, and that said plan of unitization, as contained therein, appears to conform and comply with the provisions and requirements of NDCC Sections 38-08-09.1 through 38-08-09.13.

(27) That in order to effectuate the purposes of unitization, NDCC Section 38-08-09.2, provides that the Commission is vested with continuing jurisdiction necessary or proper to enforce the provisions of this order.

(28) That in this cause there are certain rules which are necessary and appropriate to the efficient operation of the Dickinson-Lodgepole Unit, in order to promote and expedite the objective for which the unit was formed.

(29) That the rules and orders hereby promulgated for the Dickinson-Lodgepole Unit, pertaining to the injection of water and/or other substances into the reservoir, to reservoir pressure surveys, to gas-oil ratio surveys and to production tests are necessary, desirable, in the public interest, preventative of waste and protective of correlative rights.

(30) That the common source of supply which will be affected by the project has been adequately delineated.

(31) That NDCC Section 38-08-04 and Section 43-02-03-15 of the North Dakota Administrative Code ("NDAC") require each party desiring to drill or operate oil and gas wells in the state to file with the Commission a reasonable bond with good and sufficient surety, conditioned on full compliance with statutes rules and orders of the Commission.

(32) That on behalf of the Dickinson-Lodgepole Unit, the unit operator as a separate and distinct operator, should furnish a bond as provided in NDCC Section 38-08-04 and NDAC Section 43-02-03-15.

IT IS THEREFORE ORDERED:

(1) That the application filed herein be, and the same is hereby approved.

(2) That the creation of the Dickinson-Lodgepole Unit in Stark County, North Dakota, as prayed for in said application be, and is hereby authorized and approved.

(3) That the unit area of said unit shall extend to and include the land hereinbefore described in paragraph (9) of the Findings.

(4) That the plan of unitization consisting of the Unit Agreement and the Unit Operating Agreement, included in the record (as Exhibits 5 and 6) is hereby incorporated in this order by reference, and shall apply to the same extent and with the same force and effect as if actually set forth herein; that the said plan of unitization of and for said Dickinson-Lodgepole Unit is approved, all to the same extent and with the same force and effect as if set forth herein in its entirety; that if said plan of unitization does not in all respects conform to and comply with the provisions and requirements of NDCC Sections 38-08-09.1 through 38-08-09.13, the statute shall prevail.

(5) That the unitized formation shall mean the Lodgepole Formation as identified by Industrial Commission Order No. 6607, being that accumulation of oil and gas found in the interval from below the base of the Mission Canyon Formation to above the top of the Bakken Formation.

(6) That the injection of water and/or other substances into the unitized formation underlying the Dickinson-Lodgepole Unit by the unit operator for the purpose of operating an enhanced recovery project is authorized; provided, however, that prior to the commencement of such injection the operator shall obtain such permits as are required by NDAC Chapter 43-02-05.

(7) That the unit operator of the Dickinson-Lodgepole Unit may, from time to time, use certain existing wells, or wells to be drilled, for the purpose of injecting water and/or other substances into the unitized formation underlying the Dickinson-Lodgepole Unit upon approval by the Commission. The application for such approval shall be in accordance with statutes and rules of the Commission.

(8) That the unit operator shall be permitted to drill additional wells at any location within the unit area, no closer than 660 feet to the boundary of the unit, nor closer than 1980 feet to another well producing or permitted to the same pool outside the unit area.

(9) That all bottom-hole pressures and gas-oil ratios obtained by the unit operator shall be filed with the Commission. Additional bottom-hole pressure and gas-oil ratio measurements may be required by the Director, if deemed necessary.

(10) That a report of unit operations shall be filed annually with the Commission. Such report shall include but not be limited to production and injection amounts as well as recorded pressures and gas-oil ratios. Proposed plans for the unit for the coming year shall also be included in the report.

(11) That the termination of the Dickinson-Lodgepole Unit shall be as prescribed in the Unit Agreement, or as provided by NDCC Section 38-08-09.4; and that notwithstanding any provisions to the contrary, in the event the unit operator fails to commence or ceases enhanced recovery operations, the Commission upon its own motion, after notice and hearing, may consider rescinding this order so that the Dickinson-Lodgepole Unit will terminate and cease to exist.

(12) That the effective date of the Dickinson-Lodgepole Unit shall be the first day of the month following the month in which the plan of unitization has been signed, ratified, or approved by lessees and royalty owners owning the required percentage of interest in the unit area, and has been so certified by the Commission.

(13) That the provisions of this order shall supersede and replace the provisions of all previous rules and orders not consistent herewith, including without limitations all otherwise applicable spacing orders and well location rules.

(14) That the unit operator, on behalf of the Dickinson-Lodgepole Unit, shall cause to be transferred to a separate blanket bond, all wells in the unit area used in unit operations. The bond shall be in the applicable dollar amount as provided in NDAC Section 43-02-03-15.

(15) That this order shall remain in full force and effect until further order of the Commission.

Dated this 16th day of June, 1994.

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA

/s/ Edward T. Schafer, Governor

/s/ Heidi Heitkamp, Attorney General

/s/ Sarah Vogel, Commissioner of Agriculture

To Bruce Hicks, Gas Oil

STATE OF NORTH DAKOTA — IN DISTRICT COURT

COUNTY OF STARK — SOUTHWEST JUDICIAL DISTRICT

Andrea Singer Pollack Revocable Trust, Andrea Singer Pollack, Trustee, Appellant, vs. The Industrial Commission of the State of North Dakota, Conoco Inc., and all other persons having an interest in the Dickinson-Lodgepole Unit, Appellees.	CASE NO. 94C-283 NOTICE OF HEARING

NOTICE IS HEREBY GIVEN that the above-entitled case has been set for hearing before the Hon. Maurice R. Hunke at the Stark County Courthouse, Dickinson, North Dakota on March 6, 1995, at 9:30 a.m. (Mountain Time).

The purpose of said Hearing is as follows:

ORAL ARGUMENTS ON PENDING MATTER

I hereby certify that I caused a true and correct copy hereof to be mailed to or personally served upon all attorneys of record herein on February 14, 1995.

Robert O. Wefald
Charles M. Carvell
Lawrence Bender
Hon. Maurice R. Hunke

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Court Reporter
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December 28, 1994

TO: Attorneys Robert O. Wefald, Charles M. Carvell, and Lawrence Bender

RE: Stark County District Court Case No. 94C-283
Andrea Singer Pollack Revocable Trust, et al. v. Industrial Commission and Conoco, Inc., et al.

FROM: Maurice R. Hunke, District Judge MRH

Dear Counsel:

The Motion to Compel Conoco, Inc., to Produce 3-D Seismic Data dated November 1, 1994, filed by the Appellant Andrea Singer Pollack, as trustee of the Andrea Singer Pollack Revocable Trust (hereinafter ASPRT) has been submitted pursuant to NDROC Rule 3.2.

Although ASPRT, through Attorney Robert O. Wefald, has requested oral arguments on the merits of the underlying appeal, it appears that no party has requested hearing for oral argument on the pending motion. Because the parties have had adequate opportunity to present their respective positions on that motion through briefs, no hearing is necessary.

It is unclear precisely what procedural relief ASPRT is seeking through its motion. However, it is apparent that it seeks an Order providing for a rather novel procedure of discovery during the pendency of an appeal. That is, ASPRT seeks to compel the Appellee Conoco, Inc. to produce certain documents or data in the possession of Conoco, Inc.

It seems a bit late in the process to conduct or compel discovery proceedings. NDCC 28-32-09 provides for various means of discovery in administrative agency proceedings. There is no indication that ASPRT pursued any discovery or that it was denied opportunity or time for reasonable discovery. Its position is that it fully expected and relied upon Conoco to offer such potentially valuable and relevant evidence as its 3-D seismic data at the administrative hearing held on June 8, 1994. However, there is no indication in the record that ASPRT was somehow misled by Conoco or any other interested person.

NDCC 28-32-19 provides that the District Court must conduct its review of the determination of an administrative agency ". . . based only on the record filed with the court." More specific to appeals from decisions of the Industrial Commission in matters relating to oil and gas production is the direction in NDCC 38-08-14(4) that the District Court shall review those proceedings ". . . as disclosed by the transcript upon appeal."

Thus, it would be futile to compel Conoco, Inc. to produce the requested 3-D seismic information because that evidence is not a part of the record considered by the Industrial Commission in the decision now under appellate review by this Court. It does not appear appropriate under these circumstances to remand the case back to the Industrial Commission for consideration of additional evidence pursuant to NDCC 28-32-18.

Accordingly, the Motion to Compel dated November 1, 1994, filed by ASPRT is hereby DENIED.

The Court Administrator is requested to communicate with the attorneys to schedule an appropriate date and time for oral arguments upon the merits of this appeal.

MRH/sm
cc: Paulette Reule, Clerk, Stark County District Court
Ardean Ouellette, Court Administrator

STATE OF NORTH DAKOTA — IN DISTRICT COURT

COUNTY OF STARK — SOUTHWEST JUDICIAL DISTRICT

Andrea Singer Pollack Revocable Trust, Andrea Singer Pollack, Trustee, Appellant, vs. The Industrial Commission of the State of North Dakota, Conoco, Inc., and all other persons having an interest in the Dickinson-Lodgepole Unit, Appellees.	Civil No. 94C-283 **REPLY BRIEF**

An Appeal to the District Court of Stark County
From the Decision of the North Dakota Industrial Commission
Pursuant to NDCC 38-08-14 in Regard to the Unitization of
the Dickinson Lodgepole Unit in Stark County, North Dakota

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REPLY BRIEF

The Andrea Singer Pollack Revocable Trust (ASPRT), in the first section of its brief, pointed out, that under Montana-Dakota Utility Company v. PSC, 413 N.W.2d 308 (N.D. 1987) this court should give "appreciable deference" to an issue decided by an administrative agency when it is of a highly technical nature. ASPRT challenged that expertise in this particular case, and demonstrated that the commission staff did not have the level of technical expertise in the area of 3-D seismic to allow this court to give "appreciable deference" to its decision. In fact, in its brief, the Commission never even addresses this point. CONOCO, on the other hand, simply addresses it in footnote 3 to its Standard of Review section of its brief, in which it contends without further comment that the ASPRT "strains to suggest that the Commission does not have the requisite expertise on the usefulness of 3-D seismic..."

ASPRT, like any other party before an administrative agency, is entitled to proceed on the assumption that the administrative agency has the necessary technical expertise in a particular area to make a decision. Lacking the expertise, an administrative agency should use its investigative powers and its staff to become informed on the issues so that it can make a decision with sufficient expertise.

Although both CONOCO and the Commission decry ASPRT's submission of scholarly articles on the subject of 3-D seismic, those articles were only submitted after the Commission issued its Order (C.R. 100) and mis-stated in finding 17 what is now accepted in the industry as the proven usefulness of 3-D seismic in defining the boundaries of a productive mound. These articles were submitted in support of ASPRT's Petition for Reconsideration as it was necessary to call those scholarly articles to the attention of the Commission and now to this court since the Commission denied the Petition For Reconsideration and since those scholarly opinions continue to be ignored by the Commission. These scholarly articles clearly establish that 3-D seismic is used in the oil and gas industry to locate the boundaries of a particular productive mound. Typically, the scholarly articles suggest that 3-D seismic is shot over a discovery well for the very purpose of locating the boundaries of the productive formation. Both ASPRT and PLACID should have been able to rely upon the Commission staff to have the necessary technical expertise to appreciate and understand the current usefulness of 3-D seismic data. ASPRT could not (and should not) have anticipated that the Commission would be so misinformed or ignorant of such usefulness. Such ignorance should rise to the level of an error of law.

As a public body, the Commission is subject to the open meetings and open records laws, and hence, its discussion are typically on the record. Counsel for ASPRT was able to obtain excerpts of the minutes of the meetings of the Industrial Commission for June 16, 1994, (S.R. 27-34) and August 3, 1994, (S.R. 36-37). Those minutes clearly establish that the Commission with some discussion simply accepted the proposed Order drafted by the Commission's technical staff. The attorney for ASPRT requested a transcript of the discussion of the technical staff in the preparation of this Order or a tape of that discussion, but was informed that no such tape or transcript was available.

We do not know what technical expertise the Commission staff had when it prepared the Order which was eventually approved by the Commission. We get a clue, however, from the comments of Wes Norton when he presented the staff's Order to the Commission. Wes Norton stated (S.R. 29-30) that "we said that seismic is an exploration tool, we agree with Conoco on that, and does not determine reservoir quality." That apparently sums up the 3-D seismic technical expertise of the technical staff of the Commission. Wes Norton doesn't even address the difference between 2-D seismic and 3-D seismic in that comment. His comment which is reflected in Finding 17 of the Order (C.R. 100) flies in the face of the demonstrated scholarly technical opinion as established in the articles submitted by ASPRT along with its Petition for Reconsideration and established by the Affidavit of Dr. Thomas L. Davis (S.R. 7-25).

Neither the Commission nor CONOCO even attempt to discuss any of those scholarly articles or attempt to refute them. They simply suggest somehow it is improper for ASPRT to attempt to show the Commission and this Court after the fact that the Commission staff is wrong and that its technical expertise is lacking on the subject of 3-D seismic data.

Not only is there no significant evidence that the Commission staff had expertise on the subject of 3-D seismic data, when the governor questioned Wes Norton about 3-D versus 2-D seismic data, and the review of that data by a third person (S.R. 31), Wes Norton responded that the Commission would have to bring in someone who is not familiar with the information and start all over again, and that if the parties weren't satisfied, you'd still be stuck with the same dilemma. Besides, he suggested, no third party could be obtained who did not have a conflict with one of the companies (S.R. 31). There is no evidence in the record to support that comment. Additionally, ASPRT stated that it would accept the results of analysis with CONOCO's 3-D data by a third party.

The question at issue with respect to 3-D seismic data is whether or not the Commission had sufficient technical expertise for this court to give "appreciable deference" to its holding that 3-D seismic data is not useful for determining the boundaries of a productive formation. Current public record information again demonstrates how wrong the Commission's technical staff is on 3-D seismic.

The Commission, on page 9 of its brief, accepted the testimony of CONOCO's witnesses to the effect that 3-D seismic data is not helpful in delineating the boundaries of a productive pool. The Commission takes note of the testimony of CONOCO's expert, Greg Mohl, that seismic data is "totally inappropriate for delineating the boundaries of Dickinson-Lodgepole pool." Someone should have told that to Duncan Energy before it spent the money on 3-D seismic which resulted in the first productive discovery well in the Lodgepole formation since CONOCO completed the discovery well in question in this case. Attached hereto as Exhibit A is a copy of the top half of the front page of the Rocky Mountain Oil Journal, Volume 74, No. 48 for December 2, 1994, through December 8, 1994, taking note of the Duncan Energy discovery well based on a 3-D seismic survey which Duncan Energy conducted. Since 3-D seismic is being successfully used in North Dakota, including the Lodgepole formation, the Commission must acquire the technical expertise to review all data to insure the protection of the correlative rights of all owners.

The Commission and its staff in the protection of correlative rights should require anyone who comes before it with a plan of unitization to produce all of its data. This will allow the Commission and its staff to make an independent judgment based on its informed analysis of all of the data available as to the proper boundaries of a unit, rather than relying on the boundary map drawn by a party which obviously has a vested interest in having a map most favorable to it. When Duncan Energy comes in with a plan of unitization, the Commission and its staff need to become familiar with 3-D seismic, and need to see that data along with all of its other data so it can make the decision which best protects the correlative rights of all owners.

The Commission appears to have handled this case on a take it or leave it basis. It had before it CONOCO's predetermined plan of unitization, its predetermined method of enhanced recovery, and its predetermined plan of allocation. The Commission was told by Wes Norton (S.R. 31):

> <u>Wes Norton:</u> But you've got a unit here put together that 86% of the royalty owners have ratified. This is what happened in Little Knife when. They have got these people saying this is what you have and this is what your neighbor has and so forth and you come back to them with a different percentage and they have less, say, they are not going to ratify it and you're going to have a ratification problem.

In other words, the Commission faces the dilemma of approving a plan of unitization without the benefit of all the relevant information or denying unitization altogether. Wes Norton's statement demonstrates that the Commission's process of approving both a plan of unitization and certifying the necessary ratifications in a single hearing favors unitization at almost any price - including the violation of the correlative rights of a minority interest owner. In other words the Commission staff weighed heavily CONOCO's sizeable interests, and the fact that "the order will be appealed regardless." (S.R. 32). Surely a matter involving the correlative rights of all owners including the state of North Dakota, and not just PLACID, ASPRT and CONOCO, should involve more deliberation than simply the question of majority rule and the notion that a case is going to be appealed to regardless. Unfortunately, Wes Norton's statement is an invitation to interest owners who can garner the necessary 70% vote to confiscate as much of the production of the other 30% as they feel they can safely get away with, which in this case is approximately 200,000 barrels of oil rightfully belonging to ASPRT.

The Commission should have granted PLACID's and ASPRT's Petitions for Reconsideration to inquire about the 3-D seismic data given the fact that the scholarly articles establish that the

Commission staff is wrong in its understanding of the usefulness of 3-D seismic. These articles establish that only recently has 3-D seismic been used for exploration because its cost has come down to where it can be used over a broad area, but these articles clearly establish that 3-D seismic can most accurately define the boundaries of a productive mound.

The Commission, in its brief, urges the court to reject the Adverse Inference Rule and cites cases from other jurisdictions, but no case is cited from North Dakota overruling the decision of the Supreme Court in <u>Colgate-Palmolive Company v. Dorgan</u>, 225 N.W.2d 278 (N.D. 1975). In fact, this is a great case in which to follow the Adverse Evidence Rule. CONOCO spent a substantial amount of money shooting 3-D seismic data and had the data available to it well in advance of the hearing. Given the fact that CONOCO spent all this money shooting 3-D seismic over its discovery well, an inference can be drawn that CONOCO does not like the results with respect to the shape and location of the boundaries of the productive mound. ASPRT has only requested that all available data be produced and utilized so that a boundary line can be drawn accurately for this particular formation. ASPRT has consistently said that it would accept and abide by the results of such a map drawn from the 3-D seismic data by a third party.

As far as the failure of ASPRT to subpoena CONOCO's 3-D seismic data, it is clear that ASPRT raised the issue in advance of the hearing and put both CONOCO and the Commission on notice. The Commission, as an administrative agency has both prosecutory/investigative and adjudicative functions. Colgate-Palmolive Company v. Dorgan, supra at 282. As an investigative and adjudicative body, it has the power on its own to subpoena data of the parties that come before it.

One would think that when an issue has been raised, the Commission staff, and the Commission itself would have been curious enough about this 3-D seismic data and about the conflicting testimony to order that the data be produced so that it could be examined. It is of great significance that the rights of all owners, including rights of the people of the state of North Dakota through the interests the state owns in the minerals in this Lodgepole formation and ASPRT, PLACID and CONOCO be equally protected.

Although the argument is now made that ASPRT did not subpoena this 3-D seismic data, it is noted that at the hearing before the Industrial Commission, CONOCO never once made the argument that its 3-D seismic data was not subpoenaed and therefore, would not discuss it. Rather, CONOCO consistently took the position that 3-D seismic data was not useful, contrary to the expert witnesses for both PLACID and ASPRT. CONOCO also took the position that 3-D seismic data was particularly not useful for delineating the boundaries of a mound in the Lodgepole formation even though Duncan Energy, as noted above, used 3-D seismic data to drill a productive well in the Lodgepole formation. Never once did CONOCO suggest at the hearing that the data should not be discussed because it wasn't subpoenaed. Rather, it maintained that even if the data was available, it would not be useful which ASPRT has now demonstrated is now contrary to the opinions of the authors of current scholarly articles on the subject, and standard industry practices.

The Commission had an obligation to at least make an inquiry about the 3-D seismic data as Governor Schafer suggested, and not simply follow the staff recommendation that it go with the majority interest holder on a matter that is going to be appealed anyway. That hardly is representative of a decision based on technical expertise.

CONOCO's expert geophysical witness stated in his testimony that the boundary between the mound and regional Lodgepole facies cannot be imaged using seismic because of minimal velocity contrast. Even if this assertion is true, seismic, when properly calibrated with the existing well control, can provide valuable information in the determination of the reservoir limits. Unlike well control, which provides single point control, seismic provides continuous control overt its length and hence more data points.

The most obvious difference between mound and regional Lodgepole is thickness (367 feet versus 254 feet). Seismic can "see" differences in thickness of this magnitude. Thickness changes are expressed indirectly on the seismic by the draping and thinning of the rocks units immediately above the Lodgepole mound and directly by a thicker Lodgepole interval where a mound is present.

Draping and thinning of rock units over a Lodgepole mound can be mapped by isochroning (ie. time thickness map) a seismic reflector for a rock unit above the Lodgepole and the reflection corresponding to the top of the Lodgepole. The well control is used to calibrate these reflectors. Incorporation of the seismic and well control in this manner provides several hundred control points of data. Thinning of this isochron will occur over the mound and a thicker interval will be observed where the regional facies is present. Because the change between the mound and regional Lodgepole is abrupt, the margins of the mound can be placed where the steepest change in slope is observed on the isopach.

CONOCO in its Fryburg isopach map used a variation of this method. However, several shortcomings exist in its map and its use of this approach. First, the Fryburg interval that CONOCO mapped is over 1000 feet above the Lodgepole. There is no assurance that the thinning observed in rock units 1000 feet above the Lodgepole is totally due to the presence of a mound. Variations in the thickness of the intervening rock units due to sedimentological differences can also produce similar results. Secondly, CONOCO's map incorporates only the eight wells in the field area that penetrated the Fryburg.

Given the sparse number of control points used and the use of an interval so far removed from the Lodgepole, the CONOCO map, at the very best, is a very rough estimate of the mounds extent. CONOCO's application of the Fryburg isopach is best suited in an exploratory phase and not in the development of secondary recovery unit.

If CONOCO's assertion that the mound and regional Lodgepole can not be imaged by seismic is correct, the best remaining and most direct method for determining the mound's extent is mapping of the Lodgepole's thickness. From a review of the well data it is known that the difference in thickness between mound and regional Lodgepole thickness is substantial (367 feet versus 254 feet). This magnitude of thickness change can be observed on the quality of seismic data most recently acquired over the field. Also from the well control, it is known that the regional Lodgepole thickness varies minimally in the area of the Dickinson Lodgepole Field. The abrupt change from mound to regional facies is also evident, as observed in the Frenzel #79 boreholes.

CONOCO's expert engineering witness has stipulated that all of the mound above the oil/water contact, regardless of porosity or permeability, is deemed productive for unitization purposes. Using the seismic and well control available, an isopach map can be constructed of the Lodgepole. Because of the abrupt nature of the mound and regional Lodgepole contact, the limit of the mound can be placed where the greatest thickness change occurs. Stated differently, within the Dickinson Field, any thickness greater than the regional Lodgepole is due to the presence of the mound. A net pay map for the field can then be constructed by incorporating the oil/water contact map. Any part of the mound above this contact would be productive.

This approach, as described, was used by ASPRT in preparation of its exhibits for the June, 1994 North Dakota Commission hearing.

The incorporation of both the seismic and well control makes this method superior to the CONOCO Fryburg isopach approach (well control only) in determining the reservoir extent. It should be pointed out that this method is constrained by the available seismic and well control. ASPRT only had access to two recently shot seismic lines.

A better determination of the mound's limits could be undertaken if more seismic data was available to incorporate with the well control. The most ideal seismic for this approach is a 3-D seismic survey, similar to that shot by CONOCO over the Dickinson Lodgepole Field. In this type of survey, seismic receiver lines are typically shot 55 to 110 feet apart and recorded simultaneously. This results in a three dimensional volume of data that allows for more control points and better placement of the seismic reflectors in space. This in turn would allow for a better determination of the reservoir limits.

ASPRT hereby specifically renews its request for an oral argument on this appeal

Dated this 12th day of December, 1994.

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OIL JOURNAL
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Oil & Gas news from the Mountains & Great Plains

Volume 74 No. 48 December 2, 1994-December 8, 1994

Duncan Energy may have North Dakota's second Lodgepole discovery-Stark County

It has been almost two years and about ten dry holes by industry since Conoco completed North Dakota's first Lodgepole discovery in Stark County's Dickinson field. It now appears that this dry spell will end as reports coming in from the field indicate that Duncan Energy has a Lodgepole discovery at the #1-11 Knopik nwnw 11-139n-97w Stark County North Dakota. Currently at a total depth near 10,150', sources have indicated that Duncan conducted a DST in the Lodgepole below 9500' in which a "significant" amount of oil was recovered." Reportedly this oil came to the surface on the initial open of the test tool. Sources also have reported that this test supported a 20' flare. Duncan has released no data concerning this important test but unconfirmed reports indicate that the reef section in this hole encountered by Duncan may be larger than what Conoco found in Dickinson field two miles to the northeast. If in fact these reports are true, this would give the Lodgepole play in this part of the Williston Basin an important boost given the recent string of dry holes that targeted the Lodgepole. Nearest well that penetrated the Lodgepole from the Duncan indicated discovery is about one mile to the east. Operated by Conoco, the #77 Privatsky nenw 12-139n-97w bottomed in the Devonian at a depth of 9970'. No cores or tests were taken and the hole was abandoned. Log top of the Lodgepole came in at 9111' under a ground elevation of 2425'. Field reports indicate that Conoco missed the Carbonate Mound section of the Lodgepole at the Privatsky drillsite.

This rumored discovery by Duncan was drilled on a farm out from Gresham Oil and Gas (USA) Inc., and the drillsite was picked as a result of a 14 square mile 3-D seismic survey Duncan conducted in the early part of this year (see RMOJ 9-10-93). Axem Resources and Meridian Oil are reportedly partners in this venture.

Duncan has also staked a test 40 acres west of #1-11 Knopik. The #2-10 Knopik nene 10-139n-97w will presumably evaluate the Lodgepole at a depth near 10,000'. Other Lodgepole drilling to occur in this immediate area is a test planned by Conoco. Conoco plans to drill the #1-11 Mosbrucker sene 11-139n-97w. No activity has been reported at this drillsite. All three of these tests planned by Conoco and Duncan involve Vancouver based Gresham Oil and Gas (USA) Inc. via acreage contributions.

CRUDE OIL PRICES

Effective Date: November 23, 1994

AREA	Price/bbl, API
West Texas Intermediate	16.50
Central Montana	15.40
Northwest Montana	15.90
Williston Basin Sweet	15.30
No. Dakota-Billings Nose	15.30
Fryburg-Medora flat rate	14.75
Wyo. & So. Mont. Sour	13.00
Wyoming Sweet (Powder Riv Bsn)	16.00
Williston Basin sour	12.15
North Central Colorado	15.50
Four Corners	16.25
Nebraska	15 50

RIG COUNT

As reported by Hughes Christensen	This Week	Week Ago	Month Ago	Year Ago
Montana	7	6	6	4
North Dakota	13	13	11	11
South Dakota	1	1	1	1
Wyoming	31	32	32	53
Nebraska	1	1	1	2
Colorado	39	40	37	37
New Mexico	41	37	47	55
Utah	13	13	11	8

EXHIBIT A

STATE OF NORTH DAKOTA | IN DISTRICT COURT
COUNTY OF STARK | SOUTHWEST JUDICIAL DISTRICT

Andrea Singer Pollack Revocable Trust, Andrea Singer Pollack, Trustee, Appellant, vs. The Industrial Commission of the State of North Dakota, Conoco, Inc., and all other persons having an interest in the Dickinson-Lodgepole Unit, Appellees.	Civil No. 94C-283 **CERTIFICATE OF SERVICE**

The Reply Brief was served upon the parties listed below by mailing true and correct copies thereof to:

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STATE OF NORTH DAKOTA | IN DISTRICT COURT

COUNTY OF STARK | SOUTHWEST JUDICIAL DISTRICT

Andrea Singer Pollack Revocable Trust, Andrea Singer Pollack, Trustee,

Appellant,

vs.

The Industrial Commission of the State of North Dakota, Conoco, Inc., and all other persons having an interest in the Dickinson-Lodgepole Unit,

Appellees.

Civil No. 94C-283

APPELLANT'S BRIEF

An Appeal to the District Court of Stark County
From the Decision of the North Dakota Industrial Commission
Pursuant to NDCC 38-08-14 in Regard to the Unitization of
the Dickinson Lodgepole Unit in Stark County, North Dakota

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STATEMENT OF CASE

This case arose when Conoco, Inc., (CONOCO), filed a Petition for Approval of a Plan of Unitization dated April 22, 1992, with the Oil and Gas Division of the North Dakota Industrial Commission. The Petition sought the unitization of the Dickinson-Lodgepole pool, which was discovered in February of 1993, located in Stark County, North Dakota. Pursuant to a Notice of Hearing, a hearing was held before the North Dakota Industrial Commission on June 8, 1994, at which time CONOCO called witnesses and presented evidence in support of its position. The other participants in the hearing were Placid Oil Company, (PLACID), and the Andrea Singer Pollack Revocable Trust, (ASPRT), both of which presented witnesses and exhibits. Both PLACID and ASPRT supported the unitization of the Dickinson-Lodgepole field, but they disagreed with CONOCO as to the boundaries of the productive area of the Dickinson-Lodgepole field. CONOCO, PLACID and ASPRT all submitted Isopach maps of the Lodgepole mound. (Certificate of Record [C.R.] 17, 81 and 88, respectively - see also S.R. p. 3 for a same scale drawing of all three maps). These maps represented the positions of each of the companies with respect to the productive boundaries of the Lodgepole mound.

The Commission issued its Order No. 6861 in Case No. 5933 on June 16, 1994, approving the petition of CONOCO. (C.R. 100.) PLACID filed a Petition for Reconsideration dated June 30, 1994. (C.R. 101.) ASPRT filed a Petition for Reconsideration dated July 1, 1994. (C.R. 102.) CONOCO filed a Consolidated Response to the

Petitions for Reconsideration of PLACID and ASPRT. (C.R. 104.) ASPRT filed a Reply to the Consolidated Response of CONOCO (C.R. 105) supported by articles from industry publications. (C.R. 106.) The Commission, on July 21, 1994, continued the matter for 45 days or until further order of the Commission. (C.R. 107.) On August 3, 1994, the Commission issued its Order No. 6893 in Case No. 5933 denying the Petitions for Reconsideration filed by PLACID and ASPRT. ASPRT filed a Notice of Appeal and Specifications of Error dated September 2, 1994. (C.R. 109.)

STATEMENT OF FACTS

The impact of the Commission's order on ASPRT is substantial. CONOCO's own Primary Recovery Predictions (C.R. 90) show that in Tract 2 where ASPRT owns a fifty percent (50%) interest, CONOCO's Model Prediction of Ultimate Primary Recovery in Tract 2 was 2.02 million barrels, whereas in the Ultimate Primary Recovery Used for Equity Determination the total barrels dropped to 1.78 million, a difference of 240,000 barrels for a predicted loss to ASPRT's interest due to unitization of 120,000 barrels of oil. In Tract 1 where CONOCO owns a one hundred percent (100%) interest, the number of primary barrels increase from 1.86 million to 2.82 million, allocating an additional predicted 960,000 barrels to CONOCO. The estimate of loss to ASPRT is only for primary recovery and does not include the potential loss of secondary recovery reserves.

The Dickinson-Lodgepole pool was discovered in February 1993, as set forth in CONOCO's Petition for Approval of Plan of

Unitization. (C.R. 1.) No interested party has expressed any opposition to the unitization of the Dickinson-Lodgepole field, as everyone apparently agrees that unitization will enhance the net recovery of oil and related hydrocarbon products. The disagreement between CONOCO, PLACID and ASPRT was how the boundaries are drawn for the Lodgepole field and the resulting effect on the allocation of production among the various parties. CONOCO presented its Isopach of the Lodgepole pay (C.R. 17) setting forth its analysis of where the boundaries of the Lodgepole field are located. Since its Petition was approved, and since the Petition was based on its Isopach of the Lodgepole pay, the Commission necessarily accepted CONOCO's Isopach of the Lodgepole pay. PLACID's net pay Isopach map showed different boundaries to the Lodgepole field. (C.R. 81.) ASPRT's Lodgepole net pay map (C.R. 88) showed its analysis of where the boundaries of the Lodgepole field are located. CONOCO's Isopach map was based on the analysis of well data and a map of the Fryburg interval which occurs approximately 1,000 feet above the Lodgepole field, along with a "compromise" level of the oil water contact. (Tr. p. 168). PLACID and ASPRT both used that same data plus actual 2D seismic which was shot over the Lodgepole field in late 1993. In advance of the hearing, CONOCO spent substantial funds to obtain 3D seismic data on the Lodgepole field, but CONOCO stated it did not complete its analysis of the 3D seismic data and it did not take any of the 2D or 3D seismic data into consideration in preparing its Isopach map. (C.R. 17).

CONOCO's Unit Agreement and its Exhibits A and B (C.R. 9) and its Unit Operating Agreement and its Exhibit C (C.R. 10) set forth the respective interest of the working interest owners and the mineral owners as determined from the location of the Lodgepole field based on CONOCO's Isopach map. (C.R. 17). Had the Commission found that the ASPRT net Isopach map (C.R. 88) more accurately defined the boundaries of the Lodgepole field, the respective percentages of the mineral interest owners and the working interest owners would necessarily have to be recalculated, which could have been readily accomplished.

NDCC 38-08-09.5 provides that a unitization plan will not become effective "unless and until the plan of unitization has been signed or in writing ratified or approved by those persons who, under the Commission's Order, will be required to pay at least seventy percent of the cost of the unit operation and also by the owners of at least seventy percent of the royalty interests under the Commission's Order, excluding overriding royalties, production payments, and other interest carved out of the working interest, and in addition it shall be required that when there is more than one person who will be obligated to pay the costs of the unit operation, at least two nonaffiliated such persons and at least two royalty interest owners, shall be required as voluntary parties...." A witness for CONOCO, Jim Turner, stated that the unit had been ratified by 76.78677 percent for Phase I and 76.81894 for Phase II. (Tr. p. 29.) Jim Turner testified that CONOCO's interest in Phase I is 75.13624, and in Phase II it is 74.88075, giving CONOCO effective control of the whole unitization process. (Tr. p. 30.)

Sometime after the June 8, 1994, hearing, the staff of the Oil and Gas Division discussed the case, but there is no record of this discussion. The transcript of the Industrial Commission meeting of June 16, 1994, is set forth in the Supplemental Record (S.R. pp. 27 - 34). A transcript of the hearing of the Industrial Commission of August 3, 1994 has also been provided. (S.R. pp. 36 & 37).

To assist the court and counsel, ASPRT has included in the Supplemental Record a list of definitions of terms used in this case. (S.R. pp. 1 & 2). Additionally, ASPRT has included in the Supplemental Record several drawings done to the same scale which show the Lodgepole Net Pay Isopach maps of ASPRT, PLACID and CONOCO, and the LODGEPOLE STRUCTURE maps of ASPRT, PLACID and CONOCO. (S.R. pp. 3 & 5).

STANDARD OF REVIEW

Orders of the Commission must be sustained by the District Court if the Commission has regularly pursued its authority and its Findings and Conclusions are sustained by the law and by substantial and credible evidence. NDCC 38-08-14(3).

ISSUES PRESENTED

I.

Whether the Commission failed to properly draw an adverse inference as a result of the absence of CONOCO's 3D seismic data, or in the alternative, whether the Commission should have subpoenaed CONOCO's 3D seismic data.

II.

Whether the process intended by the legislature to unitize an oil field (NDCC 38-08-09.1 et seq) while protecting the correlative rights of all owners is fulfilled by the Commission's order granting CONOCO's plan of unitization.

ARGUMENT

1. <u>The Commission failed to properly draw an adverse inference as a result of the absence of CONOCO's 3D seismic data, or in the alternative, the Commission failed to subpoena CONOCO's 3D seismic data.</u>

Under NDCC 38-08-14(3), orders of the Commission must be sustained by the District Court if the Commission has regularly pursued its authority and its Findings and Conclusions are sustained by the law and by substantial and credible evidence. In <u>Hanson v. Industrial Commission</u>, 466 NW2d 587 (ND 1991), the Supreme Court held:

> Substantial evidence is such relevant evidence as a reasonable mind might accept as adequate to support a conclusion. It is something less than the greater weight of the evidence and, in other words, is something less than a preponderance of the evidence. Thus, we are required to accord greater deference to Industrial Commission findings of fact than we ordinarily to other administrative agencies' findings of fact.
>
> Ordinarily, determinations of administrative bodies are presumed to be correct.
>
> ....
>
> It is against this backdrop of limited judicial review under §38-08-14(4) [sic], N.D.C.C., and the appreciable deference we must accord the Industrial Commission's expertise in the resolution of such highly technical matters as the protection of correlative rights that we review the Commission's decision in this case. 406 NW2d 587, 590,591.

In <u>Hystad v. Industrial Commission</u>, 389 NW2d 590 (ND 1986), the Supreme Court held:

> [C]orrelative rights includes interdependent rights and duties of each landowner in the common source of supply. Each landowner is entitled to a just and equitable share of oil or gas in the pool; however, that right is limited by the landowner's duty to all the other owners of interests in the common source of supply not to damage or take an undue proportion of the oil and gas from that

> common source. Dodds v. Ward, 418 P.2d 629 (Okla. 1966); 1 Summers, Oil and Gas, Section 63 (1954). The physical characteristics and reservoir dynamics of the common source of supply necessitate the use of highly technical geological and economic information to determine the extent of correlative rights. 1 Summers, Oil and Gas, Section 63 (1954). This information necessarily includes, if reasonably practicable, the physical size, shape, and location of the common source of supply relative to each owner's tract of land. 389 NW2d 590, 596.

The legislature set forth the requirements of a plan of unitization in NDCC 38-08-09.4 in relevant part as follows:

> [E]ach such plan of unitization must contain fair, reasonable, and equitable provisions for:
> ....
> 2. ... A separately owned tract's fair, equitable, and reasonable share of the unit production must be measured by the value of each such tract for oil and gas purposes and its contributing value to the unit in relation to like values of other tracts in the unit taking into account ... such other pertinent engineering, geological, or operating factors, as may be reasonably susceptible of determination.

As will be shown, 3D seismic data constitutes "such other pertinent engineering, geological, or operating factors, as may be reasonably susceptible of determination." 3D seismic data constitutes "reasonably practicable" information from which the physical size, shape, and location of the common source of supply can be determined relative to each owner's tract of land.

The North Dakota Supreme Court in Montana-Dakota Utility Company v. PSC, 413 NW2d 308 (ND 1987) with respect to an administrative agency held:

> If the subject matter of a question before an administrative agency is of a highly technical nature, the agency expertise in that area is entitled to appreciable deference, and we are reluctant to substitute our judgment for that of the administrative agency on such matters. Triangle Oil Field

Services, Inc. v. Hagen, 373 NW2d 413 (ND 1985); Johnson v. Elkin, 263 NW2d 123 (ND 1978). 413 NW2d 308 at 312.

The deference granted by a court, however, to the expertise of an administrative agency in a highly technical area is clearly conditioned upon a showing that the agency does in fact have the expertise in the particular area so that a court can grant deference to that expertise. In this case, the Oil and Gas Division of the Industrial Commission is demonstrably wrong in its understanding of the usefulness of 3D seismic data in the development of an oil field and locating the boundaries of a particular geologic formation.

In paragraphs 16 and 17 of its Order No. 6861, dated June 16, 1994, (C.R. 100), which was prepared for it by the staff of the Oil and Gas Division, the Industrial Commission found:

> (16) That Placid and ASPRT believe that seismic information can be used to identify the reservoir boundaries, although no evidence was introduced into the record to support identification of the productive portion of the mound using seismic information.
>
> (17) That testimony by Conoco indicates that seismic information is a highly interpretive exploration tool with which general structure of a feature can be estimated, but from which reservoir quality and the fluids it contains cannot be detected. Therefore, the productive portion of the Lodgepole mound cannot be determined by seismic information.

With respect to both of these Findings, the testimony of expert witnesses and the opinions of authors of scholarly articles clearly establish that 3D seismic data is very useful in defining the boundaries of an oil field. The articles ASPRT submitted with its Reply to the Consolidated Response of CONOCO (C.R. 106) demonstrate the wide spread use made of 3D seismic in the oil and gas industry.[1]

---

[1] Some of the articles submitted in C.R. 106 include:

The <u>Role Of 3D Seismic Technique In Improving Oil Field Economics</u>, by W. Ritchie in the "Journal Of Petroleum Technology," July 1986, begins with a summary in which the author states:

> The most promising role for 3D techniques lies in the area of reservoir description. The 3D seismic method is uniquely capable of providing spatially continuous estimates of rock parameters.

In the article, <u>Optimization of Field Development Through Early Acquisition of 3D Seismic</u>, written by R.C. Myers and E.J.H. Rijiks for the Society of Petroleum Engineers in 1992, the authors note:

> It is common to shoot 3D seismic immediately after a "discovery" to define the optimal appraisal and development strategy, and maximize benefits from the improved data set. A more recent development is the shooting of 3D seismic over complete licenses to identify new exploratory prospects and allow their development to proceed even faster.
>
> The early availability of a high resolution 3D seismic data set will result in ultimate cost savings from:
> ...
> •Optimized appraisal drilling, and field development plans in terms of best drilling locations (i.e. fewer geological sidetracks) and properly sized production/ evacuation facilities....

In <u>Three-Dimensional Data Improve Reservoir Mapping</u>, written by Piet A. Ruijtenberg, Ray Buchanan and Paul Marke for the Society of Petroleum Engineers in 1990, the authors state this conclusion:

> 3D seismic surveys have become a cost-effective tool for mapping hydrocarbon reservoirs and can have a major impact on the volume of reserves estimated. The greatest benefit, however, is gained from 3D data that are recorded in a timely manner and completely interpreted, which can be done efficiently with computer-based interpretation systems. In favorable cases, intra-reservoir details (e.g., reservoir sedimentology, porosity, pore fluids, and minor faulting) can be mapped from 3D seismic data. Knowledge of these details will have a major effect on development strategy and can lead to large cost savings.

The testimony of the witnesses for PLACID and ASPRT regarding 3D seismic is supported by these articles, while the testimony of CONOCO's witnesses is not.[2]

The Affidavit of Thomas L. Davis (S.R. pp. 7 - 25) establishes his broad experience in the field of geophysics and in the use of 3D seismic information in particular. He definitely states "that 3-D seismic a very useful tool in the Williston Basin for defining the boundaries of a potentially productive formation."

In Finding No. 17, the Commission missed the point entirely with respect to 3D seismic information. Not only was there

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[2] Stephen L. Bressler, a senior geologist for PLACID, testified that 3D seismic was not used just for exploration, but also for development, and that PLACID is shooting 3D seismic over virtually all of its properties in west Texas and in the Williston Basin. (Tr. p. 171.) He also testified that, "The only way to, to map this completely accurately would be with 3D seismic, which we have been unable to acquire." (Tr. p. 174.). He also testified that 3D seismic is common in industry for accurately mapping structures, and that "it is becoming the standard method of both exploration and development, lowers the risks substantially." (Tr. p. 183.)

Ernest Gomez was a geologist employed by Intera to consult with ASPRT. He testified that 3D seismic would yield a more accurate net pay map, particularly "if the 3D seismic is indeed tied into the well control and the other control that you have in the area, you should have a very complete picture of what this reef or mound should look like." (Tr. p. 236.)

Jerry Hyrkas, a CONOCO geologist, testified that CONOCO has both 2D and 3D seismic on the Dickinson-Lodgepole field, but that this information was not used in the interpretation of the mound reservoir. (Tr. p. 60.) Jerry Hyrkas testified, "Conoco believes that seismic is a valuable tool, as an exploratory tool, but not a good tool for defining reservoir boundaries." (Tr. p. 61).

Greg Mohl, a geophysicist with CONOCO, testified that, "I consider the seismic method to be totally inappropriate for an equity type of determination." (Tr. p. 260.) He also testified that he was not aware of any geoscientist who used 3D seismic to depict a reservoir boundary for unitization purposes. (Tr. p. 269.)

substantial credible evidence to contradict the testimony of CONOCO's witnesses, but the Commission misread all of the seismic testimony as is evident from Finding of Fact 17. No one ever testified that 3D seismic information would allow a reservoir quality and the fluids it contains to be detected. The evidence and testimony was that 3D seismic data could determine the boundaries of a formation. In this particular case, when the mound is present above the oil water contact, it is productive. No one argues this point. 3D seismic alone can not determine the productive portion of a mound, but 3D seismic can determine the boundaries of the mound. All that was argued was that the boundaries of a particular geological formation could be more accurately determined with 3D seismic data, which testimony was disputed by CONOCO's rebuttal witness.

In the excerpt of the meeting of the Industrial Commission held June 16, 1994, (S.R. pp. 27 - 34), Wes Norton, the Director of the Oil and Gas Division stated to the Commission:

> We said that seismic is an exploration tool, we agree with Conoco on that and does not determine reservoir quality.

That statement is simply not supported by the weight of scholarly opinion in the oil and gas industry as shown above. The Commission staff has an obligation to keep current on the standards in the industry.[3]

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[3] Bruce Hicks of the Oil and Gas Division staff, in questioning Stephen Bressler, apparently referring to 2D seismic lines on several exhibits, stated, "We've had numerous exhibits on seismic and it's been shown to us on many different occasions that seismic is a tool to find, to explore for oil and gas and it's not

3D seismic data has been around for many years and has been used successfully in the Williston Basin to identify the boundaries of geologic formation. The rebuttal witness for CONOCO, may be correct when he says that HE was not aware of any geoscientist who used 3D seismic to depict a reservoir boundary for unitization purposes, but the articles submitted by ASPRT (C.R. 106), the testimony of Stephen L. Bressler and Ernest Gomez, and the affidavit of Thomas L. Davis (S.R. pp. 7 - 25) clearly establish the fact that 3D seismic is being successfully used in the development of oil fields. The Commission simply has been misled as to the usefulness of 3D seismic data to define reservoir boundaries, and the Oil and Gas Division staff has simply not kept up with the development of 3D seismic in the oil and gas industry.

The Commission staff is under an obligation to become familiar with the fact that 3D seismic data is a useful tool for defining reservoir boundaries. Accordingly, the deference a court normally gives to the expertise of an administrative agency on a matter of a highly technical nature should not be given in this case as it is clear from the testimony and the literature that the Commission is simply wrong when it concludes it is only "an exploration tool."

The staff of the Oil and Gas Division is under an obligation to inquire about 3D seismic when the issue is raised. It has the

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a true exact science...." (Tr. p. 219.)

Wes Norton, the director of the Oil and Gas Division, stated, "I'm not a seismic expert, but I have seen many presentations...." (Tr. p. 221).

authority under NDCC 28-32-09 to subpoena CONOCO's 3D seismic data to study the evidence that was withheld.

In its Brief in Support of the Response of the Andrea Singer Pollack Revocable Trust (C.R. 30), ASPRT advised the Commission that CONOCO was not revealing that data because that data was not favorable to it. ASPRT cited the case of Colgate-Palmolive Company v. Dorgan, 225 NW2d 278 (ND 1974) in which our Supreme Court took note of the "adverse inference" rule.

> Essentially, this rule of evidence provides that nonproduction of relevant evidence in the control of a party permits an inference that the evidence is unfavorable to that party's cause. Vol. II, Wigmore on Evidence, 3rd Ed., §285. The rule is as much a matter of common sense and ordinary judgment as a rule of law. It has received recognition by this court. 225 NW2d 278, 281.

CONOCO had the burden of rebutting that presumption under Rule 301 of the North Dakota Rules of Evidence.

ASPRT challenged the Commission to order the production of the 3D seismic data in its brief prior to the hearing as noted, but the Commission staff completely failed to understand the usefulness of 3D seismic data and the difference between 3D seismic data and the 2D seismic data that was available for this hearing. After CONOCO would not permit others to shoot 3D seismic, and after it failed to produce the 3D seismic data, the Commission failed to follow the "adverse inference" rule and draw the presumption that the 3D seismic data was detrimental to CONOCO. This rule of evidence was devised for situations such as this. To fail to draw this inference fails to protect ASPRT's correlative rights.

This matter can now be cleared up by this court ordering CONOCO, pursuant to NDCC 28-32-18, to produce the 3D seismic data for proper processing and analysis. A motion asking for this evidence to be produced under NDCC 28-32-18 is filed herewith.

In its Order No. 6893, dated August 3, 1994, denying the Petitions for Reconsideration (C.R. 108), the Commission took note of the omission by ASPRT's counsel to include with the articles ASPRT submitted in support of Reply of Andrea Singer Pollack Revocable Trust to "Consolidated Response of Conoco, Inc." (C.R. 106) Order No. 1, Docket No. 77-89 issued by the Wyoming Oil and Gas Conservation Commission approving the Unitization of the Little Missouri Field based on maps which utilized only seismic data to delineate the edge of the reservoir. That Order is included in the Supplemental Record (S.R. pp. 93 - 99). The reference to the use of seismic data is found in the report of the Little Missouri Minnelusa Field. (S.R. pp. 38 - 92, see p. 57). It is interesting to note that in both <u>Hanson v. Industrial Commission</u>, supra., and <u>Hystad v. Industrial Commission</u>, supra., the Supreme Court cited a decision of the Wyoming Supreme Court, <u>Larson v. Oil and Gas Conservation Commission</u>, 569 P2d 87 (Wyo. 1977), indicating the deference our court pays to Wyoming regarding oil and gas matters.

2. <u>The process intended by the legislature to unitize an oil field (NDCC 38-08-09.1 et seq) while protecting the correlative rights of all owners is not fulfilled by the Commission's order granting CONOCO's plan of unitization.</u>

In <u>Hystad v. Industrial Commission</u>, supra., the Supreme Court held:

> [O]ur analysis requires consideration of "correlative rights," a term not defined in our statutes providing for regulation of gas and oil production activities nor is the term defined in the regulations of the commission.
>
> In <u>Amoco Production Co. v. North Dakota Industrial Commission</u>, 307 NW2d at 842, fn. 4, we referred to the following definition of correlative rights:
>
>> "4. 'Correlative rights
>> "[T]he opportunity afforded, so far as it is practicable to do so, to the owner of each property in a pool to produce without waste his just and equitable share of the oil and gas, or both, in the pool; being an amount, so far as can be practically determined, and so far as can be practically obtained without waste, substantially in the proportion that the quantity of recoverable oil or gas, or both, under such property bears to the total recoverable oil or gas, or both, in the pool, and for such purposes to use his just and equitable share of the reservoir energy." Nev.Rev.Stat. §522.020(2). There appear to be two aspects of the doctrine of correlative rights: (1) as a corollary of the rule of capture, each person has a right to produce oil from his land and capture such oil and gas as may be produced from his well, and (2) a right of the land owner to be protected from damage to a common source of supply and a right to a fair and equitable share of the source of supply. When a legislature or administrative body regulates production practices to protect against waste, it may also regulate to insure an equitable share of the source of supply. There is some dispute over the power of the state to regulate production practices to insure an equitable distribution of the source of supply, apart from waste. See <u>Treatise</u> §204.6.' Williams &

Meyer, Manual of Oil and Gas Terms (4th ed. 1976)." 389 NW2d 590, 595, 596.

To provide for the unitization of oil fields while protecting correlative, the legislature enacted NDCC 38-08-09.1 et seq., which sets forth the procedures for unitization of oil and gas fields while protecting correlative rights. While NDCC 38-08-09.5 requires the ratification of a unit by the owners of at least seventy percent of the royalty interests, nowhere do these statutes authorize the Commission to simply follow the principle of "majority rule." Rather the Commission under NDCC 38-08-09.4 is required to issue an order which "must contain fair, reasonable, and equitable provisions for:

> 2. The division of interest or formula for the apportionment and allocation of the unit production, among and to the several separately owned tracts within the unit area as will reasonably permit persons otherwise entitles to share in or benefit by the production from such separately owned tracts to produce or receive, in lieu thereof, their fair, equitable, and reasonable share of the unit production or other benefits thereof. A separately owned tract's fair, equitable, and reasonable share of the unit production must be measured by the value of each such tract for oil and gas purposes and its contributing value to the unit in relation to like values of other tracts in the unit, taking into account acreage [hectarage], the quantity of oil and gas recoverable therefrom, location on structure, its probable productivity of oil and gas in the absence of unit operations, the burden of operation to which the tract will or is likely to be subjected, or so many of said factors, or such other pertinent engineering, geological, or operating factors, as may be reasonably susceptible of determination.

Under NDCC 38-08-09.4, the Commission has no power to include within the spaced area tracts which do not overlay the common source of supply. See Panhandle Eastern Pipe Line Co. v. Corporation Commission, 285 P2d 847, 850 (Okla 1955), Caudillo v.

Corporation Commission, 551 P2d 1110, 1115 (Okla 1976), and Calvert Drilling Co. v. Corporation Commission, 589 P2d 1064, 1068 (Okla 1979). This is exactly what the Commission's order does when it approves the unit based on the CONOCO Net Pay Isopach map which extended the eastern boundary of the unit toward a dry hole (which boundary was much more favorable to CONOCO giving it a greater share of the unit production), and which map will not stand when the Commission properly considers all the pertinent engineering, geological, or operating factors, as may be reasonably susceptible of determination.

Instead of considering all the evidence that was reasonably susceptible of determination, such as 3D seismic, the staff emphasized the fact that CONOCO's unitization plan had 86% ratification by royalty interest owners (of which CONOCO itself had more than 75%) and that the "order will be appealed regardless of what kind of an order..." (S.R. pp 31 & 32). This lack of inquiry into all the relevant evidence does not protect correlative rights, particularly of the minority royalty interest owners.

CONOCO's plan of unitization for the Dickinson-Lodgepole field involved a unit agreement (C.R. 9) and a unit operating agreement (C.R. 10), Exhibits A, B and C of which set forth CONOCO's calculations as to the relative ownership interest of each of the owners in the Dickinson-Lodgepole field. The calculations were derived from CONOCO's isopach map of the Lodgepole pay. (C.R. 17). CONOCO prepared its isopach map of Lodgepole pay using only information derived from well logs and a projection from the

Fryburg interval, neglecting to utilize 2D seismic and 3D seismic which was available exclusively to CONOCO. Since CONOCO's equity calculations were based only on its isopach map of the Lodgepole pay, and since the Commission apparently felt that it had no choice but to either accept or reject CONOCO's application, the resulting Order determined the rights of all of the owners, based on CONOCO's isopach map of the Lodgepole pay.

The problem is that the CONOCO isopach map of the Lodgepole pay shows the eastern Lodgepole mound boundaries located farther East than is justified by an analysis of all of the available data. The particular tracts in the Dickinson-Lodgepole Unit are shown on Exhibit B to the unit agreement (C.R. 9). A quick comparison of CONOCO's isopach map (C.R. 17) with PLACID's isopach map (C.R. 81) and ASPRT's isopach map (C.R. 88) [see S.R. p. 3 for a map showing all three maps drawn to the same scale] show that the main difference in the interpretation of each of the three companies is how far east the boundary of the Dickinson-Lodgepole mound is located. Each of the three maps appear to agree as to the general westward and southwest boundaries of the Lodgepole mound. CONOCO has a vested interest in pushing the boundary eastward as much as possible as it owns one hundred percent of the working interest in Tract 1 while it only owns fifty percent in Tract 2. Accordingly, the more production CONOCO can shift to Tract 1, the more money it makes at the expense of other owners. CONOCO's map shows the eastern boundary extending to the Filipi 76 well in the East half of Section 32, which is a dry hole. The maps which used the seismic data to define the eastern boundary show that edge of the mound is located approximately 1,000 feet west of the Filipi dry hole.

In its Petition for Approval of a Plan of Unitization, CONOCO, which owns approximately seventy-five percent of the working interest in the field, submitted a plan that clearly favors CONOCO and which fails to take into account both 2D and 3D seismic data which it collected, but will not disclose.

Many of the COMMISSION's Findings are not sustained by substantial and credible evidence. Finding 14 in the COMMISSION's order (C.R. 100) is not sustained by substantial and credible evidence. The expert testifying on behalf of ASPRT specifically testified that the ASPRT net pay isopach map (C.R. 88) was constructed using the well data and honoring all of the information from the well logs as well as the available 2D seismic data. PLACID presented the seismic data to the technical staff of the North Dakota Industrial Commission at an informal meeting on June 1, 1994. Also shown at this meeting were the synthetic seismic lines which were created from Sonic logs run in several wells drilled in the field. The character of the synthetics from wells which penetrated the mound was easily distinguishable from the character of the synthetics from wells which did not penetrate the mound such as the Filipi 76. The 2D seismic lines were shown to be almost identical to the synthetics both within the mound and outside the mound. The edge of the mound was very apparent on the north, east, and south sides of the mound where the 2D seismic lines were run basically perpendicular to the edge of the mound. The western edge of the mound was not as obvious because of the low angle at which the seismic line crossed the mound edge but could be estimated to within several hundred feet. It was clearly shown to the North Dakota Industrial commission technical staff that 1) the synthetic seismic lines match the 2D data and 2) the edges of the mound could be determined at the points where the seismic lines crossed the mound edge.

ASPRT's Geologist and Geophysicist analyzed the 2D seismic data totally independently from PLACID's technical staff. ASPRT relied on its own synthetic seismic lines to build its geophysical model prior to analyzing the PLACID seismic data. Contrary to past assertions by CONOCO that PLACID and ASPRT "reached totally different conclusions as to where the edges of the reservoir are located," the maps of the two companies are strikingly similar in shape and as to location of the edges of the mound. PLACID's expert witness testified that he used 2D seismic data only to locate the edges of the reservoir while ASPRT's witness testified that the seismic data was used along with well data to determine the thickness of the mound as well as to locate the mound edges.

ASPRT's map utilizes all of the data available: well control, 2D seismic data and the Fryburg structure. ASPRT's reservoir boundaries are supported by PLACID's independent use of the seismic to delineate the mound edge. Thickness shown on ASPRT's map including the "saddle" in the middle of the field is supported by the CONOCO map which utilized the well data and the Fryburg map.

The saddle shown on the ASPRT map is based on well data, the Fryburg structure, and seismic data. Clearly, the ASPRT map incorporates all of the available data. The finding that the net pay isopach map was based only upon seismic information is not sustained by substantial and credible evidence.

Finding 16 is likewise not sustained by substantial and credible evidence because the evidence presented by ASPRT was that the identification of the productive portion of the mound was identified using both seismic information and well data, honoring all of the data that was available.

Findings 18, 19 and 20 concerning the Fryburg Interval place far too much weight on the CONOCO map of the Fryburg structure (C.R. 15) without considering the highly interpretive nature of the map. CONOCO's Fryburg map is based on only two additional wells which did not also penetrate the Lodgepole section. One of these wells is in the middle of the Lodgepole field and the other is located to the northeast of the field. The Fryburg map has no data points to delineate the Fryburg structure along the western edge of the Lodgepole feature, therefore the position of the Fryburg contours are completely at the discretion of the mapper. Additionally, the particular geologic event chosen by CONOCO on which to base the Fryburg structure thickens dramatically to the northeast. Had the base of this gamma ray "hot" streak been mapped rather than the top, the position of the Filipi well on the Fryburg structure would have been approximately ten feet lower relative to the other wells. Finally, even if one agrees totally with the "quadratic equation relationship" between the Fryburg and the Lodgepole tops, it is not possible to determine how close the mound edge is to the Filipi well. Only the fact that the Filipi well should have no mound present could be concluded. The location of the edges of the mound cannot be predicted using the Fryburg marker.

The Commission's basis for its conclusions concerning the eastern boundary of the reservoir and the credibility of CONOCO'S map (Findings 22 and 23) which was the close agreement between CONOCO's material balance and volumetric estimates of original oil in place (OOIP) is not valid.

The reservoir model derived material balance estimate of OOIP is probably fairly accurate, but by no means exact. A volumetric calculation of OOIP is much less accurate. Volumetric calculations are based not only on the bulk reservoir volume depicted by a net pay map, but also include several assumed factors which affect the calculation just as much as the map, namely porosity and oil saturation. Had CONOCO used .059 for porosity instead of .054, the volumetric estimated of OOIP would have increased nearly ten percent. In other words, a one-half percent increase in porosity would add nearly 2 million barrels of oil to CONOCO's volumetric estimate of OOIP.

Probably even more inaccurate than porosity is CONOCO's assumption of oil saturation. This estimate of 89.4 percent is based on core analysis. Only a small section of the pay interval in one well was cored and analyzed. This reservoir is anything but homogeneous. CONOCO's assumption of uniform porosity and oil saturation are grossly inaccurate.

Even if one could calculate a reliable volumetric estimate of original oil in place which agreed with the material balance estimate, this would imply that the <u>size</u> of the reservoir depicted by the map is fairly accurate. Nothing about the location of the boundaries of the mound could be concluded given the sparse well control. The bases for the Commission's conclusion are totally without geological and technical merit.

Finding 24(b) is not supported by substantial and credible evidence. CONOCO's apportionment and allocation of the Unit Production among the tracts within the unit area is not fair, equitable, nor reasonable. CONOCO's own reservoir modeling study suggests drastically different apportionment of primary reserves than that proposed by CONOCO and approved by the COMMISSION. CONOCO has been inconsistent in the use of the results of the computer reservoir model. CONOCO used the model-derived estimate of field-wide primary recovery in their equity formula, yet CONOCO has stated that "due to simplistic assumptions contained within the reservoir model, the model is only useful in comparing various different operating scenarios on a field-wide scale, such as water-flooding, gas injection and primary depletion." It appears that CONOCO feels that the model is useful only if the results of the modeling study do not adversely affect CONOCO's sharing ratio in the unit.

As was shown in ASPRT's Exhibit (C.R. 90), CONOCO's failure to utilize the model's prediction of ultimate primary for the various individual wells within the unit, resulted in the addition of nearly one million barrels of recoverable primary oil to Tract No. 1 where CONOCO, not coincidentally, owns 100 percent of the working interest. The fact that CONOCO has interest holdings in all nine tracts gives CONOCO absolutely no incentive to protect the rights of all owners unless its ownership was the same in all tracts. This is certainly not the situation in this case. CONOCO owns 100 percent working interest in Tract 1 (W/2 Section 32), Tract 4 (N/2 Section 5), and Tract 9 (SE/4 Section 32). Every barrel of oil allocated to one of these three tracts at the expense of any other tract increased CONOCO's interest in the unit. For example, if 100,000 barrels of primary oil is incorrectly allocated to Tract 1 instead of Tract 2, CONOCO would lose 50,000 barrels in Tract 2 and gain 100,000 barrels in Tract 1 for a net gain of 50,000 barrels. It should be noted that the two most disputed aspects of CONOCO's unitization plan, namely the oil-water contact and the location of the eastern boundary of the Lodgepole mound have significant impact on the three 100 percent CONOCO tracts. It is apparent CONOCO has been extremely generous to itself in the mapping of this reservoir, in the selective inclusion of data which increases CONOCO's unit interest, and the selective exclusion of data which decreases CONOCO's unit interest.

The order of the COMMISSION mentions nothing about the location of the oil/water contact in the reservoir although there was a considerable amount of testimony concerning this subject. CONOCO has stated that the State A-83 well has an oil to water transition zone which starts at -9818' and continues down for 10 to 20 feet. Water saturation calculations based on the log data clearly do not indicate a long transition zone present in this well. Water saturations change from very low to very high over the course of only a few feet. If CONOCO believes that there is a 10' to 20' transition zone present in this well, then CONOCO's adoption of a uniform water saturation within the mapped pay interval is totally without merit. CONOCO's equity formula is not consistent with testimony of its own expert witness in that by definition a transition zone contains varying water saturations. CONOCO's expert witness testified that CONOCO had calculated the oil/water contact in the State 83 well to be located at a position 10 feet higher than that used in the mapping of the net pay. This alone precludes the allocation of unit production from being fair, reasonable, and equitable.

CONCLUSION

In summary, the Order of the Commission does not protect the correlative rights of all the mineral owners and working interest owners. The apportionment of unit ownership is based entirely on CONOCO's map which, at best, is subject to gross errors due to a lack of data. At worst, this map misallocates hundreds of thousands of barrels of oil worth several million dollars. The large discrepancy between CONOCO's computer model estimate of primary oil by tract and CONOCO's map-based allocation illustrates this point.

Due to the potential misallocation of the reserves in the field because of sparse well data for mapping, and due to the enormous financial impact the misallocation has on the owners, it is imperative that the Commission consider all available data to insure that correlative rights are protected. The Commission has been remiss in its failure to require CONOCO to produce the 3D seismic data for consideration by the Commission. Accordingly, the decision of the Commission approving the plan of unitization should be reversed and this matter remanded to the Commission for further proceedings.

Dated this 1st day of November, 1994.

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STATE OF NORTH DAKOTA | IN DISTRICT COURT

COUNTY OF STARK | SOUTHWEST JUDICIAL DISTRICT

Andrea Singer Pollack Revocable Trust, Andrea Singer Pollack, Trustee

Appellant,

vs.

The Industrial Commission of the State of North Dakota, Conoco Inc., and all other persons having an interest in the Dickinson-Lodgepole Unit,

Appellees.

Civil No. 94C-283

RESPONSE OF APPELLEE CONOCO INC. TO APPELLANT'S BRIEF AND APPELLANT'S MOTION TO COMPEL THE PRODUCTION OF 3-D SEISMIC

I. STATEMENT OF THE CASE

A. Introduction.

The statement of the case as presented by the Appellant, Andrea Singer Pollack Revocable Trust, Andrea Singer Pollack, Trustee ("ASPRT"), fails to provide any factual background necessary to understand how this matter made its way before the North Dakota Industrial Commission ("Commission"). As such, Conoco Inc. ("Conoco") will briefly describe the course of events which resulted in the Commission considering the matter of unitization of the Dickinson-Lodgepole Pool in Stark County, North Dakota.

B. Factual Background.

In February of 1993, Conoco completed the Dickinson State No. 74 well in the Northwest Quarter of Section 32, Township, 140 North, Range 96 West, Stark County, North

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Dakota. *Certificate of Record ("CR"), Vol. II, Tab 31 at 125.* The Dickinson State No. 74 well was completed in the Lodgepole formation and, after several days of testing, produced at a rate of more than 2000 barrels of oil per day. *Id. at 125-126.*

In July of 1993, Conoco spudded the Kadrmas No. 75 well in the Southwest Quarter of Section 31. The Kadrmas No. 75 well is located approximately 3000 feet to the southwest of the Dickinson State No. 74 well. The well was completed in September of 1993 as a producer of oil and gas and was production tested at approximately 1600 barrels of oil per day. *Id.*

In August of 1993, Conoco spudded the Frenzel No. 79 well in the Northeast Quarter of Section 31, approximately 2800 feet to the northwest of the Dickinson State No. 74 well. *Id.* Initially, the Frenzel No. 79 well failed to encounter productive reservoir and was a dry hole. *Id.* Conoco, however, "sidetracked" the well to the southeast and intersected productive Lodgepole reservoir approximately 2000 feet to the northwest of the Dickinson State No. 74 well. *Id. at 126-127.* The Frenzel No. 79 well was production tested at approximately 350 barrels of oil per day. *Id. at 127.*

In September of 1993, Conoco spudded the Filipi No. 76 well in the Northeast Quarter of Section 32, approximately 2800 feet to the east of the Dickinson State No. 74 well. The Filipi No. 76 well, like the Frenzel No. 79 ("straight hole") well, failed to encounter productive reservoir and was a dry hole. The proximity of the Filipi No. 76 well to the western boundary of the spacing unit for the well prohibited any attempt to "sidetrack" the well. Consequently, Conoco and all of its working interest partners in the well agreed to plug and abandon the Filipi No. 76 well in October of 1993. *Id.*

In November of 1993, Conoco drilled and completed the Dickinson State "A" No. 83 well in the Northwest Quarter of Section 5, Township 139 North, Range 96 West, approximately 6000 feet to the south of the Dickinson State No. 74 well. *Id at 128.* The Dickinson State "A" No. 83 well encountered the edge of productive Lodgepole reservoir. *Id. at 127 & 128.* The well was ultimately completed and produced at a rate of 300 barrels of oil per day. *Id. at 128.*

Finally, in January of 1994, Conoco drilled the Walton No. 84 well in the Northwest Quarter of Section 6, approximately 5600 feet to the southwest of the Dickinson State No. 74 well. *Id.* The Walton No. 84 well also failed to encounter productive reservoir and was a dry hole. As with the Filipi No. 76 well, no attempt was made to sidetrack the well. Conoco and its working interest partner in the well agreed to plug and abandon the well. *Id.*

Conoco first began considering the possibility of unitizing the Dickinson-Lodgepole Pool shortly after the Kadrmas No. 75 well was drilled and completed in September of 1993. *Id. at 133.* After the Frenzel No. 79 well was drilled, it became evident that the reservoir pressure in the field was quickly falling to "dangerously low levels." *Id.* Conoco, therefore, decided that the only prudent thing to do was to curtail production and conduct a study to determine the feasibility of unitizing the Dickinson-Lodgepole Pool for secondary recovery purposes. *Id. at 136.* All working interest owners agreed that unitization and secondary recovery operations were essential to increasing the ultimate recovery from the pool and prolonging the life of the field. After reaching agreement with the working interest owners, Conoco cut production in the field to 300 barrels of oil per day and the working interest

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owners began pursuing the unitization process. *Id. at 136-137.*

Four working interest owner meetings were had at which information concerning the Dickinson-Lodgepole Pool was exchanged and discussed. *Id. at 10-11.* At the first meeting, a voting procedure was unanimously adopted requiring approval of all matters by a vote of at least three or more working interest owners having a combined interest of at least 70%. *Id. at 11.* Based on that voting procedure, the working interest owners approved a plan of unitization for the Dickinson-Lodgepole Unit area on March 30, 1994. *Id. at 13.*

C. **Course of Proceedings**.

On April 22, 1994, Conoco served and filed its Petition for Approval of Plan of Unitization for the proposed Dickinson-Lodgepole Unit area. *CR, Vol. I, Tab 1.* A hearing was set for June 8, 1994 with all owners of interest being noticed of said hearing as required by law. *CR, Vol. I, Tabs 2-3.* The hearing resulted in the Commission entering Order No. 6861 in Case No. 5933, dated June 16, 1994, approving the creation of the Dickinson-Lodgepole Unit. *CR, Vol. III, Tab 100 at 1-7.* On June 30, 1994 and July 1, 1994, Placid Oil Company ("Placid") and ASPRT, respectively, filed petitions for reconsideration. *CR, Vol. III, Tabs 101-102.* Placid and ASPRT both alleged that the Commission erred in approving the application of Conoco for creation of the Dickinson-Lodgepole Unit. *Id.* By consolidated response dated July 18, 1994, Conoco resisted the petitions for reconsideration of Placid and ASPRT. *CR, Vol. III, Tab 104.* Subsequent thereto, the Commission entered Order No. 6893 dated August 3, 1994 denying the petitions for reconsideration filed by ASPRT and Placid. *CR, Vol. III, Tab 108.*

On September 2, 1994 ASPRT filed and served its notice of appeal seeking a reversal of Commission Order No. 6893 and Order No. 6861 and a remand of this matter with specific instructions to the Commission that "any 3D seismic data of Conoco be made a part of the record or released to a third party for an analysis and report to the COMMISSION as to the location of the unit boundaries as shown by 3D seismic information, . . ." *CR, Vol. III, Tab 109 at 5.* On the same date, ASPRT also filed a motion to compel the production of Conoco's 3-D Seismic. *ASPRT's Motion to Compel.*

II.
STATEMENT OF THE FACTS

A. Introduction.

Conoco notes that the statement of the facts as set forth by ASPRT consists, in large part, of arguments that were rejected by the Commission and which are not relevant to the issues presented for review. Rather than setting forth the facts as they pertain to the issues presented for review, ASPRT has seemingly set forth an objective recitation of an arbitrarily abridged version of its closing arguments. Furthermore, rather than present a fair and balanced statement of the facts, ASPRT has totally ignored the overwhelming evidence which supports the order of the Commission granting the application of Conoco in this case.

B. Facts Relevant to the Issue of the Commission's Orders Being Supported by Substantial, Credible Evidence.

On June 8, 1994, a hearing was had to consider the application of Conoco for unitization of the proposed Dickinson-Lodgepole Unit area. In support of its application, Conoco offered testimony and exhibits from a landman, Mr. Jim Turner, a geologist, Mr. Jerry Hyrkas, and a reservoir engineer, Mr. Kevin Zorn. ASPRT offered testimony and

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exhibits from a geologist, Mr. Ernest Gomez, and a petroleum engineer, Mr. Kevin Preston. Placid offered testimony and exhibits from a geologist, Mr. Stephen Bressler. As rebuttal to the testimony and exhibits offered by ASPRT and Placid, Conoco offered testimony and exhibits from a geophysicist, Mr. Greg Mohl. *See generally, Transcript of Hearing, CR, Vol. II, Tab 31.* At the close of the hearing, Mr. Robert Post Johnson offered a statement in support of Conoco's application on behalf of Wiser Oil Company, both a working interest owner and royalty interest owner within the unit area. Mr. Arthur C. Bauer offered a statement in support of Conoco's application on behalf of Lewis W. Hill, Jr., a working interest owner within the unit area. *Id. at 295-296.*

1. Conoco's evidence.

Conoco offered the testimony of Mr. Jim Turner to explain the procedure Conoco followed in securing approval for the plan of unitization. *CR, Vol. II, Tab 31 at 10-16.* Mr. Turner testified that Conoco secured approval for the plan of unitization from working interest owners owning a Phase I interest of 76.78677% and a Phase II interest of 76.81894%. *Id. at 16.* Conoco also secured approval from royalty interest owners owning a Phase I interest of 86.48866% and a Phase II interest of 86.03647%.[1] *Id.* Mr. Turner explained the terms and conditions of the unit agreement and the unit operating agreement and testified that the Dickinson-Lodgepole Unit consists of nine tracts encompassing 1436.45 acres. *Id. at 19.*

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[1] In arguing that the Commission failed to consider all the evidence, ASPRT states that Conoco's "unitization plan had 86% ratification by royalty interest owners (of which CONOCO itself had more than 75%). *Appellant's Brief at 18.* That statement is simply false. Conoco's royalty interest in the unit is 3.78948% in Phase I and 3.8194% in Phase II. *CR, Vol. III, Tab 74 at 1.*

Conoco's geologic witness, Mr. Jerry Hyrkas, testified concerning the geology of the Lodgepole formation in the area of the Dickinson-Lodgepole Unit. *Id. at 42-58.* Mr. Hyrkas pointed out that the Lodgepole formation in the Dickinson area is a "very rare geologic occurrence." *Id. at 46.* He explained that the productive rock encountered probably developed more than 300 million years ago from a build-up of fossils. The build-up was in the form of a mound or reef-like structure which is termed a Waulsortian mound. *Id. at 46.* To date, no other productive Waulsortian mound has been found in the Williston Basin of North Dakota or Montana. *Id.*

Mr. Hyrkas discussed a number of geologic exhibits to support his interpretation of the limits of the productive Lodgepole reservoir. *CR, Vol. III, Tabs 47-54.* Mr. Hyrkas explained that his study of this area has revealed a relationship between the shallower Fryburg structure and the proximity and thickness of the productive Lodgepole mound. *CR, Vol. II, Tab 31 at 52.* The relationship is that where you have a Fryburg structural high, you have a thickening of the Lodgepole mound. Where you have a Fryburg structural low, you have a thinning of the Lodgepole mound or no Lodgepole mound at all. *Id. at 52.* Utilizing information from nine wells that penetrated the Fryburg formation and seven wells that penetrated the Lodgepole formation, Mr. Hyrkas developed a mathematical relationship between Fryburg structure and Lodgepole mound thickness. *Id. at 51.*

Mr. Kevin Zorn, Conoco's reservoir engineer for the Dickinson-Lodgepole Field, testified concerning the history of development of the pool; the need to implement some sort of pressure maintenance project for the pool; the reservoir modeling studies that were conducted by Conoco; and, the feasibility of utilizing reservoir modeling to calculate cumulative production from individual wells producing from the pool. *Id. at 124-151; 289-294.*

Mr. Greg Mohl, Conoco's geophysicist, testified to rebut the testimony of ASPRT and Placid concerning the appropriateness of using seismic, to pick reservoir boundaries for unitization purposes. *Id. at 257-269.* Mr. Mohl testified that because of the physical properties of the Lodgepole formation, utilizing seismic, 2-D or 3-D, to pick the productive reservoir edges of the Dickinson-Lodgepole Pool is simply not possible. *Id. at 260.* Mr. Mohl explained that sonic logs run through the Lodgepole interval at Dickinson show no appreciable velocity contrast between productive and nonproductive reservoir within the Lodgepole stratigraphic section. *Id at 263.* Because the productive reservoir is virtually invisible to seismic, a seismic interpreter must rely on wave form anomalies in order to project where the edge of the reservoir will be located. Mr. Mohl explained that basic seismic wave theory proves that there will be a radius of uncertainty which could exceed 1000 feet. *Id. at 266.* Within this radius no one can pick the edge of a reservoir with reasonable certainty. Mr. Mohl therefore concluded that seismic data is an inappropriate tool for determining the reservoir edges in the Dickinson-Lodgepole Pool. *Id. at 269.*

3. ASPRT's evidence.

ASPRT offered the testimony of a geologist, Mr. Ernest Gomez, to introduce its interpretation of the productive limits of the Lodgepole mound. *CR, Vol. II, Tab 31 at 229-237.* Mr. Gomez explained that his map of the productive limits of the Lodgepole mound was based on a compilation of log data from the seven Lodgepole wells and seismic data obtained from Placid. *Id. at 235.*

Mr. Kevin Preston, a petroleum engineer for ASPRT, testified as to how the working interest owners reached agreement on selecting an oil/water contact for the field and how agreement was reached on the plan of unitization. *Id. at 245-247.* Mr. Preston also testified as to the results of Conoco's reservoir modeling and the fact that model results were only used for primary recovery predictions for the field as a whole and not for individual tracts. *Id. at 281-282.*

3. Placid's evidence.

Placid offered the testimony of Mr. Stephen Bressler, a geologist, to introduce its interpretation of the productive limits of the Lodgepole mound and the tilted oil/water contact. *Id. at 166-182.* Mr. Bressler explained that his interpretation of the productive limits of the Lodgepole mound was based on "a synthetic seismic model based on the sonic logs from three wells in the area." *Id. at 170.*

4. The Commission's Findings and Conclusions.

After the Commission hearing of this matter on June 8, 1994, the Commission entered Order No. 6861. *CR, Vol. III, Tab 100.* The Commission found that all the working interest owners agreed that unitization of the Dickinson-Lodgepole Pool was necessary to increase the ultimate recovery of the pool and prevent waste. *Id. at 3.* In addition, the Commission found that the testimony of Conoco indicated that seismic data is highly interpretative and not a good tool to determine the quality of a reservoir. The Commission therefore concluded that the productive limits of the Dickinson-Lodgepole could not be determined by utilizing seismic data. *Id. at 4.* The Commission further found that the structural features of the Fryburg Interval as utilized by Conoco was a "useful method to assist in determining the boundaries of the Lodgepole Pool reservoir." Id. Finally, the Commission found that Conoco's depiction of the reservoir boundaries was the most credible map presented. Id.

C. Facts Relevant to ASPRT's Motion to Compel the Production of Conoco's 3-D Seismic.

Conoco served and filed its Petition for Approval of Plan of Unitization on April 22, 1994. *CR, Vol. I, Tab 1 at 1-6.* On June 6, 1994 (44 days after Conoco served and filed its petition for unitization and 2 days prior to the scheduled hearing of the Conoco's petition), ASPRT filed and served its response and brief in opposition to Conoco's petition for unitization. *CR, Vol. I, Tab 30.* ASPRT requested that Conoco's petition for unitization be "dismissed, or in the alternative, that the request be referred back to Conoco, Inc. and the other interested parties for the purpose of negotiating and working out a proposal which is fair, equitable and reasonable to all working interest and royalty interest owners in accordance with N.D.C.C. § 38-08-09.4(2), . . ." *Id. at 3.*

At the hearing had to consider Conoco's petition for unitization, ASPRT requested that Conoco's petition be "rejected or in the alternative that it be continued contingent upon Conoco producing the 3D data or producing it into the hands of an agreeable third party who will map it." *CR, Vol. II, Tab 31 at 302.* At the close of the hearing, the hearing examiner for the Commission inquired as to why ASPRT did not file a motion prior to hearing requesting that the Commission compel Conoco to produce its 3-D seismic. Id. ASPRT responded that "it was strictly a matter of time" and that ASPRT had a right to expect that Conoco would produce all the evidence it had. *Id. at 303.*

Conoco asserted that it was justified in not submitting its 3-D seismic for four reasons. First, because of the interpretative nature of seismic, geoscientists examining identical data often reach totally different conclusions with respect to the characteristics of the reservoir. Second, because of the physical properties of the Lodgepole formation, it is simply not possible to utilize seismic, 3-D or 2-D, to pick productive reservoir boundaries in the Dickinson-Lodgepole Pool. Third, because Conoco's 3-D seismic program was conducted as an exploration tool, Conoco has a competitive advantage over their industry competitors in the area. Conoco did not wish to jeopardize this competitive advantage "by simply giving away its seismic analog to competitors." The fourth reason offered by Conoco for not offering its 3-D seismic data was the fact that the data had not been processed. *CR, Vol. III, Tab 99 at 4-6.*

The Commission agreed with Conoco -- "seismic data is an unreliable method to locate the Dickinson-Lodgepole reservoir boundary primarily because there is little velocity contrast between the productive and nonproductive Lodgepole." *CR, Vol. III, Tab 108 at 2.* The Commission further concluded that interpretative nature and unreliability of seismic data was exhibited by the dissimilarity of the maps prepared by Placid and ASPRT utilizing the same data. *Id.*

D. Facts Relevant to ASPRT's Supplementation of the Record.

After the Commission entered Order No. 6861, dated June 16, 1994, which granted Conoco's application for the creation of the Dickinson-Lodgepole Unit, ASPRT attempted to supplement the record by filing with the Commission a number of journal articles concerning the use of 3-D seismic. *CR, Vol. III, Tab 106.* The Commission found that there was no evidence to indicate that the geological formations discussed in the articles bore any similarity to the reservoir characteristics of the Dickinson-Lodgepole Pool. *CR, Vol. III, Tab 108 at 3.* The Commission therefore concluded the articles were "unhelpful, if not irrelevant." *Id.* The Commission further concluded that there was no reason why ASPRT could not have submitted these articles into evidence at the time of hearing and declined to reopen the case and make the articles part of the record. *Id.*

On appeal, ASPRT has, once again, attempted to supplement the record of this case. Without seeking leave of the Court, as provided by N.D.C.C. § 28-32-18, ASPRT has submitted 99 pages of material to supplement the record of this appeal. *See Appellant's Supplemental Record.* Included among the documents is an affidavit of Professor Thomas L. Davis, Colorado School of Mines; Professor Davis' Resume; transcripts of meetings of the Commission; reports, exhibits and an order of the Wyoming Oil and Gas Conservation Commission relative to unitization of the Little Missouri-Minnelusa Field in Crook County, Wyoming. ASPRT offers no explanation as to how this supplemental information is relevant to this appeal or why the materials were not submitted at the time of hearing.

III.
STANDARD OF REVIEW

This Court reviews orders of the Commission based upon the record filed with the Court. N.D.C.C. § 28-32-19. Orders of the Commission must be sustained by this Court if the Commission "has regularly pursued its authority and its findings and conclusions are sustained by the law and by substantial and credible evidence." N.D.C.C. § 38-08-14(4). To determine whether the Commission's findings are sustained by law and substantial and credible evidence, this Court must answer the following questions: "(1) Are finding of fact supported by substantial evidence? (2) Are the conclusion of law sustained by the findings of fact? (3) Is the agency decision supported by the conclusions of law?" Amoco Production Company v. North Dakota Industrial Commission, 307 N.W.2d 839, 842 (N.D. 1981). In reviewing the record to answer these questions, this Court should recognize that "determinations of administrative agencies should be given great weight and are ordinarily deemed correct." Hanson v. North Dakota Industrial Commission, 466 N.W.2d 587, 590 (N.D. 1991). Moreover, if the subject matter before an administrative agency is highly technical, the Court should not substitute its judgment for the expertise of the agency.[2] *Id. at 591.*

IV.
ARGUMENT

A. The Commission's Orders are Fully Supported by Substantial, Credible Evidence.

ASPRT asserts that certain findings of the Commission are not supported by substantial, credible evidence. The record, however, clearly demonstrates the weakness of ASPRT's contentions. The record contains substantial, even overwhelming, credible evidence to support the Commission's orders. ASPRT, however, ignores this evidence in its arguments.

The Commission found in its FINDING NO. 14 that "Placid and ASPRT each used

[2] ASPRT strains to suggest that the Commission does not have the requisite expertise on the usefulness of 3-D seismic for this Court to give any weight or deference to the Commission's judgment on such a highly technical matter. *Appellant's Brief at 13.* ASPRT's argument is valid only if this Court determines that the extra-record evidence supports ASPRT's position; the testimony of ASPRT's expert and Placid's expert is accepted as credible and the testimony of Conoco's witness is ignored. *Id. at 11.*

identical seismic information, along with well data, to construct their own net pay isopach maps, ASPRT Exhibit 7 and Placid Exhibit 9. The reservoir boundary on each map, however, was based only upon seismic information." *CR, Vol. III, Tab 100 at 3.* In its FINDING NO. 16, the Commission found that "Placid and ASPRT believe that seismic information can be used to identify the reservoir boundaries, although no evidence was introduced into the record to support identification of the productive portion of the mound using seismic information." *Id.*

ASPRT argues that FINDING NOS. 14 and 16 are "not sustained by substantial credible evidence." *Appellant's Brief at 20 & 22.* In support, ASPRT argues that certain seismic data presented to the Commission staff at a private meeting had on June 1, 1994 (7 days prior to the hearing of this matter) demonstrates that "the edges of mound could be determined at the points where the seismic lines crossed the mound edge." *Id. at 20 & 21.* Further, ASPRT argues its expert geologic witness testified that "the seismic data was used along with well data to determine the thickness of the mound as well as to locate the mound edges." *Id. at 21.* There is absolutely no evidence in the record to support these arguments. ?

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What is clear from the record is that ASPRT offered the testimony of its expert geological witness, Mr. Gomez, to support its interpretation of the productive limits of the Dickinson-Lodgepole Pool. *CR, Vol. II, Tab 31 at 229-237.* Mr. Gomez prepared and offered testimony on 7 exhibits.[3] Nowhere in the testimony or in the exhibits discussed and

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[3] ASPRT's Exhibit No. 2 is a cross-section running from southwest to northeast utilizing wellbore information from the Walton No. 84 well, the Kadrmas No. 75 well, the Dickinson State No. 74 well and the Filipi No. 76 well. *CR, Vol. III, Tab 83.* ASPRT's Exhibit No. 3 is a cross-section running from northwest to southeast utilizing the well bore information from the Frenzel No. 79 "straight hole" well, the Frenzel No.

offered by ASPRT is there any indication that Mr. Gomez utilized the relationship between the Fryburg structure and mound thickness in defining the edges of the productive reservoir. Only one point can be exactly defined using information from wells that penetrated the Lodgepole formation -- the edge between the Frenzel No. 79 vertical and sidetrack wells. ASPRT's refusal to recognize and utilize the relationship between the Fryburg structure and mound thickness left it to determine the remaining productive limits of the pool based on seismic data. ASPRT's argument that Commission FINDING NOS. 14 and 16 are not sustained by substantial credible evidence is, therefore, totally without merit.

Equally without merit is ASPRT's argument that certain information submitted to the technical staff of the Commission at a private meeting held on June 1, 1994 supports its position that the productive reservoir edges can be determined by seismic. *Appellant's Brief at 20-21.* Since Conoco was not invited to this private meeting with the Commission staff, it has no way of knowing what transpired at the meeting and no way of rebutting the information that was submitted at the meeting by ASPRT. Considering the fact that the information submitted to the technical staff is central to ASPRT's case, it is somewhat

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79 "sidetrack" well, the Dickinson State No. 74 well and the Dickinson State No. "A" 83 well. *CR, Vol. III, Tab 84.* ASPRT's Exhibit No. 4 is a gross isopach Lodgepole mound map based on well control of the 7 wells that penetrated the Lodgepole formation and seismic data. *CR, Vol. II, Tab 31 at 233*; *CR, Vol. III, Tab 85.* ASPRT's Exhibit No. 5 is a structure map of the top of the Lodgepole mound. *CR, Vol. III, Tab 86.* Once again, the map was constructed from well control of the 7 wells that penetrated the Lodgepole formation and seismic. *CR, Vol. II, Tab 31 at 234.* ASPRT's Exhibit 6 is structure oil/water contact map. *CR, Vol. III, Tab 87.* ASPRT's Exhibit 7 is a Lodgepole net pay map prepared on the basis of ASPRT's Exhibits 2-6. *CR, Vol. III, Tab 88; CR, Vol. II, Tab 31 at 235.* ASPRT's Exhibit 8 is a summary of original oil in place depicting ASPRT's interpretation of oil in place on a tract-by-tract basis. *CR, Vol. III, Tab 89; CR, Vol. II, Tab 31 at 237.*

surprising that ASPRT did not mention the conclusions reached at the meeting before filing its opening brief. It is likely that ASPRT never mentioned the private meeting because it did not wish to offer the evidence at hearing and give Conoco an opportunity to conduct cross examination, offer rebuttal evidence or argue the significance of the information submitted. Even more likely is that only ASPRT believed that the extra-record information supported its position. The fact which was ultimately confirmed when the Commission entered Order No. 6861 and Order No. 6893 wherein the Commission found that seismic data was not a useful tool in defining the boundaries of the productive Lodgepole. *CR, Vol. III, Tabs 100 & 108.*

The Commission found in FINDING NO. 18 that "the Fryburg Interval has regional dip to the north across the Dickinson Field and evidence presented to the Commission indicates that the Fryburg interval will be deposited abnormally high, in comparison to said regional dip, because a mound has grown beneath it." *CR, Vol. III, Tab 100 at 4.* In FINDING NOS. 19 and 20 the Commission found that "the structure of the Fryburg Interval can be a useful method to assist in determining the boundaries of the Lodgepole Pool reservoir. [and] [t]hat the Filipi No. 76 well . . . penetrated the Fryburg Interval abnormally high, although the mound was not developed under said well, suggesting that the mound edge is nearby." *Id.*

ASPRT argues that FINDING NOS. 18, 19 and 20 place far too much weight on Conoco's Fryburg structure map "without considering the highly interpretative nature of the map." *Appellant's Brief at 22.* ASPRT argues that Conoco's Fryburg map is "based on only two additional wells" which did not penetrate the Lodgepole formation and there is no well control along the western edge of the feature. _Id._ Further, ASPRT argues that even if one concludes that there is a relationship between the Fryburg structure and mound thickness in defining the edges of the productive reservoir, it is not possible to determine how close the Filipi No. 76 well is to the edge of the productive mound. _Id._ *at 22-23.*

ASPRT's argument demonstrates that it does not understand the mathematical relationship of the Fryburg structure and the mound thickness. The quadratic mathematical relationship that Conoco developed requires that no mound be present where the thickness of the non-mound rock exceeds 1095 feet. *CR, Vol. III, Tab 50.* Therefore, the lack of productive mound between the base of the Lodgepole formation and the top of the Fryburg zone in the Filipi No. 76 well and the Frenzel No. 79 well provides important validation of Conoco's depiction of the location of the productive mound.

Furthermore, as the Commission noted in FINDING NO. 23, "Conoco's net pay isopach map is the most credible map presented." *CR, Vol. III, Tab 100 at 4.* Presumably, the Commission made such a finding because the Fryburg map offered by Conoco was the least interpretative of all the maps offered into evidence in this case. The Fryburg structure map offered by Conoco includes more well data than any of the other maps offered into evidence in this case. Conoco's Fryburg structure map was based on information from two wells in the middle of the reservoir (the DHSU 37 and the DHSU 33), as well as one well to the northeast (the DHSU 20). *CR, Vol. III, Tab 51.* Moreover, the Fryburg structure is geographically defined on four sides. The geographic center of the reservoir is at the DHSU 37 well. The Frenzel No. 79 well defines the Fryburg on the northwest, the Walton No. 84 well defines the Fryburg on the southwest, the Dickinson State "A" No. 83 well defines the

Fryburg on the southeast and the Filipi No. 76 well defines the Fryburg on the northeast. *Id.* Based on this evidence, the Commission was justified in finding that "the Fryburg Interval can be a useful method to assist in determining the boundaries of the Lodgepole Pool reservoir." *CR, Vol. III, Tab 100 at 4.*

The Commission found in FINDING NO. 22 that "Conoco's volumetric calculation of original oil in place is more in agreement with the material balance calculation" lending additional credence to Conoco's determination of the location of the eastern boundary of the reservoir. *Id.* ASPRT argues that Conoco's material balance and volumetric calculations of original oil in place are not valid. *Appellant's Brief at 23.* Nevertheless, ASPRT then states that the "reservoir model derived material balance estimate" which Conoco utilized to calculate original oil in place "is probably fairly accurate, but by no means exact." *Id.* ASPRT then shifts its argument to a "what if" discussion of volumetric and oil saturation calculations. *Id.* ASPRT, however, never once points to the record to substantiate its arguments that Commission FINDING NOS. 22 and 23 are not valid. Presumably, ASPRT fails to point to the record because it has no record to point to in support of its position.

The Commission found in FINDING NOS. 24 and 24(b) that the plan of unitization filed by Conoco "contains fair, reasonable, and equitable provisions for . . . [t]he division of interest or formula for the apportionment and allocation of the unit product among the tracts within the unit area is fair, equitable and reasonable." *CR, Vol. III, Tab 100 at 4.*

ASPRT argues that Conoco's formula for allocation of production "is not fair, equitable, nor reasonable" because Conoco did not utilize the reservoir model simulator to assign primary reserves to the various tracts. *Appellant's Brief at 24.* ASPRT also complains that the Commission's order fails to address the issue of the oil/water contact in the reservoir and Conoco's own testimony on that issue demonstrates that the allocation as proposed by Conoco is not fair, reasonable and equitable. *Id. at 25-26.* ASPRT's arguments totally ignore the evidence in the record.

At hearing, Mr. Zorn presented undisputed testimony that the working interest owners discussed at considerable length the merits of utilizing the reservoir model simulator to calculate remaining primary reserves for the various tracts. *CR, Vol. II, Tab 31 at 290.* The working interest owners agreed that while a reservoir model simulator "is very useful in predicting approximately how much oil will be recovered from the entire field," the model will not "predict with any degree of accuracy how much oil will come out of individual wells." *Id.* The working interest owners, therefore, agreed that the reservoir model simulator would not be used to calculate primary production from individual wells. *Id. at 291.*

ASPRT's contention that Conoco's formula for allocation of production "is not fair, equitable nor reasonable" must be evaluated in light of Mr. Zorn's undisputed testimony that all the working interest owners agreed as to how the reservoir model simulator would be utilized. Significantly, when ASPRT had the opportunity to voice its opinion on use of the model simulator at the working interest owner meetings, it chose to remain silent. *Id.* Only after the result revealed that ASPRT would have benefited from using the model simulator to calculate remaining reserves under individual tracts did ASPRT change its strategy. Obviously, ASPRT's persistent claim that Conoco's formula for allocation is not fair and equitable has prevented ASPRT from maintaining a consistent position in this case.

ASPRT has also taken inconsistent positions with respect to Conoco's interpretation of the oil/water contact. At hearing, Mr. Hyrkas testified that the working interest owners considered various oil/water contacts for each well before unanimously agreeing on the one which Conoco presented at hearing. *Id. at 67-68.* ASPRT's expert, Mr. Gomez, confirmed that the oil/water contact as presented by Conoco was unanimously agreed upon by the working interest owners. *Id. at 234.* At hearing, ASPRT presented the same interpretation of the oil/water contact as Conoco. *CR, Vol. III, Tab 86.* On appeal, however, ASPRT has once again changed its position and now alleges that Conoco's interpretation of the oil/water contact is inconsistent with its own testimony and, therefore, is not fair and equitable. *Appellant's Brief at 26.* By waiting until appeal to challenge Conoco's oil/water contact and putting up no evidence to support its contentions, ASPRT has spared itself the test or cross-examination on this issue. Significantly, when it had its opportunity to substantiate its position at hearing, ASPRT chose to rely on the interpretation of the oil/water contact submitted by Conoco. On appeal, however, ASPRT incredibly argues that the Commission's lack of inquiry into this area has a detrimental effect on correlative rights, "particularly of the minority royalty interest owners" (Emphasis added). *Appellant's Brief at 18.*

Since ASPRT is not a royalty owner within the unit and no royalty owner appeared in opposition to the unit, there is no record basis for that contention. Obviously, ASPRT has employed a strategy of deception in an attempt to confuse the court or belittle the fact that the vast majority of the royalty interest owners support the unit.

B. **<u>ASPRT's Motion to Compel Production of 3-D Seismic is Contrary to North Dakota Law</u>.**

Contemporaneously with the filing of its opening brief, ASPRT has served and filed its Motion to Compel Conoco Inc. to Produce 3-D Seismic Data. *ASPRT's Motion to Compel.* ASPRT's motion to compel is essentially a discovery motion seeking an order from this Court on appeal to require Conoco to produce the 3-D seismic data it has in its possession relative to the Dickinson-Lodgepole Field area. *Id. at 1.* According to ASPRT, the Court, pursuant to N.D.C.C. § 28-32-18, should order Conoco to produce its 3-D seismic data so that it may be properly processed and analyzed. *ASPRT's Motion to Compel at 1*; *ASPRT's Brief at 15.* ASPRT also seems to argue that the Commission should be ordered to subpoena Conoco's 3-D seismic under the provisions of N.D.C.C. § 28-32-09. Neither position advocated by ASPRT has any merit under North Dakota law.

N.D.C.C. § 28-32-09 governs discovery matters before administrative agencies. N.D.C.C. § 28-32-09 provides, in pertinent part, as follows:

> **28-32-09. Subpoenas — Discovery — Protective Orders.**
>
> * * *
>
> 2. Any hearing officer may require, upon the request of any party to the proceedings conducted by the agency, or upon the agency's or the hearing officer's own motion on behalf of the agency, the attendance and testimony of witnesses and the production of documents and other objects described in a subpoena at a hearing or other part of the proceedings.
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> * * *
>
> 4. Interrogatories and requests for production of documents may be sent to any witness or party in proceedings before an agency in accordance with the North Dakota Rules of Civil Procedure.
>
> 5. A party, except an administrative agency, must first show good cause, by written petition, and obtain written approval of the agency or the presiding

> hearing officer, before undertaking discovery proceedings, including depositions and interrogatories.

* * *

N.D.C.C. § 28-32-09.

ASPRT has made no attempt to comply with the provisions of N.D.C.C. § 28-32-09 in seeking Conoco to produce its 3-D seismic. While Conoco served ASPRT with its Petition for Approval of Plan of Unitization (*CR, Vol. I, Tab 1.*) 47 days prior to hearing, ASPRT never made attempt to utilize the provisions of N.D.C.C. § 28-32-09 to seek the production of Conoco's 3-D seismic. At hearing, the Commission's hearing examiner specifically inquired as to why ASPRT "did not file a motion prior to the hearing requesting that the Commission order that the seismic information be produced." *CR, Vol. II, Tab 31 at 302.* Counsel for ASPRT replied that "it was strictly a matter of time" and that ASPRT had a right to expect that Conoco would produce all the evidence it had. *Id. at 303.* Contrary to counsel assertion, ASPRT did not have such a right. Under the provisions of N.D.C.C. § 28-32-09, ASPRT had an obligation to seek Commission approval to demand the production of Conoco's 3-D seismic. Further, ASPRT had an obligation to set forth "good cause" why the documents are relevant and should be produced. Berger v. State Highway Commissioner, 394 N.W.2d 678, 683 (N.D. 1986).

In Berger, the appellant challenged the decision of the North Dakota State Highway Commissioner after being arrested for driving under the influence of alcohol. Berger contended that although he did not subpoena the state toxicologist, he should have been entitled to certain records under the state toxicologist's control because the administrative hearing officer had a duty to provide that information. *Id. at 682.* The Court concluded that Berger was not entitled to the documents because he failed to make a proper showing of relevance under N.D.C.C. § 28-32-09. *Id. at 683.* As the Court explained:

> Berger took no action to press his request for further information. He did not reiterate his request. He did not initiate formal discovery. He did not apply for an order to compel discovery pursuant to Section 28-32-09, N.D.C.C., analogous to Rule 37, N.D.R.Civ.P. He did . . . not request . . . a ten day extension. He did not utilize the opportunity to petition for a rehearing pursuant to Section 28-32-14, N.D.C.C. He did not make application to adduce additional evidence pursuant to Section 28-32-18, N.D.C.C. (footnotes omitted).
>
> The assertion that Berger was denied due process to obtain relevant information is unconvincing when procedures were available for possible use which he did not attempt to utilize.

Id. at 684-685.

Similarly, in the present case, ASPRT did not avail itself of the various procedures that were available to compel Conoco to produce its 3-D seismic while this matter was before the Commission. Nevertheless, now that the matter is on appeal, ASPRT attempts to utilize the provisions of N.D.C.C. § 28-32-09 to seek the production of documents it took no action to request prior to hearing. ASPRT's reliance on N.D.C.C. § 28-32-09 is misplaced. Requests to discover information or produce documents under the provisions of N.D.C.C. § 28-32-09 are to be conducted under the general provision of the North Dakota Rules of Civil Procedure. Berger, supra at 683. Neither the Administrative Practices Act nor the North Dakota Rules of Civil Procedure allow a continuation of discovery as a case moves through the appeal process.

ASPRT's reliance on N.D.C.C. § 28-32-18 is equally misplaced. N.D.C.C. § 28-32-18 provides, in pertinent part, as follows:

> **28-32-18. Consideration of additional or excluded evidence.** If an application for leave to offer additional testimony, written statements, documents, exhibits, or other evidence is made to the court in which an appeal from a determination of an administrative agency is pending, and it is shown to the satisfaction of the court that the additional evidence is relevant and material and that there were reasonable grounds for the failure to offer the evidence in the hearing or proceeding, or that the evidence is relevant and material to the issues involved and was rejected or excluded by the agency, the court may order that the additional evidence be taken, heard, and considered by the agency on terms and conditions as the court may deem proper.

N.D.C.C. § 28-32-18

N.D.C.C. § 28-32-18 affords the parties the opportunity "to offer additional testimony, written statements, documents, exhibits or other evidence." ASPRT, however, seeks to utilize N.D.C.C. § 28-32-18 as a mechanism to conduct post hearing, court ordered discovery. ASPRT's attempt to expand the discovery process on appeal has absolutely no merit or basis in North Dakota law. A review of N.D.C.C. § 28-32-18 reveals that the purpose of the statute is to authorize the Court to remand a case back to administrative agency for the taking, hearing and consideration by the agency of additional of excluded evidence. That issue was settled by the North Dakota Supreme Court in 1988. Sadek v. Job Service, 420 N.W.2d 340, 344 (N.D. 1988). Contrary to ASPRT's assertions, N.D.C.C. § 28-32-18 is not a means by which a party can continue the discovery process as a case makes its way through the appeal process.

Even if this Court determines that N.D.C.C. § 28-32-18 is an appropriate means for ASPRT to conduct discovery on appeal, ASPRT's motion to compel should be denied. An application to offer additional evidence should not be granted unless it is shown that "the additional evidence is relevant and material and that there were reasonable grounds for the failure to offer the evidence in the hearing or proceeding." *N.D.C.C. § 28-32-18.* ASPRT has never attempted to explain why it needed more than 47 days to file its motion to compel or how the evidence is relevant. As such, ASPRT's motion to compel should be denied.

C. <u>ASPRT's Attempts to Supplement the Record were Improper</u>.

Only information or evidence that is offered admitted and made a part of the official record may be considered by an administrative agency. *N.D.C.C. § 28-32-06(1).* Unauthorized attempts to introduce information or evidence into the record are improper. <u>Insurance Services Office v. Knutson</u>, 283 N.W.2d 395, 399 (N.D. (1979). For good reason. An unauthorized submission of extra-record evidence denies opposing parties "an opportunity to examine the information or evidence and to present its own information or evidence and to cross-examine the person furnishing the information or evidence." *N.D.C.C. § 28-32-07.* In short, unauthorized submissions of extra-record evidence deprives the parties of their right to have the case decided on the evidence presented at hearing.

In this case, ASPRT attempted to introduce numerous scientific journal articles, 43 days after hearing. *<u>See</u> CR, Vol. III, Tabs 105-106.* ASPRT made no attempt to avail itself of the provisions of N.D.C.C. § 28-32-07 which authorizes administrative agencies, like the Commission, the opportunity to consider additional information or evidence not presented at hearing. Rather, ASPRT, in a somewhat simplistic and cavalier fashion, submitted 96 pages of extra-record evidence concerning 3-D seismic. ASPRT had little to say about the extra-record articles submitted other than that the articles indicted that 3-D seismic has been used "not only for the exploration and development, but also for reservoir characterization, reservoir boundary determination, and equity determination." *CR, Vol. III,* *Tab 105 at 5.*

The Commission considered the extra-record submissions, albeit it refused to reopen the case and make the articles a part of the official record. *CR, Vol. III, Tab 108 at 3.* The Commission concluded that there was no reason why ASPRT could not have submitted the articles at the hearing. Further, the Commission determined that there was no evidence to establish that the matters discussed in the articles were at all similar to the characteristics of the Dickinson-Lodgepole Pool. Id. In the absence of such evidence, the Commission was correct in concluding that "the articles are unhelpful it not irrelevant." Id.

Equally, without merit is ASPRT's second attempt to supplement the record of this appeal. Contemporaneously with the filing of its opening brief, ASPRT has submitted 99 pages of materials which are not part of the certified record on appeal. See *Appellant's Supplemental Record.* Clearly, this latest attempt by ASPRT to supplement the record is not in compliance with the North Dakota Administrative Practices Act. *N.D.C.C. Ch. 28-32.* If a party desires to offer additional testimony, written statements, documents, exhibits or other evidence it must seek leave of the Court to do so. *N.D.C.C. § 28-32-18.* If the court determines that "the additional evidence is relevant and material and that there were reasonable grounds for the failure to offer the evidence in the hearing or proceeding, . . . the court may order that the additional evidence be taken, heard, and considered by the agency." Id.

Needless to say, there was no such showing here. ASPRT, in total disregard to the provision of N.D.C.C. § 28-32-18, has not sought leave of the Court to supplement the record. Neither has ASPRT made any attempt to demonstrate that the supplemental material is relevant and that it was reasonable justified in failing to offer the same at hearing. In the absence of seeking leave of the Court and making the statutory showing, this Court is justified in disregarding the Appellant's Supplement Record. Insurance Services Office v. Knutson, 283 N.W.2d 395, 401 (N.D. 1979).

Assuming the Court were to determine a basis for considering the appellant's supplemental record, and it should not, the documents are not necessarily contrary to the Commission's determination in this case, as ASPRT suggests. In an attempt to demonstrate that 3-D seismic is useful in defining "formation boundaries", ASPRT offers the affidavit of Professor Thomas L. Davis. *Appellant's Supplemental Record at 17-25.* Presumably, in an attempt to bolster Professor Davis' statement, ASPRT offers a Feasibility Report for the Little Missouri Minnelusa Field in Cook County, Wyoming, and an order of the Wyoming Oil and Gas Conservation Commission granting the application of Ampolex (Wyoming), Inc. for unitization of the Minnelusa Formation in the Little Missouri Unit area. *Id. at 38-99.*

Professor Davis' affidavit consist of very general statements of his knowledge and experience in the oil industry and the use of 2-D and 3-D seismic. *Id. at 7-9.* There is no indication from the affidavit what information, if any, Professor Davis' reviewed before preparing his affidavit. Consequently, there is no way of knowing whether Professor Davis is in a position to provide credible testimony concerning the Dickinson-Lodgepole Pool. What is clear, however, is that Professor Davis did not challenge the testimony of Mr. Mohl, Conoco's geophysicist.

Mr. Mohl testified that because of the physical properties of the Lodgepole formation, there is no appreciable velocity contrast between productive and nonproductive rock within the Lodgepole formation near Dickinson. *CR, Vol. II, Tab 31 at 263.* Mr. Mohl further testified that because the productive reservoir is virtually invisible to seismic, a seismic interpreter must rely on wave form anomalies which results in areas of uncertainty in excess of 1000 feet. *Id. at 266.* Professor Davis' made no attempt to contradict or impeach the testimony of Mr. Mohl. Accordingly, Professor Davis' affidavit does not establish that 3-D seismic data can be utilized to delineate the productive limits of the Lodgepole formation near Dickinson.

Similarly, the Feasibility Report for the Little Missouri Minnelusa Field in Cook Count, Wyoming, and the accompany order of the Wyoming Conservation Commission does not establish that 3-D seismic data can be utilized to delineate the productive limits of the Lodgepole formation near Dickinson. Taken at face value, the report and the Wyoming Commission Order indicate that a working interest owner, McAdams, Roux & Associates ("MRA"), acquired high resolution 3-D seismic data over the Little Missouri Field in Wyoming and that data was utilized as a basis for defining the limits of the productive reservoir boundaries of the field. *Appellant's Supplemental Record at 57.* The report establishes that the Little Missouri Field is located on the eastern flank of the Powder River Basin in Wyoming and produces form the Upper "B" Sandstone interval of the Permian Minnelusa formation. *Id. at 56.* The Upper "B" sand is the only oil productive unit within the Minnelusa formation at the Little Missouri Field and directly overlays the Upper "D".

If it was ASPRT's intent to impeach the testimony of Mr. Mohl with the feasibility report (demonstrating that 3-D seismic is useful in determining reservoir boundaries), ASPRT failed miserably. The differences between the Little Missouri Minnelusa Field and the Dickinson-Lodgepole Pool are clearly apparent. The Little Missouri Minnelusa Field produces oil from a sandstone formation, the Dickinson Lodgepole Field produces from a limestone formation. MRA determined that the rock properties in the Little Missouri Minnelusa Field facilitated the use of seismic for determining edges of the productive reservoir. *Id. at 57.* Mr. Mohl testified that because of the physical properties of the Lodgepole formation near Dickinson, it is impossible to distinguish between productive and nonproductive reservoir utilizing 2-D or 3-D seismic data. *CR, Vol. II, Tab 31 at 260.* Very simply, ASPRT's extra-record submission of the feasibility report and the Wyoming Commission Order provide this Court with nothing that is helpful or relevant to this case. The Court is, therefore, justified in rejecting the evidence outright or giving it little or no weight in reaching a decision in this case.

V.
CONCLUSION

For all the reasons set forth above, Conoco respectfully requests that this Court affirm Commission Order No. 6861 and Order No. 6893 by substantive, credible evidence and that ASPRT's Motion to Compel the Production of 3-D Seismic is denied.

DATED this __________ day of December, 1994.

PEARCE & DURICK

By________________________

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CERTIFICATE OF SERVICE

I, the undersigned, hereby certify that a true and correct copy of the following document:

RESPONSE OF APPELLEE, CONOCO INC., TO APPELLANT'S BRIEF AND APPELLANT'S MOTION TO COMPEL THE PRODUCTION OF 3-D SEISMIC

was on the _________ day of December, 1994 served by placing the same in the United States mail, postage prepaid, properly addressed to the following:

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What is clear from the record is that the Commission found that Conoco's volumetric estimate of original oil in place is a closer match to the material balance calculation of original oil place than that of ASPRT. *CR, Vol. III, Tab 100 at 4.* ASPRT argues that a volumetric estimate of original oil in place or a material balance calculation of original oil in place indicates the volume of oil in place in the pool and not the location of the boundaries of the pool. *Id.* Nonetheless, what ASPRT ignores is the fact that the northwest boundary of the pool is defined by the Frenzel No. 79 well, the southern boundary is defined by the Dickinson State No. 83 "A" well and the western boundary is defined by the Walton No. 84 well. Further, the eastern edge of the pool does not extend beyond the Filipi No. 76 well. Consequently, the fact that Conoco's volumetric estimate of original oil in place is more closely matched to the material balance calculation lends credence to the fact that Conoco's estimate is more accurate. More importantly, since three sides of this pool are defined, the material balance calculation was utilized by the Commission to confirm Conoco's depiction of the eastern boundary of the reservoir.

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STATE OF NORTH DAKOTA IN DISTRICT COURT

COUNTY OF STARK SOUTHWEST JUDICIAL DISTRICT

Andrea Singer Pollack Revocable Trust, Andrea Singer Pollack, Trustee, Appellant, v. The Industrial Commission of the State of North Dakota, Conoco, Inc., and all other persons having an interest in the Dickinson-Lodgepole Unit, Appellees.	Civil No. 94C-283

. . . .

Industrial Commission's Reply Brief and Response to Motion to Produce

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I. History of the Case

1. The Dickinson-Lodgepole pool was discovered in February of 1993 with the drilling and completion of the Dickinson State No. 74 well in Section 32, Township 140 North, Range 96 West. TR. 125-26 (Zorn Test.).

2. The productive pool is relatively small, comprising not much more than about two sections of land. See Tabs 7, 35 of Record. The pool lies within a unique formation, that is, it is a pronounced mound feature. Tr. ________ (Hyrkas Test.)

3. After the discovery well, five more wells were drilled by Conoco in or near the Dickinson-Lodgepole pool. Three wells were completed as producers, the Kadrmas No. 75 well, the Frenzel No. 79 well, and the State A No. 83 well. The non-producing wells, the Filipi No. 76 and the Walton No. 84, were plugged and abandoned. TR. 126-28 (Zorn Test.).

4. By October of 1993 Conoco concluded that the reservoir pressure would quickly drop and would damage the productivity of the field if some form of pressure maintenance were not undertaken. Id. at TR. 133, 140-41. Conoco reduced production to prevent reservoir pressure from falling too quickly. Id. at TR. 134, 136. Conoco also recognized that a secondary recovery program was needed to ensure that the field was efficiently developed. Id. at TR. 135-36.

5. Conoco estimated that a secondary recovery project would extend life of the field form 12.3 years to 17.3 years and recover an additional 2.48 million barrels of oil. It also estimated that

an additional $9 million would be earned by working interest owners as a result of secondary recovery and that payments to royalty owners would increase by $2.6 million. Id. at TR. 142, 145-46.

6. Conoco then began working with the other 13 working interest owners in the area to put together a plan of unitization. Id. at TR. 10-13, 25. The plan of unitization was eventually ratified by 6 working interest owners. Id. at TR. 26. Other than Conoco, these working interest owners each owned less than 1% of the unit. Id. at TR. 26. Conoco's interest is about 73%. Id. at TR. 30. Conoco next sought ratification by mineral owners. Of the 102 royalty interest owners in the pool, 48 ratified the plan. Id. at TR. 27. Conoco, besides being the working interest owner, also owns a royalty interest in the pool, which amounts to about 4%. Id. at TR. 36. About 86% of the royalty owners and about 70% of the working interest owners ratified the plan of unitization. TR. at 14 (Turner Test.).

7. In April of 1994 Conoco filed its application with the Industrial Commission requesting approval of the plan of unitization. Tab 1 of Record.

8. The unit proposed by Conoco included 1,436 acres. TR. 13 (Turner Test.). The unit is within at least a part of six different sections of land and is divided into nine different tracts. A visual depiction of the unit is at tabs 7 and 35 of the Record. A description of the mineral owners and working interest owners in each of the nine tracts is set forth at tabs 38 and 41 of the Record.

9. The Andrea Singer Pollack Revocable Trust (hereafter "the Trust") filed a response to Conoco's petition. Tab 30 of Record. The response stated that while unitization is necessary for an effective and economic recovery of hydrocarbons in the pool, Conoco's proposal is not equitable to all working and royalty interest owners.

10. A hearing on Conoco's application was held on June 8, 1994. Appearing to resist Conoco's application were Placid Oil Co. as well as the Trust.

11. Placid's interest in the area of unitization is in the S½ of section 30 the N½ of section 31, that is, on the NW side of the unit. TR. 180 (Bressler Test.); Tab 38 of Record. The Trust's interest lies in the S½ of the section 31, that is, on the west side of the unit. Tab 38 of Record.

12. Placid and the Trust believe the area should be unitized, but objected to Conoco's application on the ground that the boundaries of the unit, as proposed by Conoco, do not accurately reflect the productive boundaries of the pool. TR. 178 (Bressler Test.); TR. 247 (Preston Test.).

13. At the hearing, Conoco, Placid, and the Trust all presented witnesses and exhibits in support of their positions. Placid and the Trust argued that the boundaries of the unit should be redrawn. If they were to be redrawn, Placid and the Trust would receive a greater allocation of the unit production and Conoco would receive a lesser amount. Placid and the Trust also argued that Conoco had in its possession evidence that it did not present at the hearing but should have been presented because it would shed

more light on the boundaries of the pool. That evidence is 3D seismic data.

14. Conoco submitted testimony and exhibits supporting its view of the boundaries of the productive pool. It responded to the requests for production of its 3D seismic data by presenting evidence that 3D seismic would not assist in delineating the boundaries of the pool. Conoco stated that 3D seismic is useful only as an exploration tool and not as a tool to delineate pool boundaries.

15. After the hearing, on June 15, 1994, Conoco submitted to the Commission a reply to the Trust's pre-hearing "Response" to the Conoco's application. Tab 99 of Record.

16. On June 16, 1994, the Industrial Commission issued its Order. Tab 100 of Record. The Commission found Conoco's view about the usefulness of 3D seismic and the pool boundaries to be more credible than Placid's and the Trust's view. Therefore, it granted the application.

17. The Trust and Placid then filed Petitions for Reconsideration. Tabs 101 and 102 of Record. On July 18 Conoco filed a Response to the Petitions for Reconsideration. Tab 104 of Record. On July 21 the Trust filed a Reply to Conoco's Response. Tab 105 of Record. Attached to the Trust's Reply were a number of journal articles discussing the use of seismic data. Tab 106 of Record. None of these articles had been made part of the record at the hearing.

18. The Commission had intended to make its decision on the Petitions for Reconsideration on July 21, the day on which it

received the Trust's Reply. In light of the Trust's submission, the Commission delayed its decision on the Petitions for Reconsideration to give it an opportunity to study the Trust's Reply. Tab 107 of Record.

19. On August 3, 1994, the Commission issued its Order denying the Petitions for Reconsideration. Tab 108 of Record. The Order responded to the arguments raised by Placid and the Trust in their Petitions for Reconsideration. It also declined to reopen the hearing record to allow the journal articles submitted by the Trust to become part of the record.

20. The Trust appealed the Commission's decision. Tab 109 of Record. Placid did not appeal.

II. Discussion

A. Standard of the Review.

"The court is to sustain the Commission's order 'if the Commission has regularly pursued its authority and its findings and conclusions are sustained by the law and by substantial and credible evidence.'" Hanson v. Industrial Commission, 466 N.W.2d 587, 590 (N.D. 1991). To satisfy this substantial evidence test there need only be evidence in the record that a reasonable mind would accept as adequate to support the order. Id. The evidence needed to support the order need not rise to the standard of "the greater weight of the evidence" or to the standard of a "preponderance of the evidence." Id.

The substantial evidence test is more easily met than the typical standard of review of administrative decisions. Id. Greater deference is given by courts to the Industrial Commission's decisions. Id. Because of the technical nature of the Commission's work, its decisions are "entitled to respect and appreciable deference." Id. at 591. See also Montana-Dakota Utilities Company v. Public Service Commission, 413 N.W.2d 308, 312 (N.D. 1987).

B. The Non-production of Conoco's 3D Seismic Data.

Conoco has in its possession the results of 3D seismic work done in the area. Conoco did not rely upon this information in putting together the plan of unitization or in presenting its evidence. The Trust argues that the 3D data could have helped to accurately locate the boundaries of the pool, and because Conoco did not produce the data, the adverse inference rule of Colgate-Palmolive Co. v. Dorgan, 225 N.W.2d 278, 281 (N.D. 1974), applies.

The adverse inference rule for non-production of evidence may no longer exist. "[T]he availability of modern discovery and other disclosure procedures serves to diminish both the justification and the need for the inference." 2 McCormick on Evidence 186-87 (4th ed. 1992). In light of modern procedural rules for discovery, the court in Jones v. Otis Elevator Co., 861 F.2d 655, 659 n.4 (11th Cir. 1988), questioned the continued need for such inferences. For the same reason the Fifth Circuit Court of Appeals referred to the similar "uncalled-witness rule" as "an anachronism" and an "archaism." Herbert v. Wall-Mart Stores, Inc., 911 F.2d

1044, 1049 (5th Cir. 1990). In Jenkins v. Bierschenk, 333 F.2d 421, 425 (8th Cir. 1964), the court affirmed the trial court's refusal to draw the inference for non-production of the defendant's son in part because "[n]o discovery procedure as to [the son] was employed."

Discovery in administrative proceeding can be as comprehensive as that available in judicial proceedings. Upon a showing of good cause, the Commission had authority to allow the Trust to undertake discovery, including interrogatories, depositions, and requests for production. N.D.C.C. § 28-32-09(4)(5). The Trust could also have asked the Commission to itself subpoena the production of the 3D seismic data for use at the hearing, which the Commission had authority to do upon a showing by the Trust of "general relevance and reasonable scope of the evidence sought." N.D.C.C. § 28-32-09(2).

The Trust did not invoke the discovery provisions of chapter 28-32. Thus, it is questionable whether the adverse inference rule applies. The Trust knew Conoco would not present the 3D data at the hearing, as it stated in its pre-hearing brief. Tab 30 of Record at 3. Thus, responsibility for non-production does not fall entirely on Conoco. The Trust should not benefit from a circumstance which it may have been able to avoid by using the procedural tools at its disposal.[1]

[1]The Trust states that in its pre-hearing brief it "challenged the Commission to order the production of 3D seismic data." Trust Brief at 14. We are not clear what is meant by "challenging" the Commission and what its legal significance is for the purposes of this appeal, but what is clear is that in its pre-hearing brief the Trust did not request the commission to order production of the 3D seismic, all it did was state that "the Industrial Commission can

Even if the rule applies, courts "often counsel caution" in its application. 2 McCormick on Evidence 186 (4th ed. 1992). E.g. Jenkins v. Bierschenck, 333 F.2d at 425. The reason for this is because the rule creates evidence from non-evidence. Some courts decline to apply the rule because it calls for speculation about what the non-produced evidence may show. E.g. Oliphant v. Snyder, 147 S.E.2d 122, 126 (Va. 1960). Other courts state that all that can be inferred is that the non-produced evidence would not have been helpful to the party possessing it, and not that it would have been adverse. E.g. United States v. Busic, 587 F.2d 577, 586 (3rd Cir. 1978).

Assuming, however, that the inference applies, it is "open always to explanation by circumstances which make some other hypothesis a more natural one than the party's fear of exposure." 2 Wigmore on Evidence 192 (___ ed. 1979). At the hearing it was made clear that this seismic data has commercial value. TR. _____ (Bressler Test.); TR. ____ (__________ Test.). Had Conoco made the data a matter of public record, Conoco would have lost the competitive advantage of being the only operator in the area with this information.

More fundamentally, the 3D seismic data was not produced because it would not be helpful in delineating the boundaries of the productive pool and, therefore, in determining what land should be included within the unit. Conoco presented two witnesses in support of this conclusion. Jerry Hyrkas stated that seismic is "not a good tool at all for the defining reservoir boundaries."

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force its disclosure." Tab 30 of Record, Brief at 3.

TR. 61 (Hyrkas Test.). See also id. at TR. 111-13; 118. Hyrkas is a senior geoscientist with Conoco. Id. at 44. Another Conoco witness, Greg Mohl, also testified that 3D seismic has limited usefulness in detecting pool boundaries. Mohl, a senior geophysicist with Conoco, has a bachelor's, master's and doctor of philosophy degrees in geology. TR. 258 (Mohl Test.). He has worked with seismic for 7 years. Id. at 268. He has taught "several short courses" on a number of seismic related subjects and work on seismic projects every day. Id. at 259. Mohl testified that the use of seismic is "totally inappropriate" for delineating the boundaries of a pool and the area to be included within a unit. Id. at 260, 269. He supported his conclusions with an extensive discussion of the matter. Id. at 260-269.

Mohl set forth three reasons why 3D would not be of material use. The first concerns the physical properties of the Lodgepole. Mohl noted that although Placid and the Trust assert the usefulness of 3D in other areas of the Williston basin and the country, neither discussed the physical properties of the Lodgepole and whether its characteristics allow for an accurate interpretation of seismic. Id. at 260. To support his view that the Lodgepole's physical properties would not support accurate use of seismic, Mohl compared the sonic log of the Kadrmas well, which is in the productive pool, with the sonic log of the Frenzel well, which did not penetrate the productive pool. Id. at 261-62. Mohl found that the velocity contrast between the productive and the non-productive pool to be "seismically invisible." Id. at 263.

Mohl's second concern about using seismic dealt with seismic wave theory. Id. at 264-67. In essence, he testified that the resolution of seismic data has weaknesses. When seismic wave interacts with the edge of a pool they interact with "in effect, the seismic blind spot." Id. at 265. The resolution of 3D is insufficient to pick where a productive pool begins and where it ends. The third reason Mohl found to reject the use of seismic to select land to include within a unit, is its highly interpretative nature. "Without exception this has been highly interpretive. It's very sensitive to the individual rock properties. It's also sensitive to the acquisition parameters of the seismic data and the processing of the seismic data . . . The bottom line is that work of this nature is very good for exploration. It can give you a general shape for, for what you're looking at and point you in the right directions." Id. at 268.

The uncertain nature of seismic data is proven by maps submitted by Placid and the Trust. Each used the same 3D seismic information in preparing the maps. TR. 333, 340 (Gomez Test.). While the trust describes the results as "strikingly similar," Trust Brief at 21, the Commission found distinctly different. Tab 100 of Record at ¶ 15. They differ in six ways, the first two of which are they are particularly significant. (The maps are shown side by side on page 4 of the Trust's "Supplemental Record.")

1. The Trust's map depicts a "saddle" in the middle of the pool. A "saddle" is a thinning of the productive zone. Placid's map does not show a "saddle."

2. The Trust shows a high to the west of the Kadrmas well (and thus smack in the middle of

the only tract in which the Trust owns an interest). Placid shows the high to be located much farther to the east, straddling sections 31 and 32.

3. The Trust shows the pool extending farther to the west than does Placid.

4. Placid shows the pool extending farther to the north and northeast than does the Trust.

5. Placid shows the pool extending farther to the east than does the Trust.

6. The Trust's contour lines east of the State No. 74 well are drawn much more sharply than are Placid's contour lines.

Using the same seismic data, Placid and the Trust drew distinctly different maps, thus giving us an example of the limits of seismic data to determine the boundaries of a productive pool.

While Placid and the Trust presented witnesses that disagreed with Hyrkas and Mohl, the substantial evidence test is satisfied. There is in the record evidence a reasonable mind would accept as adequate to support the Commission's conclusion that 3D seismic is not useful to locate pool boundaries. Because of its technical nature the court is to give conclusion deference and is not to substitute its "judgment for that of the expert." Haugland v. Spaeth, 476 N.W.2d 692, 695 (N.D. 1991). In summary, Conoco's non-production of the 3D seismic data is explained and the adverse inference rule does not apply.

This dispute among the experts is not like what occurred in Hanson v. Industrial Commission where the Supreme Court reviewed conflicting expert testimony. The court ruled that since there was relevant evidence that a reasonable mind might accept, the Commission's conclusion based on that evidence would not be overturned. "The possibility of drawing two inconsistent conclusions from the evidence does not prevent the findings from being supported by substantial evidence." Hanson v. Industrial Commission, 466 N.W.2d 587, 592 (N.D. 1991).

The Trust asks the court to go outside the hearing record to draw the adverse inference. It wants the court to review journal articles the Trust attached to its second brief in support of its petition for reconsideration. Tab 106 of Record. In its order denying the petition the Commission stated: "The Trust submitted with its reply brief copies of a number of journal articles concerning the use of 3D seismic. There is no evidence that the areas discussed in the articles bear any similarity to the characteristics of the Dickinson-Lodgepole Pool. Without such evidence the articles are unhelpful, if not irrelevant. Furthermore, there is no reason why these articles could not have submitted into evidence at the hearing. The Commission declines to reopen the case to make these part of the record." Tab 108 of Record at 3.

The Trust has gone further outside the record by filing with the court certain documents in its "supplemental record." It filed an affidavit of someone who did not appear at the hearing and exhibits and an administrative order from a Wyoming case. None of these matters were submitted for the Commission's review before, during, or after the hearing.

The court, however, may "consider only the record which was before the [agency], the transcript of the formal hearing, and any evidence presented at the hearing." Hayden v. North Dakota Workers

Compensation Bureau, 447 N.W.2d 489, 497 (N.D. 1989). See also N.D.C.C. § 28-32-19; Lipp v. Job Service North Dakota, 468 N.W.2d 133, 134 (N.D. 1991); Smith v. North Dakota Workers Compensation Bureau, 447 N.W.2d 250, 256-57 (N.D. 1989). In Knutson v. North Dakota Workmens Compensation Bureau, 120 N.W.2d 880 (N.D. 1963), the district court increased the Bureau's award to a claimant and in doing so reviewed new evidence. Since the award was not based on the record before the Bureau, id. at 882, and since the Bureau "had not opportunity to pass on such additional evidence," id. at 883, the district court was reversed.

There is a statutory procedure by which evidence not presented at a hearing can be presented to the agency. This is set forth in N.D.C.C. § 28-32-07. The Trust did not comply with this procedure. It merely submitted the journal articles. Tab 106 of Record. There is no procedure by which an appellant can petition a court for an order requesting that another party produce evidence. The court has no jurisdiction to enter what is in effect a discovery order. The court, in this case, is an appellate court. Its decision is confined to the record produced below, and that record is closed.

The Trust relies upon N.D.C.C. § 28-32-18 has authority for the court to grant its motion to compel production of the 3D seismic. That section allows the court to grant an application to offer additional evidence, upon a showing that the evidence is relevant and material and there was good cause for the failure to offer it at the hearing. Nothing in the statute, however, allows the court to grant a motion ordering another party to produce evidence.

C. <u>The Boundaries of the Pool</u>.

The Trust argues that the configuration of the unit as proposed by Conoco and approved by the Commission is in error. In particular, the Trust believes the unit's eastern boundary is located too far to the east in section 32. It also believes the west boundary should have been moved farther to the west.

The Trust argues that because Conoco has a greater interest in tract 1 of the unit, which is in section 32, than it does in tract 2, it "has a vested interest in pushing the boundary eastward as much as possible." Trust Brief at 19. There is a bit of irony in such a statement. The Trust's only interest in the unit is in tract 2, Tab 38 of Record, which is on the west side of the unit. If the unit's western boundary were moved farther to the west the Trust would receive a greater allocation of unit production.[2]

The Trust argues that the unit is inequitable because of the way in which the productive pool is configured. The Commission in its two orders made a number of findings related to this question. The Trust raises about six challenges to these findings. Trust Brief at 20-26. It is concerned with such matters as the location of the oil/water contract, the use of Conoco's reservoir modeling study in determining allocation of unit production, the accuracy of

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[2]Likewise with Placid. Its only interest lies in tracts 2 and 3, Tab 38 of Record, which are on the northwest side of the unit. It sponsored an interpretation of the geology that would have moved the unit boundaries farther to the northwest. Tab ___ of Record.

the porasity and oil saturation factors in Conoco's volumetric calculation, and the usefulness of using information from Fryburgh Interval to help understand the Lodgepole.

The essence of the Trust's argument on these points is that its witness should be believed rather than Conoco's. It does little, if anything, to explain why its witnesses are more credible than Conoco's and why the Commission acted unreasonably in agreeing with Conoco's interpretation of the geology.

III. Conclusion

The Trust's motion to produce should be denied. The is no authority allowing the court to issue the order requested, the information sought is not material, and the Trust neglected to use the methods given to procure such data. On appeal is not ..me to put together a factual case.

The Commission's decision to approve the Dickinson-Lodgepole Unit should be upheld. The substantial evidence test has been met. It is reasonable for the Commission to have accepted Conoco's evidence over the Trust's.

e:\nr\carvell\pollack brf

STATE OF NORTH DAKOTA   IN DISTRICT COURT

COUNTY OF STARK   SOUTHWEST JUDICIAL DISTRICT

Andrea Singer Pollack Revocable Trust, Andrea Singer Pollack, Trustee,

Appellant,

vs.

The Industrial Commission of the State of North Dakota, Conoco, Inc., and all other persons having an interest in the Dickinson-Lodgepole Unit,

Appellees.

Civil No. 94C-283

REQUEST FOR ORAL ARGUMENT

NOV 1994

An Appeal to the District Court of Stark County
From the Decision of the North Dakota Industrial Commission
Pursuant to NDCC 38-08-14 in Regard to the Unitization of
the Dickinson Lodgepole Unit in Stark County, North Dakota

The appellant, the Andrea Singer Pollack Revocable Trust, Andrea Singer Pollack, trustee, by and through its attorney, Robert O. Wefald, hereby requests an oral argument on the Appellant's Appeal to the district court from the decision of the North Dakota Industrial Commission. The court has discretion to allow an oral argument under NDCC 28-32-19, even though the standard of review is found in NDCC 38-08-14(3).

Dated this 1st day of November, 1994.

ROBERT O. WEFALD
Attorney for Andrea Singer Pollack
Revocable Trust
P. O. Box One
Bismarck ND 58502-0001

STATE OF NORTH DAKOTA — IN DISTRICT COURT

COUNTY OF STARK — SOUTHWEST JUDICIAL DISTRICT

Andrea Singer Pollack Revocable Trust, Andrea Singer Pollack, Trustee,

Appellant,

vs.

The Industrial Commission of the State of North Dakota, Conoco, Inc., and all other persons having an interest in the Dickinson-Lodgepole Unit,

Appellees.

Civil No. 94C-283

MOTION TO COMPEL CONOCO, INC. TO PRODUCE 3-D SEISMIC DATA

An Appeal to the District Court of Stark County
From the Decision of the North Dakota Industrial Commission
Pursuant to NDCC 38-08-14 in Regard to the Unitization of
the Dickinson Lodgepole Unit in Stark County, North Dakota

The appellant, Andrea Singer Pollack Revocable Trust, Andrea Singer Pollack, trustee, by and through its attorney, Robert O. Wefald, pursuant to NDCC 28-32-18, hereby moves the court for its Order directing the appellee, Conoco, Inc., to produce the 3D seismic data which it has in its possession regarding the Dickinson Lodgepole Field so that it can be properly processed and interpreted, and an isopach map drawn therefrom, using the well logs and other relevant data from the Dickinson Lodgepole Field. If Conoco, Inc., claims that this information is a protected trade secret, it is respectfully requested that the court issue its Order directing the production of this data in accordance with Rule 507 of the North Dakota Rules of Evidence directing that the 3D seismic data be tendered to a neutral third party for processing and final analysis under such protection measures as will protect the interest of Conoco, Inc., and any data which it claims to be a trade secret. This motion is supported by the Appellant's Brief on Appeal to the district court.

Dated this 1st day of November, 1994.

ROBERT O. WEFALD
Attorney for Andrea Singer Pollack
Revocable Trust
P. O. Box One
Bismarck ND 58502-0001

STATE OF NORTH DAKOTA | IN DISTRICT COURT

COUNTY OF STARK | SOUTHWEST JUDICIAL DISTRICT

Andrea Singer Pollack Revocable Trust, Andrea Singer Pollack, Trustee,

Appellant,

vs.

The Industrial Commission of the State of North Dakota, Conoco, Inc., and all other persons having an interest in the Dickinson-Lodgepole Unit,

Appellees.

Civil No. 94C-283

CERTIFICATE OF SERVICE

NOV 1994
RECEIVED
ND OIL & GAS
DIVISION

The Appellant's Brief, Appellant's Supplemental Record, Request For Oral Argument and Motion To Compel Conoco, Inc. To Produce 3-D Seismic Data were served upon the parties listed below by mailing true and correct copies thereof to:

Heidi Heitkamp
Attorney General
State of North Dakota
State Capitol Building
Bismarck ND 58505

Edward T. Schafer
Governor
State of North Dakota
State Capitol Building
Bismarck ND 58505

Sarah Vogel
Agriculture Commissioner
State of North Dakota
State Capitol Building
Bismarck ND 58505

Karlene Fine, Secretary
North Dakota Industrial Commission
State Capitol Building
Bismarck ND 58505

Wes Norton, Director
Oil & Gas Division
ND Industrial Commission
1022 East Divide Avenue
Bismarck ND 58501

Charles Carvell, Hearing Officer
Assistant Attorney General
900 East Boulevard Avenue
Bismarck ND 58505-0041

John Morrison
Attorney for Placid Oil
P.O. Box 2798
Bismarck ND 58502-2798

Lawrence Bender
Attorney for Conoco
P.O. Box 400
Bismarck ND 58502-0400

Frank R. Howell
Hunt Petroleum Corp.
3400 Thanksgiving Tower
Dallas TX 75201

Clyde W. Jones
P.O. Drawer 1267
Parker CO 80134

Gary D. Kalanek
3754 Kingston Drive
Bismarck ND 58501

Joe Starrett
Huntington Resources Inc.
8086 S. Yale, Suite 228
Tulsa OK 74136

Doug Kadrmas
2314 25½ Avenue South
Fargo ND 58103

Jimmy D. Campbell
1601 Elm Street, Suite 3800
Dallas TX 75201

Joan Schmidt
RR 1 Box 140
Dickinson ND 58601

said documents having been placed in the United States mail, with sufficient postage affixed, this 1st day of November, 1994.

ROBERT O. WEFALD
Attorney for Andrea Singer Pollack Revocable Trust
WEFALD LAW OFFICE, LTD.
P. O. Box One
Bismarck ND 58502-0001

INDUSTRIAL COMMISSION OF NORTH DAKOTA

Edward T. Schafer Governor	Heidi Heitkamp Attorney General	Sarah Vogel Commissioner of Agriculture

August 29, 1994

Mr. Robert Wefald
PO Box 1
Bismarck, North Dakota 58502-0001

Dear Mr. Wefald:

At its August 25 meeting the Industrial Commission considered the points raised in your August 10 letter. You suggested that the Commission's affidavits of service be sent to all parties along with the Commission's order. The Commission found your suggestion to be a good one and decided to adopt it as its policy.

Your second issue concerned the distribution of the Commission's orders. Your concern arose as the result of Mr. Bender's receipt of a fax copy of a decision prior to your receipt of the decision through the mail. While the Commission recognizes that the distribution of the order in that fashion may have led to some awkwardness between you and your client, it decided not to change its policy. It believes that the situation in which you found yourself is unique and unlikely to reoccur any time soon. To provide prompt response to requests for information from parties appearing before the Commission as well as the general public, the Commission staff will continue to fax copies of an order when they receive a specific request for it or provide an oral response on a Commission decision when asked. Should you be in need of a copy of a specific Commission decision, please contact either me or the Oil and Gas Division staff and we will furnish the information to you as quickly as possible.

Thank you for your suggestions. It is always good for us to review our procedures from time to time to make sure we are providing good service to the citizens of North Dakota.

Sincerely,

Karlene Fine

Karlene Fine
Executive Director and Secretary

KF:sc

BC: Wes Norton
Jack Wilborn
Charles Carvell

c: Edward T. Schafer, Governor
Heidi Heitkamp, Attorney General
Sarah Vogel, Commissioner of Agriculture
Lawrence Bender

PEARCE & DURICK
ATTORNEYS AT LAW
THIRD FLOOR
314 EAST THAYER AVENUE
P O BOX 400
BISMARCK, NORTH DAKOTA 58502

WILLIAM R. PEARCE (1910-1978)
WILLIAM P. PEARCE
PATRICK W. DURICK
B. TIMOTHY DURICK
CHRISTINE A. HOGAN
JOEL W. GILBERTSON
LAWRENCE A. DOPSON
GARY R. THUNE
DAVID E. REICH
JEROME C. KETTLESON
LARRY L. BOSCHEE
LAWRENCE BENDER
JANET D. SEAWORTH
MICHAEL F. McMAHON
STEPHEN D. EASTON

73-2890
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Co.
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Fax #
Fax #

HAND DELIVERED

Mr. Robert O. Wefald
Attorney at Law
2800 N. Washington St.
P.O. Box One
Bismarck, ND 58502-0001

DICKINSON-LODGEPOLE UNIT
NORTH DAKOTA INDUSTRIAL
COMMISSION CASE NO. 5933

Dear Bob:

Thank you for providing me a copy of your letter dated August 10, 1994 to Governor Schafer, Attorney General Heitkamp and Commissioner Vogel. I am writing this response because your letter has several misstatements.

First, you complain that the North Dakota Industrial Commission ("Commission") is not in compliance with the provisions of N.D.C.C. § 28-32-13(4) and that the Commission should adopt a procedure for giving notice in compliance with that statute. It is my understanding that the Commission continues to give notice of its orders in accordance with a procedure established when you served as attorney general and when I was the assistant attorney general assigned to the Oil and Gas Division of the Commission. The procedure requires the mailing of orders to all persons who make an appearance at the hearing as well as any person who offers testimony at the hearing. Pursuant to N.D.C.C. § 28-32-13(4), an affidavit of service by mail is filed indicating upon whom the order was served. For your convenience, I have included a copy of the Affidavit of Mailing for the three orders entered in Case No. 5933 concerning the unitization of the Dickinson-Lodgepole Field.

Second, you are not correct in suggesting that I have a standing request to have all orders faxed to me immediately after they are signed by the Commission. As you point out in your letter, the Commission is subject to the "Open Meeting/Open Records Law" and, as such, I attempt to keep abreast of when the Commission is meeting. In this case, a notice appeared in the Bismarck Tribune that the Commission was scheduled to meet August 3, 1994 at 2:30 p.m. (copy enclosed). Since the Dickinson-Lodgepole Unit is a very important project to my client, I contacted Ms. Karlene Fine's office at approximately 3:30 p.m. and left a message for her to return my call following the meeting. Sometime after 4:00 p.m. Ms. Fine returned my call and I inquired as to whether the Commission had considered the motions for reconsideration filed by your client and Placid Oil Company. After I was informed by Ms. Fine that the Commission had acted. I asked Ms. Fine to fax a copy of the order which I received at approximately 4:30 p.m. It has never been my practice to call the Commission "every day to see whether or not a particular decision has been made."

Third, you are misinformed that Conoco makes unsolicited contacts with your client to keep your client apprised of Commission actions. Personnel with Conoco advise me that it is your client, specifically, Mr. Kevin Preston, who continually contacts Conoco requesting information concerning the Dickinson-Lodgepole Unit and then asks specific questions regarding the Commission's actions. Conoco desires to maintain a good working relationship with all its partners in the Dickinson-Lodgepole Unit. Therefore, Conoco has made every attempt to answer Mr. Preston's questions when he calls and Conoco intends to continue this practice. It seems to me that if you are embarrassed by your client obtaining information from Conoco, you should instruct Mr. Preston to refrain from asking Conoco personnel specific questions about those matters.

Finally, I am disappointed to learn of your client's decision to appeal the Commission's order in this matter. Conoco worked very hard to put together a plan of unitization for the Dickinson-Lodgepole Field which is fair and equitable, which is supported by a overwhelming majority of the working interest owners and royalty owners and which has been approved by the Commission. As you know, the project is estimated to recover an additional 2½ million barrels of oil. There is absolutely no guarantee that if the Commission's actions in this matter are reversed that another plan of unitization will be developed which will be supported by the working interest owners, royalty owners and the

Commission. Considering the potential loss of revenue to the various owners of interest and the citizens of the state of North Dakota, I hope that your client will reconsider its decision to appeal.

Sincerely,

LAWRENCE BENDER

LB/lco

Enclosure

cc: The Honorable Edward Schafer - (w/o enc.) *Via Hand Delivery*
The Honorable Heidi Heitkamp - (w/o enc.) *Via Hand Delivery*
The Honorable Sarah Vogel - (w/o enc.) *Via Hand Delivery*
Mr. Wes Norton - (w/o enc.) *Via Hand Delivery*
Ms. Karlene Fine - (w/o enc.) *Via Hand Delivery*
Mr. Jim Turner - (w/o enc.)

Robert O. Wefald

Attorney And Counselor At Law

2800 North Washington Street
Post Office Box One
Bismarck, North Dakota 58502-0001

Phone 701-258-8945
Fax 701-255-7212

August 10, 1994

Honorable Ed Schafer
Governor of North Dakota
State Capitol
600 East Boulevard
Bismarck ND 58505

Honorable Sarah Vogel
Commissioner of Agriculture
State Capitol
600 East Boulevard
Bismarck ND 58505

Honorable Heidi Heitkamp
Attorney General
State Capitol
600 East Boulevard
Bismarck ND 58505

Dear Ed, Heidi and Sarah:

I am taking this opportunity to share a couple of observations with each of you as members of the Industrial Commission from the standpoint of one who used to be a member of the Industrial Commission but now is a representative of persons appearing before the Industrial Commission.

My recent experience is with the application of Conoco for the unitization of the Lodgepole field west of Dickinson. I will not make any specific comments about that case other than to let you know my client is going to appeal. What I want to address are two matters of concern that would be applicable to any case which I have as an attorney practicing before the Industrial Commission. My first concern is that it is my opinion that your Orders are not being properly served in accordance with Section 28-32-13(4) of the North Dakota Century Code. That section is part of the Administrative Agencies Practice Act and sets forth the requirements for service of your Orders. While this section is not a model of clarity, it is my opinion that you should adopt as a uniform practice in all cases, whether disputed or not, the requirement for an Affidavit of Service by Mail showing that your Order, or any other document you want served, has been properly served upon each of the parties to a proceeding, even in a proceeding where there is only one party. The Affidavit of Service by Mail is an important document as it is the one that starts the 30 days running to take an appeal under NDCC 28-32-15(1). Both of the Orders in this case were simply mailed by the staff of the Oil and Gas Division without the attorneys receiving any evidence of the date on which they were mailed. This problem would be solved by you as a Commission establishing a rule that all documents of the Commission are to be served on every party to each proceeding by first class mail, with each document or set of documents being accompanied by an Affidavit of Service by Mail. That would make it a lot easier for the attorneys who practice before you to know with precision exactly when the 30 days in which to take an appeal begins to run.

My next concern deals with the timing of the release of Orders or decisions of the Commission. I recognize the Industrial Commission is subject to the Open Meeting/Open Records Law, and that anyone who is at the meeting of the Industrial Commission will learn at that time whether or not a particular decision has been made and whether or not a particular Order has been signed. Typically, however, those of us who practice law do not call the courts every day nor the administrative agencies every day to see whether or not a particular decision has been made. Most of us rely upon the normal course of business with the certain knowledge that when a decision is made by a court or an administrative agency, that decision will be communicated to all attorneys for the parties at the same time. Normally each of the attorneys is mailed a copy of the decision at the same time. In the case of the Supreme Court, when the decision is made, the clerk typically calls each of the attorneys and advises them what the result of the decision of the Supreme Court is as soon as it is made. Generally the attorneys receive a copy of that decision in the next day's mail.

In this particular application of Conoco, at every stage of the proceedings I have found myself in the particularly embarrassing position of learning from my client what decision the Industrial Commission has made, my client in turn having been promptly called by Conoco and advised of the decision. Conoco obviously gets its information from its attorney, Lawrence Bender, who clearly is a lot more persistent than I am in staying on top of the Industrial Commission's work so that he knows the instant a decision is made what that decision is. I certainly commend him for his persistence and his good work. I appreciate the fact that he has asked for copies of the decisions as soon as they are made. It seems to me, however, that it would be better for the Industrial Commission to develop a rule of protocol which essentially provides that as soon as a decision is made, when it is transmitted to attorneys for one of the parties, it is transmitted to attorneys for all the parties. Which is to say that if the secretary has been requested to call a particular lawyer who is interested in the outcome of a Commission action, then the secretary should call all of the attorneys with that same information even though she has not been requested to do so. Likewise, if she is requested to fax a copy of the particular Order to one of the attorneys, she should at the same time fax it to all of the attorneys so that each of us has exactly the same information at approximately the same time. It simply is embarrassing to be put in a position of hearing of this information from your client who hears it from one of the other parties.

Incidentally, with respect to this question of notice and service, since these are decisions of the Industrial Commission, I believe the secretary of the Industrial Commission should be the one who serves by mail all of the Orders of the Commission, regardless of which of the administrative agencies operated by the Industrial Commission is involved in a particular case.

I want each of you to know that I have discussed this matter with Wes Norton, and he has explained to me that he checked and found that Lawrence Bender had made a request for a copy of the Orders to be faxed to him as soon as each Order was issued. I certainly should have made my own request, but, as noted above, it would be a better policy for all to be notified at the same time. In other words, if one is to be given immediate notice, everyone should be given immediate notice whether they request it or not.

Thank you very much for your thoughtful consideration of this matter.

Sincerely,

Bob

Robert O. Wefald

mw

c: Karlene Fine
Wes Norton
Lawrence Bender
John Morrison
Andrea Singer Pollack Revocable Trust

SFN5729

STATE OF NORTH DAKOTA)

COUNTY OF BURLEIGH)

AFFIDAVIT OF MAILING

I, Donna Bauer, being duly sworn upon oath, depose and say: That on the 4th day of August 1994, I enclosed in separate envelopes true and correct copies of the attached Order No. 6893 of the North Dakota Industrial Commission, and deposited the same with the United States Postal Service in Bismarck, North Dakota, with postage thereon fully paid, directed to the following persons, all of whom appeared at the hearing of the Industrial Commission in Case No. 5933 :

Mr. John Morrison
Fleck, Mather & Strutz Ltd.
P. O. Box 2798
Bismarck, ND 58502

Mr. Lawrence Bender
Pearce & Durick
P. O. Box 400
Bismarck, ND 58502

Mr. Doug Kadrmas
2314 25½ Ave. S.
Fargo, ND 58103

Mr. Frank R. Howell
Hunt Petroleum Corp.
3400 Thanksgiving Tower
Dallas, TX 75201

Mr. Robert O. Wefald
2800 N. Washington St.
P. O. Box One
Bismarck, ND 58502-0001

Ms. Martha Sundry
ARS Control Account Ltd. Part.
P. O. Box 22854
Denver, CO 80222

Mr. Clyde W. Jones
P. O. Drawer 1267
Parker, CO 80134

Mr. Gary D. Kalanek
3754 Kingston Dr.
Bismarck, ND 58501

Mr. R. Joe Starrett
Huntington Resources Inc.
8086 S. Yale
Suite 228
Tulsa, OK 74136

Mr. Ernest Gomez
Geologist
3609 S. Wadsworth
Suite 500
Denver, CO 80235

Ms. Joan Schmidt
RR1 Box 140
Dickinson, ND 58601

Donna Bauer
Donna Bauer
Oil & Gas Division

On this 9th day of August, 1994, before me personally appeared Donna Bauer to me known as the person described in and who executed the foregoing instrument and acknowledged that she executed the same as her free act and deed.

Erica Roberson
Notary Public
State of North Dakota County of Burleigh
My Commission expires 11-3-98

Mr. P. J. Turner
Conoco Inc.
800 Werner Court
Casper, WY 82601

Mr. Jerry Hyrkas
Conoco Inc.
800 Werner Court
Casper, WY 82601

Mr. Kevin Zorn
Conoco Inc.
800 Werner Court
Casper, WY 82601

Mr. Stephen Bressler
Placid Oil Co.
1601 Elm St.
Suite 3800
Dallas, TX 75201

Mr. R. Kevin Preston
P. O. Box 22066
Denver, CO 80222

Mr. Jimmy D. Campbell
1601 Elm St.
Suite 3800
Dallas, TX 75201

Mr. Greg Mohl
Conoco Inc.
800 Werner Court
Casper, WY 82601

SFN5729

STATE OF NORTH DAKOTA)
) AFFIDAVIT OF MAILING
COUNTY OF BURLEIGH)

I, Donna Bauer, being duly sworn upon oath, depose and say: That on the 27th day of July 1994, I enclosed in separate envelopes true and correct copies of the attached Order No. 6880 of the North Dakota Industrial Commission, and deposited the same with the United States Postal Service in Bismarck, North Dakota, with postage thereon fully paid, directed to the following persons, all of whom appeared at the hearing of the Industrial Commission in Case No. 5933 :

Mr. John Morrison
Fleck, Mather & Strutz Ltd.
P. O. Box 2798
Bismarck, ND 58502

Mr. Lawrence Bender
Pearce & Durick
P. O. Box 400
Bismarck, ND 58502

Mr. Doug Kadrmas
2314 25½ Ave. S.
Fargo, ND 58103

Mr. Frank R. Howell
Hunt Petroleum Corp.
3400 Thanksgiving Tower
Dallas, TX 75201

Mr. Robert O. Wefald
2800 N. Washington St.
P. O. Box One
Bismarck, ND 58502-0001

Ms. Martha Sundry
ARS Control Account Ltd. Part.
P. O. Box 22854
Denver, CO 80222

Mr. Clyde W. Jones
P. O. Drawer 1267
Parker, CO 80134

Mr. Gary D. Kalanek
3754 Kingston Dr.
Bismarck, ND 58501

Mr. R. Joe Starrett
Huntington Resources Inc.
8086 S. Yale
Suite 228
Tulsa, OK 74136

Mr. Ernest Gomez
Geologist
3609 S. Wadsworth
Suite 500
Denver, CO 80235

Ms. Joan Schmidt
RR1 Box 140
Dickinson, ND 58601

Donna Bauer
Donna Bauer
Oil & Gas Division

On this 28th day of July, 1994, before me personally appeared Donna Bauer to me known as the person described in and who executed the foregoing instrument and acknowledged that she executed the same as her free act and deed.

Evie Roberson
Notary Public
State of North Dakota County of Burleigh
My Commission expires 11-3-98

Mr. P. J. Turner
Conoco Inc.
800 Werner Court
Casper, WY 82601

Mr. Jerry Hyrkas
Conoco Inc.
800 Werner Court
Casper, WY 82601

Mr. Kevin Zorn
Conoco Inc.
800 Werner Court
Casper, WY 82601

Mr. Stephen Bressler
Placid Oil Co.
1601 Elm St.
Suite 3800
Dallas, TX 75201

Mr. R. Kevin Preston
P. O. Box 22066
Denver, CO 80222

Mr. Jimmy D. Campbell
1601 Elm St.
Suite 3800
Dallas, TX 75201

Mr. Greg Mohl
Conoco Inc.
800 Werner Court
Casper, WY 82601

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NO. 5933

IN THE MATTER OF THE PETITION OF CONOCO INC. FOR AN ORDER PROVIDING FOR THE UNITIZED MANAGEMENT, OPERATION, AND FURTHER DEVELOPMENT OF THE DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION; VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE.

REPLY OF ANDREA SINGER POLLACK REVOCABLE TRUST TO "CONSOLIDATED RESPONSE OF CONOCO INC."

The Andrea Singer Pollack Revocable Trust ("ASPRT") hereby submits this reply to the response dated July 18, 1994 by Conoco Inc. ("Conoco")

I. A. 2-D Seismic Data.

Actual seismic data utilized by Placid and ASPRT was not introduced into the record because it was not owned by Placid or by ASPRT, but by a third party who acquired the data with the intent of marketing it. Had the actual data been introduced, it would have become available to the public and would have lost any market value it may have had. Because the seismic data so clearly defined the edges of the Lodgepole mound at the four points where the two seismic lines crossed the boundary of the mound, Placid made the data available to the working interest owners in the proposed unit, including Conoco. Additionally, Placid presented the seismic data to the technical staff of the North Dakota Industrial Commission at an informal meeting on June 1, 1994. Also shown at this meeting were the synthetic seismic lines which were created from Sonic logs run in several wells drilled in the field. The character of the synthetics from wells which penetrated the mound was easily distinguishable from the character of the synthetics from wells which did not penetrate the mound such as the Filipi 76. The 2-D seismic lines were shown to be almost identical to the synthetics both within the mound and outside the mound. The edge of the mound was very apparent on the north, east, and south sides of the mound where the seismic lines were run basically perpendicular to the edge of the mound. The western edge of the mound was not as obvious because of the low angle at which the seismic line crossed the mound edge but could be estimated to within several hundred feet. It was clearly shown to the North Dakota Industrial Commission technical staff that 1) the synthetic seismic lines match the 2-D data and 2) that the edges of the mound could be determined at the points where the seismic lines crossed the mound edge. ASPRT's Geologist and Geophysicist analyzed the seismic data totally independently from Placid's technical staff. ASPRT relied on its own synthetic seismic lines to build its geophysical model prior to analyzing the Placid seismic data. Contrary to past assertions by Conoco that Placid and ASPRT "reached totally different conclusions as to where the edges of the reservoir are located," the maps of the two companies are strikingly similar in shape and as to location of the edges of the mound. Placid's expert witness testified that he used seismic data only to locate the edges of the reservoir while ASPRT's witness testified that the seismic data was used along with well data to determine the thickness of the mound as well as to locate the mound edges. ASPRT's map utilizes all of the data available: well control, seismic data, and the Fryburg ? structure. ASPRT's reservoir boundaries are supported by Placid's independent use of the seismic to delineate the mound edge. Thickness shown on ASPRT's map including the "saddle" in the middle of the field is supported by the Conoco map which utilized the well data and the Fryburg map. The saddle shown on the ASPRT map is based on well data, the Fryburg structure, and seismic data. Clearly, the ASPRT map incorporates all of the available data.

I. B. Oil/Water Contact.

Conoco has stated that the State A-83 well has an oil to water transition zone which starts at -9818' and continues down for 10 to 20 feet. Water saturation calculations based on the log data clearly do not indicate a long transition zone present in this well. Water saturations change from very low to very high over the course of only a few feet. If Conoco believes that there is a 10' to 20' transition zone present in this well, then Conoco's adoption of a uniform water saturation within the mapped pay interval is totally without merit. Conoco's equity formula is not consistent with testimony of its own expert witnesses in that by definition a transition zone contains varying water saturations.

I. <u>C. Fryburg Relationship to the Lodgepole Mound</u>.

ASPRT has stated that the Fryburg interval can be used as an indirect indicator of the possible presence of a Lodgepole mound. However, the structure of Fryburg, approximately 1000' above the

exact log, but only it is a useful tool

we didn't say the could be picked

Lodgepole mound, cannot be used to determine the exact location of the edge of the reservoir. Conoco places far too much weight on the map of the Fryburg structure considering the highly interpretive nature of the map. Conoco's Fryburg map is based on

there are 3 ([illegible] 20, 33 + 37)

only two additional wells which did not penetrate the Lodgepole section. One of these wells is in the middle of the Lodgepole field and the other is located to the northeast of the field. The Fryburg map has no data points to delineate the Fryburg structure

yes [illegible] Granzel + [illegible] Walth[illegible]

along the western edge of the Lodgepole feature. Additionally, the particular geologic event chosen by Conoco on which to base the

no evidence in the record to support this

Fryburg structure thickens dramatically to the northeast. Had the base of this gamma ray "hot" streak been mapped rather than the top, the position of the Filipi well on the Fryburg structure would have been approximately ten feet lower relative to the other wells. Even if one agrees totally with the quadratic equation relationship between the Fryburg and the Lodgepole tops, it is not possible to determine how close the mound edge is to the Filipi well. Only the fact that the Filipi well should have no mound present could be concluded. The location of the eastern edge of the mound cannot be predicted using the Fryburg marker.

II. A. Defining Reservoir Boundaries With Seismic Data.

As stated above, the synthetic seismic lines presented clearly show the distinct differences in the seismic response in areas where the Lodgepole mound is present. Conoco states that "Mr. Greg Mohl testified that defining oil accumulations and precise reservoir boundaries based on actual seismic data is theoretical and speculative". However in Mr. Mohl's home state of Wyoming, the Oil and Gas Conservation Commission approved the Unitization of the Little Missouri Field based on maps which utilized only seismic data to delineate the edge of the reservoir (Cause No. 3, Order No. 1, Docket No. 77-89). Furthermore, Conoco's assertion that 2-D and 3-D seismic data is used only as an exploration tool is incorrect. For many years, seismic data has been used to define and develop fields. In recent years, the use of 3-D seismic data has been used not only for the exploration and development, but also for reservoir characterization, reservoir boundary determination, and equity determination. (See attached papers.)

There is no evidence to support that you can use seismic info to find the reservoir in this Lp res. this is the 1st mound found in ND.

Conoco stated three reasons for not utilizing their 3-D seismic data to help delineate the boundaries of the Dickinson-Lodgepole Unit. First, Conoco states that it is not possible to pick the edge of the mound due to the physical properties of the Lodgepole. This is simply untrue. The mound edge was clearly visible on the 2-D seismic data and should be even more apparent using the 3-D data. Obviously, Conoco must have felt that the Lodgepole mound feature could be clearly seen on 3-D data or they would not have gone to the great expense of acquiring, processing, and interpreting approximately a township (36 square miles) of high resolution 3-D data. Second, Conoco states that it would jeopardize its competitive advantage over the rest of the industry "by simply giving away its seismic analog to competitors such as Placid and the Trust" (ASPRT). Placid and ASPRT stated at the unitization hearing they did not need to examine the 3-D data, but would accept the interpretation of an impartial third party industry expert who could review Conoco's 3-D data under strict confidentiality requirements. Conoco's third reason for not offering its 3-D seismic data was that the data had not been completely analyzed or interpreted. Conoco stated that their analysis began in mid-May. Industry 3-D experts have advised that this data could be fully interpreted in a matter of weeks. It is unreasonable for Conoco to base the equity formula for this unit utilizing only sparse well data when 3-D seismic data, one of the most definitive and widely used tools in the oil and gas industry today, is available, albeit, only to Conoco at this point. Use of 3-D seismic is a proven tool in Michigan, West Texas, New Mexico, and overseas in reservoirs very similar to the Dickinson Lodgepole. (See attached papers.) 3-D seismic has also recently been used in the unitization of the Canadian equivalent of the Lodgepole, the Souris Valley formation. 3-D seismic data was used to exclude tracts which contain no Souris Valley pay in the Parkman Unit in southeast Saskatchewan.

Is this a "moral"? I don't think so.

II. <u>B. Volumetric versus Material Balance Estimates of Original Oil in Place (OOIP).</u>

ASPRT agrees the material balance estimate of OOIP of 18.25 million barrels derived from Conoco's computer reservoir model is a reasonable estimate. ASPRT's witness testified that this

Preston said 16.1M

estimate was within the 15 to 20 million barrel range of OOIP that

before all info from wells was available

had been calculated by ASPRT using conventional material balance calculations. It should be noted that the volumetric calculations of OOIP derived from both the Conoco map and the ASPRT map also fall within this range. ASPRT's map is the most credible due to the utilization of all the data used by Conoco plus the incorporation of the 2-D seismic data. Even if the OOIP estimates from volumetric calculations and material balance calculations agree exactly, it is inappropriate to conclude that the net pay map is correct. One can only conclude that the reservoir volume depicted by the map is approximately correct. Nothing about the shape or boundaries of the reservoir on the map can be concluded.

since we have very good control on the north, south + west of the mound only the eastern limit can be moved.

Both Conoco and ASPRT could have easily modified their net pay maps still honoring the data used to construct the maps, so that the volumetric calculation exactly matched the material balance estimate. But, common practice within the industry is to leave the map as unmodified when there is close agreement between the material balance and volumetric calculations as is the case with ASPRT's map and Conoco's map. If it is felt that the material balance estimate is more accurate than the volumetric estimate, each tract's volumetric estimate is proportionately adjusted so that the total of the individual tract's estimates equals the material balance estimate. If there is a higher degree of confidence in the volumetric calculation than the material balance estimate, no ratioing of the individual tract volumes is necessary. It is unclear to ASPRT how much confidence Conoco has in its computer reservoir model material balance estimate of OOIP. Conoco used the model-derived OOIP and the model-derived estimate of field-wide primary recovery in their equity formula, yet Conoco has stated that "due to simplistic assumptions contained within the reservoir model, the model is only useful in comparing various different operating scenarios on a field-wide scale, such as waterflooding, gas injection and primary depletion." It appears that Conoco feels that the model is useful only if the results of the modelling study do not adversely affect Conoco's sharing ratio in the unit. As was shown in ASPRT's Exhibit No. 9 (attached), Conoco's failure to utilize the model's prediction of ultimate primary for the various individual wells within the unit, resulted in the addition of nearly one million barrels of recoverable primary oil to tract No. 1 where Conoco owns 100% of the working interest. The fact that Conoco has interest holdings in all nine tracts gives Conoco absolutely no incentive to protect the rights of all owners unless its ownership was the same in all tracts. This is certainly not the situation in this case. Conoco owns 100% working interest in Tract 1 (W/2 Section 32), Tract 4 (N/2 Section 5), and Tract 9 (SE/4 Section 32). Every barrel of oil allocated to one of these three tracts at the expense of any other tract increases Conoco's interest in the unit. For example, if 100,000 barrels of primary oil is incorrectly allocated to Tract 1 instead of Tract 2, Conoco would lose 50,000 barrels in Tract 2 and gain 100,000 barrels in Tract 1 for a net gain of 50,000 barrels. It should be noted that the two most disputed aspects of Conoco's unitization plan, namely the oil-water contact and the location of the eastern boundary of the Lodgepole mound have significant impact on the three 100% Conoco tracts. It is apparent Conoco has been extremely generous to itself in the mapping of this reservoir, in the selective inclusion of data which increases Conoco's unit interest, and the selective exclusion of data which decreases Conoco's unit interest.

Conoco has stated that it has secured the support of more than 76% of the working interest owners in the unit. This 76% "support" is comprised of less that 2% interest not owned by Conoco. Conoco has the "support" of less than 7% of the working interest owned by parties other than Conoco.

[illegible] allowed [illegible] injection as he suggests on the following page.

Based on the foregoing, ASPRT respectfully requests that the Commission reconsider and stay its Order. With the exception of drilling many additional wells in this field, the most accurate means of insuring fair, reasonable and equitable allocation of unit reserves is through the use of 3-D seismic data. The most logical approach would be for Conoco to make its 3-D data available to the North Dakota Industrial Commission or a third party expert. If Conoco refuses to make this data available, both Placid and ASPRT have stated their willingness to shoot their own 3-D data if Conoco would grant the necessary permits to do so. ASPRT wants to reiterate that it fully supports the formation of this secondary recovery unit and that its only argument is over the equity determination.

Additionally, ASPRT wants to point out that revisions to the equity formula need not delay the initiation of the waterflood. The owners of the unit have already initiated the well work necessary to begin injection below the oil/water contact.

Dated this 20th day of July, 1994.

ROBERT O. WEFALD
Attorney for Andrea Singer Pollack
Revocable Trust
P. O. Box One
Bismarck ND 58502-0001

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NO. 5933

IN THE MATTER OF THE PETITION OF CONOCO INC. FOR AN ORDER PROVIDING FOR THE UNITIZED MANAGEMENT, OPERATION, AND FURTHER DEVELOPMENT OF THE DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION; VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE.

CERTIFICATE OF SERVICE

The Reply Of Andrea Singer Pollack Revocable Trust To "Consolidated Response Of Conoco, Inc." was served upon the parties listed below by hand delivering true and correct copies thereof to:

Lawrence Bender
Attorney for Conoco, Inc.
P.O. Box 400
Bismarck ND 58502-0400

John Morrison
Attorney for Placid Oil Co.
P.O. Box 2798
Bismarck ND 58502-2798

said documents having been hand delivered by me, this 21st day of July, 1994.

ROBERT O. WEFALD
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Revocable Trust
WEFALD LAW OFFICE, LTD.
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Robert O. Wefald

Attorney And Counselor At Law

2800 North Washington Street
Post Office Box One
Bismarck, North Dakota 58502-0001

Phone 701-258-8945
Fax 701-255-7212

July 1, 1994

Karlene Fine, Secretary
N.D. Industrial Commission
State Capitol Building
Bismarck ND 58505

JUL 1994
RECEIVED
ND OIL & GAS
DIVISION

Dear Karlene:

Enclosed for filing is the original Petition for Reconsideration which I am filing on behalf of the Andrea Singer Pollack Revocable Trust with respect to the Commission's recent Orders in three cases involving the Dickinson-Lodgepole Unit. Would you kindly bring this matter to the attention of the Industrial Commission.

Sincerely,

Robert O. Wefald

ps
enc: orig. Petition
c: Wes Norton
Kevin Preston
John Morrison
Lawrence Bender

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NO. 5933

IN THE MATTER OF THE PETITION OF CONOCO INC. FOR AN ORDER PROVIDING FOR THE UNITIZED MANAGEMENT, OPERATION, AND FURTHER DEVELOPMENT OF THE DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION; VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE.

PETITION FOR RECONSIDERATION BY
THE ANDREA SINGER POLLACK REVOCABLE TRUST

The Andrea Singer Pollack Revocable Trust (ASPRT), pursuant to Sections 38-08-13 and 28-32-14 of the North Dakota Century Code, hereby petitions for reconsideration of the Industrial Commission's Order No. 6861 in Case No. 5933 which was signed on the 16th day of June, 1994, and served by mail on the 21st day of June, 1994. ASPRT asks that the Industrial Commission reconsider its Order based on the points and concerns hereinafter set forth.

1. ASPRT's principal concerns are with several of the findings set forth therein and the conclusions based on those findings.

2. ASPRT does not object to findings 1-7, 11-13, 15, 21, 25, and 28-32.

3. ASPRT objects to findings 9 and 10 because they include more tracts than are necessary under the area justified by the

ASPRT net isopach map. Finding 10 is also objected to along with findings 8, 24, and 26 because they purport to find that the proposed unit protects correlative rights and is fair, reasonable and equitable. We believe those "conclusions" are not justified based on the evidence and should be reconsidered and changed when the commission reconsiders findings 14, 16-20, 22 and 23.

4. Finding 14 is clearly erroneous and is not supported by the record. The expert testifying on behalf of ASPRT specifically testified that the ASPRT net pay isopach map, ASPRT Exhibit 7, was

the actual line was not drawn using well data, the well data only should show

constructed using the well data and honoring all of the information from the well logs as well as the available 2D seismic data. [In

Conoco said 3D is not available (do not use seismic to identify the res boundary) use only to identify general structure

addition to 3D seismic data, Conoco also has 2D seismic data that it did not make available. The finding that the net pay isopach

We stated the "reservoir boundary" was based only on seismic -

map was based only upon seismic information is clearly erroneous.

5. Finding 16 is clearly erroneous because the evidence presented by ASPRT was that the identification of the productive portion of the mound was identified using both seismic information and well data, honoring all of the data that was available.

6. Finding 17 is clearly erroneous because Conoco's

Conoco evidence on seismic was more credible than other testimony

testimony with respect to seismic information being useful only for exploration is not supported within the industry. Conoco clearly has 3D seismic information within its control which it did not produce. At a minimum, the Commission's Order should be stayed until such time as the 3D seismic information Conoco has in its possession can be analyzed, and if necessary, given to a third party for the purpose of creating a net pay isopach based on that

3D seismic information and the well data, and the interpretation of the Fryburg Interval if the Commission deems that information concerning the regional dip of the Fryburg Interval to be useful. Conoco's statement about the usefulness of 3D seismic information to find reservoir boundaries is contrary to the experience of the industry.

there is not experience w/ mound except this feature

7. Findings 18, 19 and 20 concerning the Fryburg Interval place far too much weight on the Conoco map of the Fryburg structure without considering the highly interpretive nature of the map.

there were three

[redacted]. One of these wells is in the middle of the Lodgepole field and the other is located to the northeast of the field. The Fryburg map has no data points to delineate the Fryburg structure along the western edge of the Lodgepole feature.

testimony by Hughes indicated northerly regional dip which was not refuted

Additionally, the particular geologic event chosen by Conoco on which to base the Fryburg structure thickens dramatically to the northeast.

no evidence in record

Had the base of this gamma ray "hot" streak been mapped rather than the top, the position of the Filipi well on the Fryburg structure would have been approximately ten feet lower relative to the other wells.

no evidence in record.

8. Findings 19 and 20 are totally without basis. Even if one were to agree with the quadratic equation relationship between the Fryburg and the Lodgepole tops, it is not possible to determine how close the mound edge is to the Filipi well. Only the fact that the Filipi well should have no mound present could be concluded.

The location of the eastern edge of the mound cannot be predicted using the Fryburg marker.

9. Finding of fact No. 22 is essentially irrelevant. The fact that Conoco's volumetric calculation is six percent above the material balance calculation, suggests that its net isopach map is too big, while ASPRT's volumetric calculation suggests that its map is too small. These calculations are simply estimates based on interpretations of some of the data available. ASPRT's calculations are based on well logs and seismic data while Conoco's calculations are based only on the well logs. wrong! - are also using Fryburg structure to determine mound edge.

10. Findings of fact 23 is clearly erroneous and not supported by a fair interpretation of all the evidence. The most credible net isopach map presented was the ASPRT isopach map which was based on both seismic information and the well data.

WHEREFORE, ASPRT respectfully requests that the Commission reconsider and stay its Order. The fact that Conoco has 3D seismic data it is unwilling to release for analysis continues to cause ASPRT concern that this unit is not fair, equitable or reasonable, and that it does not protect correlative rights.

Dated this 1st day of July, 1994.

ROBERT O. WEFALD
Attorney for Andrea Singer Pollack
Revocable Trust
P. O. Box One
Bismarck ND 58502-0001

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NO. 5933

IN THE MATTER OF THE PETITION OF CONOCO INC. FOR AN ORDER PROVIDING FOR THE UNITIZED MANAGEMENT, OPERATION, AND FURTHER DEVELOPMENT OF THE DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION; VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE.

CERTIFICATE OF SERVICE

The Petition for Reconsideration by the Andrea Singer Pollack Revocable Trust was served upon the parties listed below by mailing true and correct copies thereof to:

Lawrence Bender
Attorney for Conoco, Inc.
P.O. Box 400
Bismarck ND 58502-0400

John Morrison
Attorney for Placid Oil Co.
P.O. Box 2798
Bismarck ND 58502-2798

said documents having been placed in the United States mail, with sufficient postage affixed, this 1st day of July, 1994.

ROBERT O. WEFALD
Attorney for Andrea Singer Pollack
Revocable Trust
WEFALD LAW OFFICE, LTD.
P. O. Box One
Bismarck ND 58502-0001

Mare of a processing paper; i.e. wavelet processing

Detailed reservoir definition by integration of well and 3-D seismic data using space adaptive wavelet processing

By ELIO POGGIAGLIOLMI
EnTec Energy Consultants
London, England

and

RON D. ALLRED
Conoco Norway
Stavanger, Norway

Temporal and lateral resolution of seismic data is principally determined by the shape and duration of the propagating wavelet. Accurate wavelet estimation and the ability to change its shape are both of paramount importance to achieve the maximum resolution afforded by the available bandwidth.

Wavelet processing has been widely applied, since the 1970s, to enhance the resolution and stratigraphic interpretability of seismic reflections. Early pioneering work in this area was described by Norman Neidell and Poggiagliolmi in "Stratigraphic modeling, interpretation, geophysical principles and techniques" (*AAPG Memoir 26*, 1977).

However, this subject is complex and controversial. For example, 10 years after the cited article, a comparison of wavelet processing by 10 geophysical contractors showed inconsistencies in polarity, reflection time, and character (see "Wavelet processing seminar" by J. Denham, *TLE*, February 1987). One reason for lack of agreement is the variety of statistical models used for wavelet estimation. The proliferation of such models can be seen by referring to the proceedings of a 1986 workshop on "Deconvolution and Inversion" held in Rome. Ten papers were presented, each proposing a different approach to wavelet estimation.

In the thought-provoking paper "Why don't we measure seismic signatures" (GEOPHYSICS 1991), Anton Ziolkowski rejected statistical wavelet deconvolution methods by categorically stating that they are unreliable. He cited signature deconvolution as the only valid alternative. His views and conclusions were contested in many letters subsequently published in GEOPHYSICS. A more recent contribution to this debate was made at the EAEG's 1992 meeting in Paris when P. De Beukelaar et al. presented a "realistic" model experiment which demonstrated that reliable wavelets can be extracted from properly processed seismic data and "exact" well log data. In practical situations, where noise and artifacts are present in both well and seismic data, these authors proposed a multiwell approach to reduce the variance in the estimated wavelets.

This agrees with the approach expressed by Poggiagliolmi et al. in "Reservoir petrophysics of Bima Field North-West Java Sea" (*Proceedings of the Indonesian Petroleum Association*, 1988) which described a multiline, multiwell approach to wavelet extraction/processing and demonstrated that it produced extremely good ties between seismic and well data at 35 well locations.

This paper will discuss the application of an integrated multiwell wavelet estimation and shaping procedure to data from the Heidrun Field offshore Norway. The space adaptive wavelet processing procedure involves borehole analysis, extraction of wavelets at well locations, and performs implicit spectral inversion to condition the seismic pulse to a common, broadband, zero phase wavelet. The objective was to increase the resolution and fidelity of the seismic data which could, in turn, minimize interpretation uncertainties of geologic units, faulting, and truncation boundaries.

Borehole data from seven appraisal wells and seven 3-D migrated seismic tie lines were input to the pilot study (Figure 1). Borehole information from well 5A was not included due

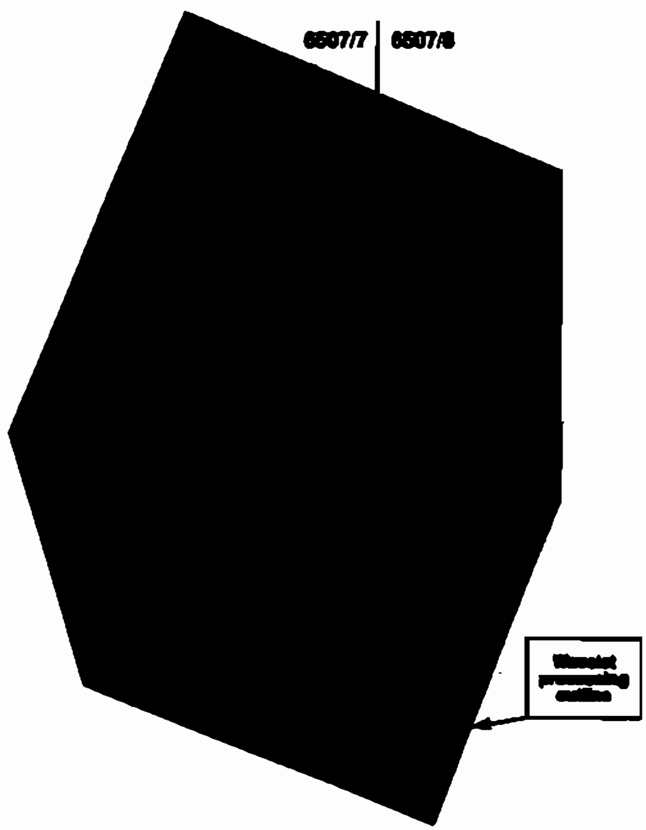

Figure 1. Outline and well locations of Heidrun Field.

to lack of well log data. Data processed through 3-D migration were used. All seven tie lines were wavelet processed and integrated with the well data through a common broad band, zero phase wavelet. As a result of the marked improvement in data quality in the pilot study, wavelet processing was carried out on the entire Heidrun 3-D survey (approximately 12 000 line-km).

Method. Wavelets can often be reliably extracted from stacked seismic traces and well acoustic logs (sonic and density). However, before using this data, the logs must be properly edited, calibrated, and converted to seismic time by means of borehole seismic (checkshot or vertical seismic profile). Unreliable logs and inaccurate calibration to borehole seismic are often the cause of unstable and nonconvergent extracted wavelets.

Log editing is based on a multiwell, multiline approach and is carried out iteratively and by direct interaction between borehole and seismic data. This editing involves objective comparison of the logs with borehole and surface seismic data. In the event of discrepancies, the logs are iterated through a data validation and editing cycle until well logs and depth-to-time functions reach optimum reliability with no bias or forced fitting between well and seismic data.

Comparison between logs and seismic serves as a useful check on the validity of the logs after each editing cycle. This comparison alone is not used as a justification to obtain a match with the seismic by further log editing. Any log editing is carried out only when it can be justified by reference to all available borehole data.

The ability to estimate wavelets from stacked traces relies on the assumption that traces close to the well can be described by a wavelet convolved with the well reflectivity series. Provided this assumption holds, wavelets can be extracted by least squares deconvolution of the seismic traces by the well reflectivity series.

Examples of wavelets extracted from well 8-1 and well 7-5 are shown in Figure 2. The shapes are quite different. Similar differences were found with the wavelets extracted at all other well locations, making it evident that the wavelet in the 3-D migrated data is spatially variable.

It was considered that the problem was unlikely to be related to well data since the edited log quality was high and the extracted wavelets were short and convergent. In addition, good ties between seismic traces and synthetic seismograms, produced with the extracted wavelets, were observed at all seven well locations. Consequently, the wavelets in the data contained an intrinsic space variant component which was not introduced by the extraction process. A space adaptive operator was calculated individually for each trace to zero the phase of the estimated wavelet and to normalize the estimated spectrum to a common average spectrum, derived from the input data.

After application of this process, wavelets were reextracted at the seven well locations and were found to be close to zero phase and spatially stable. This allowed any residual phase component in the wavelet to be estimated using a simultaneous multiwell wavelet extraction approach. In this approach, the statistical confidence of the residual phase derived at each well location is used to weigh the phase contribution to the final operator design. Having done this, it is possible to calculate the final operator from all the wells simultaneously and with greater confidence than with no applied weighting.

Wavelet processing. The final step in the space adaptive wavelet processing sequence involves the amplitude spectrum inversion of the previously spectrally normalized narrow band zero phase traces. The technique is an iterative process which, for a given input trace and associated wavelet, produces a broadband output trace which is consistent with the available bandwidth. Wavelets extracted after space adaptive wavelet processing are shown in Figure 3. These wavelets are symmetrical with very low sidelobe activity. Similar wavelets were extracted at all well locations, confirming the spatial stability and quality of the wavelet processing.

The effectiveness of the wavelet processing procedure is illustrated by Figures 4–5. The former shows raw migrated seismic traces (without wavelet processing) connecting two wells. Synthetic seismograms are inserted for visual correlation. The correlation is poor between the synthetics and the 3-D traces even though some well log editing had already been carried out. From an inspection of the signal and noise power spectra in Figure 6a, it is evident that the frequency response of the 3-D migrated data (without wavelet processing) is unstable with the dominant frequency ranging from 16 to 25 Hz for the seven seismic tie lines. The same instability is seen in the extracted wavelets in Figure 2.

Figure 5 shows the results after the application of space adaptive wavelet processing to the 3-D migrated traces. Now synthetic seismograms and surface seismic share the same zero phase broadband wavelet. The correlation has improved dramatically and the formation tops can be easily transferred from well logs to the surface seismic via the synthetic seismogram.

A comparison of power spectra in Figures 6a-b shows the bandwidth of the signal (solid lines) has increased from 10–40 Hz to 8–60 Hz at -20 dB down from the maximum response.

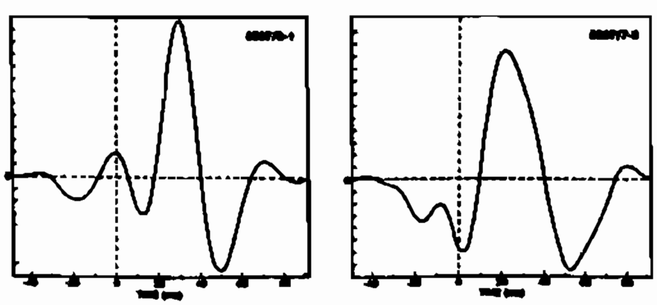

Figure 2. Wavelet extraction from migrated stack (before wavelet processing).

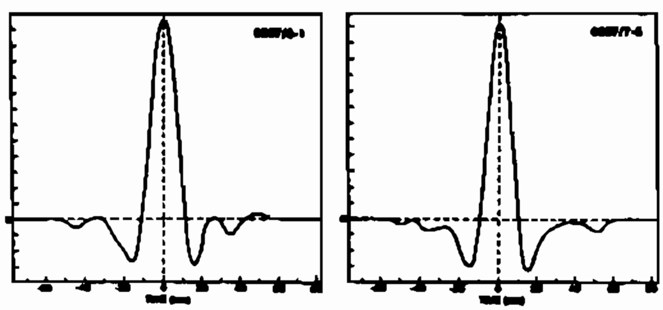

Figure 3. Wavelet extraction from wavelet processed data.

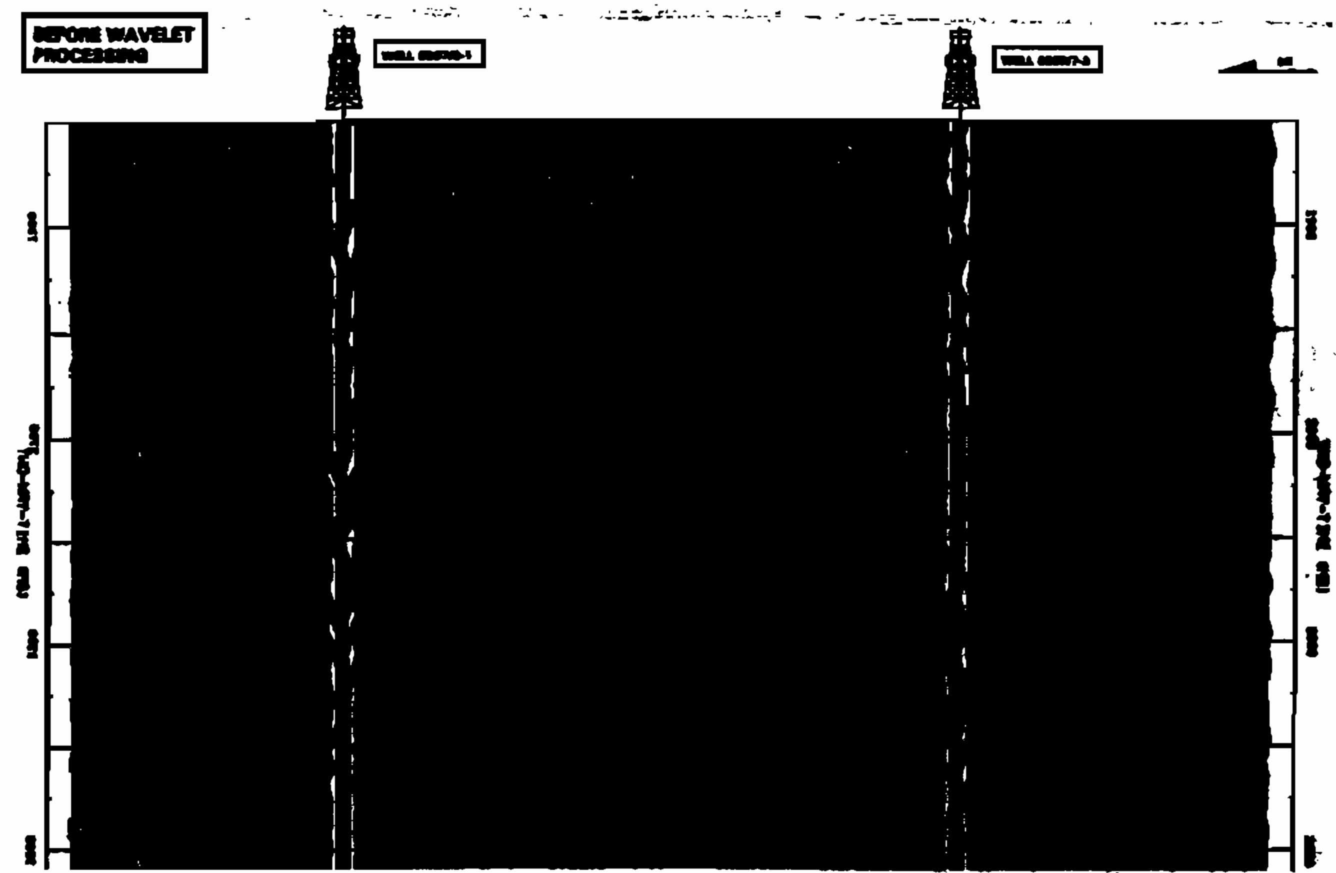

Figure 4. Well synthetics compared to migrated stack.

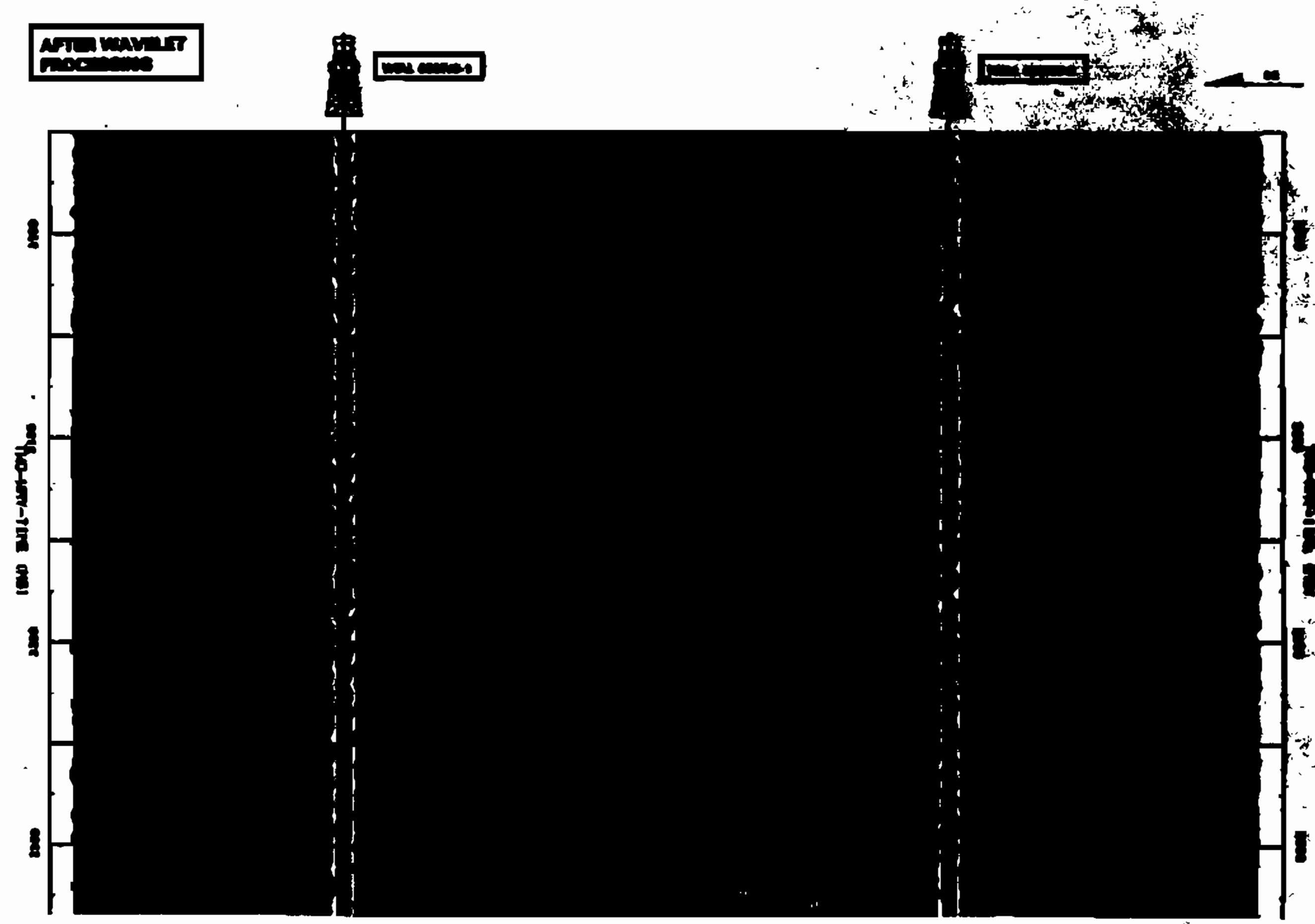

Figure 5. Well synthetics compared to wavelet processed data.

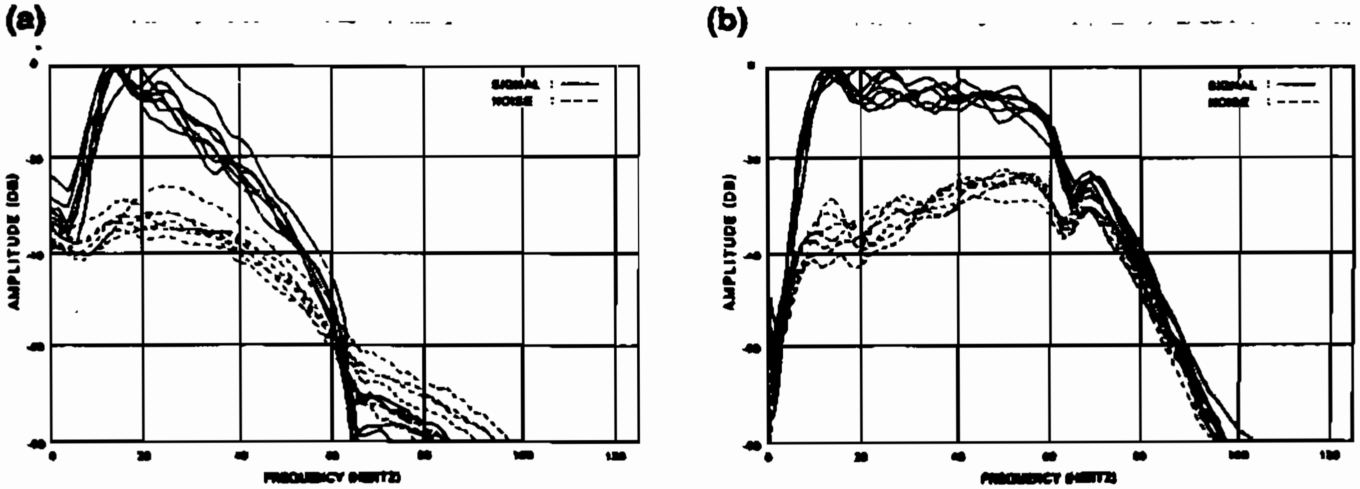

Figure 6. Signal and noise power spectra (a) before and (b) after wavelet processing.

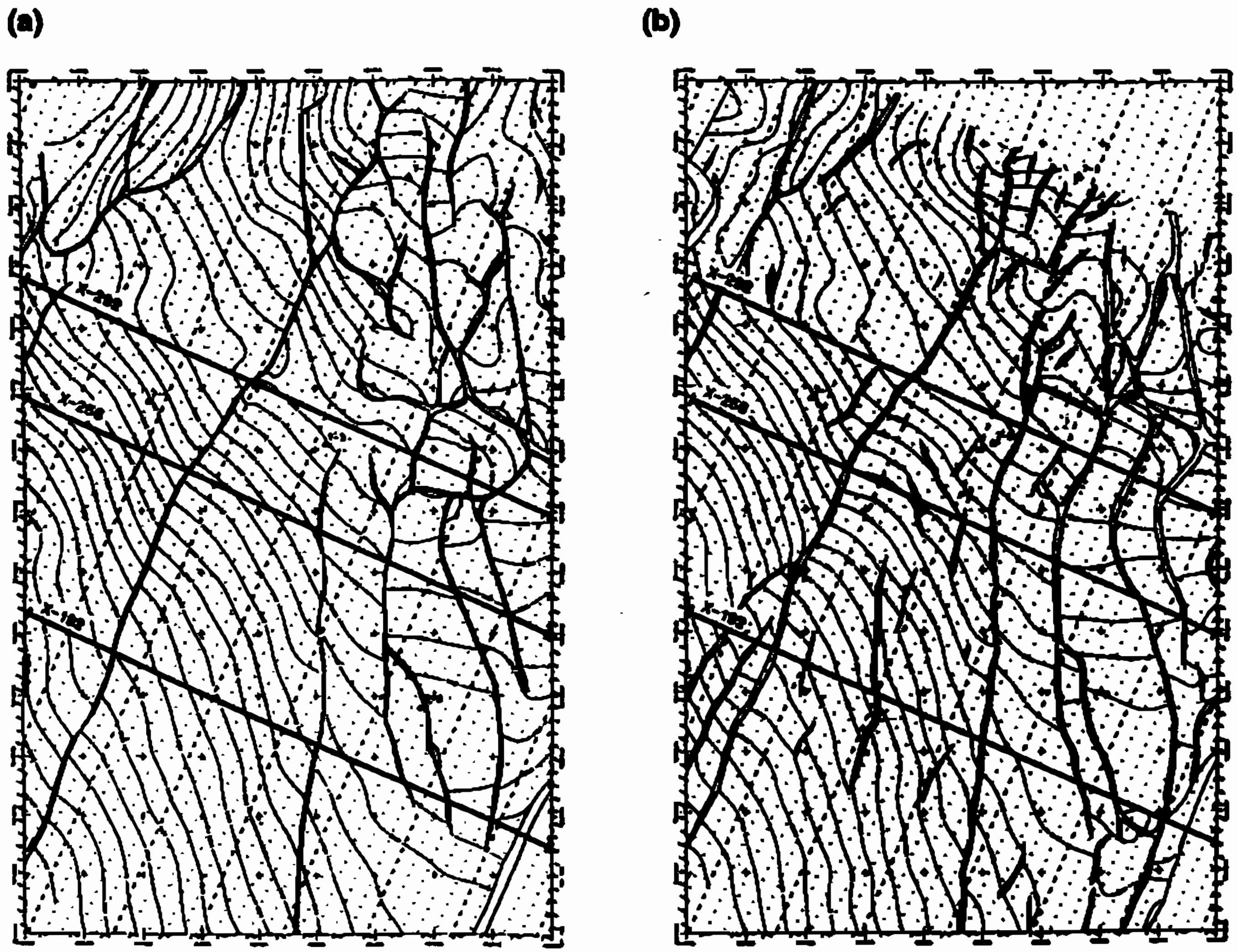

Figure 7. Depth structure maps (a) before and (b) after wavelet processing.

The fluctuations of individual spectra are due to reflectivity coloration (geologic information) which has not been degraded by space adaptive wavelet processing.

Since this wavelet processing approach uses the full knowledge of the wavelet in the seismic traces, it is less sensitive to noise than conventional deconvolution methods. As a result, improvements in the signal-to-noise ratio can be achieved within the available bandwidth. The bandwidth of the output traces is normalized to the upper and lower limits of the available bandwidth down to where the signal-to-random noise ratio is equal to unity.

The noise spectra, shown as dashed lines in Figures 6a–b, were calculated using a method proposed by A.J. Berkhout (see "Least squares inverse filtering and wavelet deconvolu-

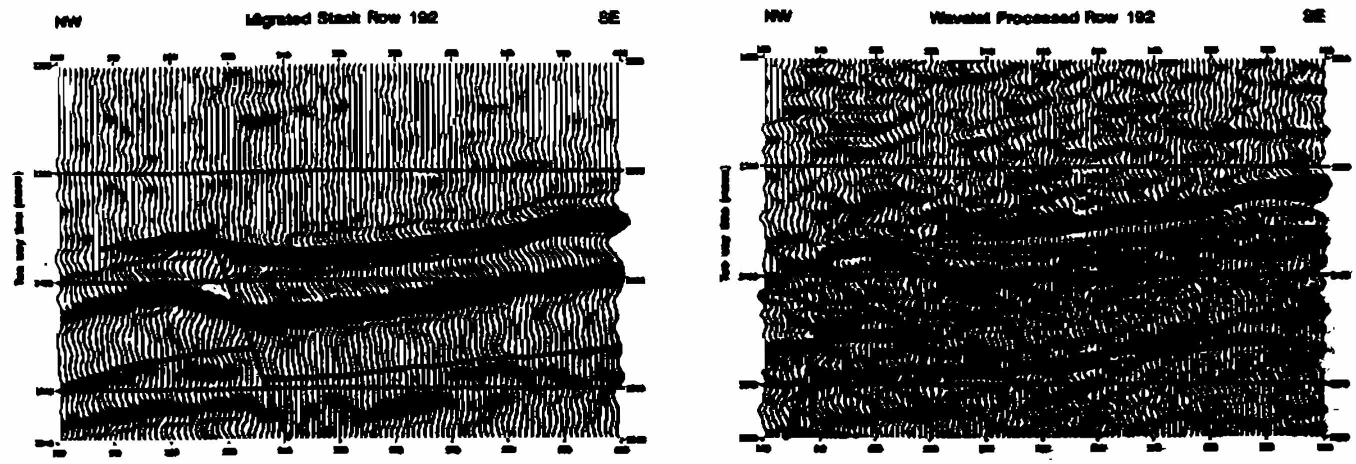

Figure 8. Interpretation on row 192.

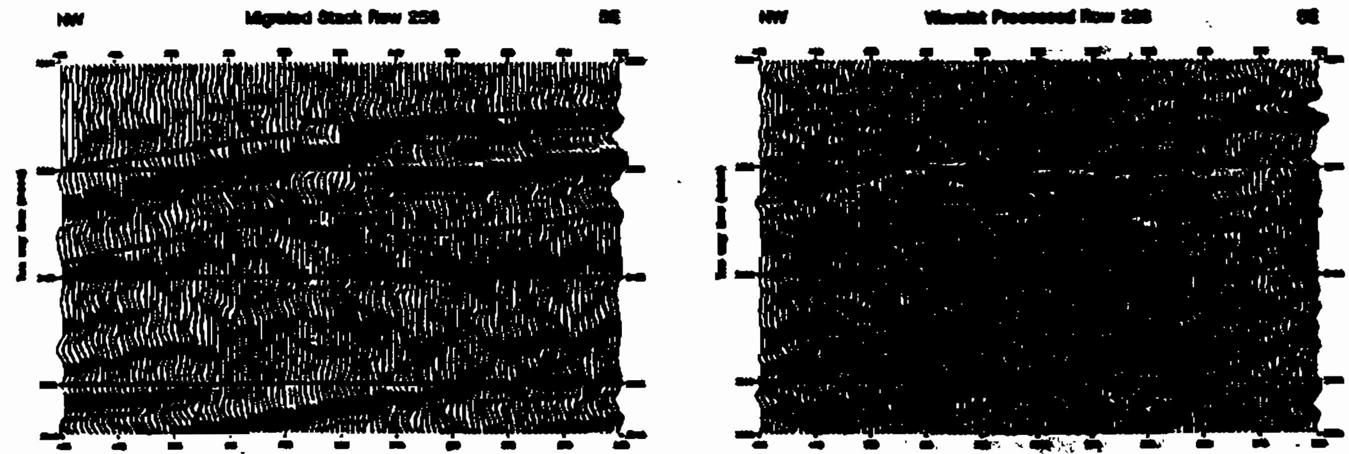

Figure 9. Interpretation on row 256.

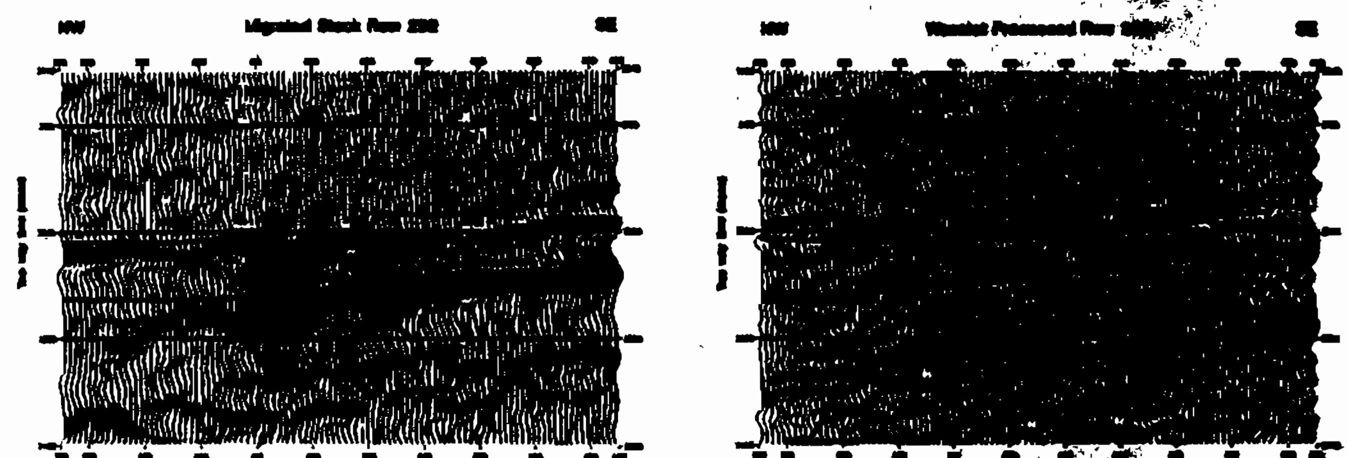

Figure 10. Interpretation on row 292.

tion," GEOPHYSICS 1977) which utilizes auto and cross correlations to estimate the coherent and incoherent components in the seismic data. It can be seen that the energy of the noise has been increased at higher frequencies by the space adaptive wavelet processing procedure, resulting in the slightly noisier overall appearance of the section in Figure 5. However, it is very important to note that separation between the signal and noise spectra in Figure 6b has also increased at the same frequencies resulting in a higher signal-to-noise ratio. This is in stark contrast to the deterioration of this ratio at higher frequencies, which is well known to occur after spectral whitening by conventional deconvolution.

Interpretation. A comparison of two different structure maps for top of Fangst Group, the main Upper Jurassic gas and oil reservoir, is shown in Figure 7. One map was produced using migrated stack data and the other from wavelet processed data. The latter shows more continuity in the fault trends, maps faults in areas where faulting was not previously observed, identifies faults with smaller offsets, and better characterizes the Top Fangst Group producing a more detailed map.

The locations of three seismic lines are given in Figure 7. Figures 8–10 illustrate differences in interpretation between the migrated stack and wavelet processed versions of each. The most striking difference is the contrast in overall appearance. The migrated stack data have a low frequency look that is characterized by broad peaks and troughs. The wavelet processed seismic clearly has higher frequency signal with peaks and troughs being sharply defined (with little additional noise).

In Figure 8, the migrated stack data give good event definition for the Base Cretaceous unconformity (blue) and Top Fangst Group (yellow) but it is very poor for the Base Fangst Group event (green). However, the wavelet processed seismic had good event resolution at all interpreted horizon levels and contains far more faulting. This is important because faults must be avoided in locating new Heidrun wells. The top reservoir event (yellow) on the wavelet processed section is a better defined trough than on the migrated stack. The Base Fangst Group, almost nonexistent on the migrated stack data, is clear on the wavelet processed section.

In Figure 9, a fault at CMP 524 is interpreted on the migrated stack section but not seen on the wavelet processed data. The data quality of the wavelet processed seismic is good, suggesting that a fault cut should not have been interpreted at this location. Conversely, a fault at CMP 572 is observed as a clean cut on the wavelet processed seismic but is not seen on the migrated stack data. Again, the Base Fangst Group event is very poorly defined on the migrated stack but well defined on the wavelet processed version.

In Figure 10, the wavelet processed seismic shows more fault detail than the migrated stack data and event resolution has been improved especially at the Base Fangst Group (Top Ror Formation).

Results. Heidrun Field is to be developed with a tension leg platform. This allows drilling of wells prior to platform installation. The objective of wavelet processing was to integrate borehole data with surface seismic data for the purpose of obtaining greater detail in the reservoir section in order to improve selection of well locations. At the time of writing, five of 15 planned wells have been completed. Results are consistent with the more detailed characterization of geologic events provided by the wavelet processed seismic. Furthermore, small scale faulting through the reservoir interval, which could affect reservoir thickness and productivity, has been avoided in these wells due to the information on the wavelet processed data. Conventional wisdom is that wavelet processing is primarily intended to facilitate stratigraphic interpretation, but it is clear that space adaptive wavelet processing has proved an effective method for improving temporal and spatial resolution of the 3-D seismic data on Heidrun Field.

Because of these results, further work was carried out on

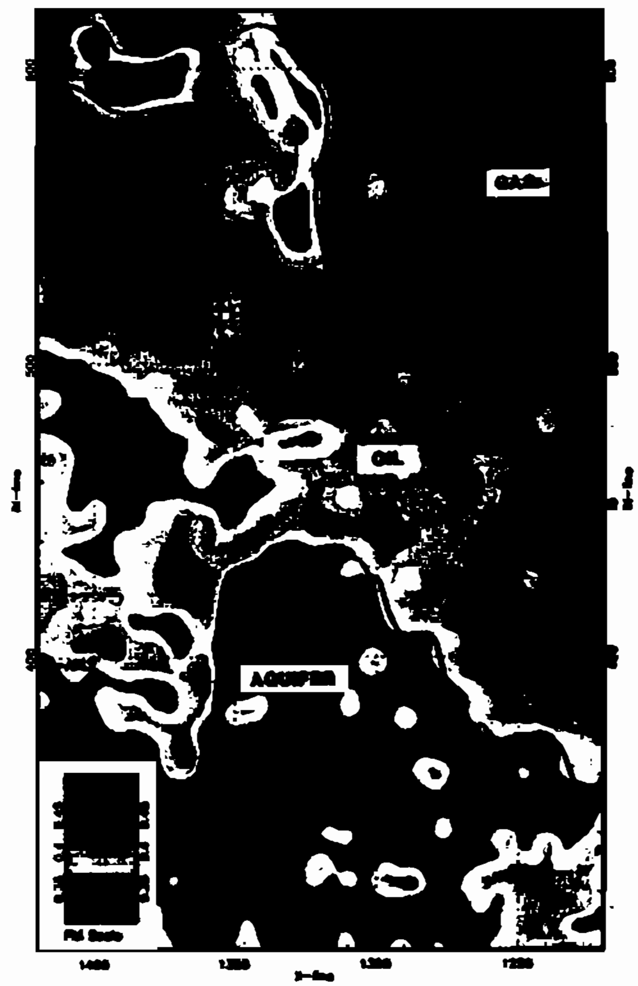

Figure 11. Seismic acoustic porosity for the Fangst reservoir interval.

well and seismic data to derive porosity and fluid distribution from petrophysically calibrated acoustic amplitudes. During the first stage of this work, the wavelet processed 3-D data were converted into high resolution absolute acoustic impedance. Calibration of acoustic impedance to porosity was performed using a petrophysical-acoustic model generated from all available well data. This has a wide range of reservoir description applications ranging from quantitative facies distribution analyses to reservoir volumetrics. Moreover, by deliberately not correcting for hydrocarbon effects, pore fluid boundaries can be seen as anomalies on seismic acoustic porosity maps. An example of gas, oil and aquifer distribution derived from acoustic porosity criteria for the Fangst interval is shown in Figure 11. Here the acoustic porosity values within the aquifer are close to those of the rock effective porosity. The acoustic porosity is anomalously high in the oil leg (36–42 percent) due to the high gas-oil ratio, and even higher (42–50 percent) in the gas interval. The subject of borehole-calibrated surface seismic to deliver reservoir description parameters will be treated in a later publication.

Acknowledgement: The authors wish to thank the Heidrun Unit-Owners for permission to publish this paper.

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Technology

On the Cover

This total-net-producible-gas-sand isopach map represents an integrated 3D seismic method of comprehensive analysis for known gas reservoirs. The paper beginning on Page 777 examines this method for finding and recovering new reserves. Cover by Alex Asfar.

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Role of the 3D Seismic Technique in Improving Oilfield Economics

W. Ritchie, SPE, Geophysical Service Inc.

Summary. As the various disciplines interacting in our industry begin to recognize the need for an integrated approach, the three-dimensional (3D) seismic method has emerged to help reduce the uncertainty inherent in finding and recovering new reserves.

The 3D method improves the accuracy of the subsurface information obtained from surface-recorded measurements over conventional seismic techniques by comprehending the spatial or 3D nature of the problem to be solved. The increased detail and accuracy obtained from the technique allow better definition and delineation of the structural (or stratigraphic) trap; hence, reservoir management can proceed with less uncertainty, enhancing the value of in-situ reserves.

The most promising role for 3D techniques lies in the area of reservoir description. The 3D seismic method is uniquely capable of providing spatially continuous estimates of rock parameters. **When it is integrated with available well and core data, areal distribution of net pay, porosity, or hydrocarbon content across the reservoir can be derived and add significantly to the quality of information provided by the integrated database input to the reservoir simulation process.**

Fewer dry holes, better well placement, earlier production, and greater total hydrocarbons recovered are the result. Thus the 3D seismic method offers positive leverage on the net present value of the field.

Introduction

Any business venture can be conceptualized by the following graphic:

$ Expenditure		$ Revenue
!	Time	!

The goal is to influence positively the relationship between the three variables to improve cash flow and, hence, the net present value (NPV) of the project.

In our industry, this equates to reducing the number of dry holes or inefficiently located wells, obtaining optimum production from each well through effective well placement and reservoir management, and bringing production on-stream as early as possible.

As the industry extends its search to more complex geologic environments and looks for smaller plays, the critical need to maintain or improve its cost-effectiveness remains, and the application of new techniques to support this objective must be a constant consideration.

Figs. 1 and 2 provide an analysis of producing and dry-hole footage drilled in the U.S. over the last 30 years by industry phase. While it is expected that most of the producing footage has been drilled in the development phase, it is not intuitively obvious that in absolute footage, more dry-hole footage is also drilled in this phase, and this suggests the opportunity to increase profits by reducing this unproductive expenditure.

While approximately 80% of development wells are productive, individual well efficiency remains an area for improvement. With sparse information, the placement of wells to optimize individual well productivity (within the context of total reservoir management) must be considered to have ample scope for improvements in efficiency. Improvements in both the quantity and the quality of information can only reduce uncertainty and enhance the decision-making process.

The dual goals of improved success ratios and increased well productivity are keys to enhancing the value of in-situ reserves.

A breakdown of expenditure by major cost classification in the exploration and the development/production phase indicates that geology and geophysics account for approximately 12% of exploration expenditure, much of it associated with conventional reflection seismic surveys. It is in this prediscovery phase that seismic methods have historically been used.

Insignificant expenditure for geology and geophysics is associated with development and production. New technologies, however, such as vertical seismic profiling, seismic inversion, and 3D seismic techniques, have begun to play an emerging role in this environment, and 3D has proved its utility with more than 200 onshore and 300 offshore surveys, improving the cost-effectiveness of the development phase.

The 3D seismic method particularly can play a central role because of its ability to provide high-resolution, continuous information of not only reservoir geometry, but also inferences on reservoir rock characteristics and variations in those characteristics across the reservoir.

In addition, these seismic methods have progressed significantly in their ability to communicate information in terms familiar to the petroleum engineer. Reliable transformations from the time/amplitude seismic domain to depth, thickness (gross and net), as well as layer velocity and *areal* porosity distributions within the reservoir have

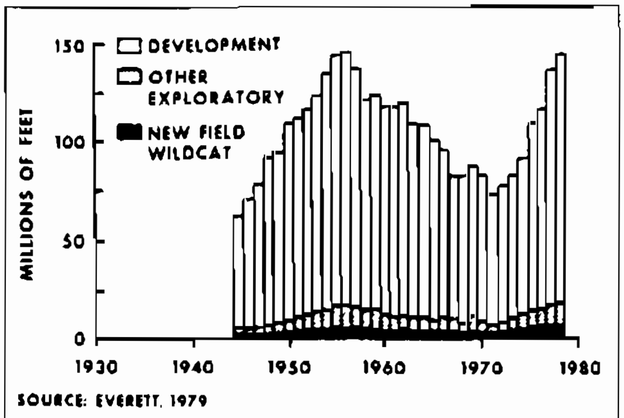

Fig. 1—Producing-hole footage history by well classification.

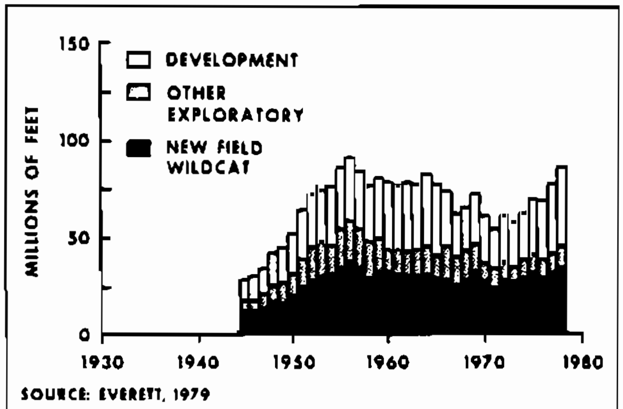

Fig. 2—Dry-hole footage history by well classification.

TABLE 1—HYDROCARBON-CYCLE-STAGE REQUIREMENTS

Phase	Need	Objective
Exploration	Delineation	Reserve estimates Well placements
Development	Description	Reservoir management Life extension
Production	Simulation	EOR process selection
Enhanced Recovery		

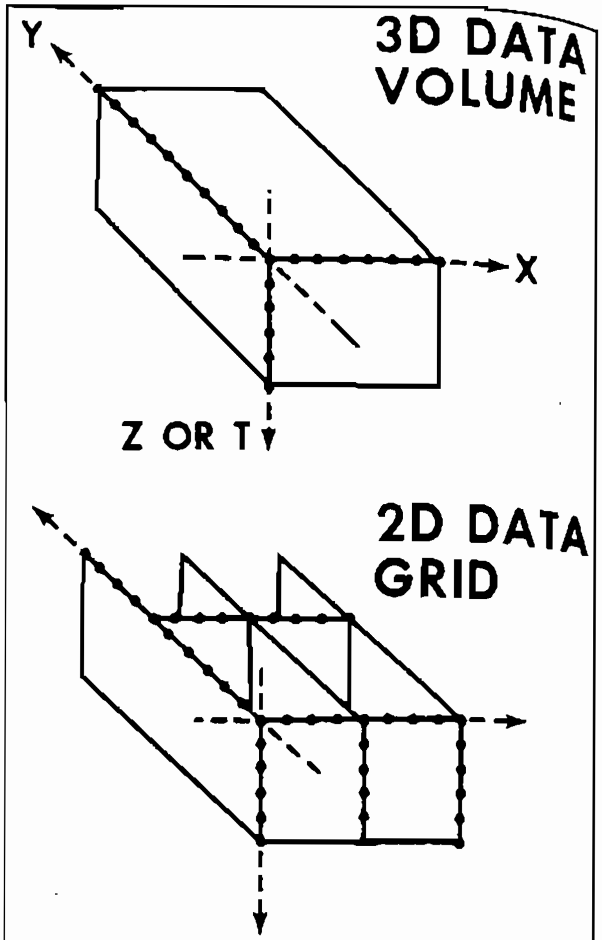

Fig. 3—3D seismic data volume vs. 2D seismic grid.

recently been introduced. Removal of such communication barriers accelerates effective integration of relevant data sources.

Incorporating sophisticated seismic techniques into the integrated development program can reduce the uncertainty inherent in our imperfect knowledge of subsurface conditions and rock properties. This can lower total industry expenditure required to discover a given level of proven reserves or, alternatively, provides an opportunity to increase the reserves found from a given level of expenditure.

This is the context in which the ability of the 3D seismic method to provide an accurate, spatial subsurface image and, hence, improved well placement and more efficient extraction of reserves should be viewed in this context.

The Need

The requirements at each stage of the hydrocarbon cycle are indicated in Table 1. As we progress from the exploratory to the production phase, the requirement for information proceeds from the macrolevel of delineation of reservoir boundaries to the microlevel of the pore space.

At each stage, increasing detail is required as a comprehensive description of the reservoir is developed incorporating all available data sources. The basic elements encompass reservoir geometry, physical parameters, and heterogeneity.[1]

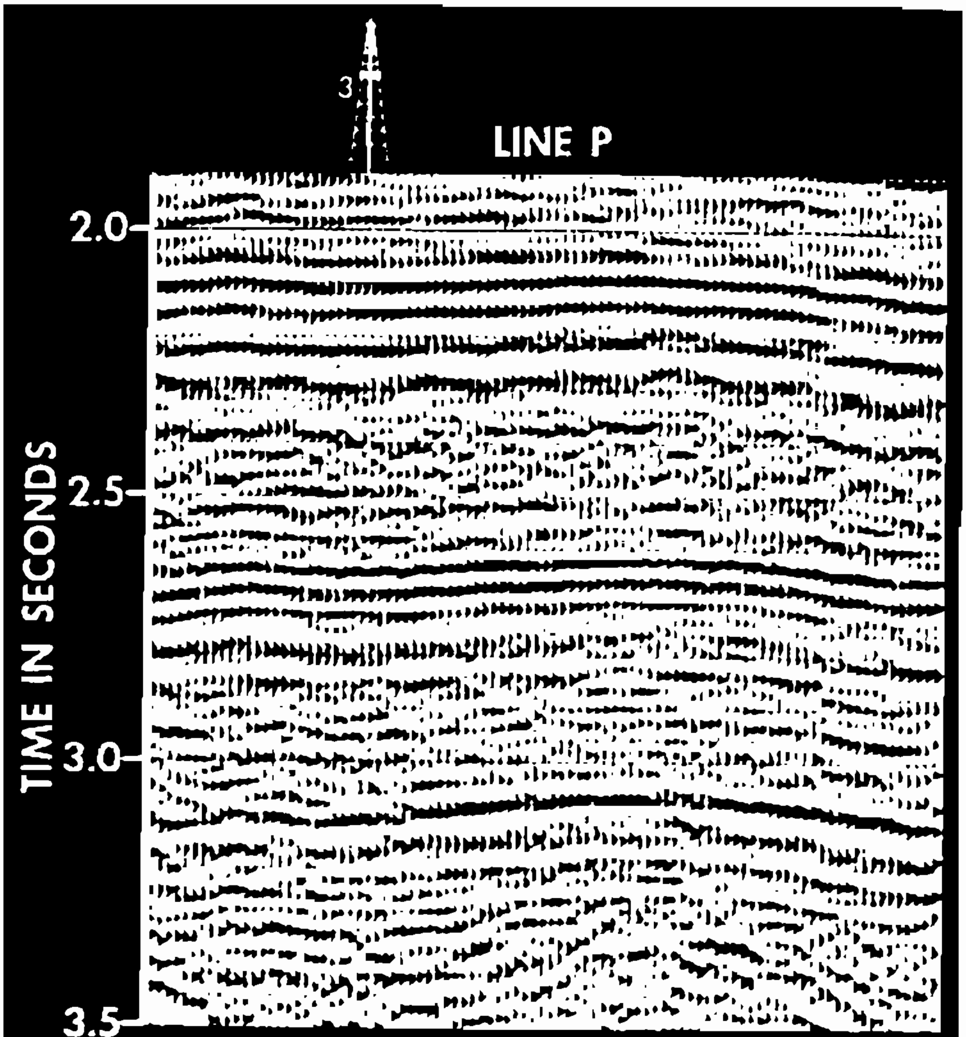

Fig. 4—Vertical seismic perspective of a producing anticline. (Courtesy of Occidental E&P Co.)

TABLE 2—3D METHOD BENEFITS

3D Attributes	Geologic Benefits	Economic Benefits
3D migration	Accurate geometry	Fewer dry holes
3D density	Reservoir delineation	More production per well
Data volume	Interpretability	Fewer development wells
Spatial continuity	Heterogeneity	Earlier production
		Enhanced value of reserves

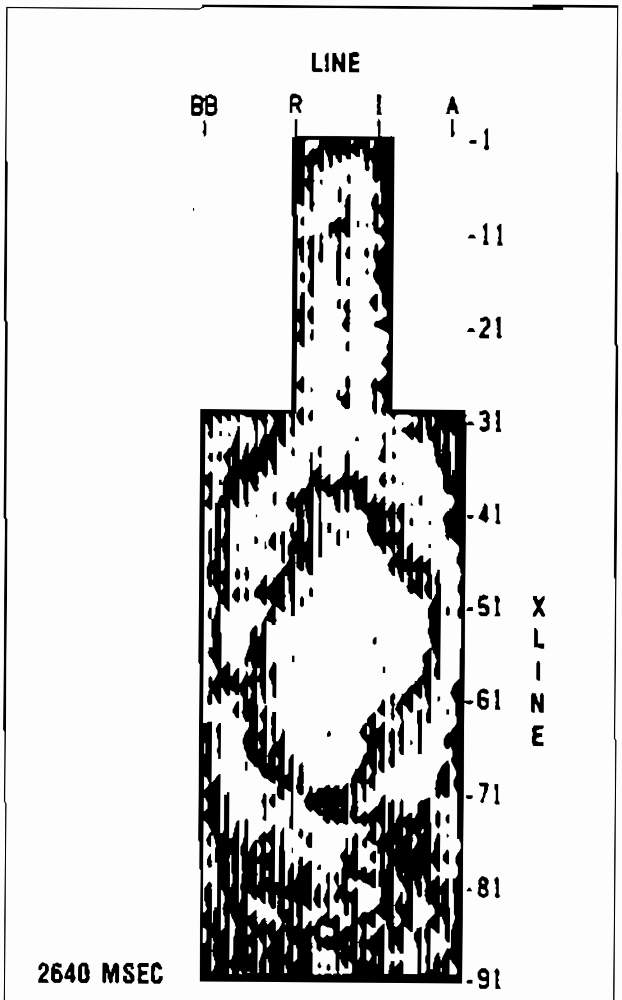

Fig. 5—Horizontal seismic perspective of a producing anticline. (Courtesy of Occidental E&P Co.)

Clearly, only the integration of geology, seismic, wireline, and core analysis can adequately provide a total description of the reservoir.

Traditionally, seismic and geology have provided the macrolevel inputs (geometry), while wireline and core methods contribute the microlevel data. There tends to be a separation between these disciplines with little cross correlation to extract maximum information from the seismic data base.

The description provided to the reservoir simulation process has been constrained at the microlevel because only discrete, sparsely sampled information is available (i.e., at well locations). Thus reservoir heterogeneity is inadequately described. At the other end of the spectrum, the reservoir geometry—thickness, depth, dip—is poorly defined because data exist only on coarsely sampled vertical seismic sections throughout the prospect.

Three-dimensional seismic techniques provide significant improvements in structural accuracy and high resolution of overall geometry, and, when integrated with other data sources, can provide a spatially continuous representation of the reservoir characteristics—rock properties and pore content.

High structural accuracy, fault system definition, and spatially continuous input to the reservoir description greatly reduce uncertainty and enhance the quality of the subsequent decision-making process.

The 3D Seismic Method

Although it has been of major importance in facilitating the discovery of many fields over the last 50 years, the reflection seismic method has always been constrained in its ability to provide a true subsurface picture because it is trying to resolve a spatial or 3D problem within the confines of a 2D vertical plane. The result is a distorted or poorly focused image. Further, by working with a sparse grid of 2D seismic, the interpreter must rely on experience and intuition to fill the large no-data zones within the grid. In the presence of any degree of geologic complexity, high uncertainty remains even after a tight seismic grid, increasing the probability of an unsuccessful well.

By use of specialized areal acquisition techniques and large-capacity computer processing, the 3D seismic reflection method provides a volume of seismic data that is correctly sampled in three orthogonal directions (x,y space and depth) to provide the resolution necessary to solve the geologic problem within the area encompassed by the survey. Fig. 3 portrays the 3D volume vs. 2D grid concept. Thus the method applies a spatial solution to a true 3D problem and provides a correctly focused, accurate image of the rock configurations in the subsurface before the development program is initiated, thus improving the probability of effective placement and successful wells. Three-dimensional surveys typically provide subsurface information samples every 100 to 150 ft [31 to 46 m] throughout the reservoir space.

The 3D data volume offers structural accuracy, high resolution, and a horizontal perspective of the subsurface by allowing the user to slice horizontally to view the total prospect area at a single depth—analogous to removing the geologic overburden to the target level and viewing the resulting subcrop map. This display is the Seiscrop™ section.[2] The user can view—at the prospect level—structural closure, geologic dip, strike orientation, degree of dip, and tracks of fault planes on a single display. Figs. 4 and 5 illustrate the concept and its application for a closed anticlinal feature.

While seismic is recorded in the time/amplitude domain, the use of available sonic logs and/or vertical seismic profiles recorded in wells on the prospect can provide definitive ties to depth.

The seismic inversion technique permits the time/amplitude information to be transformed to depth/interval velocity (transit time) or synthetic sonic logs on a continuous basis across the prospect. Extraction of this information along a geologic boundary across the extent of the reservoir permits portrayal of changes in reservoir characteristics. The use of relationships (such as those proposed by Wylie[3]) to convert velocity to porosity attributes provides insight into the quality of the reservoir throughout the prospect area. This spatially continuous horizontal perspective is an invaluable addition to the information base.

The benefits provided by the 3D method are summarized in Table 2.

Applications

The 3D technique has been applied successfully to a wide spectrum of complex geologic problems in most operating environments—e.g., Arctic ice, rugged overthrust terrain, desert, and jungle conditions. Development projects

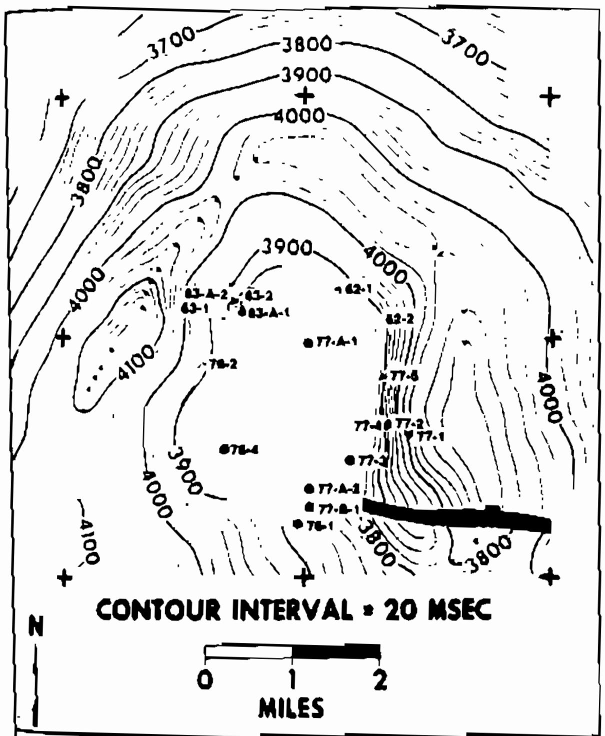

Fig. 6—Structure based on conventional seismic data. (Courtesy of Hunt Oil Co.)

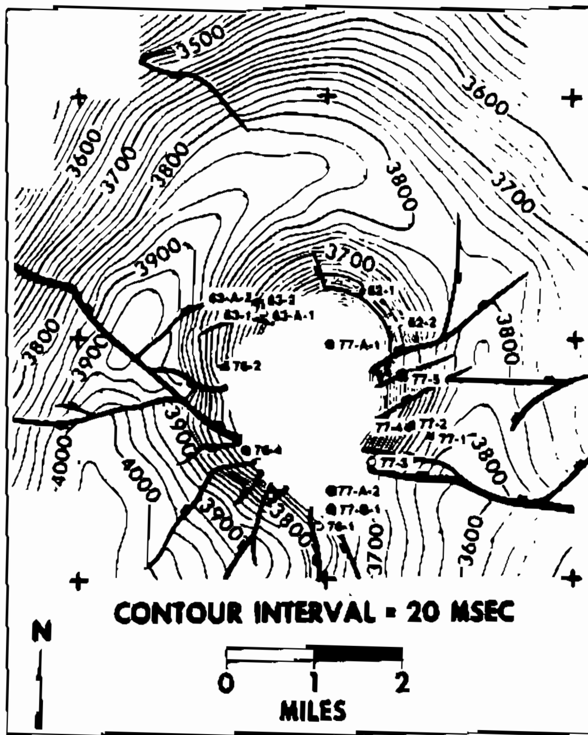

Fig. 7—Structure based on 3D seismic data. (Courtesy of Hunt Oil Co.)

in such diverse areas as Alaska, Peru, Holland, and onshore China have incorporated the 3D technique into the integrated plan.

The following quotation exemplifies its impact on the ongoing development of the giant East Painter reservoir field in the Rockies Overthrust:

"To date, a total of 16 wells have been drilled on the East Painter reservoir structure. Thirteen of these were spudded after the 3D survey was completed, and their locations were guided by the 3D mapping used in conjunction with the incoming subsurface control from the development drilling. All of the wells have been successful without any significant structural surprises on the Nugget horizon. The 3D mapping allowed up to six development wells to be drilled at one time, which greatly accelerated development of the field. The wells were drilled to an average depth of 12,500 ft [3810 m] with an average cost per well of $4 to $5 million. The cost of the East Painter 3D survey was $1.6 million—a good value!"[4]

Figs. 6 and 7 show structural maps around a gulf coast salt dome interpreted from two integrated close-grid conventional seismic surveys and from a 50-square-mile [130-km] 3D survey (with x,y spacing at 110 ft [34 m]), respectively. Although production was established at several wells around the dome, successive wells produced conflicting results because of poor information regarding the true location of the salt face and the effect of faulting around the dome. As discussed by Blake *et al.*,[5] the 3D survey provided an accurate and well-defined understanding of both the salt/clastic interface and the complex radial fault system associated with the piercement dome. Thus the reservoir mechanisms interacting around the dome can be understood more readily and development drilling can proceed more effectively.

Figs. 8 and 9 represent a vertical profile through an existing field in Europe with conventional and 3D seismic applications, respectively. A secondary recovery program is planned, and detailed definition of the fault system is desired. The clarity and definition of the faulting focused by the 3D method is clearly visible. High structural resolution will enhance the success of the secondary recovery program.

The extension from structural information to the extraction of information on reservoir conditions is portrayed in Fig. 10. Kurfess *et al.*[6] described the 3D application for development of an oil field in the Peruvian jungle, and the structural content is exhibited in Figs. 4 and 5. The data were subsequently investigated to extract information on production limits. Fig. 10 represents the lateral variation in velocity within the reservoir following inversion of the seismic data volume to portray acoustic velocity. The correlation between zones of lower velocity (as a result of hydrocarbon content) and the producing wells is demonstrated. Improved spatial resolution of reservoir conditions is available.[7]

The power of the spatially continuous horizontal perspective is well demonstrated in Fig. 11. A buried channel is clearly delineated in the subsurface. After removal of the moderate structure, the horizontal section was extracted from the 3D data volume. Anomalous amplitude behavior clearly exhibits the channel feature interpreted to be porous but water-filled to the south and gas-filled to the northeast, where highest amplitude differences exist. Note that this conforms to the structural position (contours superimposed) with the gas-filled zone structurally high in relation to the southward extent of the channel.[6]

Fig. 12 represents the result of a comprehensive analysis of a known gas reservoir to derive net-gas isopach maps. The illustration shows the total-net-producible-gas-

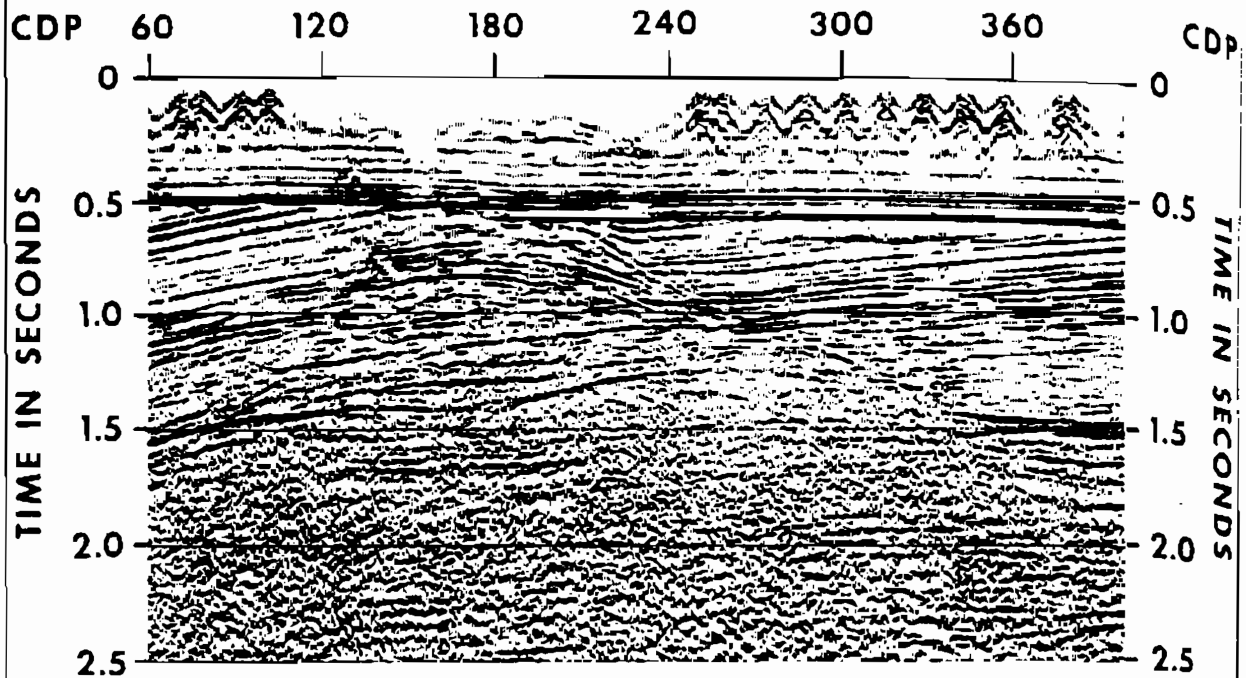

Fig. 8—Distorted seismic image of complex structure (2D seismic).

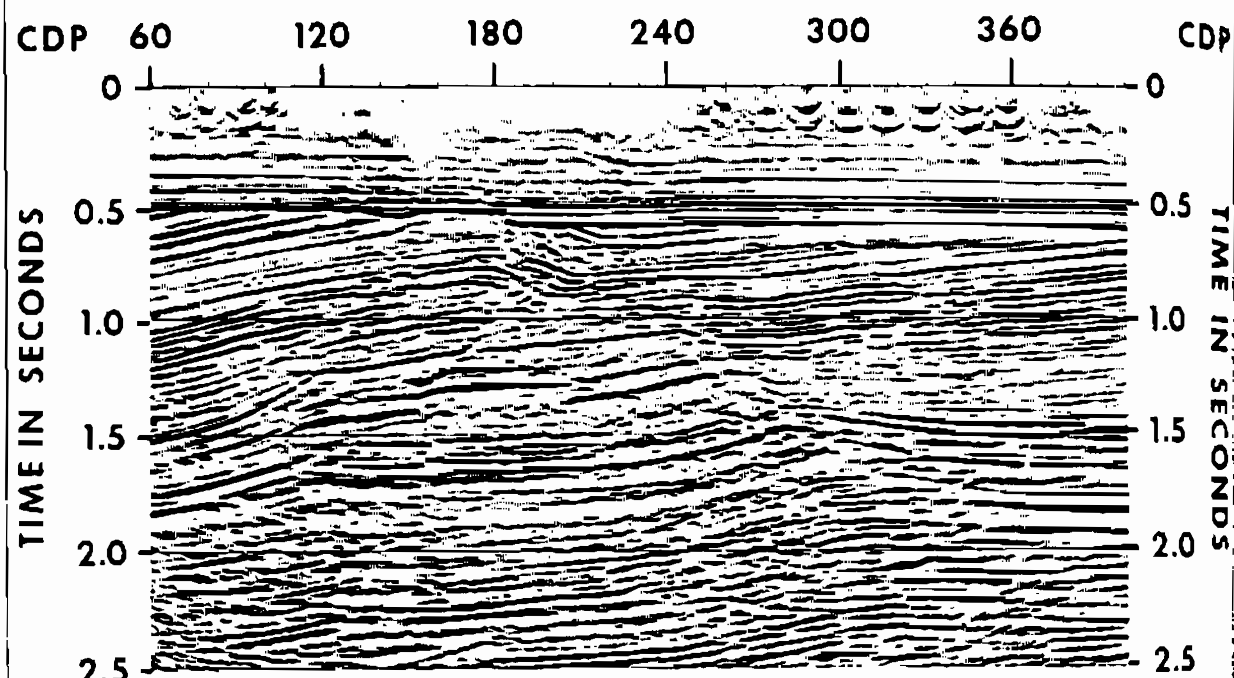

Fig. 9—Focused image after 3D techniques (note fault clarity).

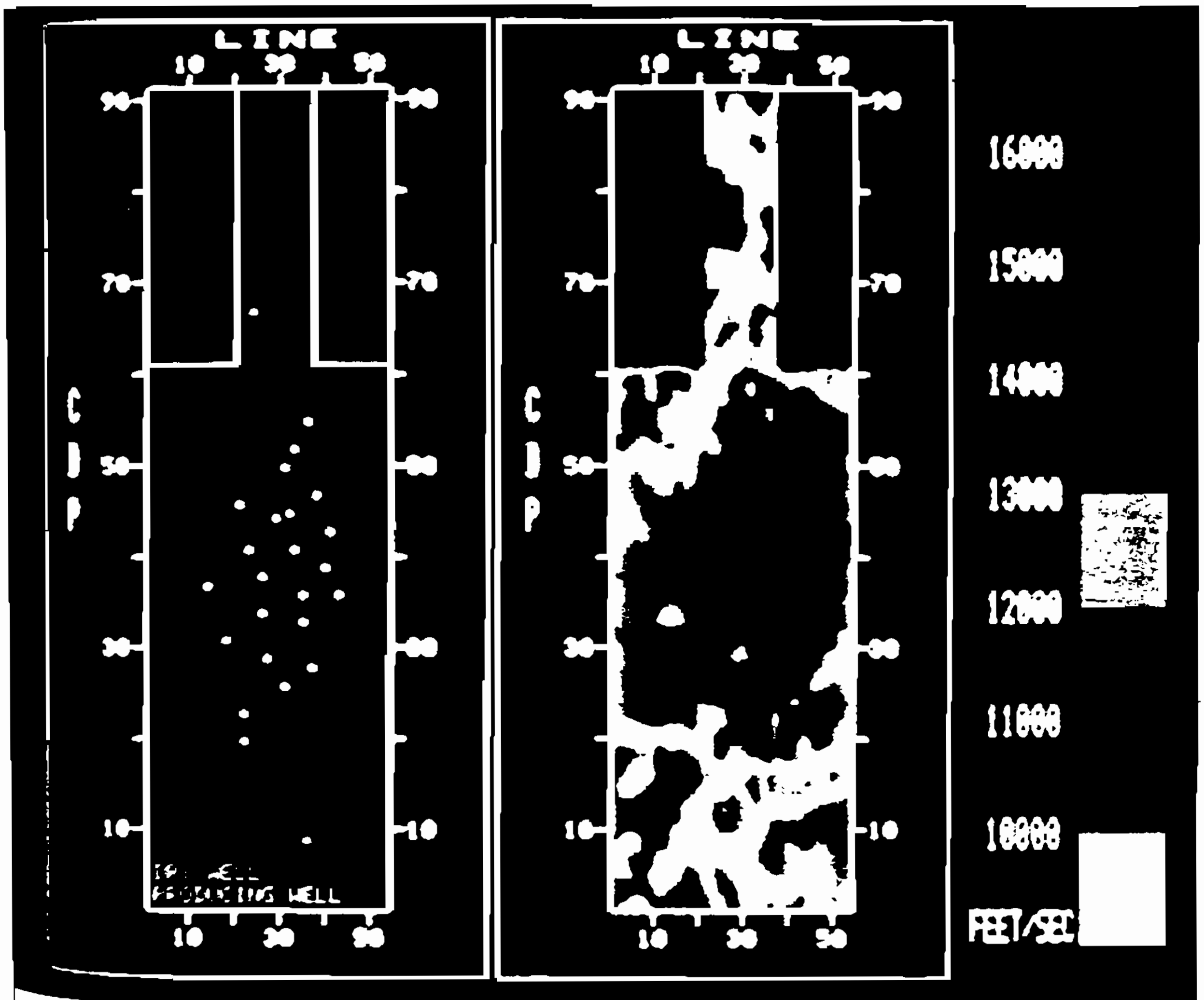

Fig. 10—Horizon Seiscrop velocity section indicating hydrocarbon content. (Courtesy of Occidental E&P Co.)

and isopach map that ties five wells in the area with a standard deviation of 8 ft [2.4 m].[8]

Thus, a primary benefit of inserting the 3D seismic method into the total development plan is high geometric resolution and detailed information on the spatial distribution of rock parameters and content. This is feasible because of the many information samples of the subsurface available from 3D grids that are typically 100 to 150 ft [31 to 46 m] throughout the reservoir.

The 3D Decision

In large-scale development projects—such as those in Alaska, the Overthrust Belt, and the offshore environment—the benefits derived from 3D clearly outweigh the costs incurred. In many smaller fields, however, the decision to use 3D must be more closely scrutinized from a benefit-vs.-cost perspective. Fig. 13 illustrates the decision process in a conceptual sense.

The process can be explained in monetary terms in the equation that conceptually determines the increase in the expected monetary value, ΔEMV, of the project:

$$\Delta EMV = \Delta P \times F_r \times r - COST3D.$$

The change in probability of success, ΔP, represents reduced drilling expenditure with fewer dry holes and perhaps fewer producing wells because of better placement made feasible by the greater amount of valid subsurface information. The reserve increase factor, F_r, assumes greater reserve recovery through improved reservoir management. Reserves, r, represents the current present value of the program.

To maximize the utilization of 3D methods in the development and production of hydrocarbons, the benefit/cost relationship must be favorable and meet the company's required ratio. In any given prospect, a series of scenarios can be developed to assess the economic viability of incorporating 3D into the development program.

Fig. 14 shows the impact of various likely scenarios on the NPV of a 12-well field modeled under assumptions typical of the 1983 Williston basin environment—e.g., Scenario 1 assumes that improved information available from 3D allows wells to be brought on-stream in order of decreasing productivity (i.e., best wells first). The NPV is fractionally increased (i.e., 3D pays for itself). Scenario 2 eliminates one dry hole and results in a 10% improvement in NPV. The most optimistic scenario with one less dry hole and 5% improvement in reserve recovery from fewer total producing wells shows a 60% improvement in field NPV.*

*Although dollar/cost assumptions have changed dramatically since 1983, the relationships remain valid

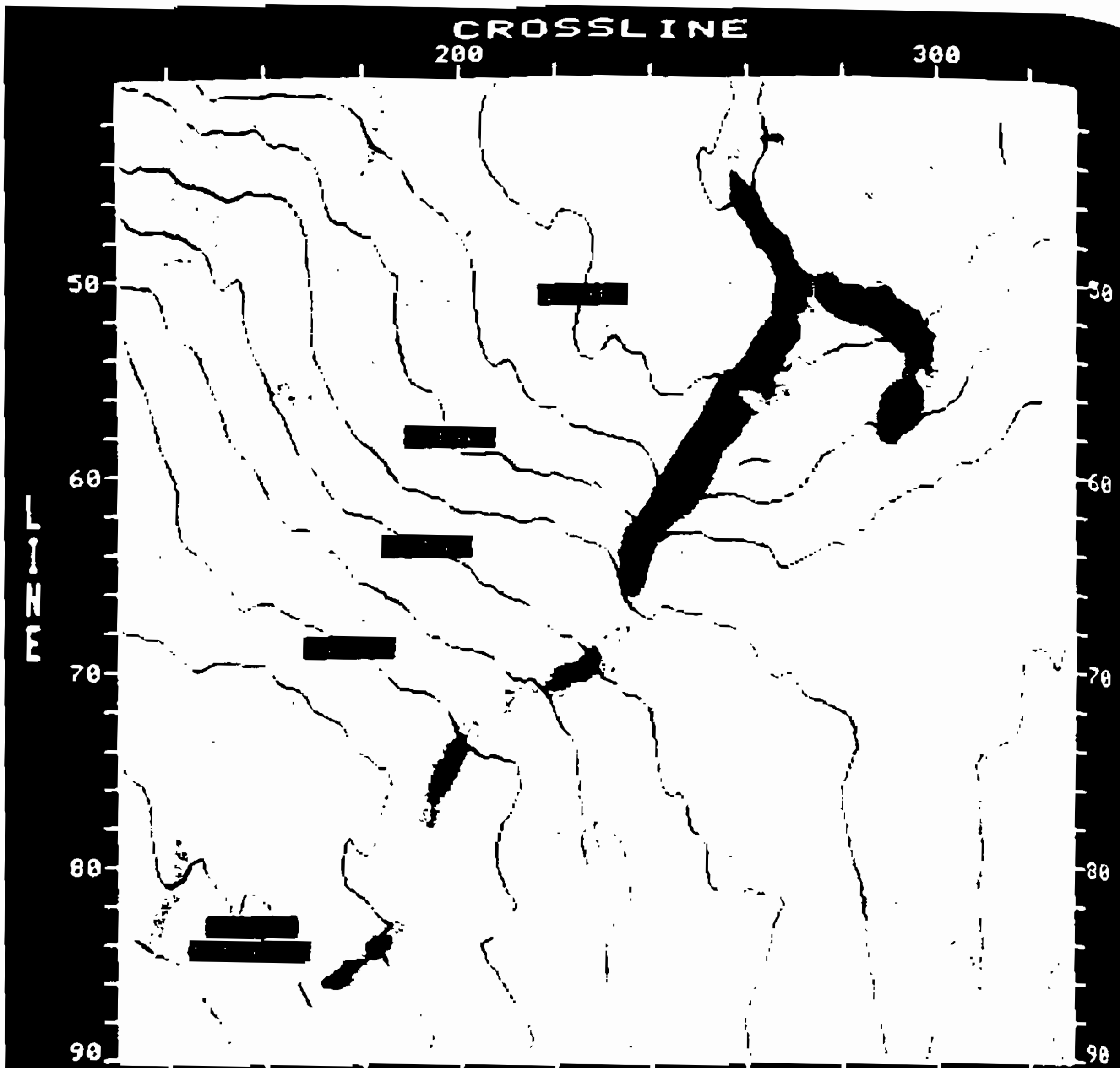

Fig. 11—Horizon Seiscrop section showing channel delineation and associated structure. (Courtesy Chevron U.S.A. Inc.)

Thus the use of 3D can be balanced against expected improvements in income by the modeling of expected outcomes under any given field conditions. The tradeoff can thus be viewed in its proper economic context—i.e., the impact on cash flow over the life of the field.

The design of a 3D seismic survey is tailored necessarily to the specific surface and geologic conditions of the prospect and is matched to the technical and economic objectives of the development program. Specialized acquisition techniques ensure that the most cost-effective solution to the problem is implemented.

Note that the synergistic value of 3D spatial continuity tied to direct downhole wireline and core measurements will provide a total value significantly greater than the sum of the values added by each technique independently. Maximum value enhancement is achieved only by full integration of the results of the various interacting disciplines.

Conclusions

Advanced reflection seismology has demonstrated its application to a wide variety of postdiscovery and field development problems, particularly through the use of the 3D seismic method. This technique has proved itself in many onshore and marine programs over the last 10 years.

Its emerging role is based on its ability to provide greater understanding of the structural and stratigraphic relationships in the subsurface than conventional methods because it adopts a truly spatial solution to a 3D problem and provides much greater detail and resolution than 2D seismic grids.

Reservoir description delineation is made possible with greater certainty, and with improved well placement and reservoir management, the manager can optimize the relationship between expenditure, revenue, and time to maximize the NPV of the program under his supervision.

By adopting an *integrated* approach incorporating state-of-the-art technologies in geophysics, geology, and engineering, the industry can maintain reserve replacement goals as it addresses increasingly complex geologic environments in search of smaller traps.

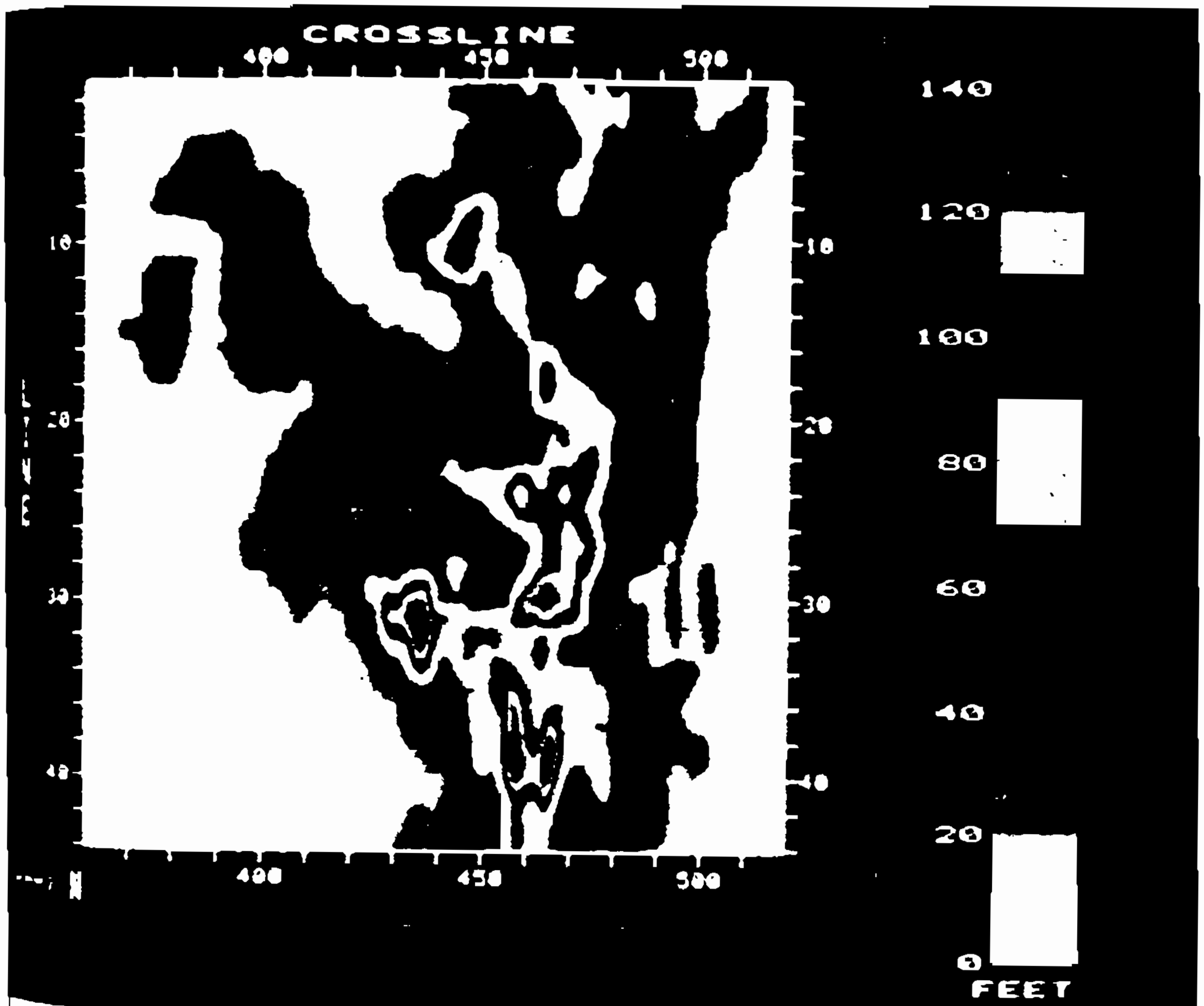

Fig. 12—Total-net-gas-sand isopach map. (Courtesy of Chevron U.S.A. Inc.)

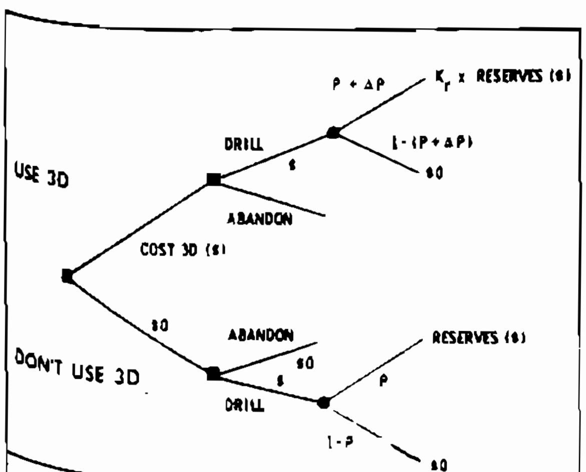

Fig. 13—Three-dimensional decision process.

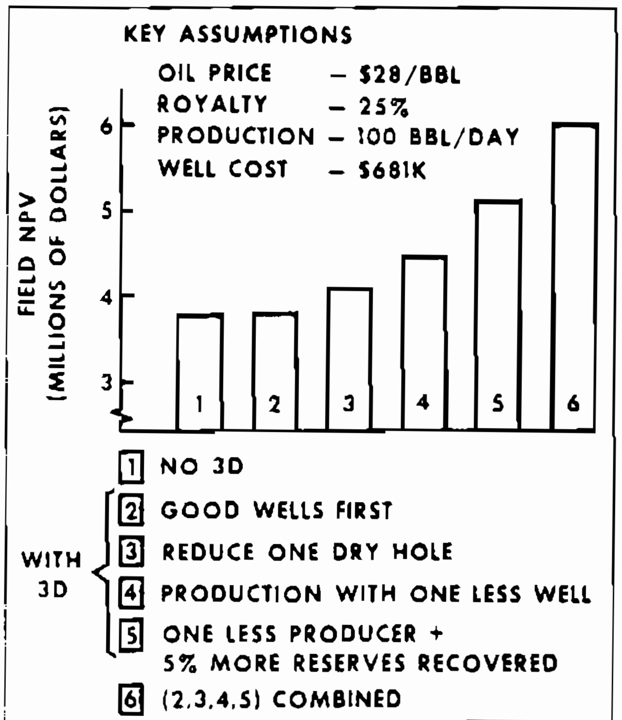

Fig. 14—Economic impact of 3D on Williston basin model.

The 3D seismic method will play an increasingly important role in achieving the energy goals of the future.

Acknowledgments

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I thank these companies for their release of these data examples.

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SI Metric Conversion Factors

bbl	×	1.589 873	E−01	=	m^3
ft	×	3.048*	E−01	=	m
mile	×	1.609 344*	E−00	=	km

*Conversion factor is exact.

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Optimization of Field Development Through Early Acquisition of 3D Seismic

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Abstract

3D seismic is a powerful and cost-effective geophysical technique to acquire data from which detailed structural and stratigraphical information can be extracted. It generally allows a realistic evaluation of reserves and uncertainty ranges required to optimise field development planning. Such a realistic quantification of uncertainties is a pre-requisite in the application of probabilistic techniques for gross hydrocarbon rock volume estimation. Consequently, the acquisition of 3D seismic at an early stage, i.e., directly following the drilling of a discovery well, is strongly recommended.

Although the cost of 3D seismic is, in some cases relatively high, the incremental cost per barrel is generally small when compared to the costs of "dry" or misplaced wells and of sub-optimal development of a field. Techniques have been developed to reduce acquisition and processing costs as well as to speed up interpretation procedures. Horizon-oriented interpretation, using automatic volume tracking programmes and attribute extraction techniques, has proven to be a fast and efficient way to outline subtle geological detail.

3D seismic interpretation greatly improves the delineation of fault blocks and the understanding of fluid and pressure communication. It has generated new prospects below and adjacent to developed fields, generally resulting in an increase in reserves, especially in structurally complex settings with stacked reservoirs.

3D seismic has contributed significantly in improving the validity of fault seal investigations by juxtaposing slices of 3D seismic data parallel to and on either side of a fault plane. These fault slices have been used to display juxtaposition across faults of seismic amplitudes related to lithology and/or hydrocarbons.

The information obtained from 3D seismic, when using these advanced interpretation techniques, is even more essential in the planning of expensive horizontal wells, which play an increasingly important role in field development.

The importance of early acquisition of 3D seismic will be illustrated by examples from several major hydrocarbon provinces in which the Shell Group is active.

References and Illustrations at end of paper.

Introduction

•Seismic Surveys Acquired by Shell

The development of 3D seismic is seen by senior management as the single most important technological break-through in many years. One of the first 3D seismic surveys was acquired in 1975 over the Schoonebeek field, Holland. Since that time, the annual cumulative area of full-fold subsurface coverage (and the number of 3D surveys) acquired has been increasing dramatically (Ref. 1) (Figure 1). In 1990, 3D seismic acquisition totalled some 16,000 square kilometres, of which about 40% was on land. Two thirds of Shell's seismic surveys are currently 3D as opposed to only 10% in 1986. Current annual seismic acquisition activity level, operated by Shell companies, amounts to some US$ 300 million (Ref. 2).

•Early acquisition of 3D seismic

The decision to efficiently utilise 3D seismic has to be taken as early as possible because of the longer time needed to acquire and process 3D seismic data (Refs. 3 and 4). It is common to shoot 3D seismic immediately after a "discovery" to define the optimal appraisal and development strategy, and maximize benefits from the improved data set. A more recent development is the shooting of 3D seismic over complete licenses to identify new exploratory prospects and allow their development to proceed even faster.

The early availability of a high resolution 3D seismic data set will result in ultimate cost savings from:

•Improved understanding of the spatial distribution of hydrocarbon reserves and uncertainties;
•Optimised appraisal drilling, and field development plans in terms of best drilling locations (i.e. fewer geological sidetracks) and properly sized production/evacuation facilities;
•Earlier plateau production, and;
•Longer plateau duration.

The economic justification for shooting 3D seismic is generally based on any one or more of the above cost-saving criteria. In the offshore environment particularly, 3D seismic is easily justified since the entire cost of a survey is often less than the cost of sidetracking one mis-targeted appraisal or development well

By contrast, late 3D seismic acquisition is likely to be hampered by the location of surface facilities and the noise arising from drilling and production activities. This can result in a less-than-optimal seismic coverage and quality of the data.

•Seismic Interpretation workstations

3D seismic data is routinely interpreted on an interactive "workstation". This is required to efficiently interpret the vast amounts of data from a 3D survey and to cross-check the interpretation using a large variety of different displays. These well publicised methods include amplitude evaluations, lateral prediction techniques, and dip/azimuth and illumination displays (Refs. 5, 6 and 7). These methods allow the interpreter to map subtle features not immediately evident from the interpretation of individual lines.

Field-development strategy based on 3D seismic

•Quantification of uncertainty

Depth conversion and volumetrics can easily be performed by transferring the time interpretation(s) to specialised computer mapping applications. Generally, the technically "most likely" time pick and velocity interpretations are made, whilst ranges of uncertainties are defined to generate maximum and minimum time maps and velocity-distribution maps. These are needed to quantify the amount and spatial distribution of uncertainties in hydrocarbons initially in place, using proprietary software.

In-house studies of volumetric uncertainties have shown that the most significant variable in calculating hydrocarbons-initially-in-place is related to the gross-hydrocarbon-rock volume. This is a function of depth at top and base reservoir and of the hydrocarbon/water contact. The relative variation in hydrocarbons-initially-in-place caused by varying other parameters is relatively insignificant to the possible variations caused by depth shifts.

Comprehensive geological models are routinely constructed using Shell's proprietary 3D computer modelling system (Monarch). This system combines all available well data with structural information derived from 3D seismic interpretation and geological knowledge, including uncertainty estimates. These data can be used to rapidly and interactively assess the sensitivity of hydrocarbons in-place to varying interpretations and generate expectation curves. The shape and slope of the curves reflect the degree of uncertainty, as illustrated in Figure 2, in the case of a fault block which has been drilled and of a "virgin" prospective block (Ref. 8).

Routine Applications of 3D Seismic

•Structurally complex areas

The more structurally complex a field is, the greater the need for more (and higher quality) seismic data to make a proper interpretation. To achieve this, a 3D seismic survey provides the optimum information.

There is no direct means of ascertaining the presence (or absence) of hydrocarbons in undrilled fault blocks. However, detailed 3D seismic interpretations often provide sufficient indirect evidence to significantly reduce the uncertainty, in this respect. Such interpretations have commonly shown that faults tend to be shorter and less continuous than indicated on interpretations based on 2D data. As a result, in some cases, significantly more oil-in-place has been determined from maps based on 3D than on 2D data. For example, in the Cawthorne Channel field, Nigeria, a full field review based on a 3D seismic interpretation, showed a 300 million barrel increase (24% of original STOIIP), of which nearly 200 million barrels (65%) was attributed to the 3D interpretation results (Figure 3).

•Fault seal investigations

When a well is drilled and encounters oil or natural gas in one fault block, the question frequently arises about the hydrocarbon fill in adjacent/juxtaposed prospective blocks. The major factors that control hydrocarbon distribution within fields are lateral spill-points at the termination of (discontinuous) faults, and seal (or lack of seal) along fault planes. Two variables need to be addressed when evaluating the seal integrity along fault planes formed penecontemporaneously: (1) juxtaposition of clays against the reservoir sandstones and (2) the degree of clay smear in the fault gouge (Ref. 9).

To evaluate spill points and degree of clay smear along faults, proprietary software is used that maps the fault plane and creates juxtaposition maps of the up-thrown and down-thrown blocks (Figures 4 and 5). Using these juxtaposition plots, the throw and hence the clay smear along the fault can be quantified, semi-automatically. Using the fault plane map, well trajectories can be planned to penetrate multiple stacked hydrocarbon-filled reservoirs in an optimal position.

•New prospects adjacent to known accumulations

Low-relief structures have considerable uncertainties in estimated hydrocarbons in place. In these situations, small velocity variations can alter the structural configuration dramatically. Variations in shallow overburden velocities are a result of near-surface phenomena (e.g. caliche/hard pan zones) and surface corrections are needed to "datumise" the data.

One particular example of low-relief structures in the desert of the Sultanate of Oman illustrates this point. The true structural configuration of the four small leads, called Ihsan, Jameel, Mawhoob and Al Burj, as defined by 3D seismic interpretation, was considerably different from that derived from 2D data. The new data showed Ihsan and Mawhoob to be one continuous structure, and Jameel and Al Burj to form a separate single structure (Figure 6) (Ref. 4). The determination of oil-in-place after the 3D seismic interpretation is significantly more reliable than that based originally on 2D seismic. This translated into a ten-fold increase in oil-in-place and a complete revision of the field development plan.

The interpretation of the structurally complex EA field in Nigeria benefitted significantly from the acquisition of 3D seismic. Several new fault traps containing stacked reservoirs were identified from the 3D seismic and the presence of hydrocarbons could be inferred from what are now becoming routine seismic amplitude studies. In Nigeria, the development of nearly all Shell-operated fields is now planned to be based on 3D seismic interpretation. Additionally, it is now routine policy to acquire 3D seismic, for exploration and appraisal purposes, over much larger areas than just over the known fields .

•Horizontal well planning

The success of a horizontal well can be significantly enhanced by defining the well track utilizing 3D seismic data. Horizontal wells are being drilled routinely now that this drilling technology has reached a more mature state. When the success of the horizontal well is dependent on reservoir heterogeneities (e.g. open-fracture orientation) or accurate targetting (e.g.

thin reservoir zones or thin hydrocarbon columns), then 3D seismic interpretation is the prime tool to plan the details of the well path.

The geological planning of a horizontal well is aided by:
•time slicing (horizontal seismic displays at the desired time);
•horizon slicing (displays along and parallel to a given reflector), and:
•attribute displays (e.g. dip, azimuth and amplitude) to accurately prognosticate formation and reservoir boundaries, and fault characteristics (e.g. type, location, direction, length and throw) with increased accuracy.

Under optimal conditions, these displays provide the interpretation necessary to:
•either avoid or intersect sub-vertical faults;
•identify major variations in reservoir development and;
•indicate the extent of swept/flooded areas of the reservoir.

In one Shell-operated field in the far East, 3D seismic is routinely used to drill wells in reservoir sandstones below the descending gas/oil contact to delay gas cusping (Figure 7). In this case, all three stacked reservoirs were successfully penetrated, over a horizontal distance of some 3000 ft, at approximately the same structural elevation. This level of detail was only achieved after 3D seismic was acquired and the ensuing success of a horizontal well campaign.

In tight (low-productivity) reservoirs, well production is often enhanced by intersecting natural, open fractures. In one Shell-operated Southern North Sea gas field, amplitude, dip and azimuth maps were interpreted at Top Rotliegend and NNE-SSW trending lineaments could be seen (Figure 8). These "faults" have little vertical offset and are not well expressed on the dip map (Figure 8a), but show up on the azimuth map (Figure 8b). These have been associated, in one field, with tight reservoir, based on appraisal drilling, and in another nearby field, appear to separate areas with different gas/water contacts (Ref. 7).

•Reservoir/block depletion

In the Yibal Field (Sultanate of Oman), studies of a combination of seismic attribute maps at the Top Shuaiba reservoir have shown significant variations in the pattern of amplitude anomalies near faults and water-injector wells. Low amplitudes have been associated with most existing water-injection wells and high water-cut production wells. The seismic amplitude map (Figure 9) has been used to plan both horizontal and vertical infill production wells. The oil/water contact is represented as a phase reversal on seismic (Figure 10, point 1) and clearly seen on the amplitude map especially in the northeastern part of the field (Figure 9). A dimming of the seismic amplitude around injector well Y-61W (point 2, Figure 10) is also seen around most other existing water injectors and can be contrasted with the high amplitude 1 km updip where successful producer well Y-308 was targetted (Point 3).

Infill wells planned, using 3D seismic, are expected to result in improved ultimate recovery from areas of the reservoir where primary production has been adversely affected by water-conducting faults.

Conclusions

1. Early acquisition of 3D seismic can aid considerably in the structural definition and quantification of uncertainties of hydrocarbons-in-place in oil and gas fields.

2. 3D seismic can only be interpreted efficiently on a "workstation" because of the massive amounts of data that should be used to aid the interpretation.

3. The additional costs of 3D over 2D seismic can, generally, be justified by:
   a) optimising field development plans in terms of numbers of wells (and reducing the number of geological sidetracks), and sizing of production and evacuation facilities;
   b) reaching plateau production earlier and maintaining it longer, and;
   c) delaying abandonment.

4. 3D seismic is the key to interpreting subtle structural and stratigraphic detail which is generally beyond the resolution of 2D seismic and well data. This can lead to considerable additional hydrocarbon reserves in and around known fields.

5. Using fault slicing and clay-smear-potential techniques, and direct hydrocarbon indicators from amplitude studies, the hydrocarbon fill of complex, faulted structures can often be assessed reliably.

6. In cases, hydrocarbon saturation of reservoirs can be calibrated against seismic attributes. These calibrated data can be successfully used to guide appraisal and development drilling.

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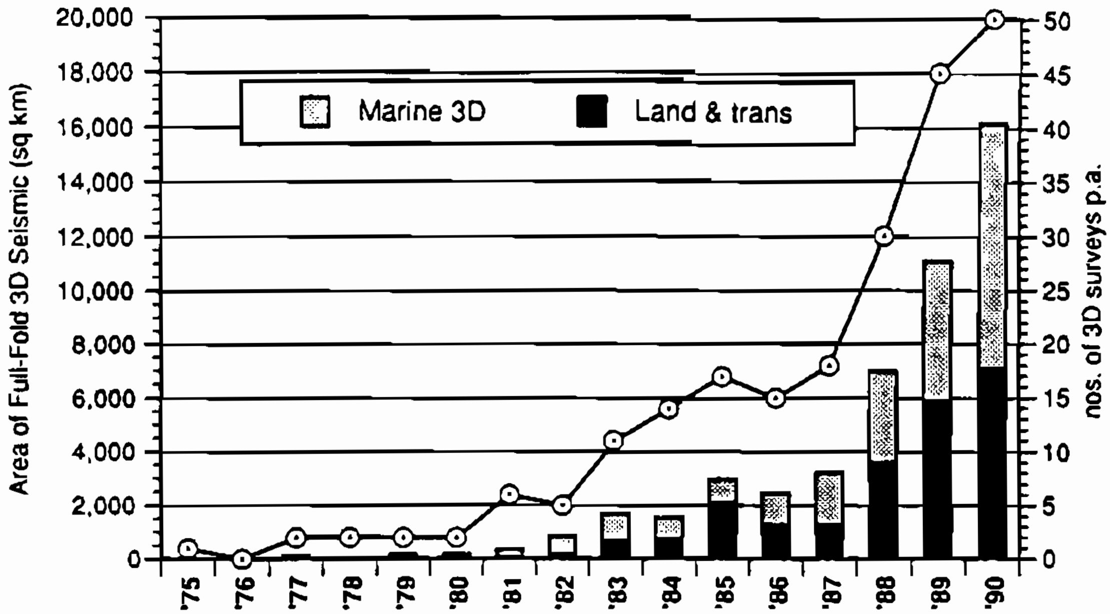


Fig. 1 3D seismic acquisition in Shell Group (outside North America) (from Rijks and Jauffred, 1991)

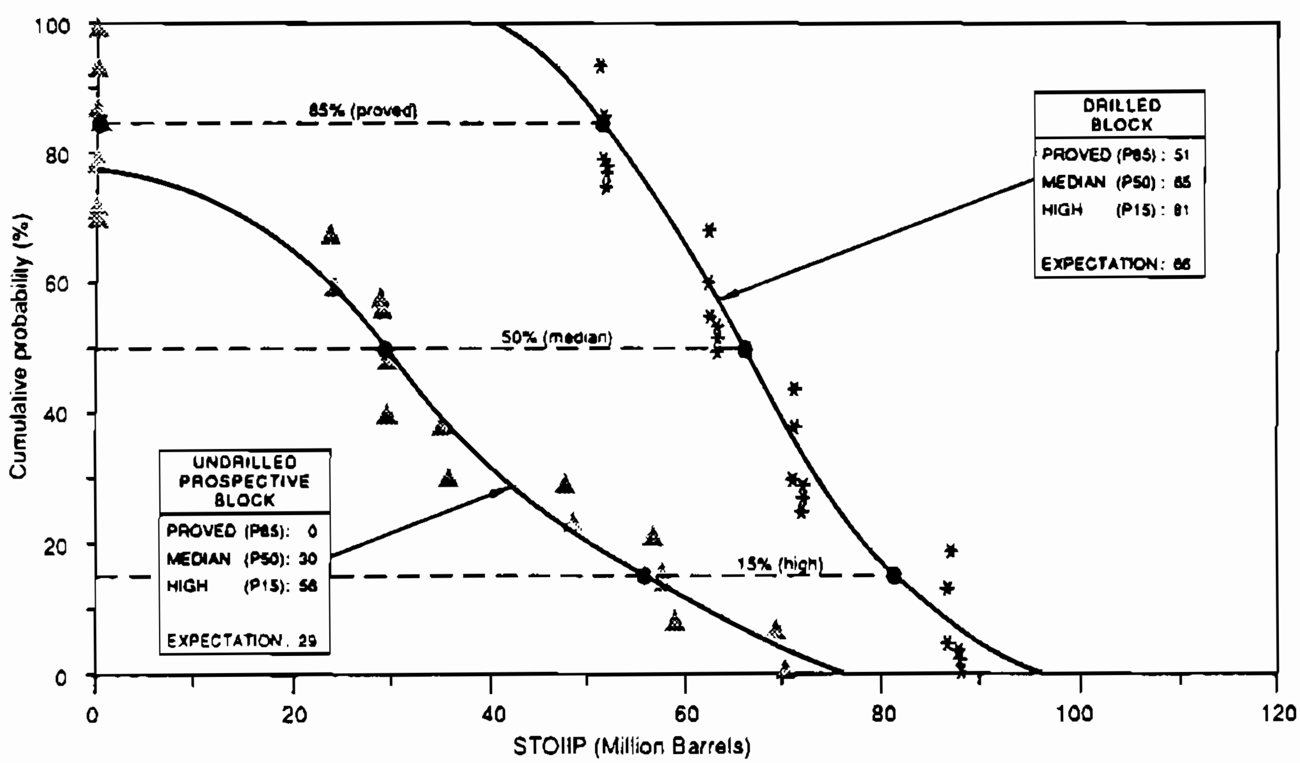


Fig. 2 STOIIP expectation curves, EA-field, Nigeria (from Le Varlet et al., 1991)

H/2125/1 (D115.1)

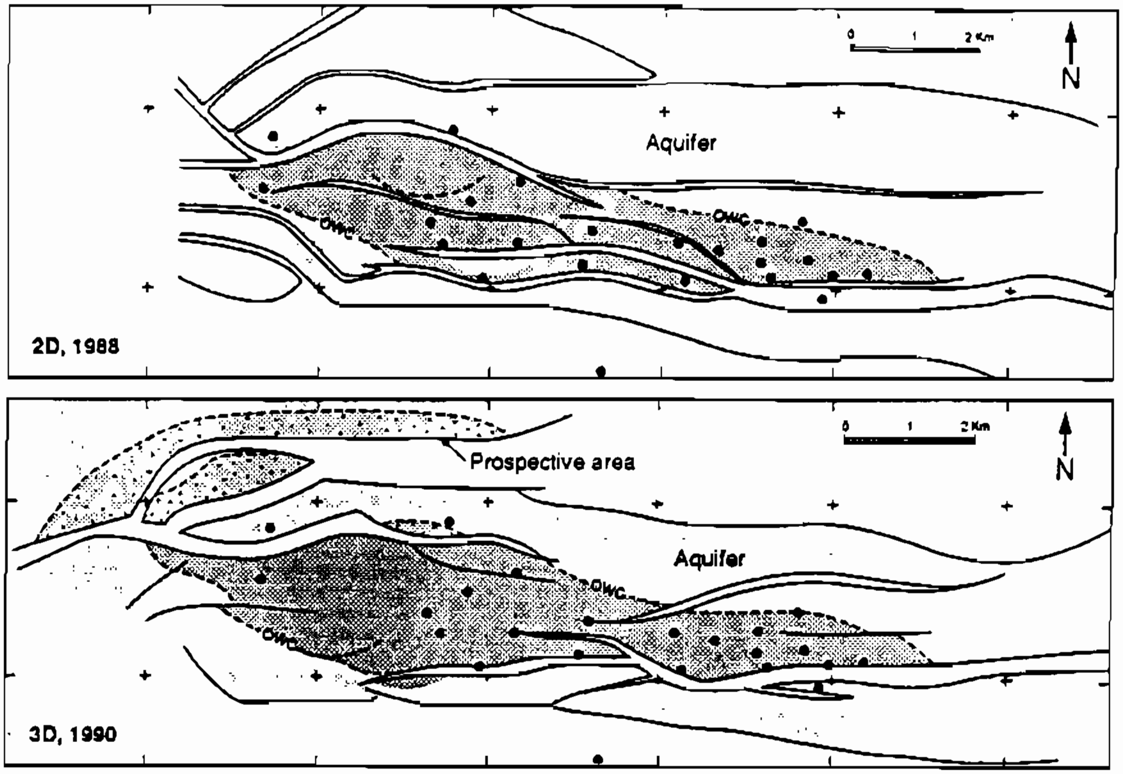


Fig. 3 Structure maps of "G" sands based on 2D and 3D seismic, Cawthorne channel, Nigeria

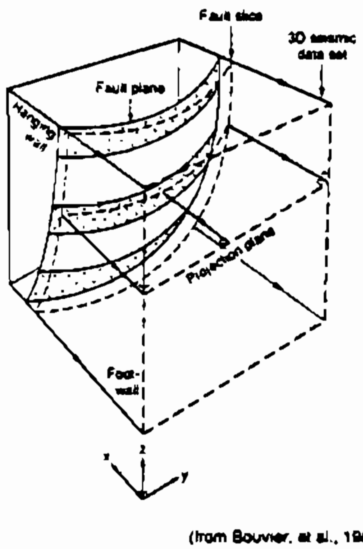


Fig. 4 Position of fault slice and projection plane in relation to footwall and hanging wall of dipping normal fault.

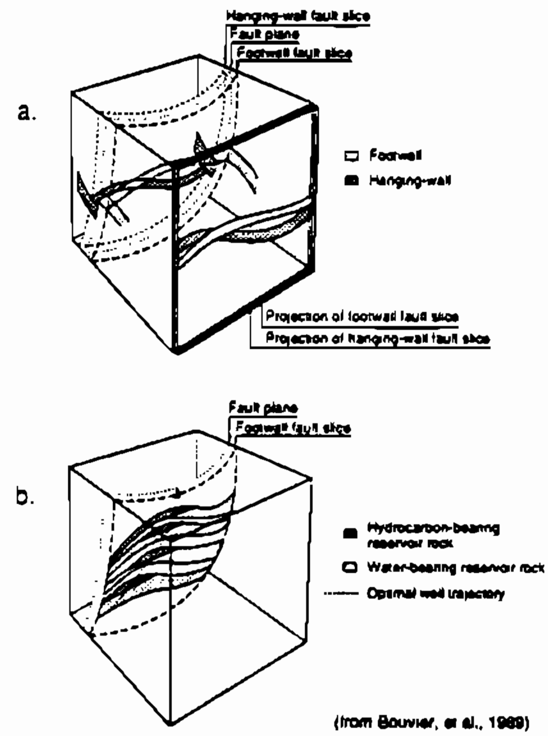
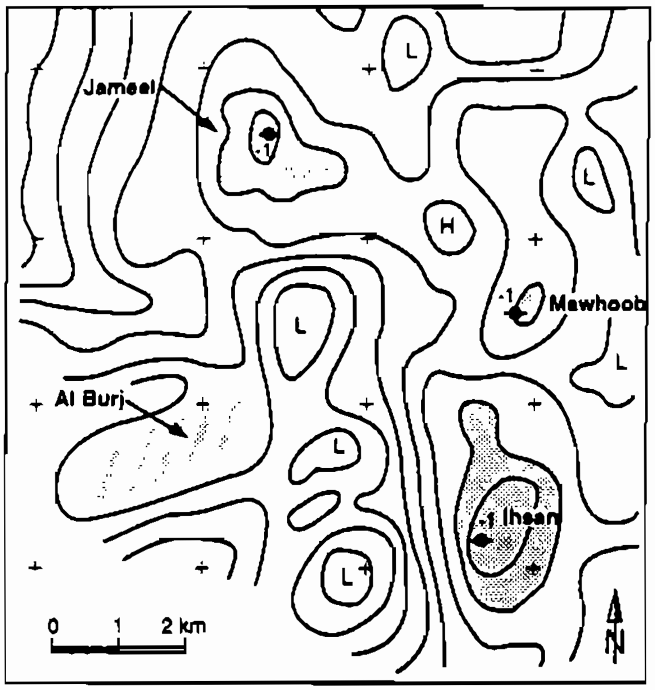
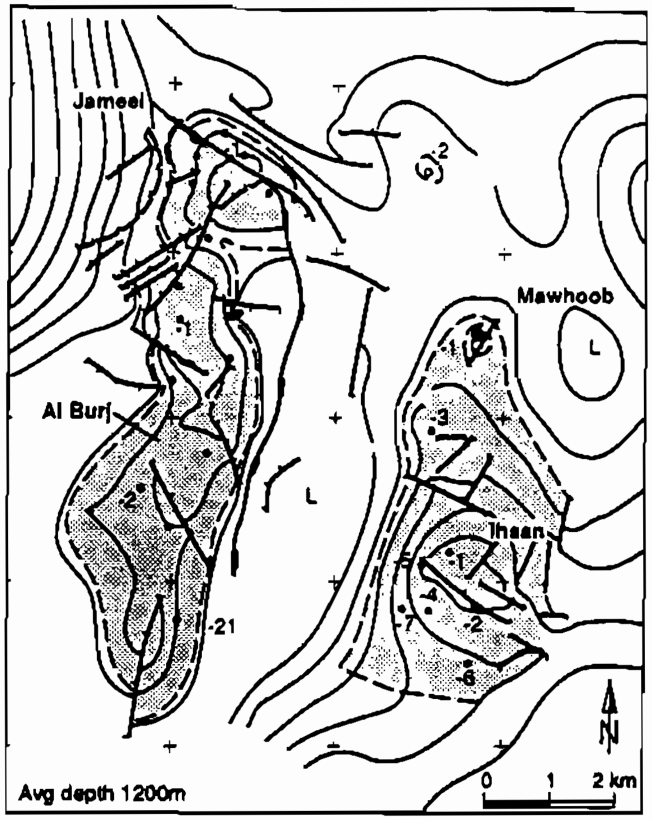


Fig. 5 Two examples of the applications of fault slices:
a. Use of a hanging wall and footwall fault slice to determine reservoir seal juxtaposition.
b. Use of footwall fault slice to determine an optimum well trajectory.



6a

Volumetrics (STOIIP x 10^6 m^3)	
Jameel / Al burj	Ishan / Mawhoob
10.0	9.6



6b

Volumetrics (STOIIP x 10^6 m^3)	
Jameel / Al burj	Ishan / Mawhoob
101.9	41.5

Fig. 6 Ihsan, Jameel, Mawhoob and Al Burj (Sultanate of Oman) leads using 2D seismic (Fig. 6a) and the final interpretation of the low-relief structures using 3D (Fig. 6b)

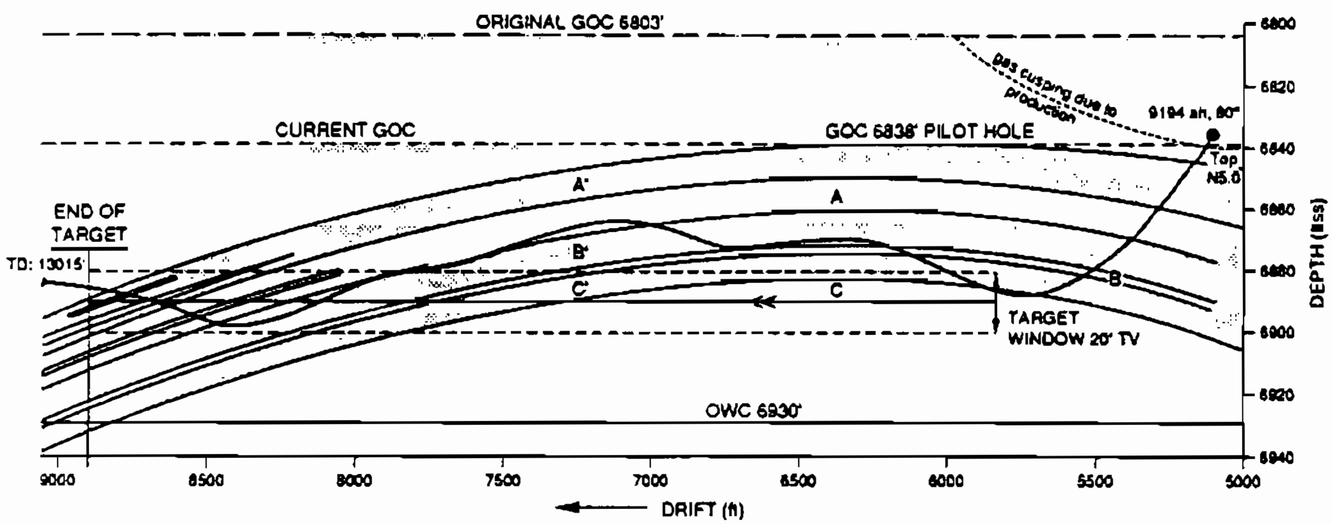


Fig. 7 Horizontal well section drilled below the current gas/oil contact, purposely to intersect the three reservoir sandstones, A, B and C

H7312S/3 (D115 I)

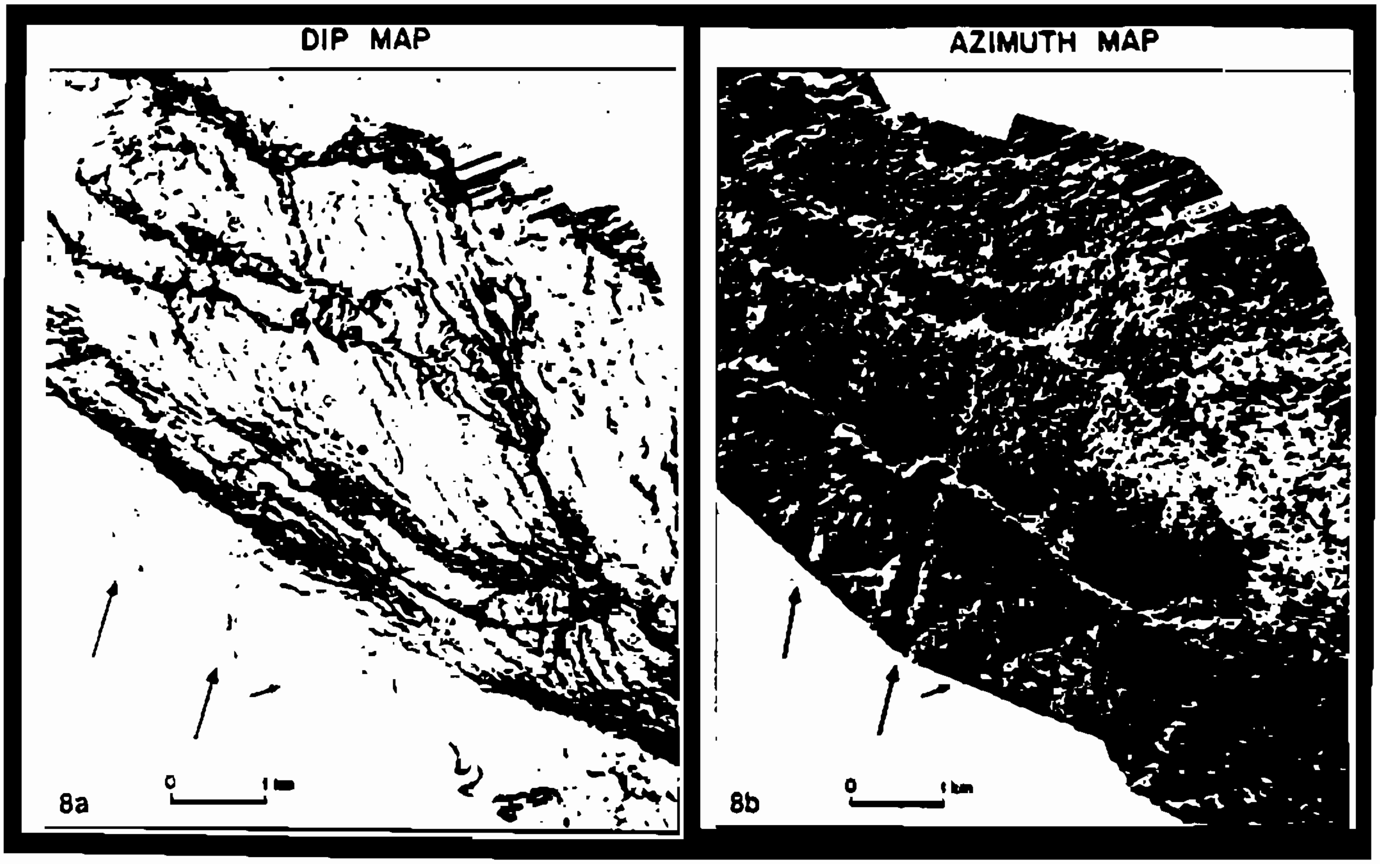


Fig. 8 Dip and azimuth displays highlighting subtle fracture zones (arrows) in tight sandstone gas-bearing reservoir that have been used to plan horizontal wells in the southern UK North Sea (from Rijks and Jauffred, 1991)

Fig. 9 Yibal Field (Sultanate of Oman) amplitude map of top Shuaiba chalk reservoir showing anomalies associated with water flood pattern along faults and around water injector wells. Dark pattern is low amplitude (water) and light color is high amplitude (oil)

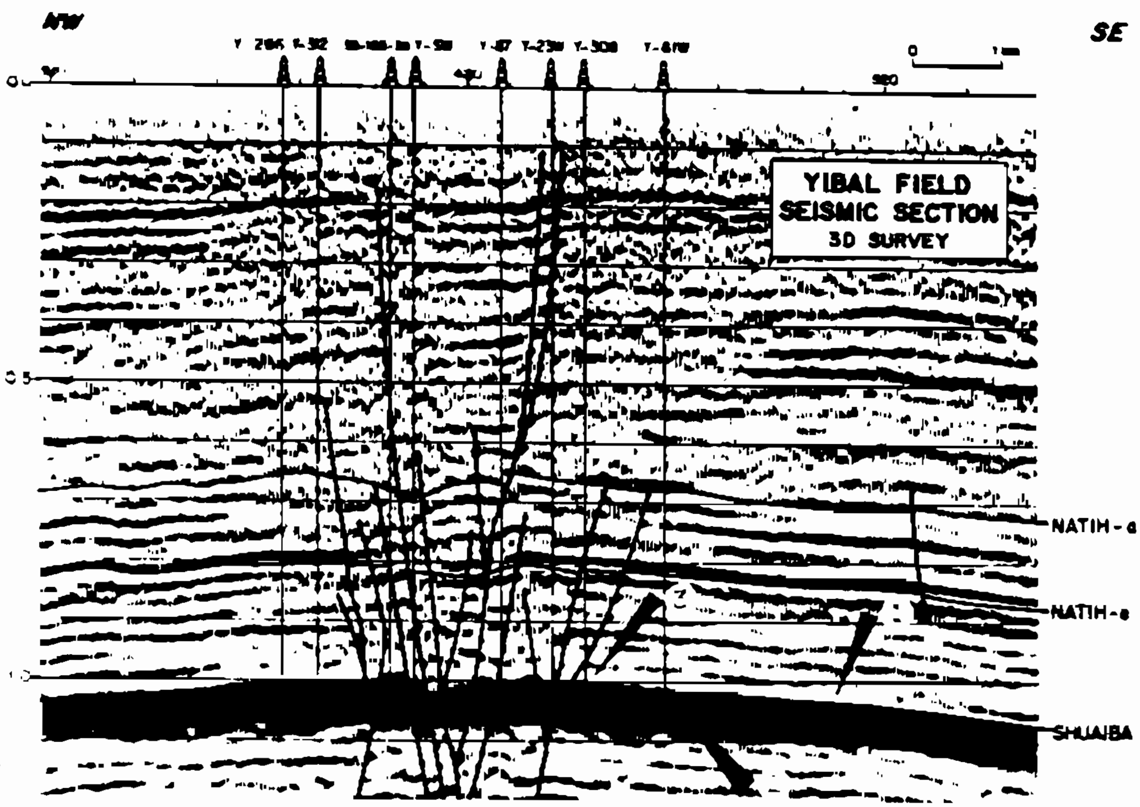


Fig. 10 Yibal Field, Oman, NW-SE seismic section showing change in amplitude at oil/water contact (1), dimming of amplitude at water-injector well Y-61W (2) and high amplitude near infill well Y-308 (3)

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The Value of 3D Seismic in Field Development

by L. Gaarenstroom, *Shell U.K. E&P Co.*

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ABSTRACT

Since 3 Dimensional Seismic Surveys were introduced in the North Sea in 1976 Shell Expro has carried out ten such Surveys covering most of their fields.

The 3D seismic method is considered as a tool of growing importance for field development, especially for the marginal and economically sensistive fields. Appraisal and development drilling indicates that most fields are often more complex than originally anticipated.

Interpreted 3D seismic data available in the pre-development phase of a field's life in combination with appraisal well data could substantially support sound decisions on platform construction, drilling slots, and field development drilling.

In the example discussed, we show that an early understanding of complicated reservoir structures and structural discontinuities is a pre-requisite for optimum development of a complex structural-stratigraphic trap, such as the Cormorant Field (fig. 1).

INTRODUCTION

The main advantages of a 3D Seismic survey over a 2D conventional seismic survey are:

a. It provides a volume of closely spaced three-dimensionally time migrated data, and a significantly enhanced signal to noise ratio.

b. The collapsing of diffractions from fault boundaries and other discontinuities or distorted images, to their point of origin, in a 3D manner.

Reference and illustrations at end of paper.

These advantages allow for a greater fault definition and detail in structural delineation. Based on experience and results from the previously conducted 3D surveys the paper will briefly describe some principles of 3D seismic. Technical considerations i.e. the importance of proper sampling in the line as well as the crossline direction, positioning and streamer feathering will be discussed.

OVERVIEW OF THE 3D SEISMIC DATA CONCEPT

3D or areal seismic data may be defined as standard reflection data for which the sampling points are evenly distributed over a particular area of interest, instead of along a line (or plane) as in the case of conventional 2D Seismic. After the data points contained in the 3D data cube (fig. 2) have been three-dimensionally migrated, there is an almost unlimited amount of display options available to facilitate the structural interpretation.

i. Any vertical slice through the data cube resembles a 2D line, free of energy from outside the 2D plane (side swipes).

ii. A horizontal slice through the data cube provides a direct horizontal presentation of the subsurface, and will show all seismic events for a single time value.

iii. As one is no longer bound to the original traverses of data collection any random broken line connecting several wells in a field for correlation purposes is another option. Moreover any well to be drilled in a field will be very close to a 3D migrated data point, enabling better prediction of formation depths and lithologies.

Migration. In the 3D migration procedure reflection and diffraction events can be imaged to their true spatial positions. Disturbing responses (side swipes) not belonging to the plane of section and not directly related to the geology will be removed. The 2D migration effect is depicted in figure 3.

In this figure AB and CD are two adjacent wave paths which are normally incident to a reflecting interface at points BD. In the unmigrated profile these reflection points are plotted at the source detector (mid) points p and q. As can be observed in the unmigrated case we measure a false structural dip, an error in depth and a shift of the reflection point. Migration is performed by moving the reflection point along the wave front till they become tangent to that wave front. Since seismic wave fronts propagate in the earth in three dimensions we can only reconstruct an accurate vertical and horizontal structural cross section of the earth seismic responses if seismic data (points) are collected over a regular surface area and migrated in a 3D sense. The 3D migration of a data point is often done in two steps; first in the line direction and there-after in the crossline direction (fig. 4).

Figure 5 illustrates the improvement of a seismic section from the Central North Sea after 3D migration. It can be observed that the cusping effect, caused when a reflection profile is shot across a narrow syncline (reflections from both sides of the syncline are recorded on the same subsurface location) only is removed after 3D migration, and the syncline restored.

In figure 6 it is interesting to observe the improvement of the overburden markers, in particular the definition of the small faults, the anticlinal structure is steeper after 3D migration and side swipes are removed out of the plane of section.

Subsurface Sampling. The maximum line spacing which is required to avoid migration aliasing is depicted in figure 7. The required grid spacing between "Common Mid Points" is shown as a function of velocity, dip and frequency (for the derivation of this graph a constant subsurface velocity of 2000 m/sec has been assumed). For a structural dip of 30° at a level of this particular velocity we find a grid spacing of about 20m. For steeper dips the distance will decrease. By using a coarser grid than calculated one runs the risk of acquiring a data set which still cannot be properly migrated and interpreted due to spatial aliasing.

Binning and Streamer-feathering. In 3D acquisition the subsurface data points are binned which means that the survey area is covered by square grids of typically 50 x 50 m (for the offshore UK 50 x 25 m in line and crossline direction). All the midpoints falling within the bin are stacked together and referred to as a "binstack" trace, at the centroid of the bin (fig. 8) If the feathering of a particularly long streamer is large resulting in large displacement towards the end of the streamer, midpoints from neighbouring lines with a different move out due to dip and feathering (fig. 9) will overlap and cause midpoint smearing. The effect of scatter within a bin will act as a high cut filter on the data. When stacking along a sailed line (prime line binning), offset and spacing problems in the direction of shooting are usually minimal provided that there is no excessive cable feathering. The major source of error is due to irregular line spacing and feathering resulting in inadequacy in sampling in the crosstrack direction. As streamer feathering angles are often varying in direction and magnitude trace assemblage in a pre set bin area can be highly irregular resulting as already mentioned in variable stack response. To optimise results, bins could be created after plotting of the common midpoints (CMP's). In this manner only relevant traces are forced into the bin (selective binning).

Positioning and Navigation. The correct positioning of the recorded data points is probably the most important part of a three dimensional survey. We have to make sure that the binned or stacked sub-surface points from the different shot-receiver pairs are correct to about 20m. For land surveying this is of limited concern as it will be no problem to maintain a high standard of accuracy. Marine seismic surveys however always suffer from tides, ocean currents and weather conditions as well as static interference of radio electronic positioning systems affecting the accuracy of navigation of the seismic vessel and the hydrophone streamer. Most contractors nowadays offer an "on-line" check on the subsurface coverage by direct on-board processing of the topographical data, which allows for on the prospect re-recording of the data falling outside the positioning specifications. For average offshore conditions using fixed radio beacons on rigs or platforms a positioning error of the survey antenna not exceeding 10m should be adhered to. The position of the streamer is relative to the ships heading and is monitored at several stations along the streamer by build in magnetic compasses. The error is a function of the distance from the boat to the hydrophone stations and can be as high as 50 to 70 m for the large offsets.

The significance of CMP positioning is illustrated in figure 10 Both profiles are of identical subsurface coverage. The top profile was processed from data with excessive streamer feathering and using areal binning. The lower profile was processed from the same data after correcting for inadequate streamer positioning and using prime line binning. The improvement of the profile is evident and mainly due to improved C.M.P. positioning

RECONSTRUCTION OF THE FAULT PATTERN (Fault Aliasing)

The accuracy of reconstructing an event, be it a seismic signal, a surface or a fault pattern is dependent on the sampling of the event. This is demonstrated in figure 11 where a fault pattern is constructed based on line A, B and C 1000m apart. After reducing the line spacing to 500m by shooting lines P, Q and R, a completely different fault system of 3 NE-SW faults is constructed. The fault F indicated on line R can only be reconstructed after further narrowing of the seismic grid. Figure 12 demonstrates the evaluation of the fault pattern with increasing sampling density for the Cormorant block IV accumulation.

THE CORMORANT CASE BLOCK IV INITIAL DEVELOPMENT PLAN

The Cormorant Field (fig. 1) lies in the western part of the Brent province in the Northern North Sea, some 100kms north-east of the Shetland Isles, in water depth of 160-170m. The main reservoir is in Middle Jurassic Brent Sands, contained in a westward tilted mega fault block, roughly 22km by 3km. The source of the contained hydrocarbons is Upper Jurassic Kimmeridge shale. The top seal is provided by Upper Jurassic shales and claystones. The field is subdivided into four separate fault blocks. We will concentrate on the slump Block IV to illustrate the concept.

The field is currently being produced through two platforms Cormorant Alpha in the South and North Cormorant in the north and a centrally located Underwater Manifold Centre (UMC). In general the Development strategy has been for updip producers supported by flank injectors.

The reservoir sands form part of a south-north prograding delta. The sandstones are of variable quality and continuity; good clean sands interbedded with argillaceous sands and shales. Structural discontinuities are also manifest, as both small and large scale faulting. These different types of discontinuities were recognised at an early stage in the development of the field. To aid in the solution of these problems a dense 3D seismic grid was acquired and is an integral tool in the present activities.

Figure 13 illustrates the improvement in resolution of the seismic data during the successive 1971, 1975 and 1981 (3D) surveys. The structural map depicted in figure 14 based on the 1971 vintage seismic survey with a line spacing of about 2000 x 800m, indicates a large tilted unfaulted block at its culmination subcropping against the Lower Cretaceous Unconformity. On these data the discovery well was drilled.

After two vintages of infill seismic lines reducing the line density to about 500 x 200m a new revised map of the field (fig. 15) was constructed. This map already suggests a much more complicated and faulted structure. The large fault separating Block I and II as well as the eastern boundary fault of block III has been mapped. In sddition, the slump Block IV with a configuration of south-west to north east trending faults was recognised.

The resulting development plan, based on this interpretation was to produce Block IV from a series of crestal wells, supported by flank water injectors (fig. 12a). These wells would be drilled from a platform located between Blocks III and IV and from a UMC in the south, tied into the platform.

When development drilling commenced in 1981, it was realised that the structural nature of Block IV was not as envisaged. Reservoir pressures, production-injection performance and fault cut-outs indicated that the wells were draining or injecting a number of isolated fault blocks.

Interpretation of the 3D data set, which as can be seen from figure 13 is of superior quality as compared to the previously acquired conventional seismic vintages, resulted in a different structural concept. Focussing on Block IV we observe that instead of the south-east, north-west faulting we now find a north-south trending fault system, giving credence to the suspicion from the well data of the compartmentalized nature of this block. The reflector of the top Brent formation is most consistently represented by the zero crossing point above a block loop on the zero phase reflectivity section (fig. 16). The reflector itself is sometimes difficult to correlate because of the changing character of the event. Variation in character is mainly due to truncation of the reservoir by the overlying Humber formation and variation in thickness of the reservoir sands.

The density and improved definition of the 3D data set allowed for a reliable correlation of the Brent. Figure 16 demonstrates the correlation of the synthetic well trace derived from the calibrated sonic and density logs, with the 3D migrated seismic traces around the wells. The structural map constructed from the 3D data set (fig. 12b) shows a number of north-south trending fault blocks, which were not recognised earlier due to insufficient sampling leading to fault aliasing. It is likely that there are around ten isolated sub-blocks, each of which has to be developed separately by paired production and injection wells. Figure 12b also illustrates the revised development plan for the Block, based on the 3D seismic interpretation and development history.

COST AND COST EFFECTIVENESS

The average km price, of acquisition and data processing, for a 3D Seismic survey to date averages £600 per km. (average cost for "Dual Source Arrary" 3D acquisition technique). An average size field containing 500 MMbls STOIIP which is covered by a 3D Seismic survey totalling some 1600 line kms would cost in the order of £960,000. In general it can be stated that the cost of a 3D survey over an average field is often less than half the cost of an appraisal or development well.

CONCLUSIONS

- The correct spatial sampling of a 3-dimensional data volume together with proper immaging of scattered energy after 3D migration allows for a detailed structural interpretation, and understanding of the sub-surface geology.
- The key to a successful marine 3D seismic survey lies in careful planning of acquisition parameters such as sampling density, and optimum navigation and positioning of both vessel and streamer.
- The costs of a 3D survey over an average field are relatively low compared with the cost of one well.
- Interpreted 3D seismic data available in the pre-development phase of a fields life enables the definition of a detailed structural reservoir model, and might:

* save the cost of a mislocated or dry hole
* optimise production drilling
* avoid errors in platform siting

ACKNOWLEDGEMENTS

The author is grateful to the following companies for their approval on publishing this paper:

Esso Exploration and Production U.K. Shell U.K. Exploration and Production.

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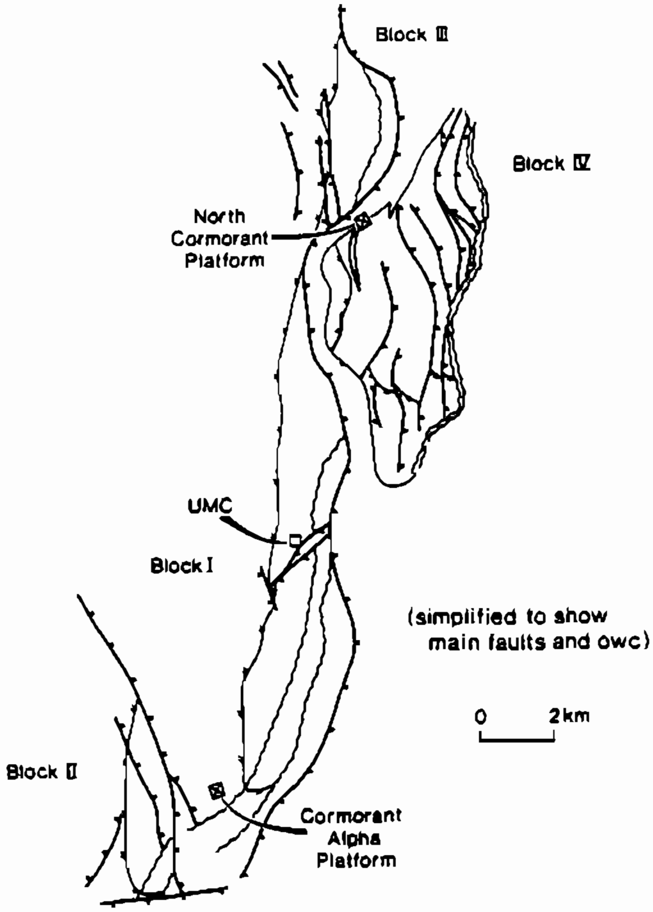

Fig. 1—Cormorant field Top Brent structure map.

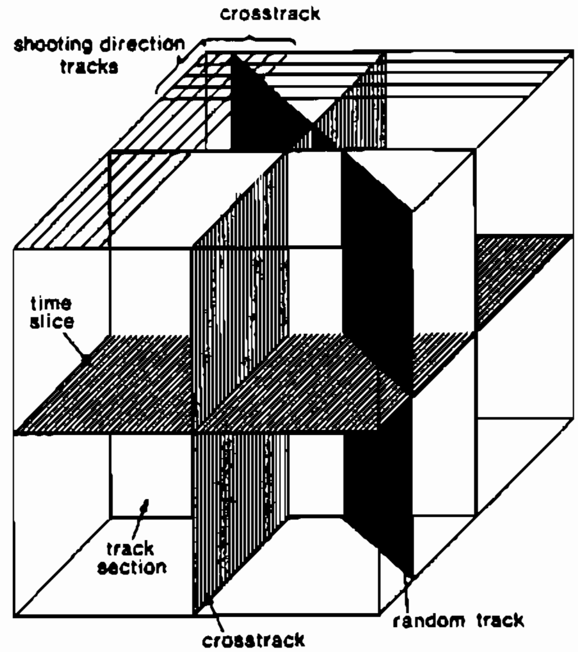

Fig. 2—3D data cube

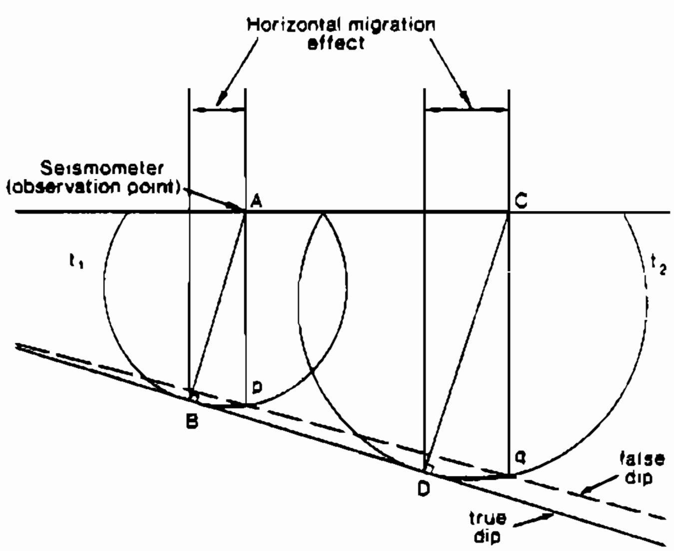

Fig. 3—Migration of reflection points

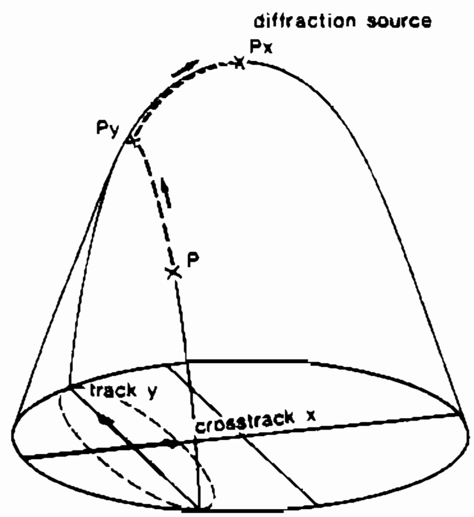

Fig. 4—Two step migration of diffraction energy

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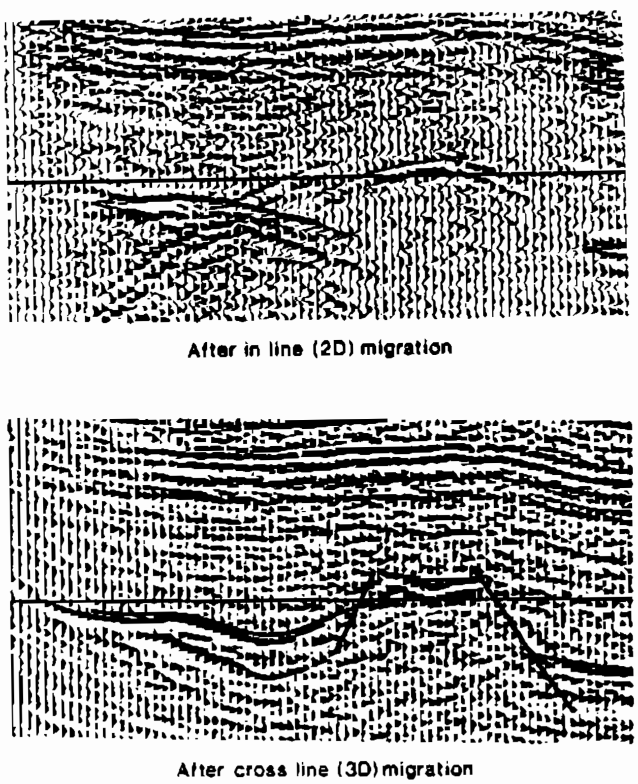


Fig. 5—Central North Sea comparison of 2D and 3D migration

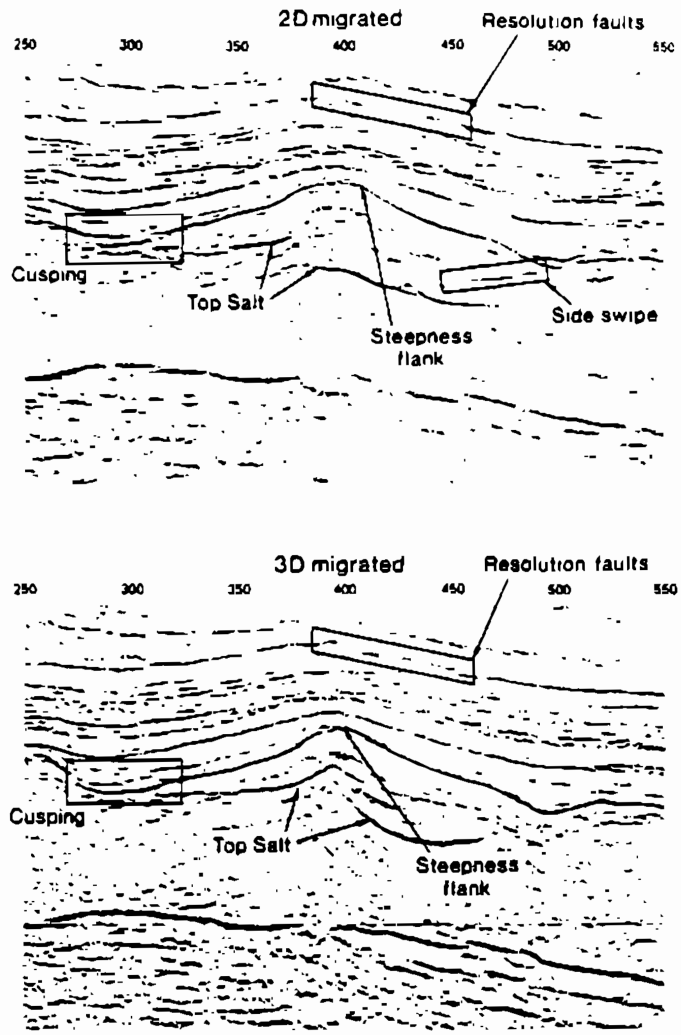
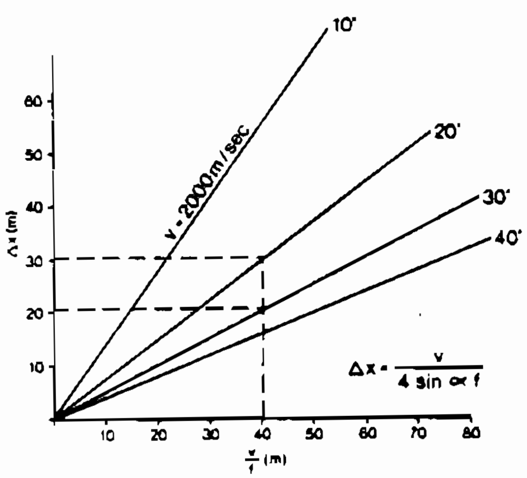


Fig. 6—Central North Sea, improvement of resolution after 3D migration



Δx - CDP grid spacing
α - formation dip angle
f - signal frequency
v - velocity

Fig. 7—CDP grid spacing as function of dip, frequency and velocity

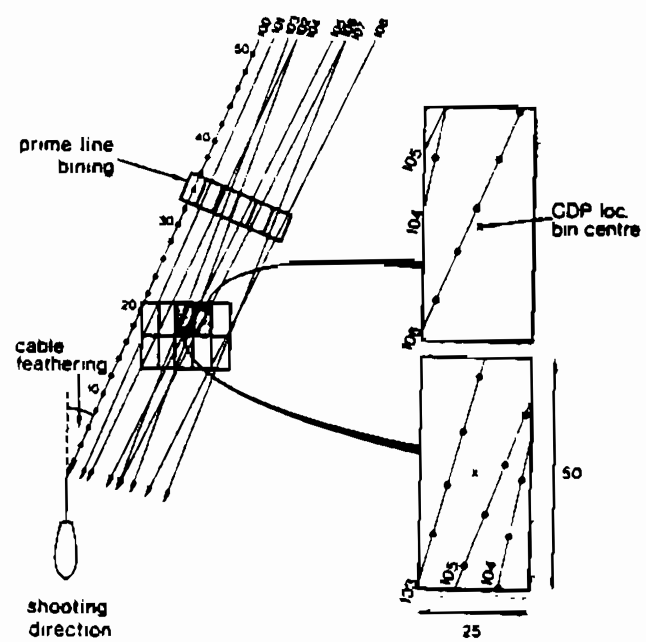


Fig. 8—3D trace binning

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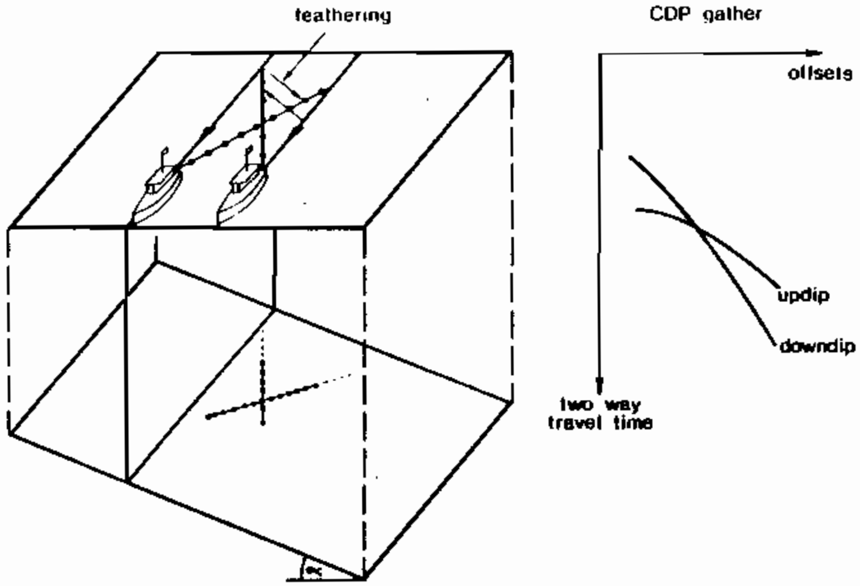

Fig. 9—Effect of streamer feathering

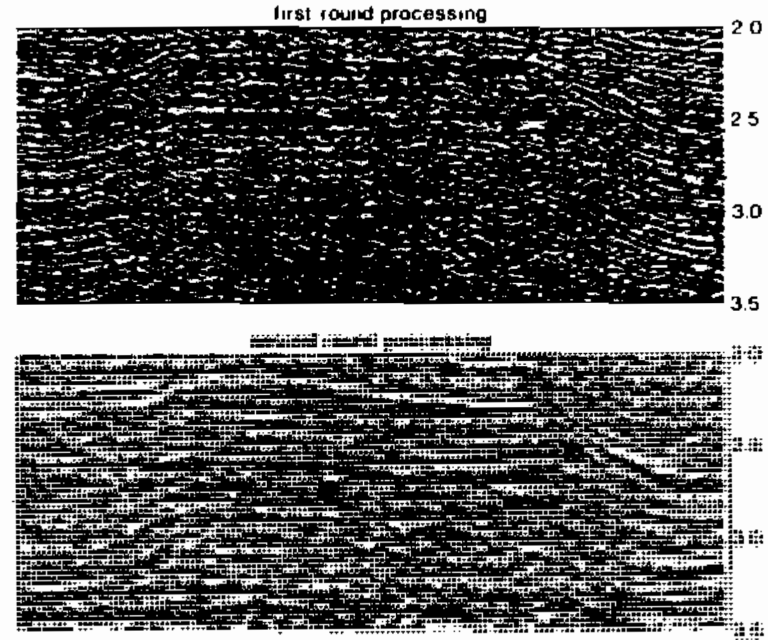

Fig. 10—Improvement of data after correcting for positioning errors

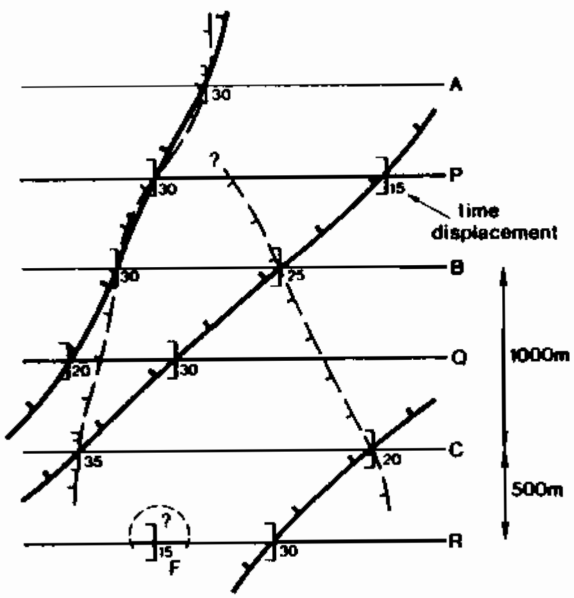

Fig. 11—Fault missing

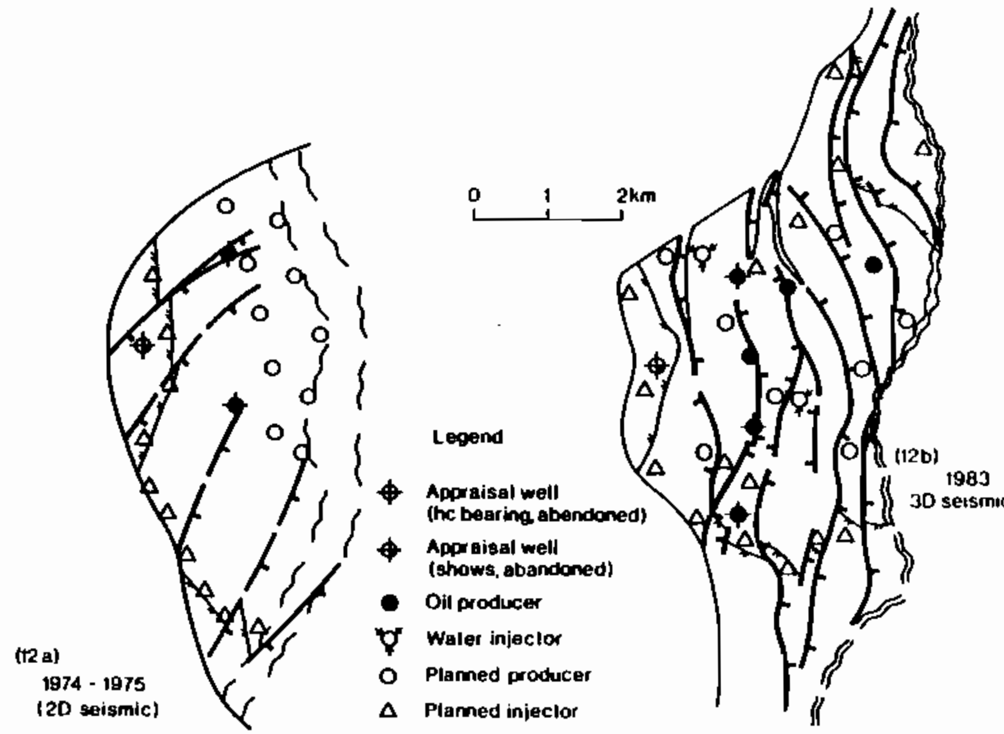

Fig. 12—North Cormorant schematic top structure maps of Block IV showing the development strategy in 1976 and 1984

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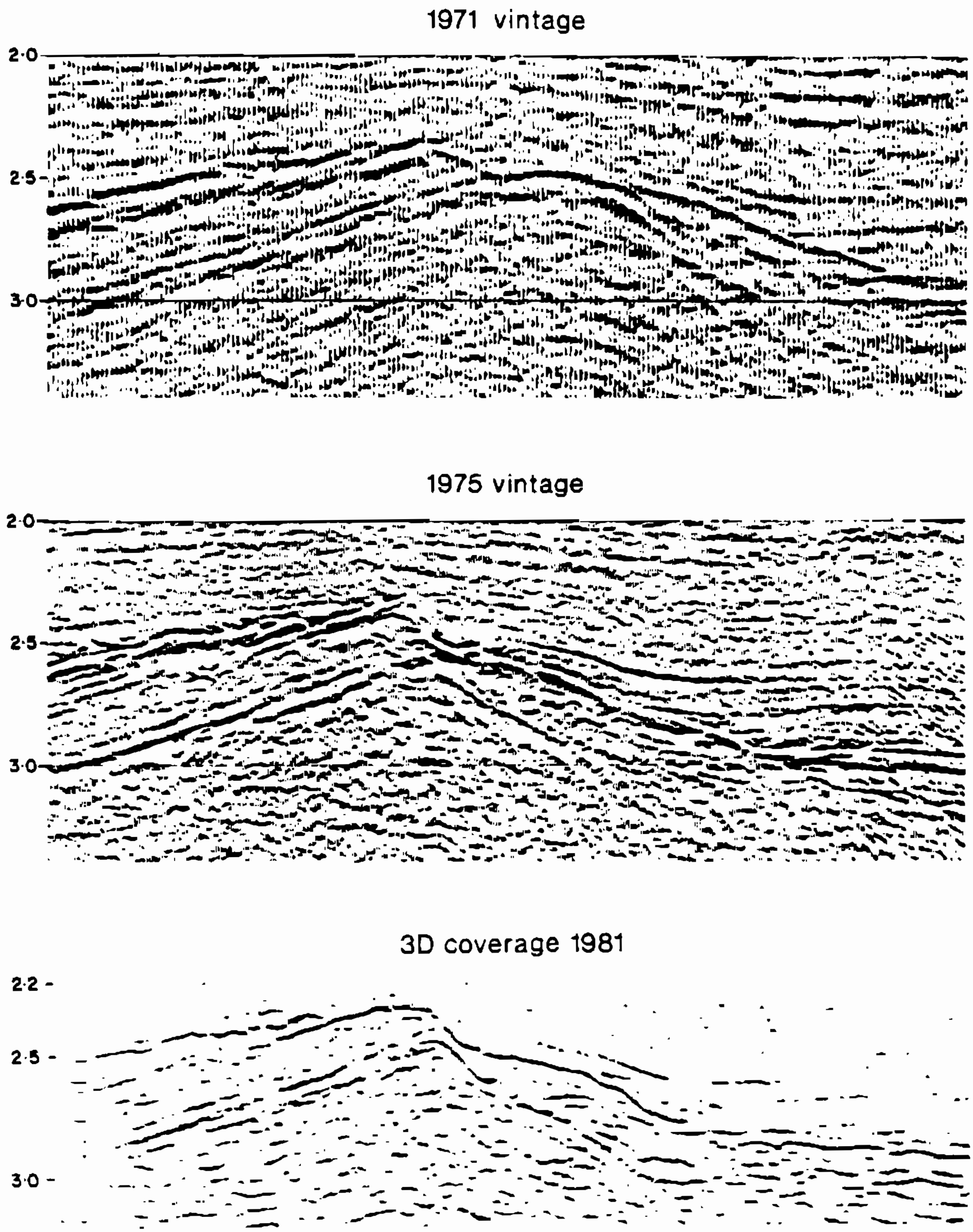

Fig. 13—Comparison of same coverage of different seismic data vintages.

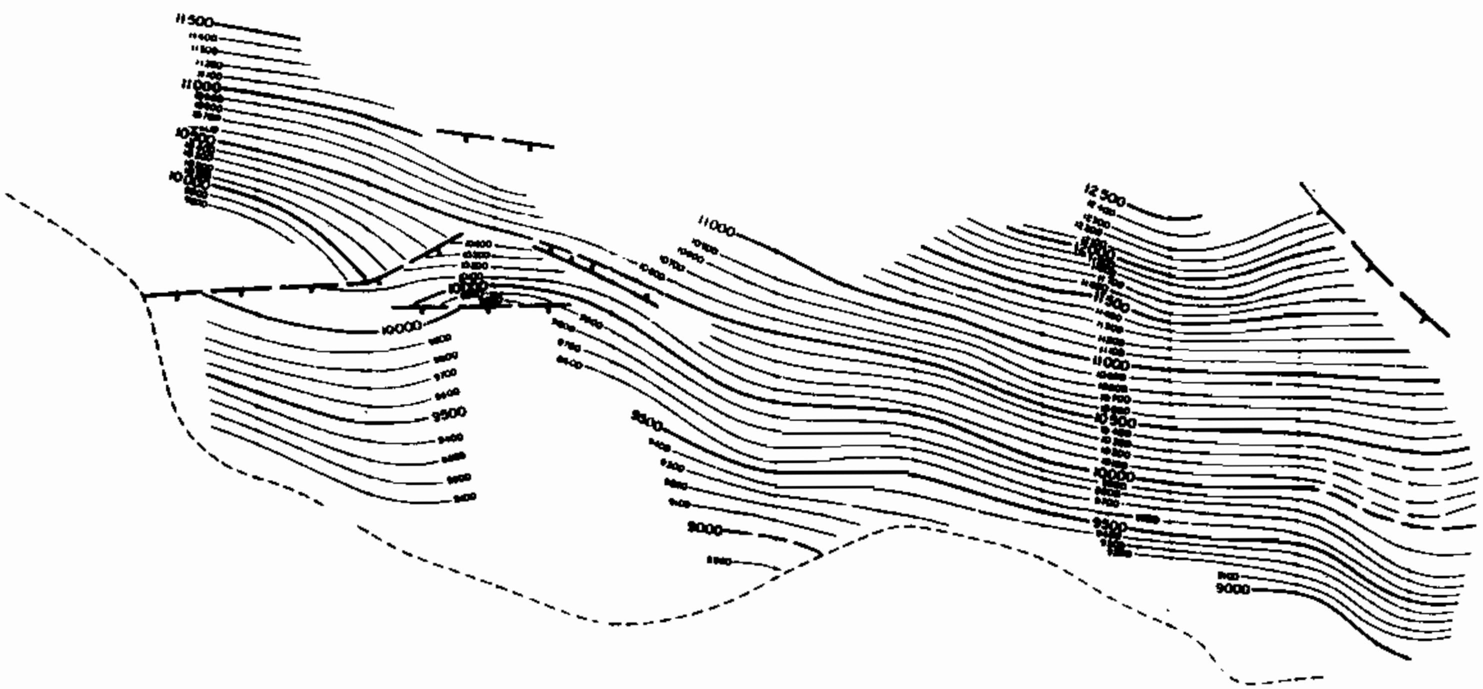

Fig. 14—Structural map based on 1971 seismic data grid.

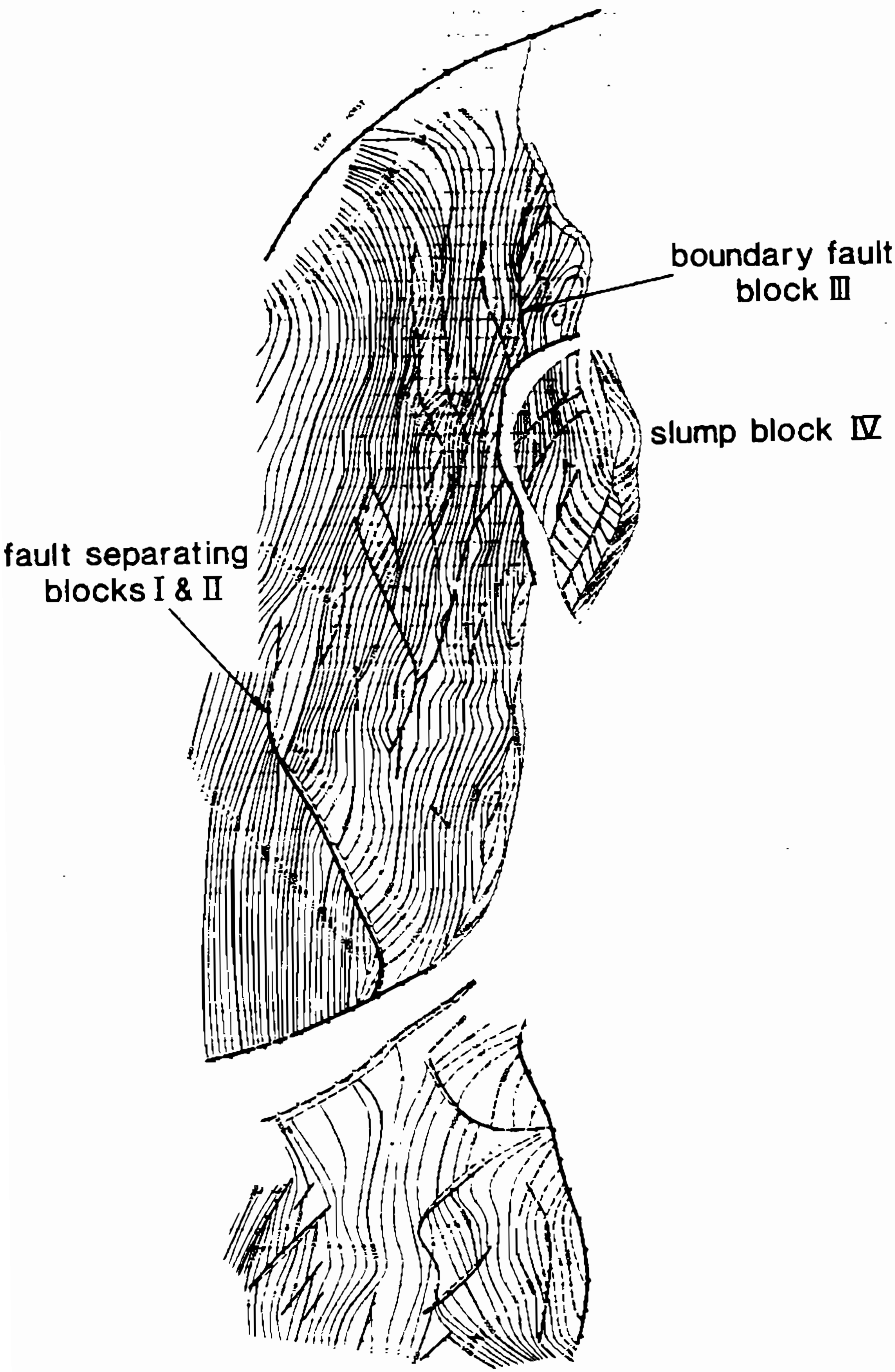

Fig. 15—Structural map based on up to 1975 2D seismic data grid.

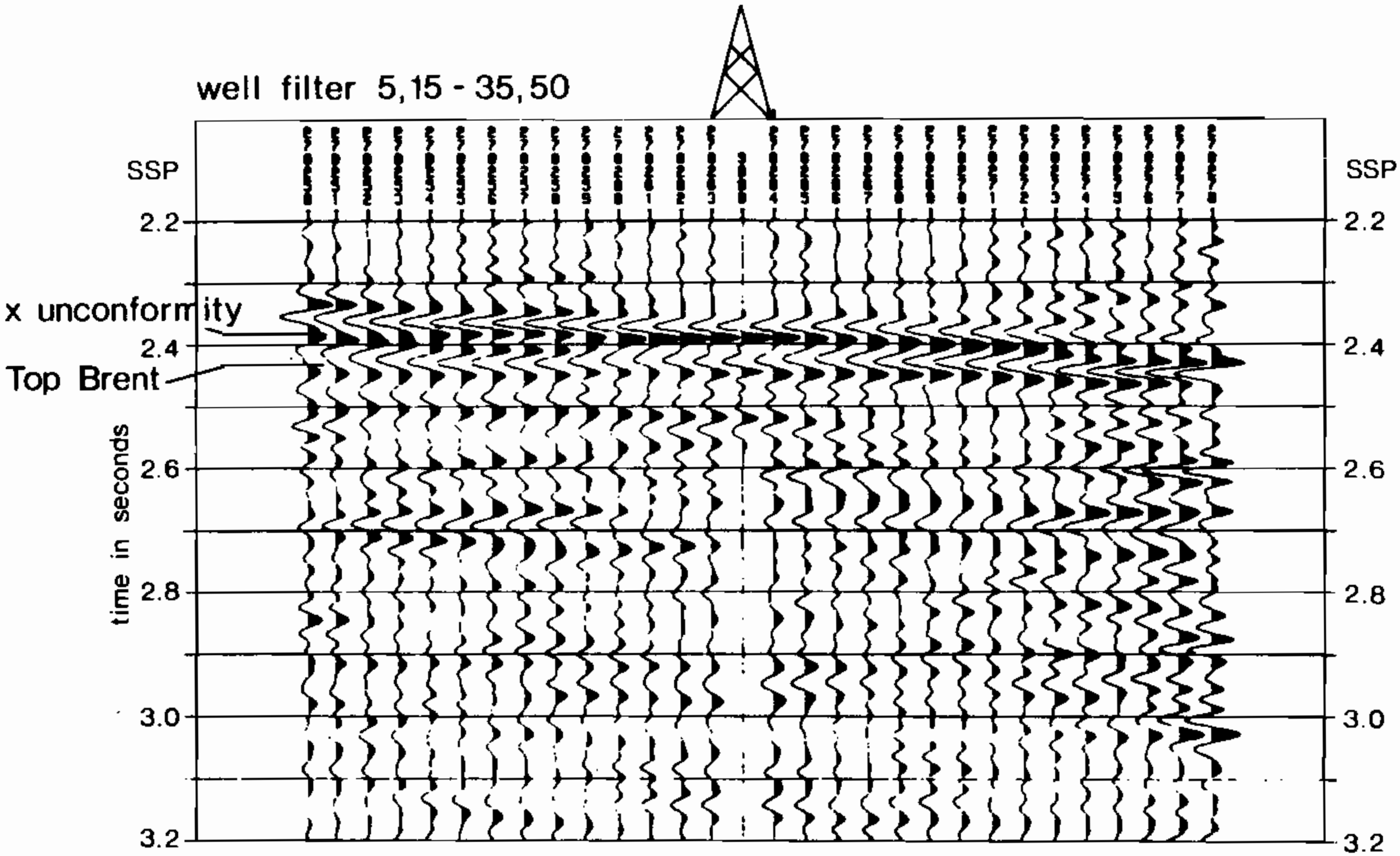

Fig. 16—Match between synthetic well trace and 3D seismic data.

ERRATA

SPE 13049

The Value of 3D Seismic in Field Development

by L. Gaarenstroom, *Shell U.K. E&P Co.*

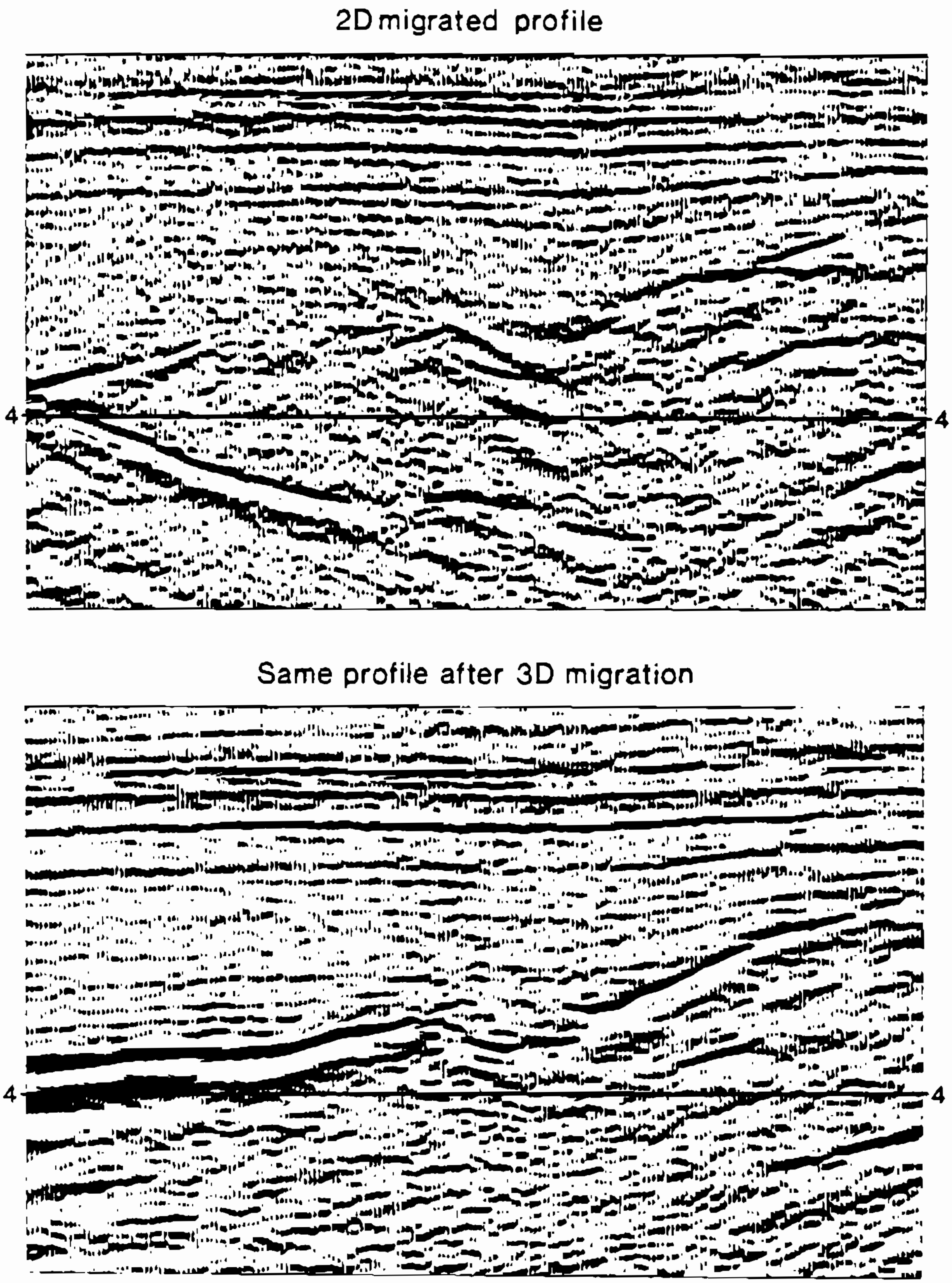

Fig. 5

SPE 13049

Offshore South East Asia 82 Conference
9 — 12 February, Singapore

EXPLORATION III — GEOLOGY SESSION

Enhanced Analysis Of 3-D Seismic Survey Over A Carbonate Province

by M. R. Thapar and B. R. Ayme, Cities Service Company, USA

Seismic response from carbonate rocks varies from weak reflections (dim spots) associated with reef-like features to strong reflections from carbonate rocks having a much higher velocity than the surrounding rocks. Amplitude, frequency, and velocity of seismic reflections can be diagnostic of hydrocarbon presence.

A three-dimensional (3-D) seismic survey was carried out for Philippines Cities Service, Inc. by Geophysical Service, Inc. in February, 1978. One of the objectives of this 3-D survey is to define the shape and size of the productive Nido features. It is also important to determine the relative locations of these features. Finally, the 3-D seismic survey data are to be employed for locating new exploratory wells to increase the oil reserves within the Nido area. A three-dimensional seismic survey is well suited for resolving reflections anomalies from reef-like (dome-shaped) features by employing some of the state-of-the-art processing techniques.

We are able to display seismic data in various colors by using the CIT-CHROME™ seismic color processing system. These color plots can be attributed to seismic parameters like amplitude, frequency, absorption, energy, and energy frequency. Our experience with frequency anomalies over known hydrocarbon-saturated zones indicates that low frequency anomalies can be an indicator for the presence of hydrocarbons.

All of the 88 seismic lines are processed in color to show "Energy Frequency" of the seismic reflections. These "Energy Frequency" color plots are laminated on plexiglass sheets to form a 3-D color display. A close examination of this 3-D display reveals some interesting geophysical observations regarding the location of some of the noncommercial wells.

Introduction

The seismic response from carbontates varies from weak reflections (dim spots) associated with reef-like features to strong reflections due to a large acoustic impedance contrast between the carbonates and the surrounding formations.

A three-dimensional (3-D) seismic survey was carried out for Philippines Cities Service, Inc. by Geophysical Service, Inc. in February, 1978. One of the main objectives of this survey is to define the shape and size of the productive Nido features. It is equally important to determine the relative locations of these features. The 3-D seismic data are useful in locating exploratory wells.

This 3-D seismic survey covered an area of 17.2 km. x 8.7 km., with 88 seismic lines. These seismic lines were recorded at 100 meter intervals.

We have processed these seismic lines in color to create a 3-D color display. Horizontal constant time slices were also processed in color to make a movie film of the seismic data with depth.

The seismic attributes included in the CIT-CHROME™ seismic color process are listed in Figure 1. Parameters like relative true amplitude, structure true amplitude, frequency, energy and attenuation/absorption can be displayed as a function of color. The measurement of wave propagation quantities is a useful tool for interpretation and processing of seismic data.

Cit-Chrome™ color process can help the interpreter in detecting hydrobarbon-indicator anomalies, structural features like highs and fault, lithology and stratigraphic traps. Minor character changes in seismic reflections are accentuated by the use of multiple colors. The changes in geophysical parameters displayed in color are measured with increased resolution as compared to the black-and-white seismic display.

It appears that color processing can aid the interpreters to explore for oil- and gas-saturated zones. Cit-Chrome™ color processing is helping us do a better job of processing and analyzing the seismic data.

Cit-Chrome™ Color Processing System*

Cit-Chrome™ color processing is a three-step process. Seismic data is first processed for color separation and then displayed on black-and-white films. The final step is the making of a color display by the use of DuPont's Cromalin® process, or on an Applicon color plotter. Several different seismic parameters, like true amplitude, structure true amplitude, frequencies, and energy can be displayed in color by Cit-Chrome™ color processing system.

Relative True Amplitude In Color

In a black-and-white display of a relative true amplitude seismic section, a geophysicist sees the amplitudes in a qualitative manner, e.g., amplitudes appear either large, medium, or small. A relative true amplitude in a black-and-white section for an offshore line is shown in **Figure 2.**

Two levels of amplitudes (high and low) can be observed on the black-and-white display (**Figure 2**). It is quite difficult to detect any variations within the large amplitudes observed on this display. Also, an opposite-polarity display is required to detect anomalies in the negative oscillations (troughs) of this section. A color display of the same true amplitude seismic data is shown in Figure 3. In this color display not only many more levels of variation can be noticed, but also both polarities as compared to the black-and-white plot can be observed. Only one of the six wells marked on the section is dry. The remaining five wells to the left are all producers. The producing sands are marked by the bright reflection amplitudes shown in red color.

Structure — Truamp In Color

A structure section is a display of seismic data which brings out the weak reflections that cannot be seen clearly on a relative true

* A U. S. Patent on Color Processing of seismic data has been issued to Cities Service Company.

amplitude seismic section (Figure 4). A structure section is obtained by applying an automatic gain control operator to the relative true amplitude seismic data. Subsequently, the relative true amplitude information is not present on the structure section. Therefore, two polarities of the structure section and two polarities of the relative true amplitude section must be displayed for an examination of relative true amplitude and structure. This information just described can only be displayed in four black-and-white plots of a given seismic section. But, a color structure-truamp display can show all of this information in one display as shown in Figure 5. The colors in Figure 5 show the relative true amplitude of the seismic data. An AGC operator has also been applied to the seismic data to bring out the structure. All of the peaks and troughs are displayed in color.

Frequencies In Color

The frequency values can be color-coded and displayed as a color section. We can display the frequencies either with structure or with relative true amplitude. The frequencies displayed are the dominant frequencies measured from the seismic data. An example of frequencies in color is shown in Figure 6. From limited experience, it appears that low frequency anomalies are seen at or directly below the zone of production. Some experimental evidence in the literature suggests that the seismic signal loses high frequencies in transmitting through the gas/oil zone. This means that the high frequencies present above gas/oil zones are absorbed and only low frequencies are reflected. In this example (Figure 6), colors representing low frequencies (0—25 hz) are green, cyan, and violet. These three colors are more apparent in the areas of production.

Energy Display In Color

In an energy display only the strongest reflections can be observed. The energy of seismic data is computed and then superimposed on the seismic amplitudes (Figure 7). This operation further enhances the signal-to-noise ratio. This energy-bearing data is displayed in color in order to show the relative changes of energy as shown in Figure 8. As mentioned above, this color display shows only the strongest reflections as compared to the truamp section (Figure 3).

Energy Frequency Display In Color

An energy frequency color display is shown in Figure 9. This energy frequency display shows the dominant frequency of the strong energy reflection events. This type of display is useful for studying the frequency changes in bright spot-type anomalies.

Survey Area

This 3-D seismic survey was carried out over an area located offshore Palawan Island. The generalized tertiary stratigraphy for the eight basins in South East Asia located from Burma to Palawan (Figure 10) is given by Wood (1978) and Beddoes (1979). The production in the Nido Field is from reef buildups.

3-D Color Display

The energy frequency color displays of all of the 88 seismic lines are created on Plexiglas sheets. An example of energy frequency color display of Line 1 is shown in Figure 11, and a frequency color display of the same line is shown in Figure 12.

The reason for selecting the energy frequency display over the frequency display for making 3-D color displays is that the energy frequency display allows us to see in the third dimension. Also the low-frequency anomalies are good indicators for the presence of hydrocarbons. A picture of the 3-D display outlines the carbonate platform and the reef buildup.

3-D Color Slices

A slice represents the seismic data derived by constant time sampling of seismic lines over an area. In other words, a horizontal time slice is a constant time seismic anomaly map over the area.

These horizontal seismic slices are displayed in color with respect to the amplitude anomaly (Figure 14) or the frequency anomaly (Figure 15). The color displays of horizontal slices are created at 4 millisecond interval, and used to make an animated movie film to depict changes over the subsurface with depth.

The 3-D seismic data is also useful for computing a crooked seismic line passing through different wells in the area.

Conclusions

Anomalies due to the best producing B-feature in the area can be seen in the 3-D color display, and also in the frequency and amplitude movies. We continue to develop the 3-D color process (display and movies) to enable other types of structural features or stratigraphic traps.

The 3-D seismic surveys and 3-D color displays will increase our chances for finding oil and gas.

Acknowledgements

We would like to thank the management of Cities Service Company for allowing us to present this paper. The authors also appreciate the efforts of Jack McClarnon and his color processing group. We are thankful to patricia Lawfer and Lloyd Winn for their help in putting this manuscript together.

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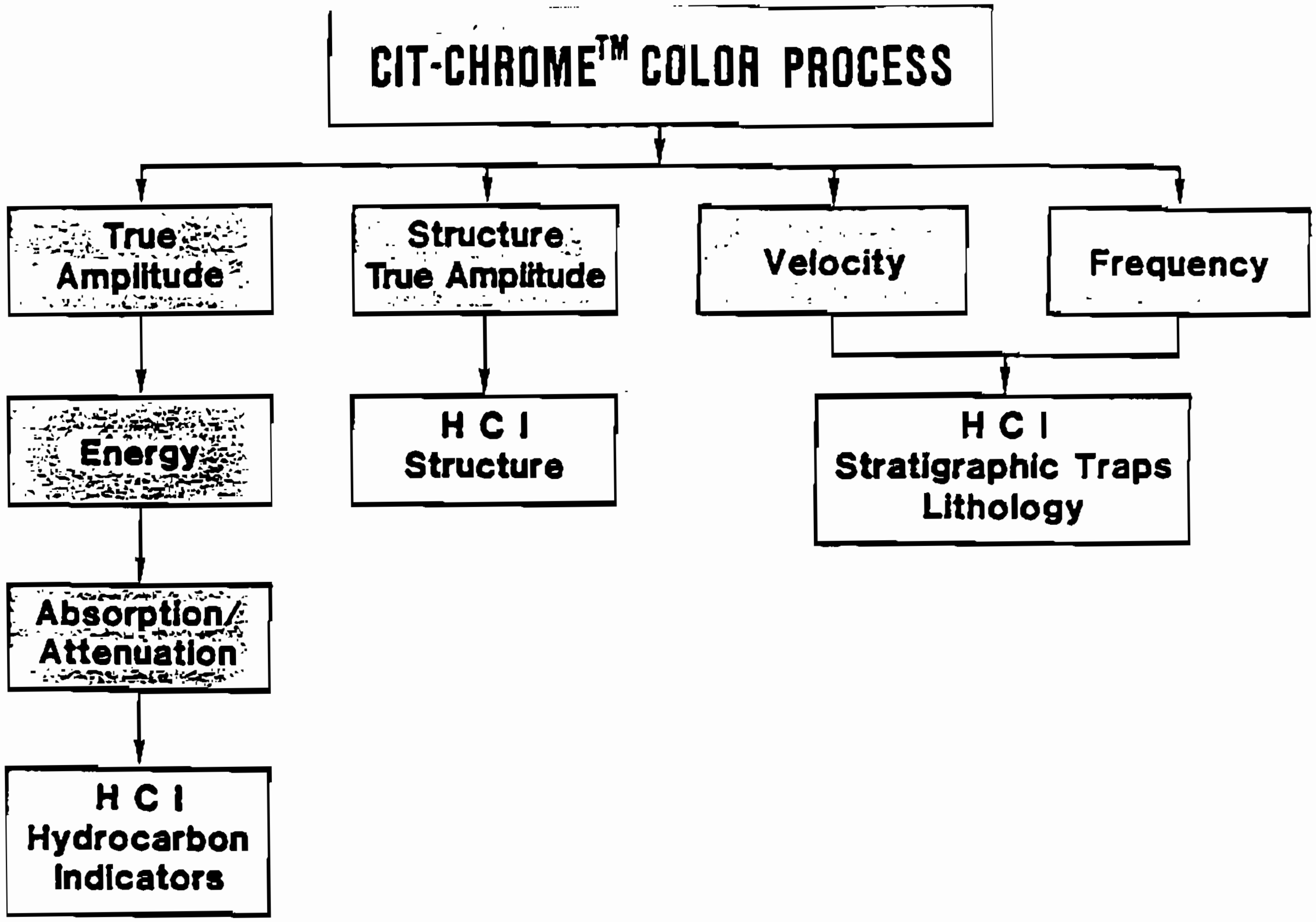

Figure 1 Cit-Chrome™, Trade Mark of Cities Service Company. This process is patented by Cities Service Company.

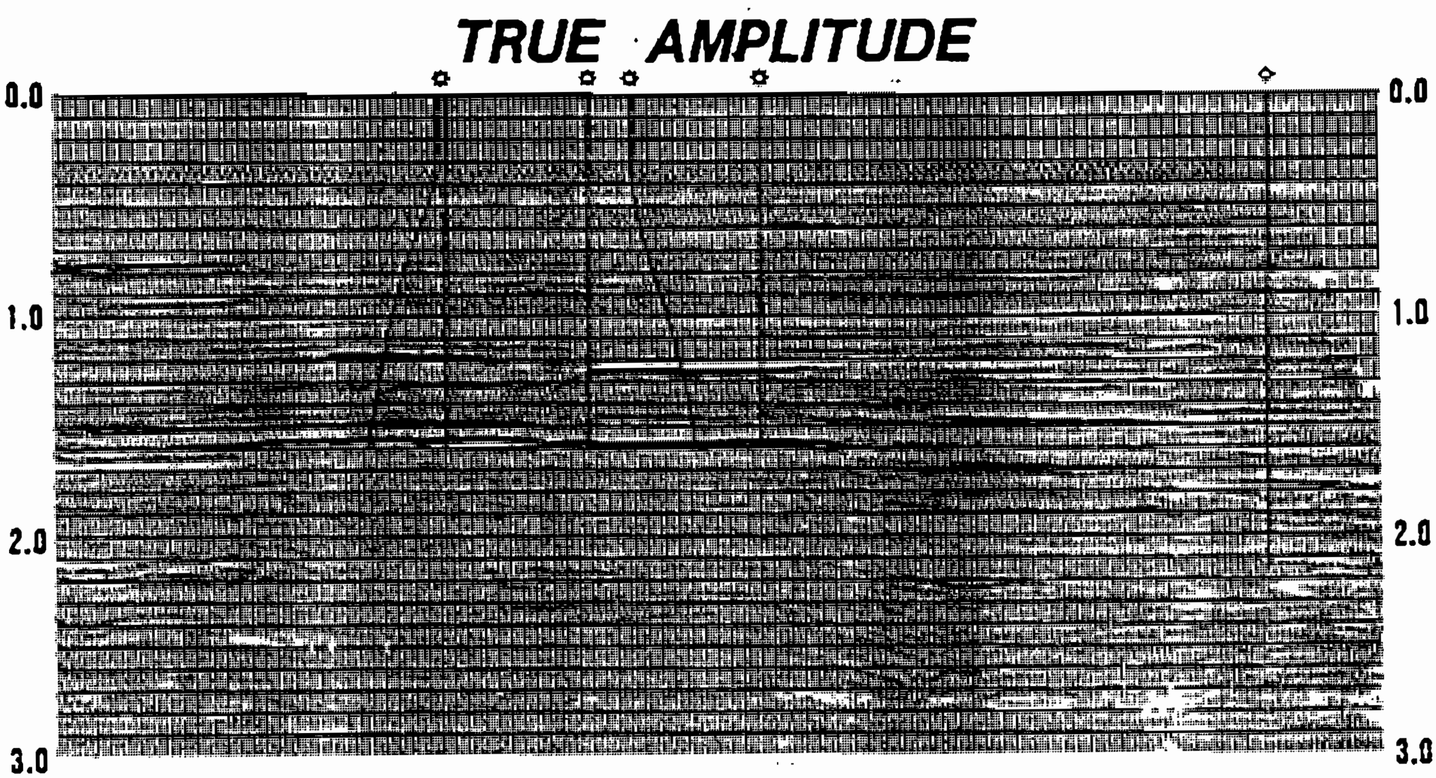

Figure 2 Black and white display of a relative true amplitude of an off-shore Louisiana seismic line.

TRUE AMPLITUDE

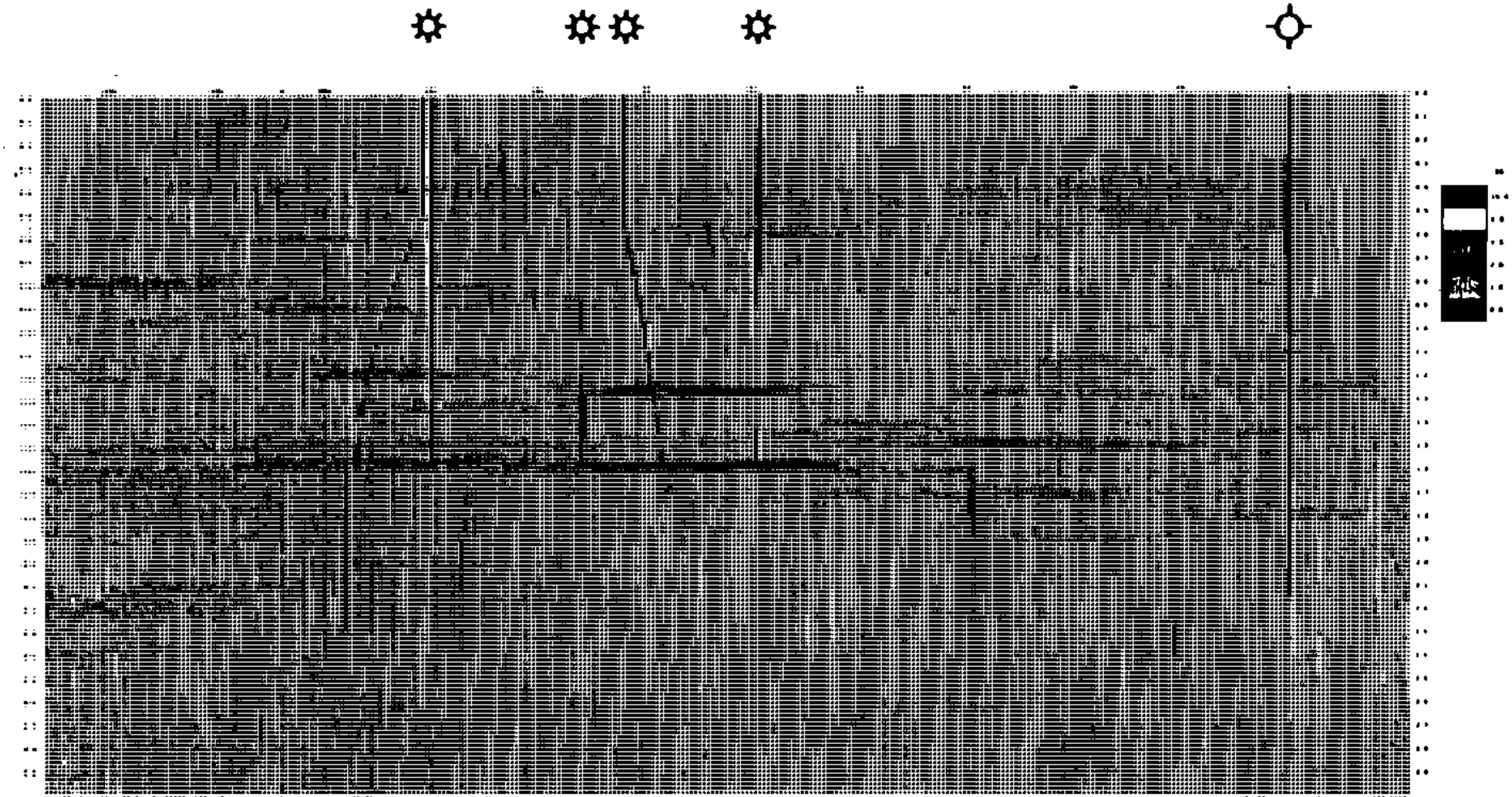

Figure 3 Relative True Amplitude Color Display of Data in Figure 3.

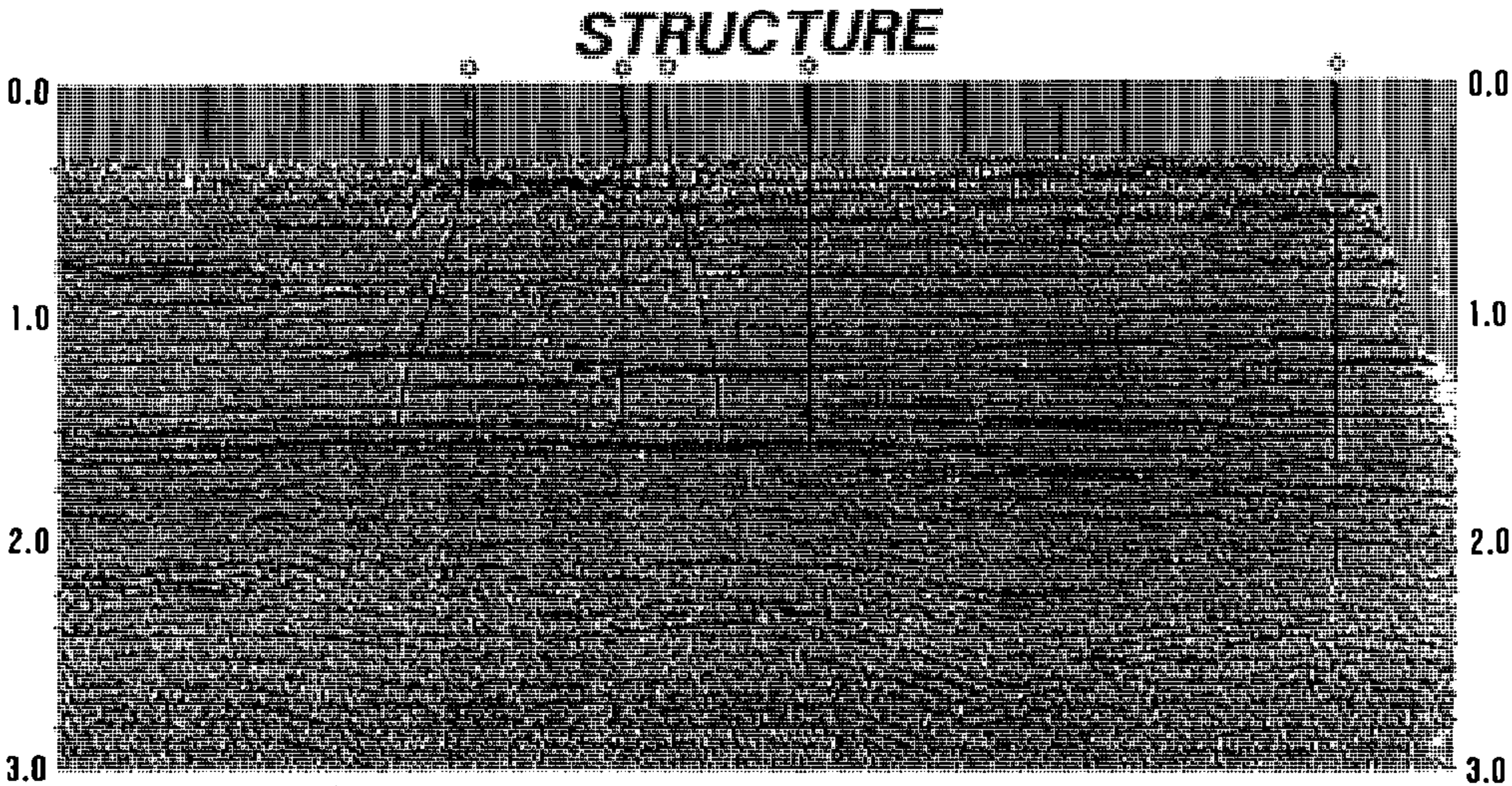

Figure 4 A black and white structure section of an off-shore Louisiana seismic line.

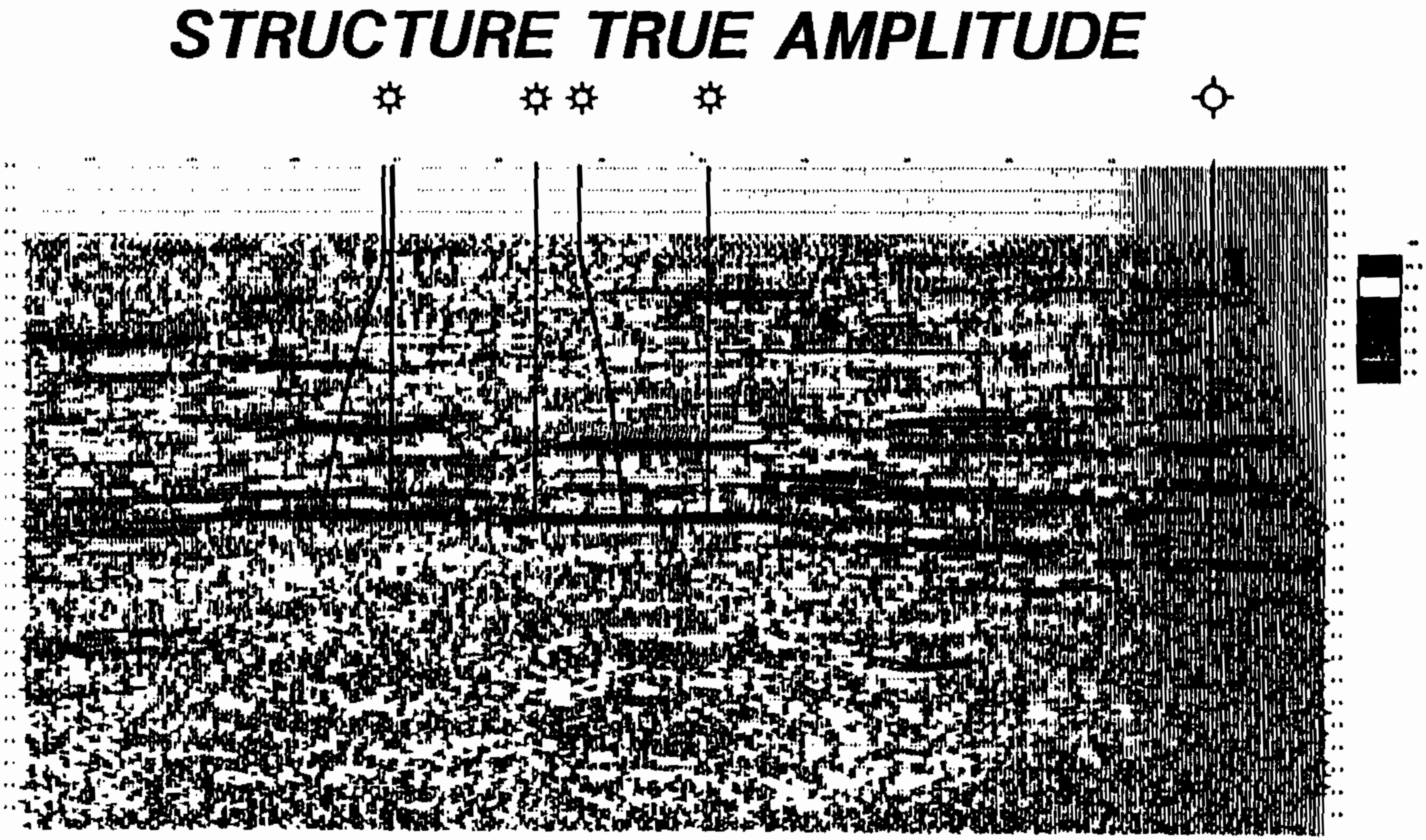

Figure 5 Structure True Amplitude Color Display of Data in Figure 3.

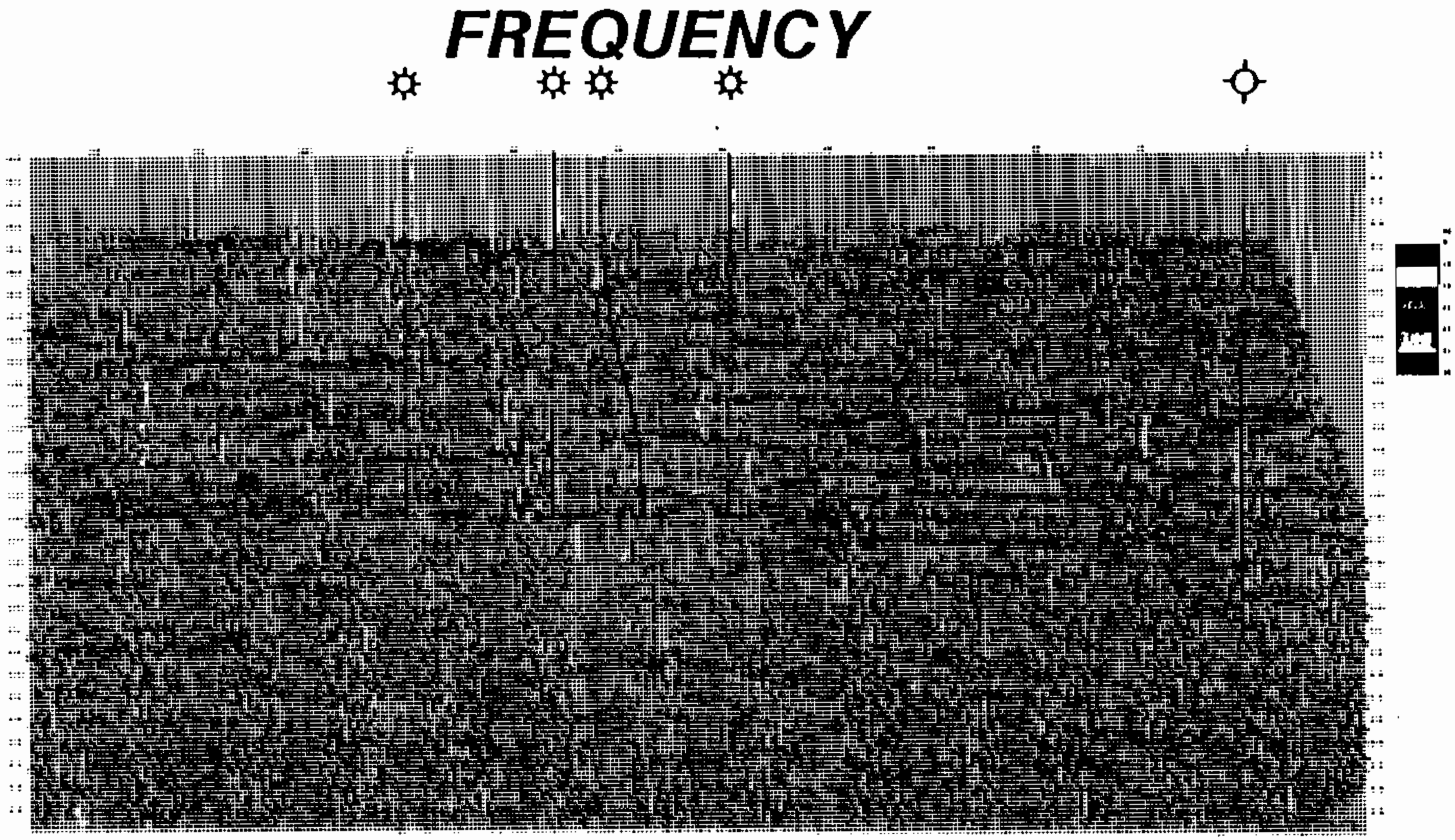

Figure 6 Frequency Color Display of Data in Figure 3.

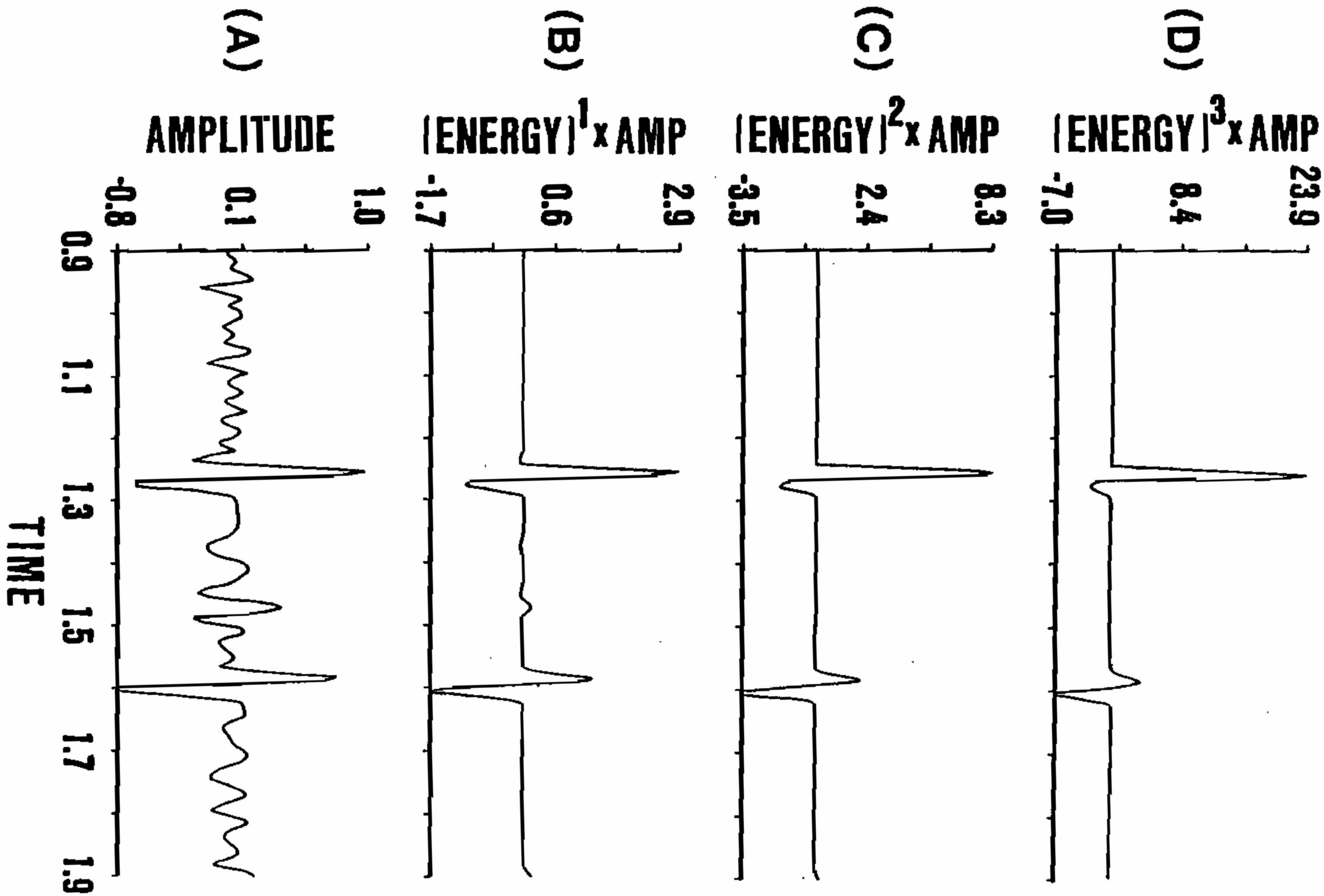

Figure 7. This figure shows the process of creating an energy trace from a stacked seismic section.

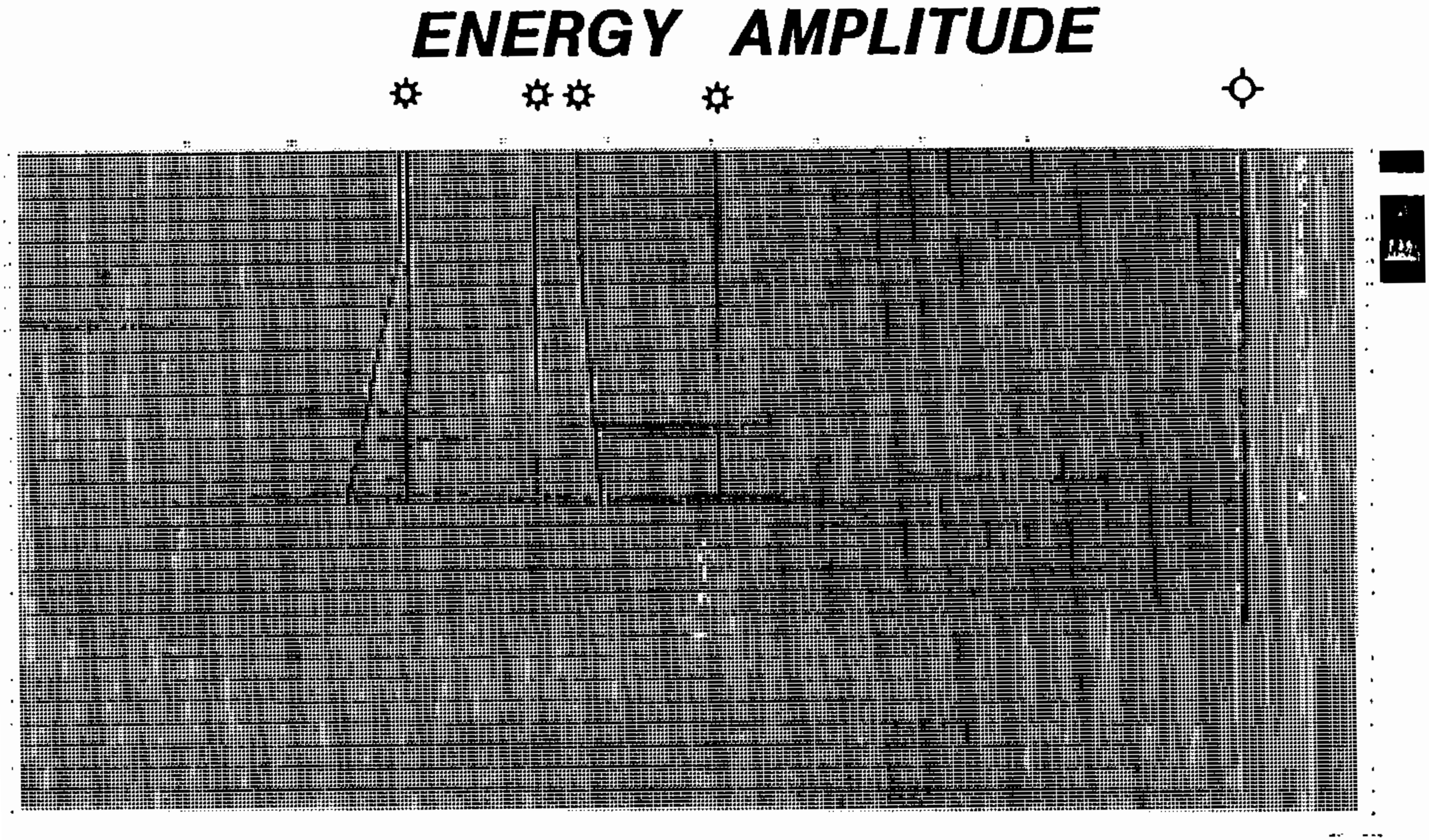

Figure 8 Energy Display in Color of Seismic Data in Figure 3.

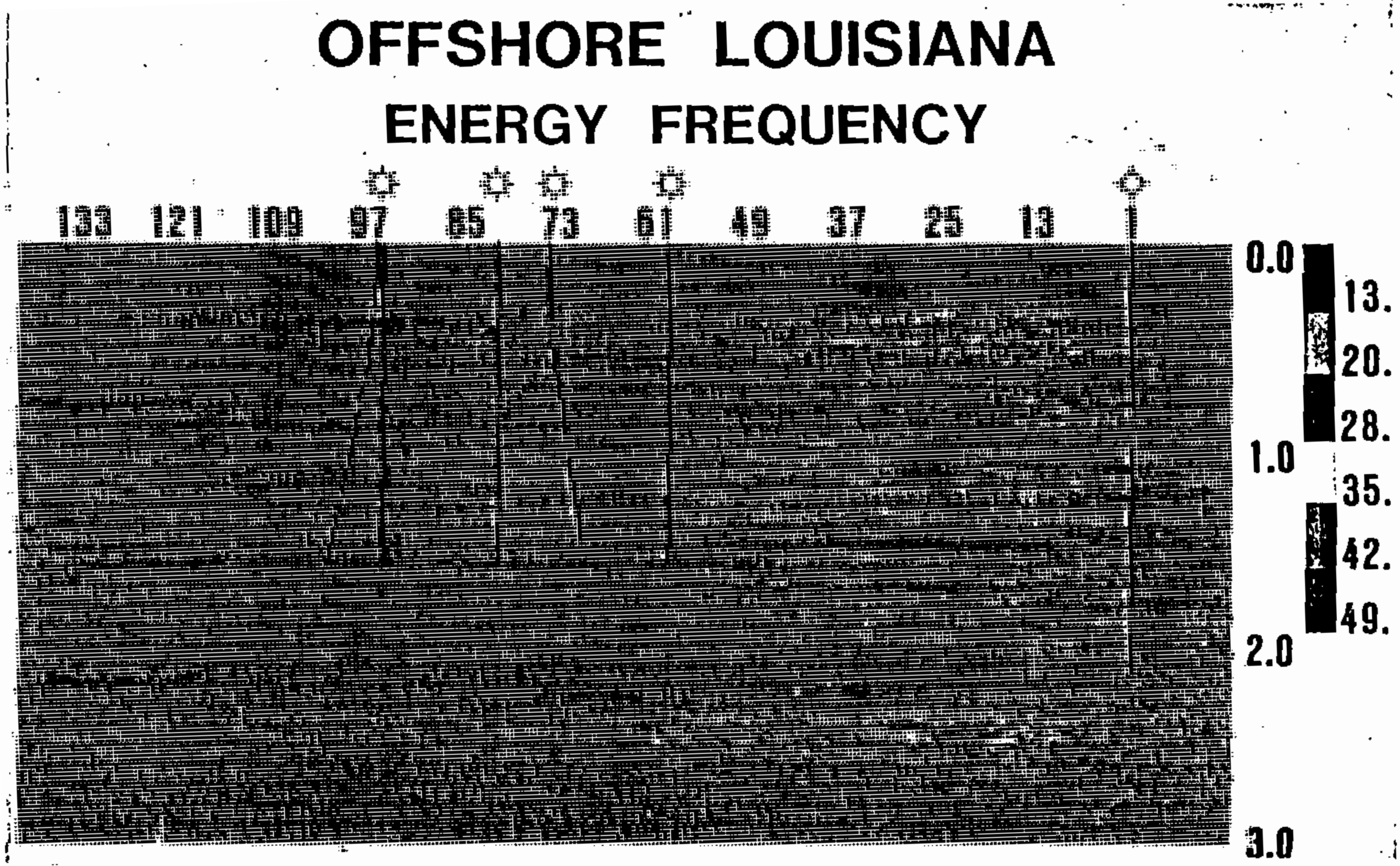

Figure 9 A color display showing the dominant frequency of the dominant energy reflections.

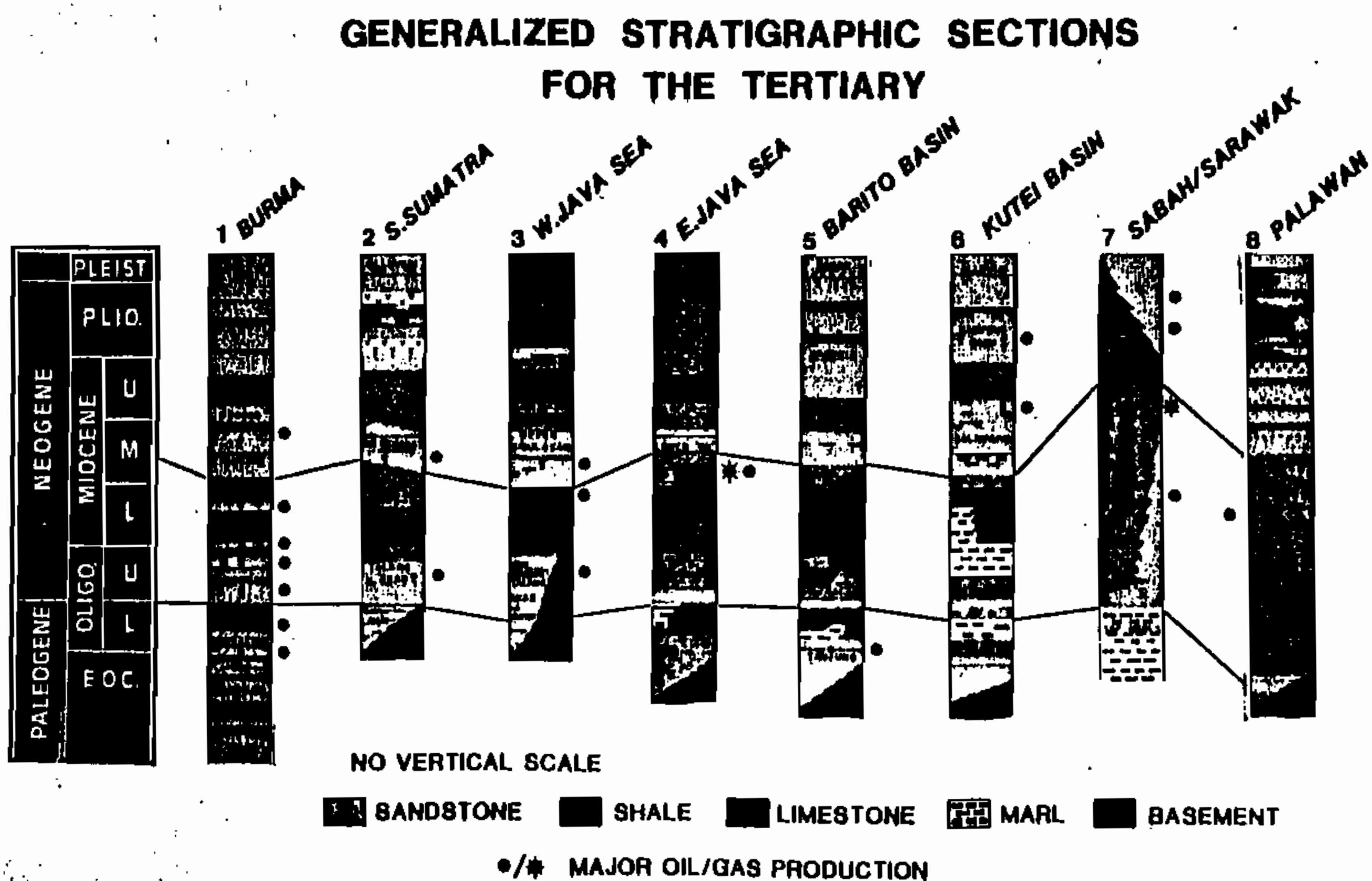

Figure 10 Generalized stratigraphic sections for the Tertiary in South East A

OFFSHORE PALAWAN
ENERGY FREQUENCY
LINE 1

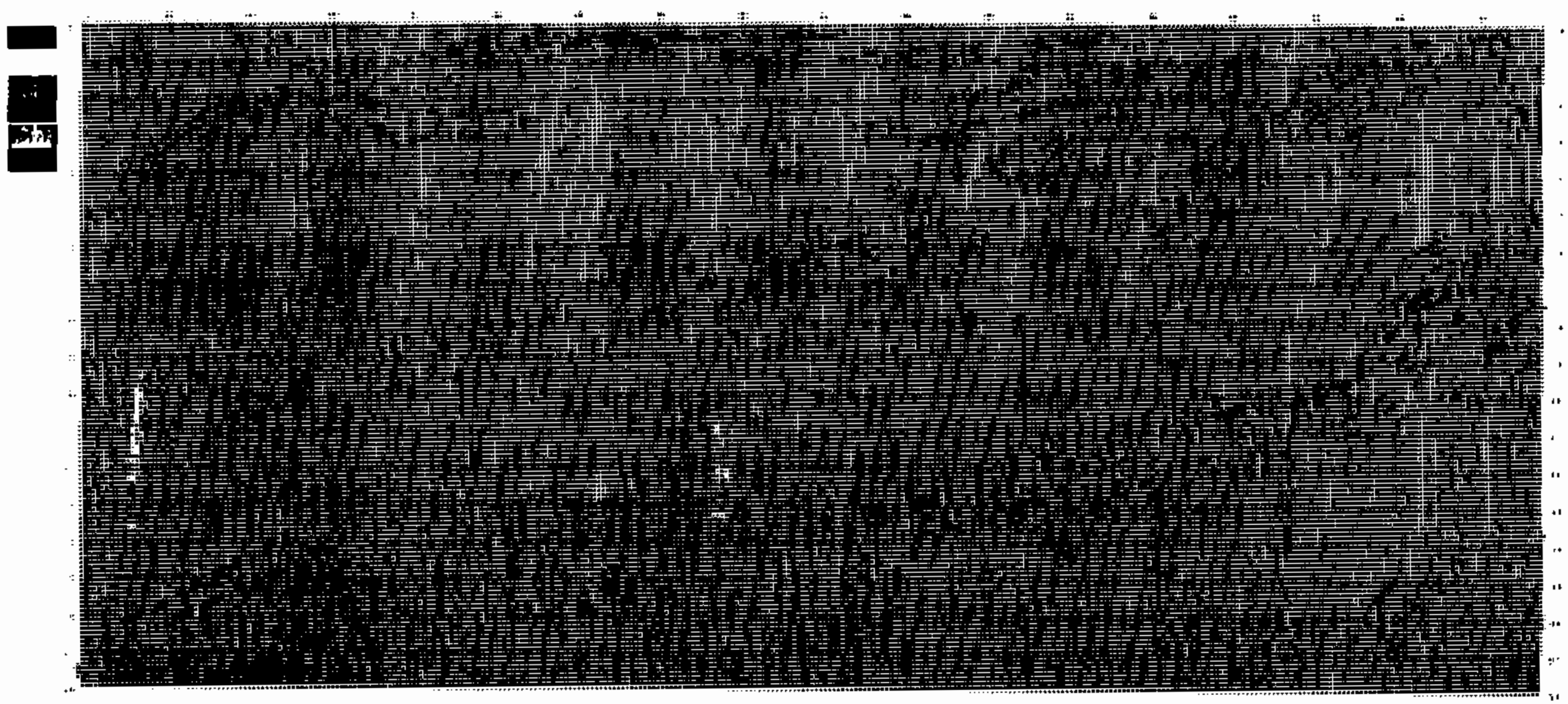

Figure 11 Energy frequency color display of Line 1 of the 3-D seismic survey.

OFFSHORE PALAWAN

FREQUENCY
LINE 1

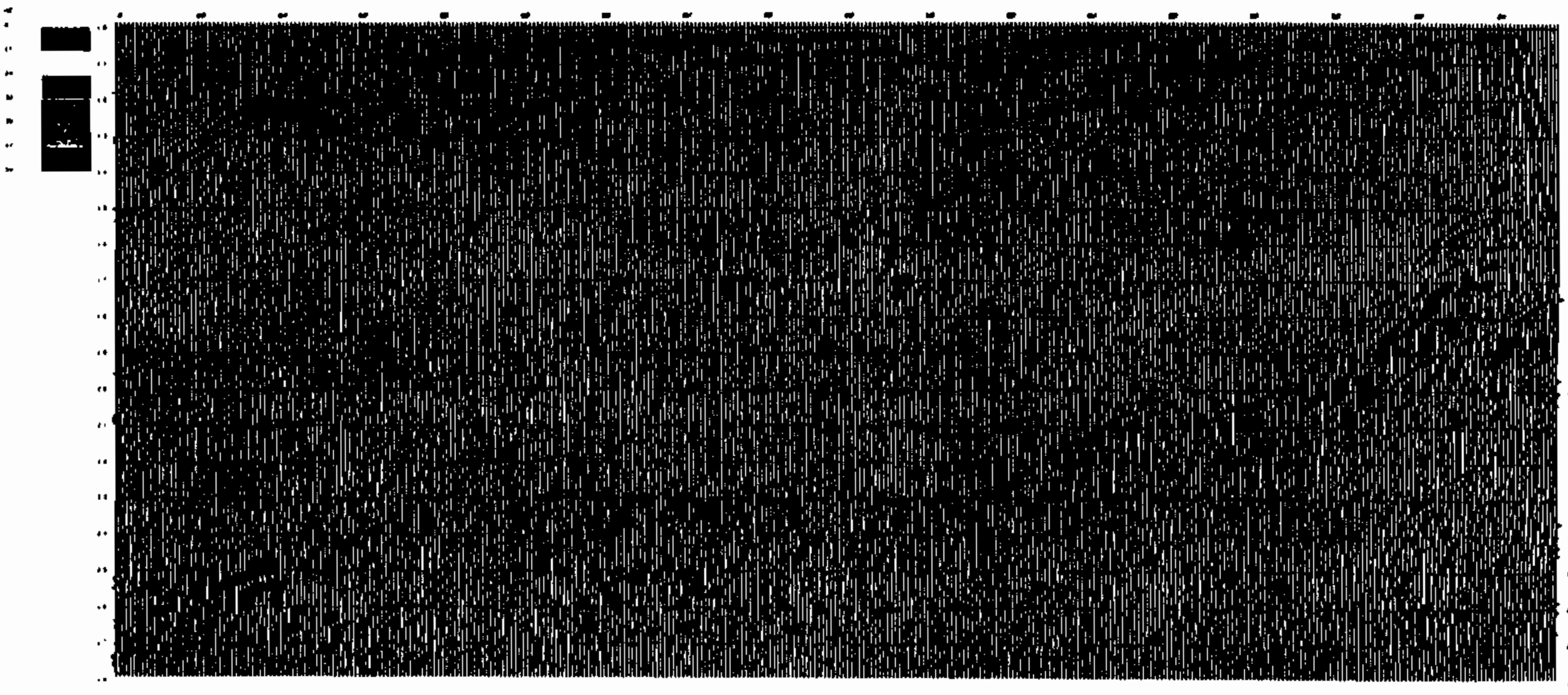

Figure 12 Frequency color display of Line 1 of the 3-D seismic survey.

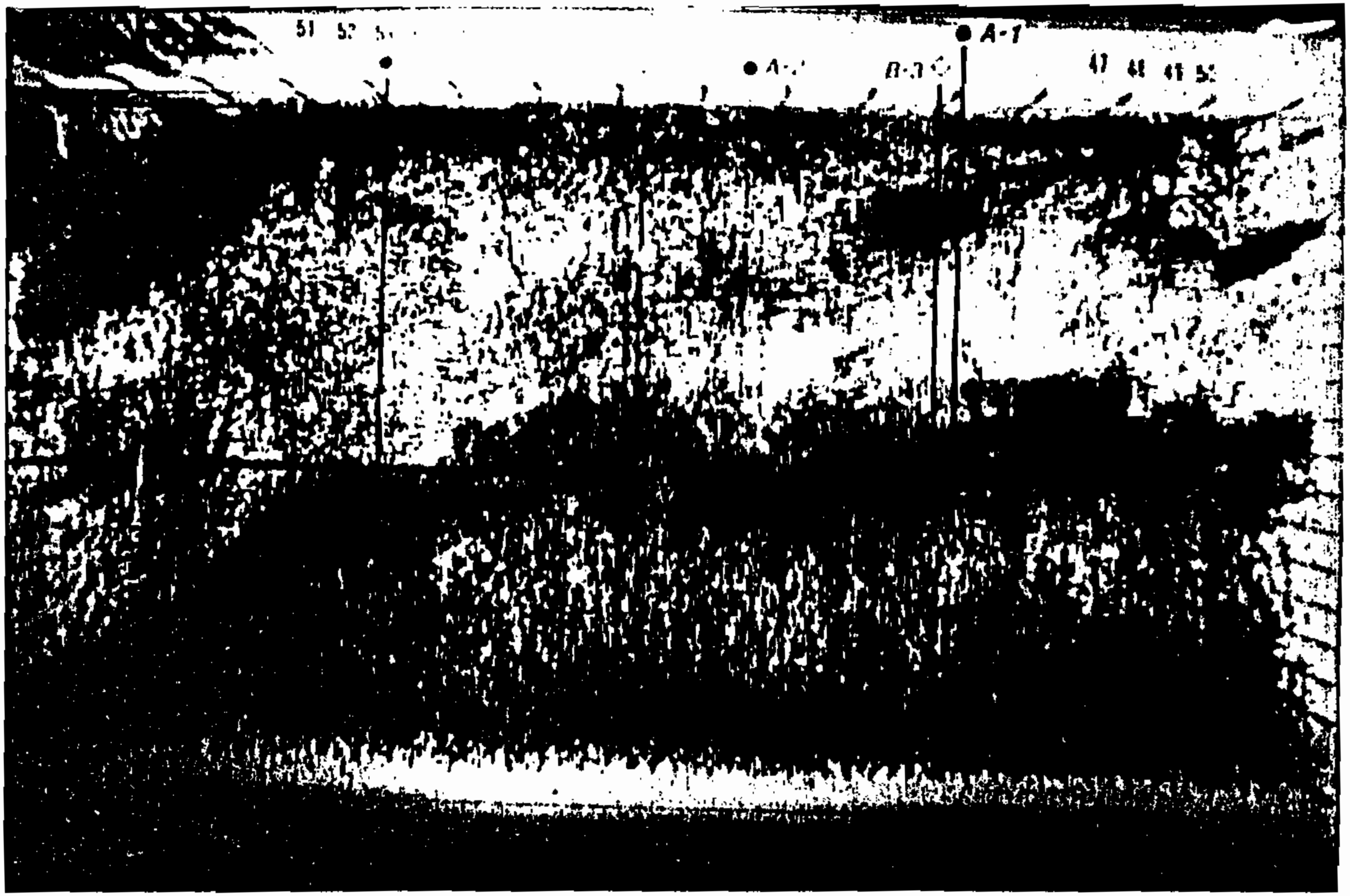

Figure 13 A picture of the 3-D color display of seismic lines covering production areas.

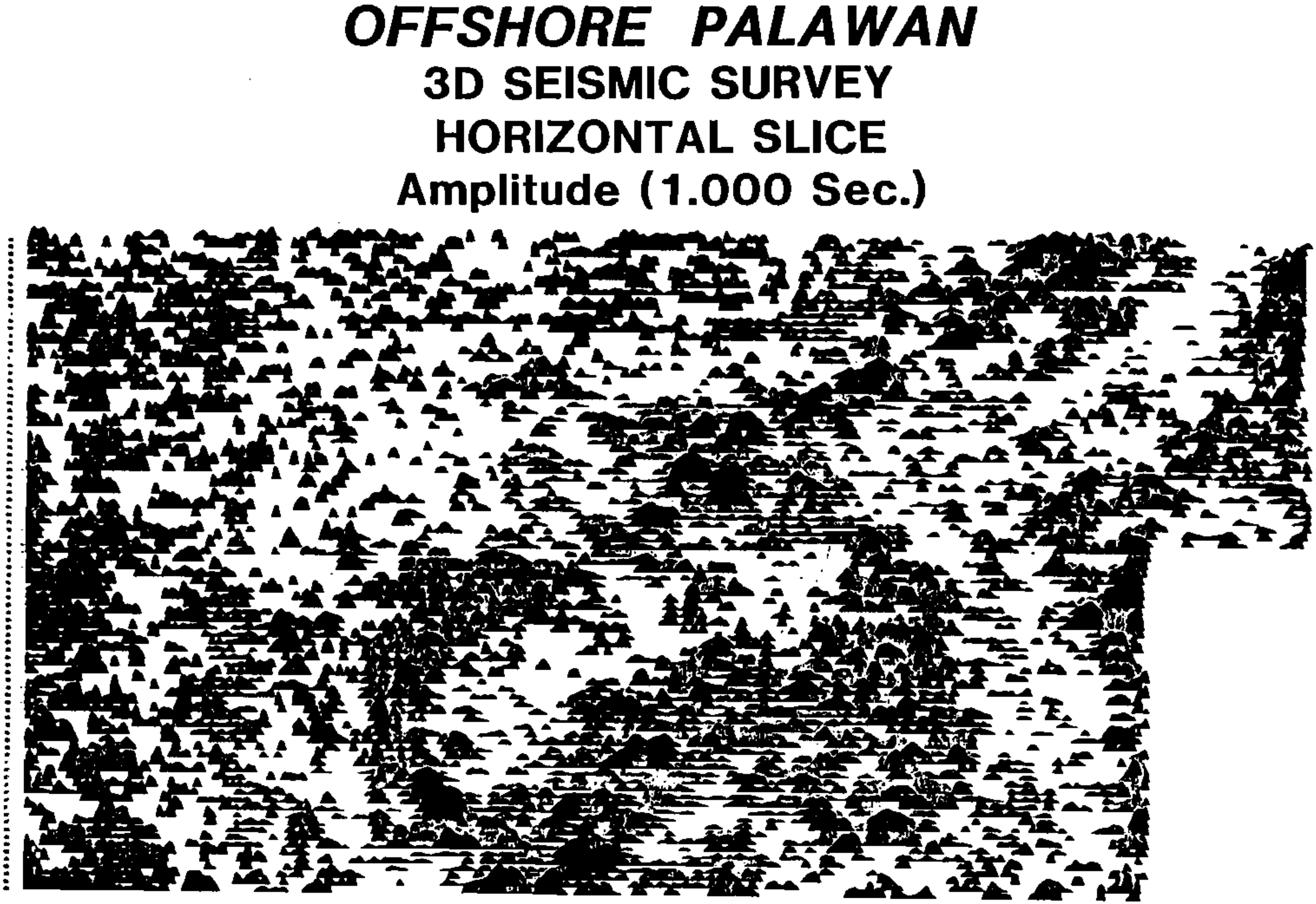

Figure 14 Color amplitude display of a horizontal slice over the 3-D area.

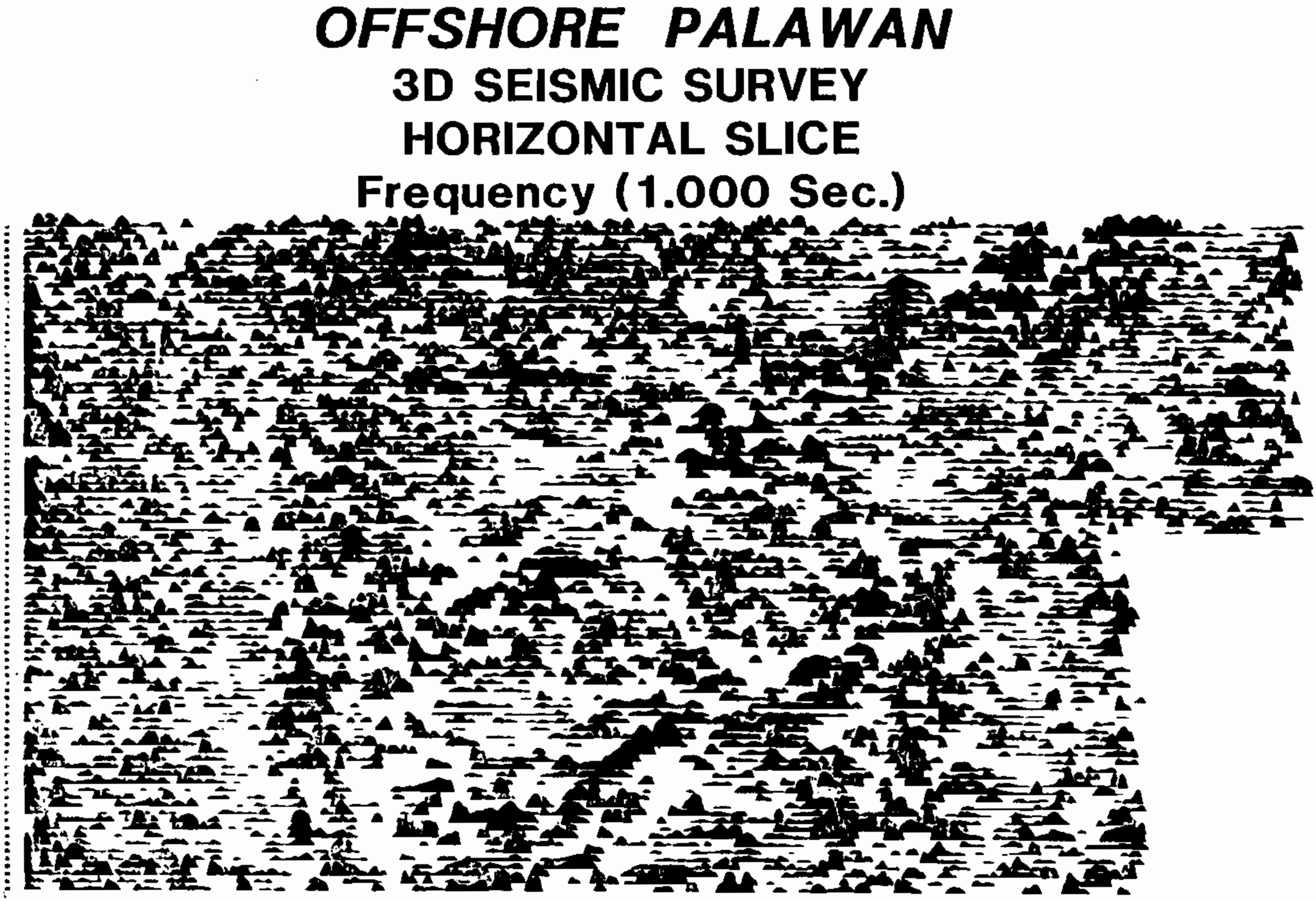

Figure 15. Color frequency display of a horizontal slice over the 3-D area.

Three-Dimensional Data Improve Reservoir Mapping

Piet A. Ruijtenberg, Ray Buchanan, and **Paul Marke,**
Shell Intl. Petroleum Mij.

Summary. The use of 3D seismic data results in a clearer and more precise subsurface picture than obtainable with 2D data. Thus, 3D data can have a major impact on the volume of estimated reserves. Examples demonstrate that 3D data also provide the basis for detecting subtle changes in reservoir development, fluid contacts, and minor faults.

". . . changes in reserve levels. . . can make the difference between an economic venture and a financial disaster."

Introduction

Over the last 25 years, seismic data have increasingly influenced hydrocarbon field development. Analog data before the 1960's had relatively poor resolution and, although often sufficient for exploration and appraisal siting, was generally too coarse and inaccurate to affect development planning significantly. The succeeding digital seismic acquisition allowed for increasingly sophisticated processing and signal enhancement. Further technological improvements in the early 1970's enabled us to recognize a reservoir directly from preserved relative amplitudes and, in favorable cases, to identify reservoir contents. At this time, 2D seismic data became important in field development. With increased use, however, the limitations of 2D seismic, caused by inadequate areal coverage and inaccurate reflector positioning, became more apparent. Although seismic wave propagation through the earth is a 3D phenomenon, all processing and seismic displays assume it to be 2D, only acting along the axis of the line of acquisition. While this has only a small effect in relatively flat, unfaulted geological settings, this is not the case in most hydrocarbon fields where out-of-plane energy from adjacent structural elements can cause seismic reflections to be superpositioned and blurred. These weaknesses were recognized in the mid-1970's and led to the first attempts at 3D surveys. (Refs. 1 through 4 provide a complete discussion on 3D acquisition and processing.)

Today, 3D seismic surveys are an accepted part of the early data-acquisition process, leading to optimized appraisal sites, refined reserve estimates, and more firmly based development plans. This method provides better control over structural shape (particularly fault orientation and interrelationships) and improves the ability to map stratigraphic variations in detail. The detailed coverage and use of consistent acquisition parameters also make 3D surveys a powerful tool for investigating seismic amplitude changes. Interactive workstations facilitate rapid display of horizon amplitude maps, and color displays allow subtle amplitude changes to be differentiated. Amplitude changes may be caused by variations in acoustic contrast at top- or intra-reservoir levels that reflect features such as increasing/decreasing porosity and net reservoir development. Changes in pore content may also affect the amplitude and, in some cases, can be used to map hydrocarbon extent or, in the best circumstances, to indicate swept zones from zones of water injection or depletion around producing wells. Minor faults or fractures that are too subtle to note on individual lines often are displayed as linear-amplitude features. Using horizon amplitude maps allows the geologist/seismologist to inject a new level of detail into understanding the field. Future developments in seismic technology will allow an increasing sophistication in our ability to "see" at the intrareservoir level.

Growth of 3D Surveys

Fig. 1 shows the growth of 3D surveys for the Shell Group of companies. Initial growth was slowed by technical problems and by the need to justify economically the use of the more expensive 3D data acquisition and processing methods. Many of the early surveys were acquired in hostile offshore areas, such as the North Sea, where it was easier to demonstrate that significant savings could be made by avoiding dry-hole locations, thereby reducing (1) the number of appraisal wells needed and (2) the risk in siting development locations that optimized drainage areas. The greatest impact, however, was the ability to match platform size, number of well slots, and production facilities to the more accurately determined field reserves.

These results led to rapid expansion in the use of 3D surveys from 1981 onward. By 1987, the total number of surveys conducted was about 100. Acquisition of additional areal coverage in 1988 doubled that of 1987. Most of the 1988 surveys were conducted over hydrocarbon fields to provide a better appreciation of reserves and to guide development-well siting. When this can be achieved at a reasonable cost, there is an increasing tendency to include adjacent exploration prospects within the 3D survey area.

Virtually all these surveys are considered to justify the additional acquisition costs. (Additional cost of 3D acquisition compared

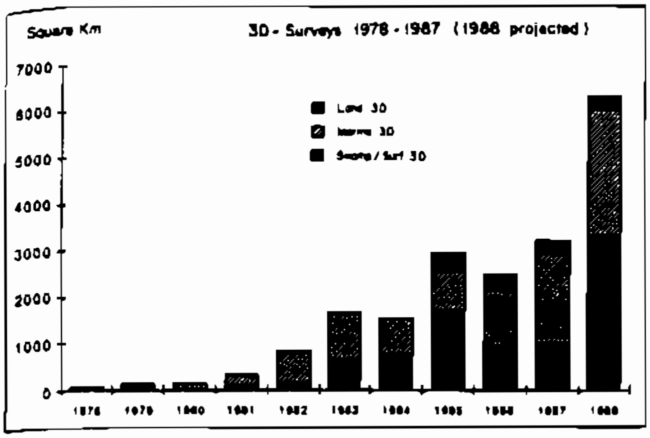

Fig. 1—Shell Intl. 3D surveys.

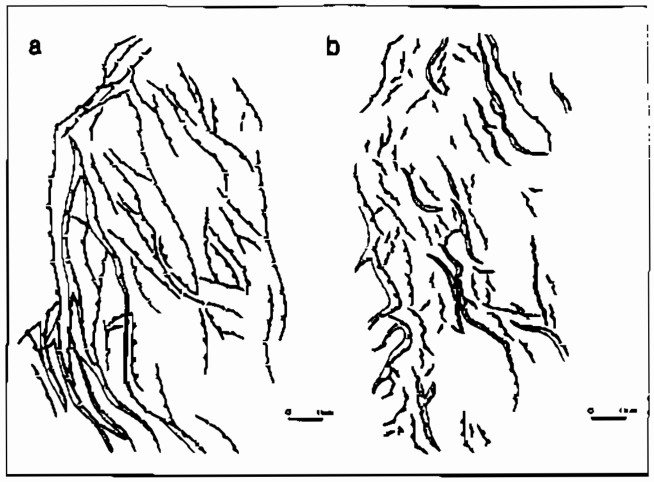

Fig. 3—Comparison of fault interpretation at Sirikit field, Thailand, (a) where 20% of the data were used and (b) where all the data were used.

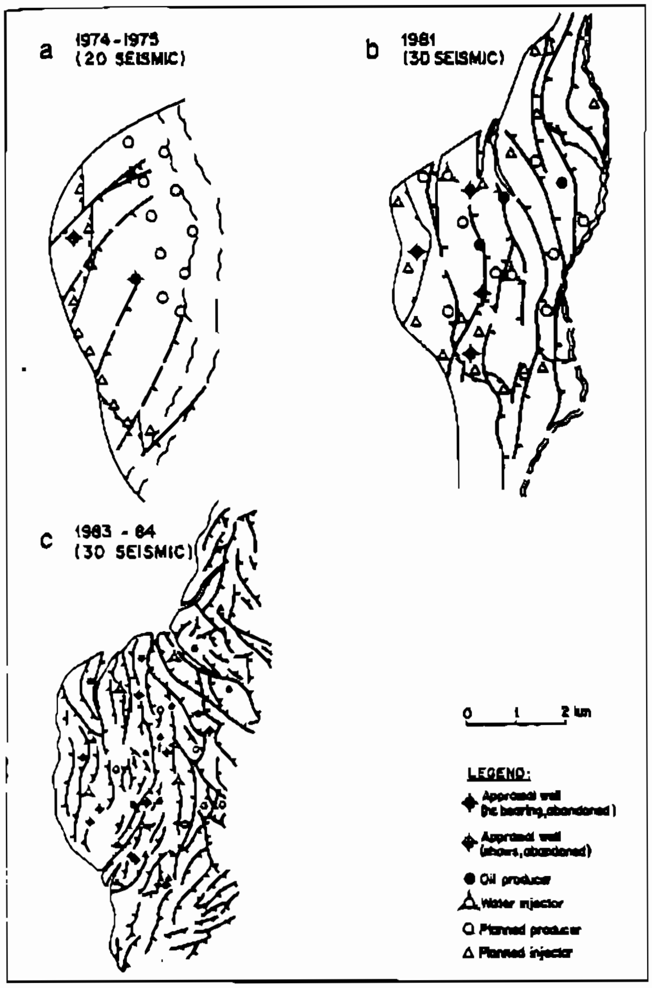

Fig. 2—Comparison of 2D and 3D structural maps at Block IV, Cormorant field, U.K. North Sea.

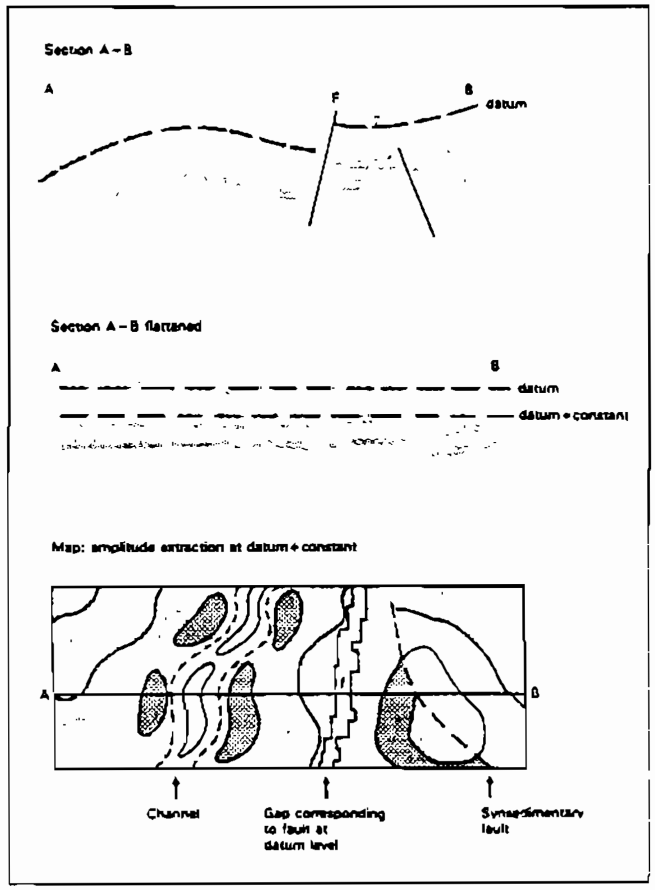

Fig. 4—Horizon selecrop principle.

with 2D acquisition is now very small; typically, a 3D land survey costs the same as a 2D survey with 500-m [1,640-ft] line spacing.[4]

The improved definition of 3D data can change reserve estimates by large amounts. A survey of 10 North Sea fields shows changes in reserves 7 to 81% of the amounts predicted from 2D surveys, with the average change being 36%. Obviously, such changes in reserve levels have a major impact on field-development plans and can make the difference between an economic venture and a financial disaster.

A 3D survey is now almost routine for most new fields and plays an important role in the decision-making process, especially for offshore fields. In a newly discovered field, the benefits of a 3D survey usually outweigh the cost. This may not be the case in an established field, where the decision depends on the size of the remaining reserves and on the economic impact of potential changes to the development plan; however, many old fields are currently being covered by 3D seismic surveys. Ref. 5 gives an example where a 3D seismic survey was found to be beneficial, even after more than 200 wells were drilled. The following sections demonstrate how 3D data can provide better knowledge of structure, reservoir, and the extent of hydrocarbons.

Structure Mapping

The need for 3D seismic acquisition and processing is more acute where the struc-

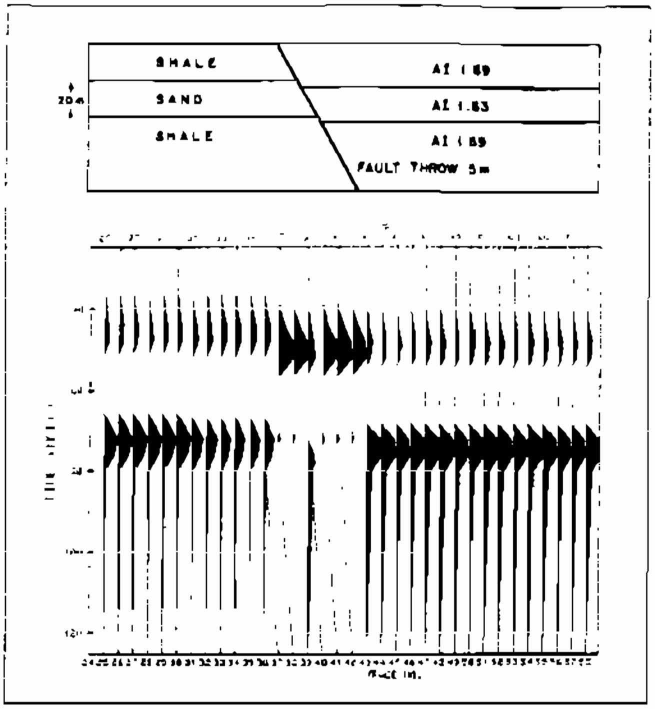

Fig. 5—Modeled amplitude variation caused by a small fault.

Fig. 6—Amplitude map showing minor faulting expressed as anomalies.

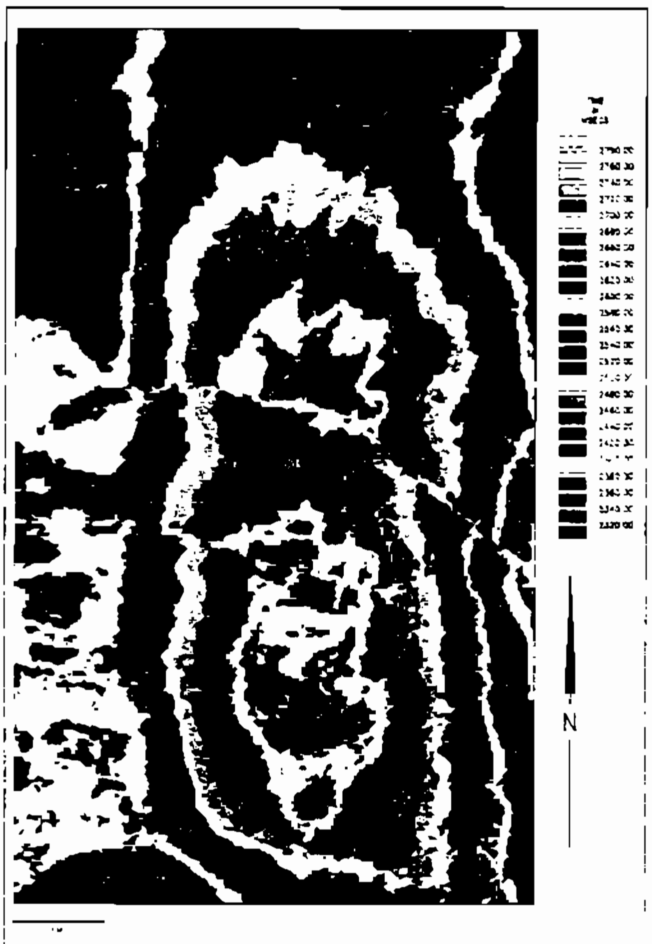

Fig. 7—Time/structure map of faulted anticline.

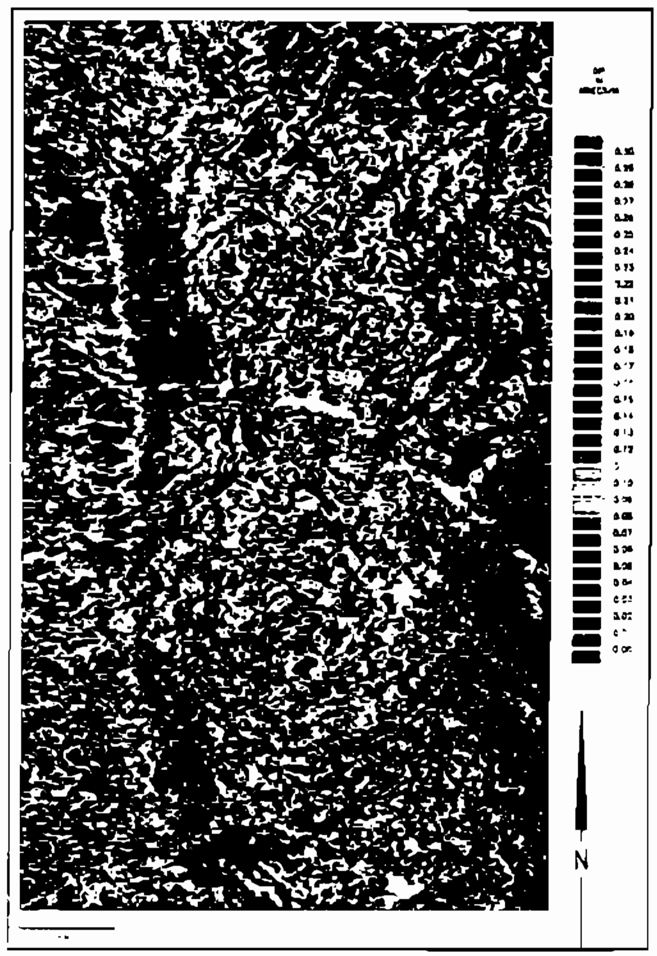

Fig. 8—Dip map calculated from Fig. 7.

Fig. 9—Azimuth map calculated from Fig. 7.

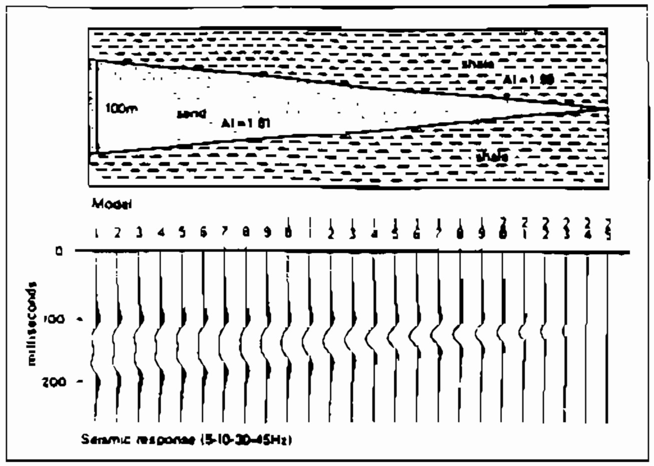

Fig. 10—Modeled seismic response of a sand wedge.

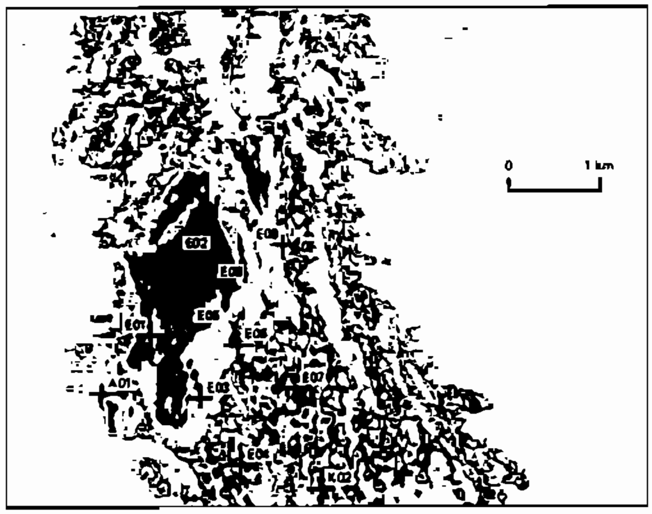

Fig. 11—Amplitude map that is 36 milliseconds below top shale at Sirikit field, Thailand. High amplitude (red) is coincident with regressive deltaic sand body encased in shale. Purple crosses represent wellbore positions.

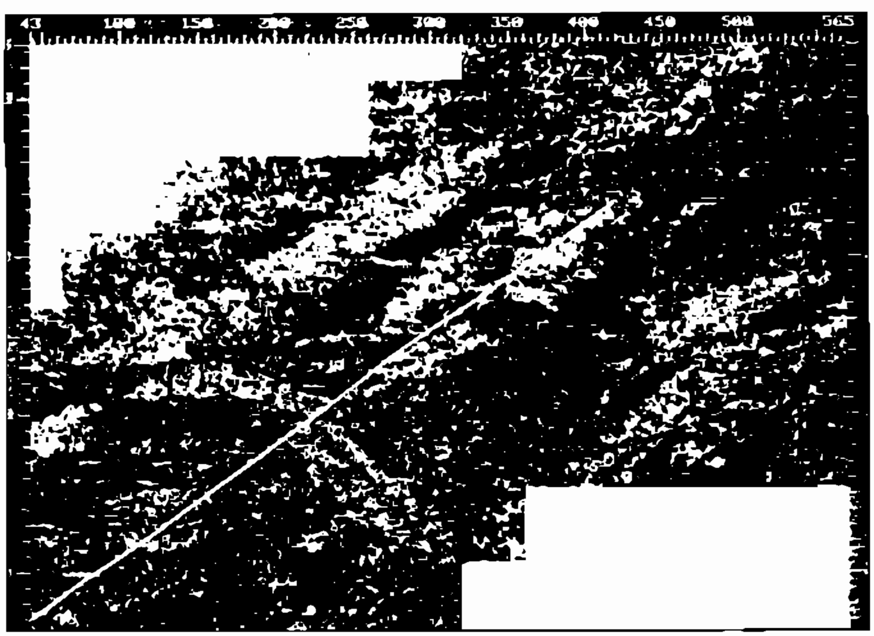

Fig. 12—Amplitude map showing channel feature offset by fault.

"The message from the Cormorant example is simple: plan for 3D acquisition at an early date. . .and. . .ensure that acquisition parameters use the seismic bandwidth appropriately."

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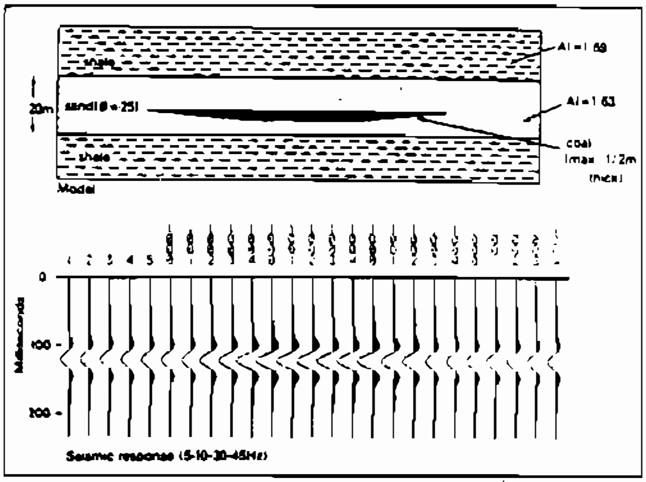

Fig. 13—Modeled seismic response of a thin coal seam.

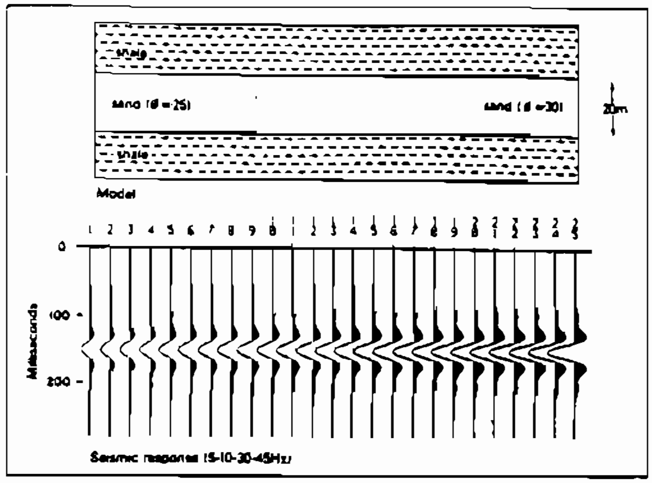

Fig. 14—Modeled seismic response of a reservoir with porosity variation.

(From Page 25)

ture is nonuniformly dipping and extensively faulted. Block IV of the Cormorant field in the U.K. North Sea is an example (**Fig. 2**).[6] This large downfaulted block produces from the Middle Jurassic Brent-sand sequence at about 3000 m [9,840 ft], where the reservoir is 80 to 170 m [260 to 560 ft] thick and is eroded on the east. By 1975, three wells had proven the block to be oil-bearing and the interpretation of the close grid of 2D seismic lines indicated relatively minor internal faulting (Fig. 2a). The development plan was for crestal producers with a line of water injection wells at the oil/water contact (OWC) on the west.

When development drilling began in 1982, it became apparent that the block was more complexly faulted than predicted and that these faults acted as barriers, dividing the field into a number of semi-isolated areas. The interpretation of a 1981 3D seismic survey (Fig. 2b) confirmed the complex faulting and showed the isolated blocks to be at right angles to the planned waterdrive direction. The development plan was changed so that producer/injector pairs were located within each fault block. The 3D interpretation also showed that the fault spacing was, at least locally, of the same order as 100-m [328-ft] line spacing and hence that closer control would be needed to discern the fault pattern fully. A more detailed 3D survey shot in 1984 with a line spacing of 37.5 m [123 ft] shows Block IV to be even more densely faulted (Fig. 2c), and although the dominant structural grain remains the same, the new map has had a considerable effect on the detailed well locations and the reserve-distribution appreciation.

The message from the Cormorant example is simple: plan for 3D acquisition at an early date so that the interpreted results can be accounted for as early as possible in the development cycle and, for optimal subsurface images, ensure that acquisition parameters use the seismic bandwidth appropriately.

A second example is Thailand's Sirikit field (**Fig. 3**), an onshore field that produces from thin-bedded, Tertiary, fluviolacustrine deposits. The field was discovered in 1981, and it quickly became apparent from both initial appraisal-well results and 2D seismic interpretation that it was structurally complex. A 3D survey with a 40-m [130-ft] line spacing was acquired in 1983. Initial interpretation was done from hard copies, and to cope with the huge data set, only every fifth line (the equivalent of a 200-m [660-ft]

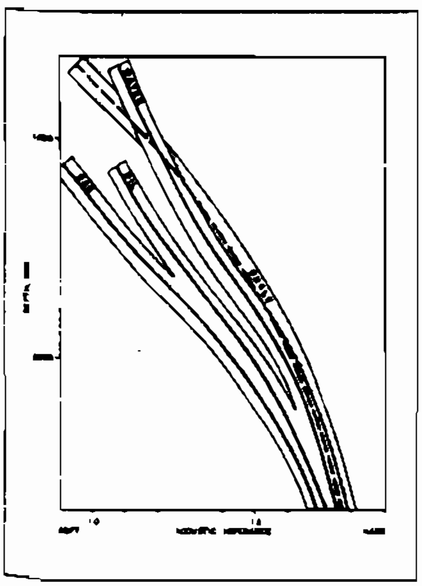

Fig. 15—Acoustic impedance trend curves.

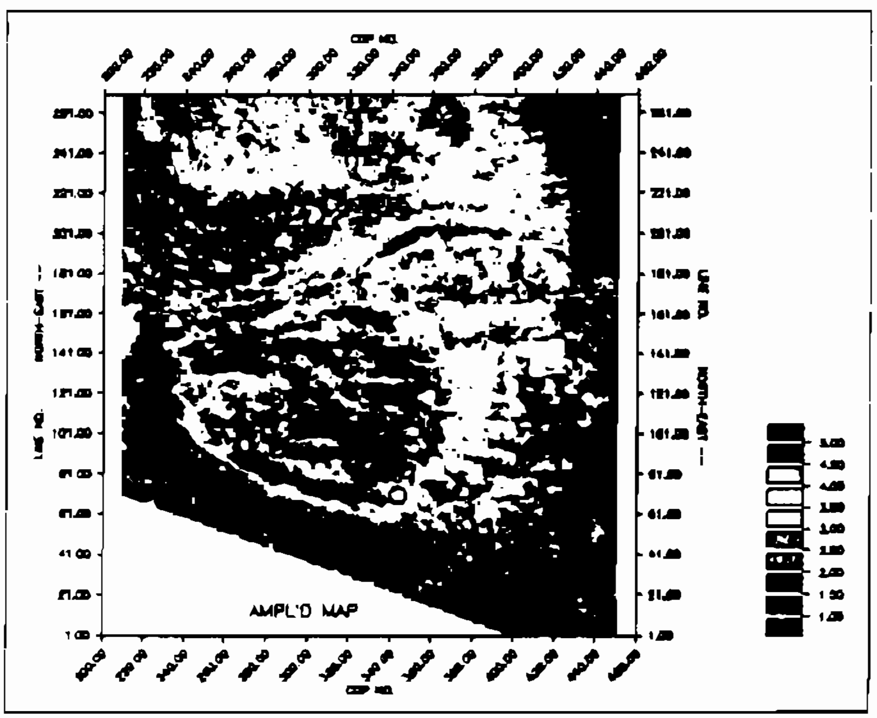

Fig. 16—Amplitude map of a North Sea gas field. Dark circular area coincides with gas-bearing sands.

line spacing) was used (Fig. 3a). At a later stage, the survey was reinterpreted on an interactive workstation with all the available data (Fig. 3b). Comparison of the two interpretations shows the fault aliasing, which occurs when fault length/frequency is smaller than the line spacing. The "short cut" interpretation shows the faults to be simpler, straighter, and more continuous than indicated by the more detailed examination; hence, the short cut leads to the conclusion that the fault blocks should be isolated, while the detailed interpretation anticipates a degree of communication. The wells would be positioned differently for the two cases.

If 3D data sets are not fully utilized, especially in complex geological settings, the result will be a false economy. Because the widespread use of interactive workstations is a recent occurrence, many of the early 3D surveys were interpreted by hand and only a fraction of the total data sets were used. These older surveys should be reinterpreted. This can be done relatively quickly with automatic-pick software, whereby horizon picks are computer generated by extrapolation from an input grid of interpreted lines. The density of such an input grid is determined by the structural complexity at the objective levels.

Use of Seismic Amplitudes

3D seismic surveys yield considerably more detail about the reservoir and its contents than conventional interpretation. Seismic reflections are caused by the acoustic impedance (i.e., the product of density and seismic velocity) contrasts between adjacent layers. Assuming a simple case of a thick reservoir overlain by a thick caprock, the signal reflected at the interface is a function of the contrast of acoustic impedance between them. The strength (amplitude) of the seismic reflection can be altered by three principal effects: (1) changes in caprock properties (density, velocity, and lithology); (2) changes in reservoir properties (as above) caused by changes in porosity, mineralogy, or fluid content; and (3) changes in the geometry of the interface such as steep dips, faulting, and fracturing. Because caprocks generally have relatively constant properties over large distances, changes in reflection amplitude are most likely to be caused by reservoir variation and/or geometry. Use of seismic amplitude data can thus yield valuable information on the reservoir and its contents.

3D seismic can be used to construct a very detailed amplitude map of a reflector, as shown in **Fig. 4.** Amplitude variations on these maps can be interpreted from calibrations with well data, which, for example, may indicate that low amplitudes always coincide with low porosity in the wells. Alternatively, the shape or patterns on the maps may be interpreted: e.g., the anomaly may have a channel shape, a drainage-pattern shape, etc.

For very thin reservoirs, the amplitude of the corresponding reflection is directly proportional to its thickness, thus complicating the interpretation of amplitude effects. Assuming, however, that reservoir and caprock properties remain constant, amplitude variations can be used to estimate the thickness variations of these thin reservoirs.[7,8]

Minor Faults. In conventional seismic interpretation, faults are recognized as offsets of horizon reflectors. Smaller faults, however, may have such a minute reflector offset that they appear as an inconsequential perturbation. Minor faults, although not directly detected, can be deduced from the local amplitude reduction that results from imperfect migration, juxtaposition of different lithologies, and interference. A single line having such an amplitude anomaly is not significant, but when a number of lines displaying the anomaly form a linear trend at the top of the reservoir that is subparallel to the directly mapped fault trends, the confidence in interpreting the anomaly as a small fault is greatly increased. Such features can be displayed on horizon amplitude maps—i.e., maps of amplitude variation on a flattened horizon. **Fig. 5** shows the modeling principle for amplitude maps like **Fig. 6.**

The solid lines in Fig. 6 represent the clearly defined faults. The offset of the fault causes a break in the reflection, and the linear-amplitude anomalies subparallel to the faults are considered to be caused by the minor faults. Confidence in this interpretation is gained from the observation that such amplitude anomalies are often seen as the continuation of a directly mapped fault.

Dip and azimuth[9] are other attributes useful for mapping small-scale faults. Dip and azimuth are calculated from a time map (**Fig. 7**) and then displayed (**Figs. 8 and 9**). Lineaments in either or both attributes could reveal fault locations. The time map shows the fault trend; the precise location and the en-echelon arrangement is clear only on the dip map (Fig. 8), especially in the northeast. The azimuth map, displayed as artificially illuminated from the east, gives details that are not apparent on the other maps. Two identifiable fault trends are interpreted to be conjugate fault sets related to transtensional deformation. When combined with well information on fault and fracture orientation, horizon attribute maps (such as amplitude, dip, and azimuth), can provide insight into small-scale reservoir disturbances that can impose a permeability anisotropy or, in extreme cases, that can divide thin-bedded reservoirs into isolated blocks.

Lithological Variation. Use of the horizon seiscrop technique with an interactive workstation provides a powerful tool for quickly examining amplitudes at different levels within the reservoir sequence.[7,10] Seiscrops can be constructed for a particular horizon (i.e., top reservoir) and adjusted to the amplitude peak at that level. Deeper levels within the reservoir can be examined by taking new seiscrops at constant time gaps (e.g., 8 milliseconds) below the mapped horizon (see Fig. 4). This allows examination of geologically meaningful intervals within the reservoir itself because individual seiscrops can be tied in with well data. **Fig. 10** shows a modeled case of the decrease in sand-body thickness that arises because reflections from the top of the sand increasingly interfere with reflections from the unit base. For instance, this situation could occur over a channel sand or, at a larger scale, over a mouth bar, as shown in **Fig. 11** from the Sirikit field.[11] The sands of Sirikit are generally very thin, typically less than 5 m [16 ft], and are interbedded with equally thin layers of silt and shale so that the individual reservoirs are below seismic resolution. One of the thicker sands is encased within a 50-m [160-ft] -thick lagoonal shale, similar to that shown in Fig. 10. The seiscrop in Fig. 11 shows that sandstone generates a seismic amplitude that is based on its thickness. Available well controls show the anomaly to be confined to an area of thick (up to 16 m [50 ft]) sand development that decreases (to only 3 m [10 ft]) on the edge of the anomaly.

Channel features can also be discerned from amplitude seiscrops. The example in **Fig. 12,** taken from an onshore field, shows a channel-like amplitude trend that appears to be offset by a transform fault. In this case, the interpretation is not confirmed by observation from well data, although it does agree with the geological setting. An isolated channel reservoir like this would not be drained unless by a dedicated well; however, such studies allow development plans to be adapted to the reservoir distribution.

Great care is needed with such interpretations because other phenomena can cause similar amplitude variations. **Fig. 13** shows one possibility, where a very thin coal seam generates a channel-like feature. **Fig. 14** shows that changes in reservoir porosity can also cause amplitude variation, and hence that diagenetic and depositional changes in the reservoir must be considered. The geological setting must be accounted for, and it is often necessary to construct theoretical models based on local rock properties to be able to eliminate some of the possibilities and concentrate only on the more probable.

Fluid Content and Porosity. Because changing the fluid content of a reservoir can affect both density and seismic velocity, it follows that changes in fluid content can also affect the acoustic contrast and hence the seismic amplitudes. And, because the porosity of rocks generally decreases with depth, the acoustic impedance of rocks also changes with depth.

Fig. 15 shows a typical acoustic-impedance/depth relationship. At shallow depths of about 2000 to 2500 m [6,660 to 8,200 ft], water and oil- and gas-bearing sands have sufficient differences in acoustic impedance to be differentiated on the basis of the seismic amplitude response. Between 2500 m [8,200 ft] and depths of 3000 to 4000 m [9,800 to 13,120 ft], the acoustic im-

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The Role of 3D Seismic on the Future Development of the Idd el Shargi Field, Offshore Qatar

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SPE Members

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ABSTRACT

This paper discusses the results of the 3D Seismic Survey acquired in 1987 in the Idd el Shargi North Dome with the objectives of defining the detailed structural picture of the Shuaiba reservoir.

Initially pattern waterflood was the preferred development option as the field appeared simple and sparsely faulted based on old 2D seismic. 3D interpretation has shown two main fault systems, one of which had not been recognised before. The crest is intensively faulted whereas the flanks are either unfaulted, or have only one fault system. The crestal area will now be developed by gas/oil gravity drainage process. Other areas of the field are still under study.

INTRODUCTION

The Idd el Shargi (IS) consists of two separate culminations: North and South Domes which have different structural and sedimentological histories. The structure is located offshore Qatar, about 90 km east of Doha (Fig.1).

The North Dome (ND), was discovered in 1960 when well IS-2 penetrated the oil column in the NE midflank of the structure and tested 27° API (0.89 g/cm^3) oil at a rate of 170 BPD (27 m^3/d). Of the three offshore producing fields Shuaiba is only hydrocarbon-bearing in the Idd el Shargi North Dome (ISND).

References and illustrations at end of paper.

The reservoir was initially 720 psi (4964 kPa) undersaturated, bubble point pressure is 1660 psi (11444 kPa). The initial reservoir pressure and temperature were 2380 psi (16408 kPa) and 160°F, (71.1°c) respectively. The oil viscosity is 2.5 cp (0.0025 Pa.s). Original oil in place is estimated to be 2607 MMSTB (414.2 10^6 stock-tank m^3). Oil production started in 1964 and 39 wells have been drilled so far, of which 14 have been completed and produced at times; since then cumulative oil production as of 1.1.90 was only ca. 37 MMSTB (5.9 10^6 Stock-tank m^3) (or 1.5% of the STOIIP). Individual wells have shown variable rates, but in general rates are low: <1000 BPD (158.9 m^3/d). However, crestal wells have shown excellent production performance in response to simple matrix acid jobs. During the period 1976-1986 modern stimulation techniques, like WISPER (WIdely Spaced Etched Ridges) (Ref.1) and CFA's (Closed Fracture Acidisation) were employed in order to improve the low well productivities. Some outstanding improvements were obtained as a result of connecting the hydraulically induced fracture to the natural fracture/fault system in the crest and midflank of the field.

A secondary gas cap was developed in the Shuaiba as a result of an internal blowout in well IS-14. The gas influx from the underlying Jurassic Arab reservoirs started in 1964 and there is evidence that it has ceased in the early 1980's. Analysis of the reservoir historical data suggests that the best reservoir production was obtained during the period of gas influx i.e when the reservoir was being produced under a form of gas/oil gravity drainage. This is the underlying statement in the selection of the reservoir development process.

RESERVOIR DESCRIPTION

Stratigraphy

The Shuaiba Formation is Aptian in age. It is the uppermost formation of the Thamama Group (Lower Cretaceous) and is overlain by the shales of the Nahr Umr Formation (Albian) and underlain by the shales of the Hawar Formation which are Barremian in age (Fig.2). Shuaiba is among the important hydrocarbon-bearing reservoirs in the Middle East.
The Shuaiba is very productive from a reef complex onshore Abu Dhabi (Ref.2). However, no proper Shuaiba reef has been discovered so far in Qatar.

Geology

The Shuaiba thickness varies about a NE/SW trending axis from ca. 335 ft (102 m) in the crest to 320 ft (100 m) on the flank (Fig.3).

The reservoir has been subdivided into four zones A, B, C and D, which are 95 (29m), 90 (27.4m), 80 (24.4m) and 65 ft (19.8m) thick respectively. These zones are easily correlatable across the field (Fig. 4). The Shuaiba sediments were deposited on a shelf of variable depths and record a period of fairly rapid transgression followed by more prolonged regression. With the exception of minor reefal facies the chalky limestone displays similar depositional characteristics throughout most of the Shuaiba, although the allochem content is much higher in the zone A, decreases in the zones B and C, becoming higher again in the zone D. Lithologically the Shuaiba is formed of chalky limestone which could be subdivided into 3 main rock-types:

1) Lime packstones to mudstones whereby the depositional texture is largely controlled by variable skeletal content of Orbitolina. The matrix is chalky, sometimes pelletal lime mud. These rock-types form the bulk of the Shuaiba.

2) Argillaceous lime mudstones/wackestones which are of limited vertical extent and occurring as local influxes e.g. at the base of zone A and also within zone C.

3) Algal bioherms occurring at the base of zone D. This is characterised by Lithocodium Bacinella growing as bafflestone, stabilising the muddy shallow shelf.

Reservoir Properties

The chalky matrix has imparted on the rock low matrix permeabilities of 1-5 md (0.98 x 10^{-3} u m^2 - 4.9 x 10^{-3} u m^2).

Porosities on the otherhand are highest (up to 32%) in the upper part of Shuaiba in the crestal area and decrease towards the base and flanks (ca. 12%).

Significant mouldic leaching and solution channelling have enhanced the reservoir properties of zone A, especially in the crestal area where the degree of faulting/fracturing is intense, rendering it by far the best part of all of the Shuaiba zones with permeabilities up to 50 md (49 x 10^{-3} um^2). Insignificant leaching occurs in the upper part of Shuaiba B at the crestal area and in the basal part of zone D, whilst almost none occurs in zone C (Figs. 4 and 5). Leached micropores (2-6 um) within the mud matrix have little impact on permeabilities.

Pressure solution and cementation processes, had affected the reservoir to various degrees. Products of pressure solution are stylolites, microstylolites and clay seams which occur as swarms especially in zone C. The $CaCo_3$ provided during the process has resulted in the cementation of the porosity of the lime mud matrix.

STRUCTURE

The ISND is an elongated NE/SW halokinetically induced dome which at Shuaiba level is some 12 x 7 km in size. The vertical closure is about 600 ft (182.9m) with a transition zone (Sw > 50%) 150 ft (45.7m) thick. The maximum height reached by the secondary gas cap, which has now receded, was ca. 100 ft. (30m) (Fig.5). Dips along the flanks are ca. 5 becoming gentler in the south western part of the structure.

Isochore maps indicate steady growth and uplift from early Jurassic to the present.

Uplift was particularly vigorous during the period late Aptian to late Coniacian, at the end of the Cretaceous/early Tertiary. These periods of accelerated uplifts correlate with regional tectonic activity and regional erosional events.

2D SEISMIC PICTURE

A structural review completed in 1984 has shown the ISND as a sparsely faulted structure with a NW/SE fault direction (Fig.6). However deviated crestal wells have intersected many more faults than the 2D seismic had shown. The results of well tests (stimulated and non-stimulated) and the erratic distribution of well productivities have demonstrated the role of faults/fractures in the behaviour of this low permeability reservoir. It was therefore felt that a 3D Seismic would give the resolution required to obtain a detailed structural picture of the reservoir, which would aid in formulating a convincing development plan.

3D SEISMIC DATA

The 3D Seismic, the first to be recorded in Qatar, was acquired in 1987. A common depth point grid spacing of 26.7 m inline and 37.5 m crossline was used. The survey was designed to give the highest possible resolution.

Tight tolerances were stipulated and imposed for primary positioning, acoustic source characteristics and cable geometry. Most of the data were acquired using dual source array 'flip-flop' shooting (2284 km). Areas severely congested by surface facilities were covered using a combination of single array (696 km) and two-boat undershooting (236 km). The total surface coverage was 3216 km covering an area of 160 sq.km and yielding an area of subsurface data of 5882 km.

The data obtained are of excellent quality, although plagued by residual multiples. Small tidal variations caused minor crossline jitter over the high frequency shallow section. These were smoothed out using a crossline coherency operation. The data had been processed to zero phase.

The vertical resolution was excellent. Faults with throws of 15 ft had been routinely distinguished on timeslices and horizon time maps. Indeed, narrow (1 to 2 common depth points) linear zones with no apparent vertical displacement have been detected using amplitude and horizon processing techniques.

Laterally the positional accuracy of faults is not expected to be better than a band 245 ft (74.6m) wide.

Interpretation Procedure

The primary reflections were identified by matching the seismic with the synthetic seismograms on the workstation. The near top Shuaiba reflector showed as a rather broad low frequency negative event with moderate and variable amplitude. Confidence in mapping this event was not high. The event was generated by acoustic impedance increase at the top of the Shuaiba C, and it was affected by multiple interference over the crest and towards the NW flank.

The following mapping procedure was adopted using the interactive seismic workstation :

- Suitable events for the interactive interpretation were identified.
- A broad network of inlines and crosslines and random lines were interpreted using the auto-tracking program.
- This was used as a seed for automatic interpretation of the entire 3D Seismic data set.
- By iteration through the automatic interpretation and inspection phases a satisfactory result could be obtained.
- Fault informations were obtained from the interpreted horizon data using map processing techniques.
- Fault pattern maps were made using the discontinuity, amplitude and horizon time maps in combination.

The combination of timeslices, amplitude, time contour maps and discontinuity displays have been used for fault detection down to fault throws of about 15 ft. In addition linear features without obvious vertical displacement can be distinguished. These have been incorporated in the mapping, and were interpreted as faults with throws $\leq$ 15 ft. (4.6 m). Amplitude data was very useful in faults mapping. Faults occur as linear zones of low amplitude, due to the discontinuity in the reflecting surface.

3D Seismic Picture

The 3D seismic revealed the presence of two sets of faults: an oldest NW/SE set of normal faults and a relatively younger NE/SW set of oblique slip faults. The two sets intersect over the crest of the structure forming an orthogonal pattern of fault blocks of varying sizes, the smallest being 500 x 250 ft. (152.4 x 76.2 m). There are about 150 such fault blocks over the crestal part of the field (**Fig. 7**).

The NW/SE Normal Faults

This set is sparsely developed over the field and dip at about 60 degrees. Few of these faults have large throws (up to 150 ft). The large faults affect the sequence between base Laffan and top Sudair.

However, the majority of the mapped faults have moderate throws, ranging between 15 (4.6m) and 60 ft. (18.3m). The larger the throw the longer its lateral and vertical continuity.

Typically a fault with 50 ft (15.2m) throw may extend for up to 1.5 km laterally and about 500 m vertically (Fig. 8).

These faults are commonly arranged en echelon laterally and vertically, so that the relatively small displacements are carried through the field in narrow zones. Plastic deformation, possibly accompanied by secondary fracturing, takes up the strain in the intervening and overlapping regions between en echelon faults.

The NE/SW Oblique Slip Faults

This set of fault was not apparent from the 2D seismic surveys. They are steep on the flanks (ca. 70 degrees) becoming vertical over the crest and with highly variable throw. They occur as a dense swarm of en echelon faults extending from the SW flank, where they form small compressional ridges associated with reverse faulting, through the crest of the field and splaying out into a radial pattern to the NE (Fig. 7).

A three fold complex of flowering upwards grabens which pass downwards into narrow fault zones is present over the crest (Fig. 9).

The fault characteristics mentioned above can only be explained by wrench faulting.

Downflank, where salt piercement was relatively mild strike-slip movement dominate dip-slip movements. Over the crestal area where salt upwelling is vigorous normal dip-slip movements dominate and hence oblique - slip faulting has taken place.

The structural picture depicted by the 3D seismic in a midflank location of the field has been confirmed by the first well drilled following the interpretation of the 3D seismic. The well intersected 5 minor faults with cumulative throw of 65 ft (19.8 m) very much in line with the 3D seismic picture.

Natural Fractures

The fracture system is probably intimately associated in time and space with the two distinct directions of faults. The NW/SE trending faults are probably accompanied by two types of fractures : subvertical dilational fractures and conjugate antithetic and synthetic shear fractures to the main fault.

Fractures associated with the NE/SW set of oblique slip faults are likely to be predominantly subparallel subvertical hybrid dilational/shear types. These may be partly open or closed.

Natural fractures are an important component of the reservoir, especially where permeabilities are low.

They strongly influence the selection of the convenient reservoir process, depletion strategy, ultimate recovery and the well completion/ stimulation design. Geological analysis must attempt to provide quantitative information about fractures (size, distribution, frequency, orientation, sealing/conductive properties --- etc). Understanding the origin of the faults is a step forward towards understanding the accompanying fracture system.

Core recoveries are poor over the crest due to the softness of the formation as a result of intense faulting and leaching. This made it difficult to study the fracture system in detail. From the few core recoveries obtained from vertical wells, vertical and subvertical fractures have been reported. They are mostly $\leq$ 1 mm wide and vary between being healed and open.

To resolve these uncertainties, coring of a horizontal well and running of the Formation Micro Scanner and/or Bore Hole Televiewer are being considered for the near future.

Fluid Flow Characteristics of the Faults System

The NW/SE normal faults were essentially emplaced at shear plane failure angles (60°). They were developed over a prolonged period of time with stick-slip periods. Such mode of occurrence may have increased the chances of clay smear and during each stick period the fault fracture zones may have become annealed and cemented. Some flank wells encountered this set of faults with fault/zones which appear to be tightly cemented and with no mud losses. Therefore, it is more than likely that the NW/SE faults are sealing, at least in the downflank of the structure.

On the otherhand the NE/SW faults were essentially developed as oblique - slip and strike-slip steep faults, emplaced as a result of a regional compressional pulse. They are hybrid shear/dilational faults and therefore more likely to be associated with extensive brecciation, volume increase fabric rearrangement and hence permeability enhancement.

Mud losses are associated with this set of faults and therefore they are more likely to be open and are expected to be more permeable to fluid flow than the NW/SE set.

Structural Domains

The field, at Shuaiba level, has been subdivided into 5 structural domains, based on fault intensities, trends and types (Fig. 7).
Domain I occupies the crestal part of the field. It is comprised of a complex orthogonal fault pattern and highly leached rock, rendering this domain the best as far as permeabilities are concerned.

Domain II is dominated by the NE/SW oblique-slip and strike-slip faults. Reservoir behaviour is expected to be dominated by directional permeability parallel to this set of fault.

Domain III is located downflank to the west and east and is being intersected only by the NW/SE set which is believed to be non-conductive, especially in the downflank part of the field. The influence of faulting on reservoir behaviour is likely to be minimal.

Domain IV is located in the NE part of the field. This domain is sparsely faulted by the NE/SW set which might provide local fluid conductivities pathway. In general domain IV is dominated by matrix properties.

Domain V is the least faulted of the 4 domains, occurring in the NW and SE northern half of the field. Matrix properties are expected to dominate the reservoir behaviour.

FIELD DEVELOPMENT PLANNING

The above described domains will be used as the basis for the determination of the further field development of the Shuaiba reservoir. Because of its heterogeneous and anisotropic permeability system, the Shuaiba will be developed in a phased manner. The first phase is aiming for the best part of the reservoir (domain I).

Before the 3D Seismic a pattern waterflood development was proposed. However, with the evidence from the 3D seismic and with reservoir performance evaluations, for an extensive fault/ fracture system over the crest, the development methodology has been revised. The waterflood option has been declined fearing that the fault system may act as a short circuit for water flow within the Shuaiba.

Alternatively a gas/oil gravity drainage process has been determined to be the most attractive and feasible reservoir development mechanism for the crestal part of the Shuaiba reservoir (Ref. 3). The process will be tested in a pilot involving 4 wells : a gas injector, 2 horizontal producers and a monitoring well. Conceptually gas will be injected in zone A and oil be collected on Zone D. The intention is to intersect faults in the producers deliberately. The detailed 3D seismic picture is necessary in order to achieve such tight well objectives. Ideally such wells should be designed using a seismic workstation.

The gravity drainage process relies on natural forces, gravity and capillary, to drain the oil from the matrix into the faults/fractures. The efficiency of the process will be affected by the degree and intensity of fracturing which is one of the major uncertainties facing the success of this reservoir process.

CONCLUSIONS

1 - The Shuaiba reservoir in the Idd el Shargi field, offshore Qatar, contains a huge oil accumulation locked in a tight chalky matrix with very low well productivities.

2 - Based on 2D Seismic, the structure was sparsely faulted and with NW/SE trend. This structural picture had been used as the basis for extensive well stimulation techniques. The results obtained are incompatible with a simply faulted structure.

3 - The 3D Seismic depicted a highly faulted structure with two sets of faults intersecting over the crest in a rather orthogonal pattern.

The oldest set was developed as normal faults trending NW/SE and dipping at ca. 60 degrees.

The relatively younger set was developed as a swarm of oblique - slip and strike-slip subvertical faults trending NE/SW. The faults are of limited vertical and lateral extent with throws of < 100 ft (30.5 m).

4 - The origin of these faults and the associated fluid losses suggests that the NE/SW set is relatively more permeable than the NW/SE set. The accompanying fracture system would be expected to behave similarly. This could be significant in connection with determining the drilling direction for maximum production,

especially that horizontal wells are to be employed in the field development.

5 - Based on the fault intensities, types and trends, it was possible to subdivide the Shuaiba reservoir into 5 structural domains. These domains have probably different fracture/ matrix relationships and hence different flow properties.

6 - The structural domains would form the framework for determining the further field development, in a phased fashion. The first phase will be deployed over the crestal part (domain I) of the field.

7 - A gas/oil gravity drainage process has been determined to be the most promising and feasible for successful development of the crestal part of the Shuaiba reservoir. Conventional pattern water flood is unlikely to succeed in the presence of an intense fault system.

8 - Although the reservoir has been determined to be highly faulted, the intensity of the fracture system is still uncertain. The latter is of prime importance for successful and efficient implementation of the gas oil gravity drainage process. Future geological analyses and efforts should aim for quantitative characterisation of the fracture system.

NOMENCLATURE

BPD	=	Barrel Per Day
K	=	Permeability in milli darcy (md)
MMSTB	=	Millions Stock Tank Barrel
STOIIP	=	Stock Tank Oil Initially In Place.

ACKNOWLEDGEMENT

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SI Metric Conversion Factors

°API		141.5/(131.5 + °API)		=	$g.cm^3$
bbl	x	1.589 873	E - 01	=	m^3
CP	x	1.0*	E + 00	=	mPa.S
°F		(°F-32)/1.8		=	°C
ft	x	0.3048*	E - 01	=	m
md	x	9.869 233	E - 04	=	um^2
psi	x	6.894 757	E + 00	=	KPa

*Conversion factor is exact.

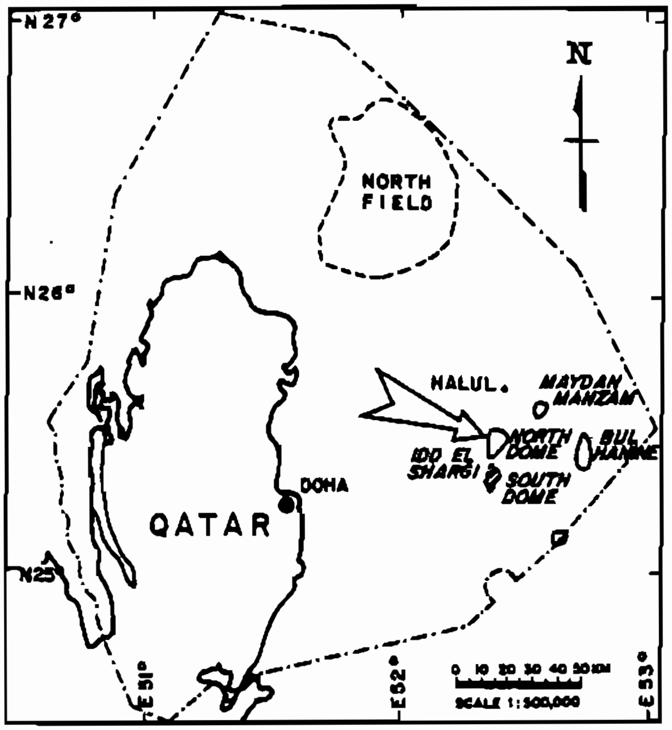

Fig. 1—Situation map, Qatar.

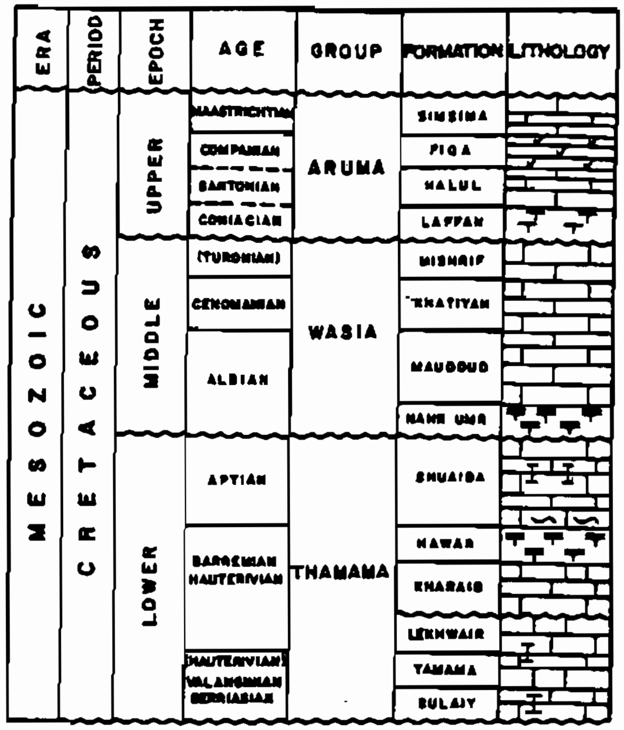

Fig. 2—Generalized Cretaceous lithostratigraphic column of Qatar.

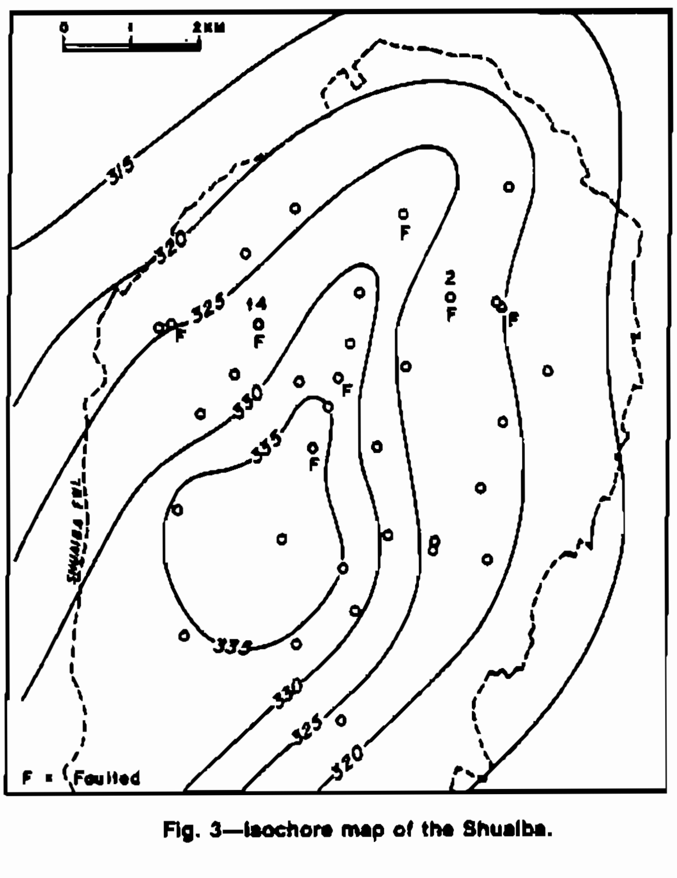

Fig. 3—Isochore map of the Shuaiba.

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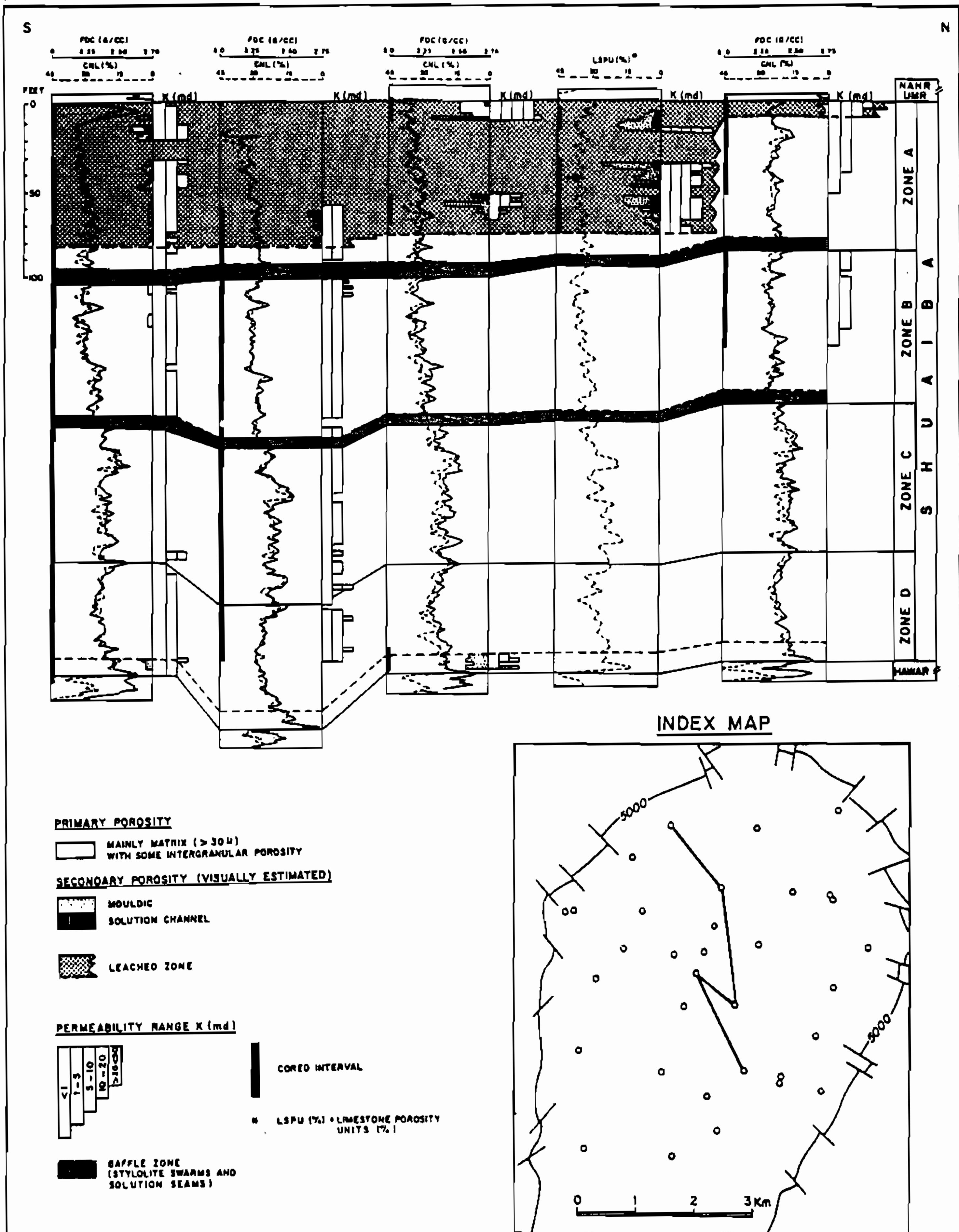

Fig. 4—North/South geological correlation section across the Shuaiba reservoir.

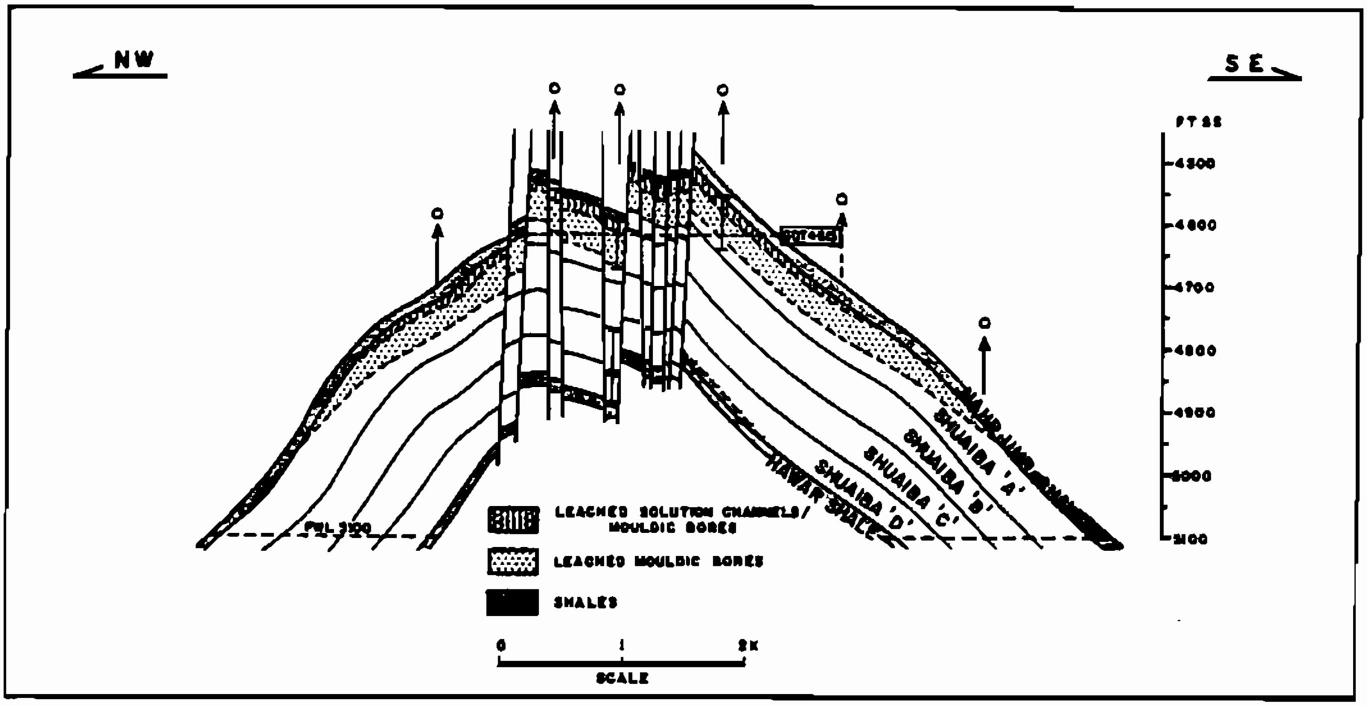

Fig. 5—SE/NW structural section across the Shuaiba reservoir.

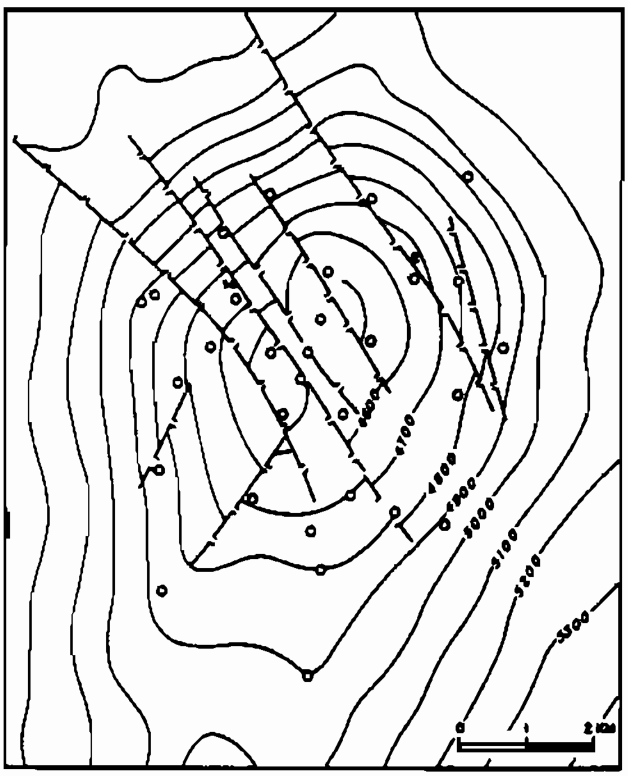

Fig. 6—2D seismic depth contours, top Shuaiba.

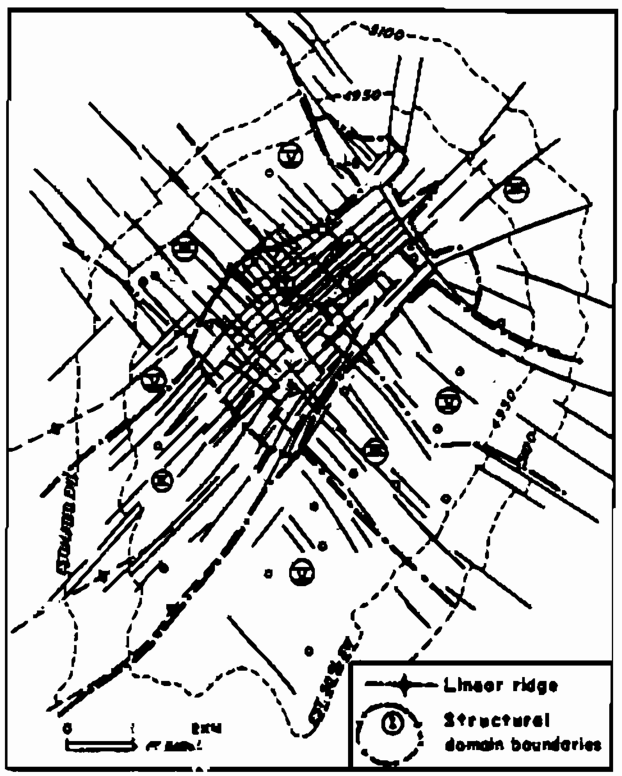

Fig. 7—3D seismic simplified map, including structural domains.

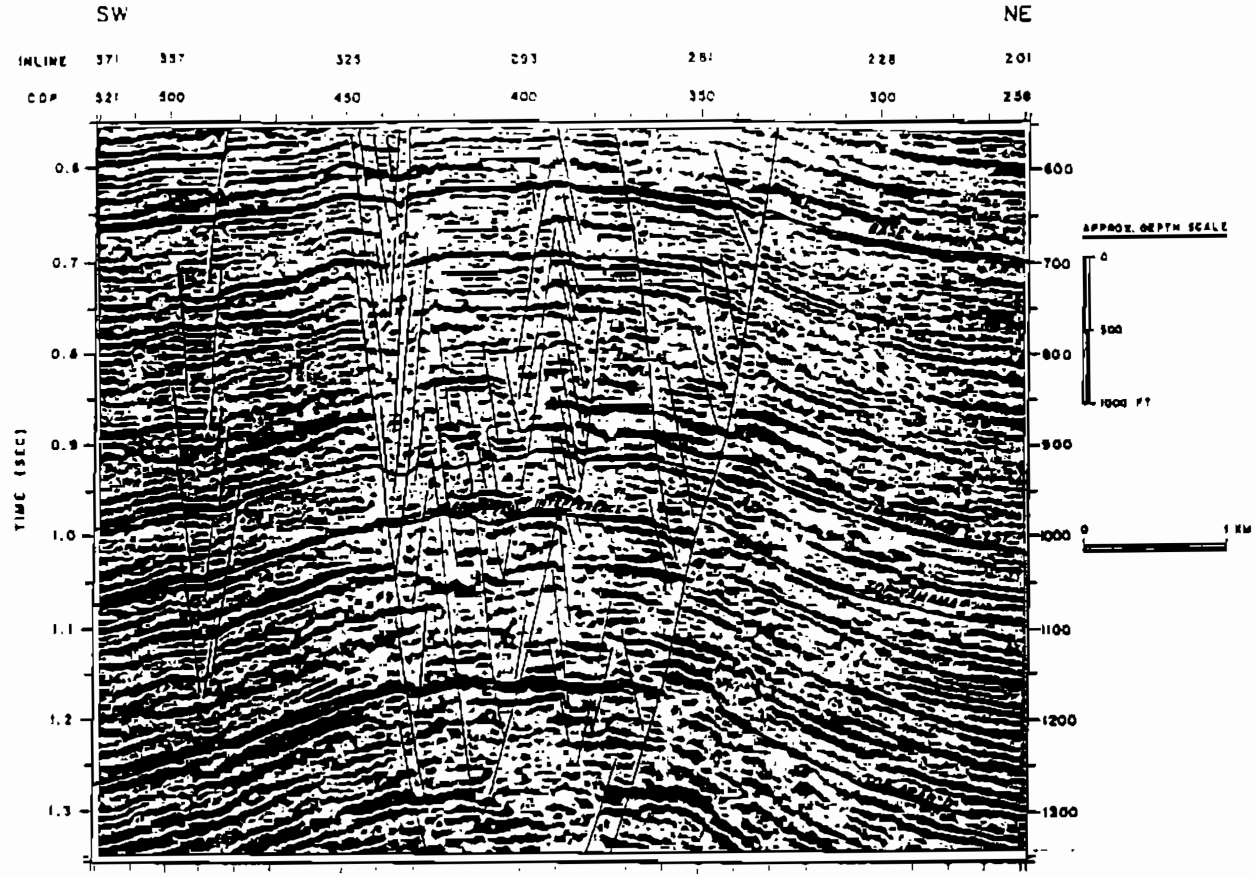

Fig. 8—3D seismic section perpendicular to the NW/SE fault system

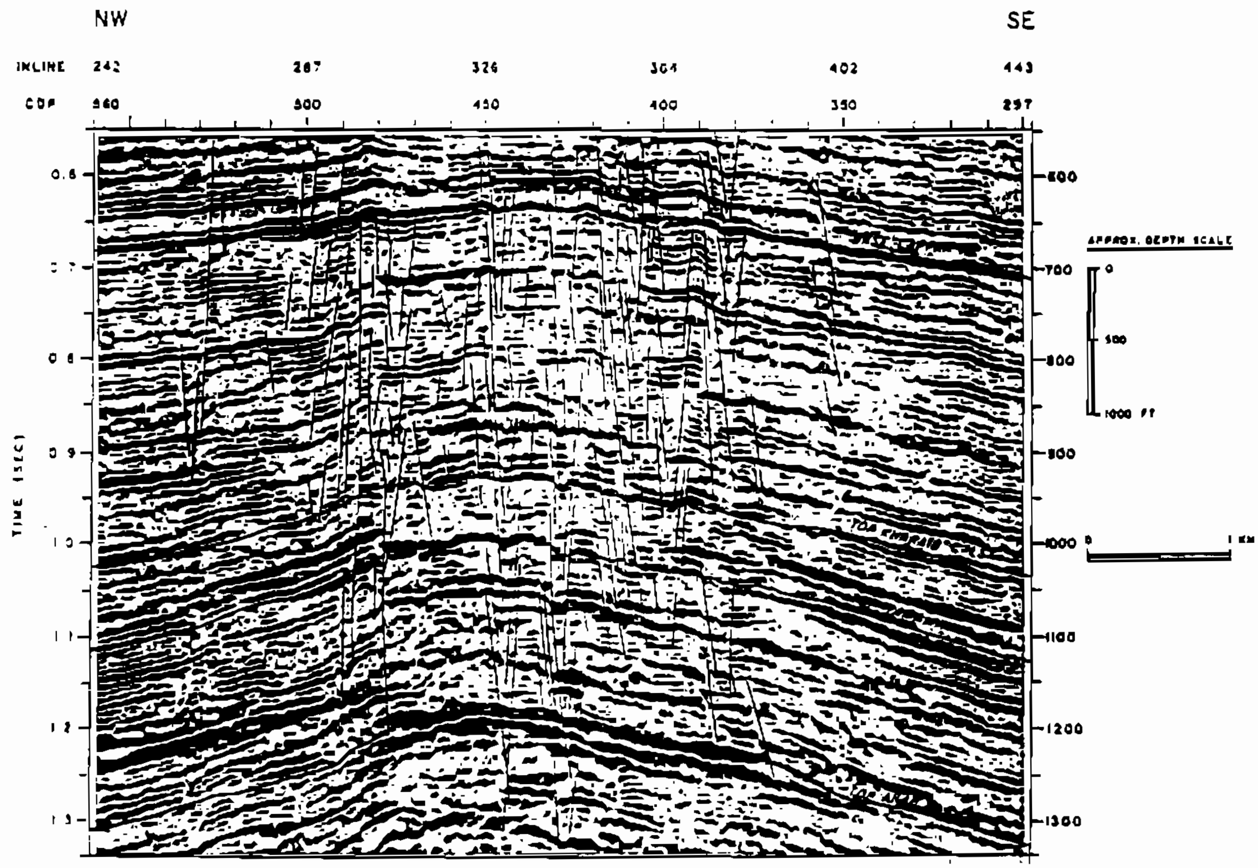

Fig 9—3D seismic section perpendicular to the NE/SW fault system

SPE 24744

Areal 3D Seismic Methods for Reservoir Characterization Case History From the Niger Delta

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ABSTRACT

In the 1950s, early exploration period in the Niger Delta witnessed the use of 2D (two - dimensional) Seismic reflection method which is a adequate for imaging large subsurface geologic features including growth faulting and roll - over anticlines. This technique involves the Common Depth - Point Method (CDP) which acquires a plane of seismic information in distance along the surface and in time into the geological section, and is used to improve the signal - to - noise (S/N) ratio, to remove multiples and consequently give a representation of the subsurface particulrly if the data are collected up - or downdip.

By mid-1980s, the obvious geological structures have, in general been discovered and it became necessry to adopt a more sophisticated technique such as the 3D (three - dimensional) Seismic method to delineate more subtle reservoirs and resolve complex fault patterns in order to aid exploration as well as facilitate efficient field development. The case history discussed in this paper involves the use of areal 3D Seismic method for delineating the reservoir characterisation of the OK-field located in a shallow water area of the Western Niger Delta.

The areal 3D sismic technique is superior to the earlier CDP method in that a cube of seismic data can be collected in two dimensions in space and in one time by a variety of pattern adopted for gathering the 3D data for the OK-field's reservoir which involves the shooting into lines of detectors which are at some angle to line of sources. The objective is to adequately sample the subsurface so that changes in vrious parameters such as the amplitude, phase or power in the seismic signal or velocity of propagation can be mapped areally and interpreted as an indication of changes in the physical properties of the rock matrix.

The 3D data for the field was acquired, processed through migration and it was possible to display what is essentially a cube of seismic data as a series of layers cut horizontally and vertically through the reservoir complex. This is done on a television screen for video presentation and reproduction, while the addition of on interactive computer system enables a three dimensional interpretation of the seismic data to be made. The net effect is that an efficient and cost-effective reservoir development was accomplished by proper timing and appropriate location of production wells for the drainage of this field.

INTRODUCTION

The main objective of this paper is to determine the effectiveness of the areal 3D (three-dimensional) seismic technique in resolving complex fault aliasing problems and ultimate delineation of the reservoir limits of an offshore Niger Delta field. The cost - effectiveness of the areal seismic method is also discussed as well as evaluation of its superiority to the more conventional Common - Depth - Point (CDP) method involving the two dimensional (2D) reflection seismic acquisition.

In the early period of exploration in the Niger Delta (i.e. 1950s to mid-1980s), the CDP method was adequate and routinely used to image large subsurface features including growth faults and roll-over anticlines. The exploration of most licenced areas in the Niger Delta was well advanced by middle 1980s and most of these obvious geologic structures have, in general, been exhausted making exploration more difficult and challenging. Since it was difficult as a general rule to find new and perhaps substantial reservoirs, the 3D technique came of age for resolving complex fault aliasing problems, and fine - tuning of seismic data for quality required to image subtle features and precise reservoir parameters to facilitate efficient field development.

Of high priority is the replacement of fastly deplected domestic hydrocarbon, and recent efforts to add reserves rapidly and cheaply have produced new dimensions in exploration technology involving 3D seismology and vast regional seismic surveys. These new advances have consequently increased the volume of information to be processed and interpreted. 3D seismic data acquisition in the Niger Delta commenced in 1984 and by 1991, the total yearly field production by the Joint Venture operators in Nigeria on Land, Swamp and Offshore had increased by about ten-fold (figure 1).

3D data acquisition aims at correctly sampling seismic traces in time (temporally) and their locations have to be such that such space is sampled to eliminte spatial aliasing problems.

The bin size may be about 12.5 meters in the inline and 25 meters in the crossline direction whilst the 2D data acquisition grid may be up to 500 meters or more. The sampling theorem states, "Band - limited functions can be reconstructed from equispaced data if there are two or more points per cycle for the highest frequency present" (Sheriff, 1973). In general, this means that the shortest wavelength has to be sampled at least twice.

The velocity in a rock is given by:

$$V = f . W$$

Where: f is the frequency

w is the wavelength

Hence, the frequencies generated by the source are vital to the resolution in areal mapping. The thinnest bed that can be detected by a wavelength W has a thickness of about W/8 (Widest, 1973). With this field configuration, the areal 3D seismic technique generates a volume of information: two dimensions in length on the surface and one in time into the earth, whereas the 2D (CDP) method gives a two dimensional picture in one plane only which would not totally define an oil reservoir which in nature is three dimensional (See figure 2).

Migration is the main goal of 3D prospecting and done usually in two steps (inline and crossline directions).

In 3D areal data migration, the hyperbolae becomes hyperboloid of revolution. 3D migration involves much more than 2D migration which is simply imaging by summing pulses (or trace amplitudes) that are distributed along hyperbolae. The velocity is vital (Gardner et al, 1974), and the information aperture must be precise. Too small an aperture results in incorrect imaging whilst too large an aperture may partially destroy the image (Sheriff, 1980). A new goal in interpretation is the use of interactive graphics, whereby the data set are examined interactively on video screen.

AREAL 3D SEISMIC DATA ACQUISITION

Figure 3 shows the field configuration of the areal seismic pattern used for 3D data acquisition in the shallow water area of the OK-field located offshore west of the Niger Delta. The areal shooting technique is obtained by laying out geophones along one line (usually straight) and recording shots at point along another lines of geophones and can be used to record each shot simultaneously or, in the extreme a rectangular grid of geophones in swaths can be used as in fig. 3. Shot points are at 25 meters apart, whilst the buoys are 200 meters apart along the vessel path.

Hence 88 buoys are arranged in even rectangles of 2000 by 700 square meters to form a single swath. With 100 meter shot line spacings and 25 meter shot intervals, a CDP bin size of 12.5 x 50 meters is obtained. Shot line usually extend 50 percent beyond the buoy rows to achieve acceptable fold of coverage, and the source is generated that effectively samples an area.

3D surveys are labour intensive and for this case History, being in shallow water environment, the individual channel (recording the seismic traces) had to be deployed and its position recorded separately in lieu of towing streamer cable (see figure 4). The data recorder is equipped with wireless digital telemetric system which transmits data from individual hydrophones (each attached to a buoy containing necessary electronics) back to the recording vessel. A Nav buoy simply drops the hydrophone, weighted and attached to an anchor and the Digiseis buoy are attached to the hydrophone only by the signal line with its length approximately twice the depth of the water. The Nav buoy is equipped with a navigation set, fathometer, and a polycoder to record both the location of the buoy and the depth of the water.

The cost of an areal survey is reduced by increasing the number of channels recorded per shot. With over 500 channels per shot, the cost of 3D and 2D data acquisition are about equal. McDonald (in 1979) demonstrated the result of comparing the recording systems and arrangements for the areal and CDP linear surveys (see table 1). Twice as many seismic traces can be collected in about one-third of the time in the areal survey, indicating that sufficient data can be collected at reduced cost for reservoir evaluation in relatively short time.

MIGRATION AND IMAGING

Unlike 2D data processing which involves simply summing of trace amplitudes along hyperbolic diffraction patterns, 3D migration is the main goal of 3D seismic data processing, involving summing up of trace amplitudes along surface of a hyperboloid of revolution in areal surveying. Since it is independent of the structural dip, 3D migration can give the correct and total picture of the subsurface and is usually of great help to the interpreter.

In practice, migration is an imaging process of putting reflection into its correct position in space. This is illustrated by fig. 5 in which the normal reflection from a single dipping interface is misplaced downdip on the seismic section. Unless seismic reflection data are collected over horizontal layer of even thickness, the reflected pulse will be incorrectly positioned on the seismic section. This phenomenmon accounts for the unmigrated diffraction patters predominant along the fault plane which was not well defined on a normal stack seismic section along dip line-B from the survey area (fig. 6). Comparing with the same line A when migrated as in fig. 7, there is improvement of the dipping events.

The Dip Move Out (DMO) process was also applied to further improve the data quality by way of ultimately resolving the fault aliasing problems predominant as observed on the 2D seismic data. The DMO is a migration process which would transform the pre-stack data set so that each common mid-point (CMP) gather of traces actually contains events from the same depth point, as defined by the normal incident ray. The process migrate each trace to zero offset so that each common offset section becomes identical to a zero offset section. The absence of DMO would not guarantee this sitution and this is illustrated in fig. 8 whereby the reflector point is dispersed further up dip for increasing offset (Deregrowski, 1986). When DMO is applied, data quality improvement observed on fig. 7 is further confirmed as it resulted in better definition of the fault plane and dipping events (see fig. 9).

DISPLAY AND INTERPRETATION

Since the 3D data gives a complete areal picture of the subsurface struvture, sections can be taken in any direction, vertically and horizontally, changing the goal of interpretation accordingly for 3D seismic data. The intepretation is provided with a cube of data and the objective is to create a three-dimensional geological interpretation. To examine a cube by looking at two-dimensional cross-section plotted on paper is time consuming, laborous and has become old fashioned. A new goal in interpretation is the use of interactive graphics as a tool whereby new invention for displaying volume of data is used to simplify the interpreter's work.

Figure 10 illustrate various ways in which 3D seismic data can be displayed for interactive interpretation, namely:

- **Vertical sections, in constant X or Y**
- **Vertical sections horizontal and,**
- **Vertical sections, and arbitrary line sections**

Figure 11 shows the comparison between a dip line with 2D seismic data which was reshot in the 3D mode in the study area. It should be noted that the 3D seismic section has a fairly compressed horizontal scale while both sections are processed through the migration stage with the nearest well projected to the lines by 500 and 600 meters. There is considerable improvement on the 3D section where additional synthetic and antithetic faults to the major fault A are observed in areas where seismic events otherwise appear to be continuous in a broad rollover anticline as shown by the 2D seismic section. Seismic events are also better defined in the shallow and deeper horizons on the 3D section.

A time slice taken horizontally from the 3D data at 1680m/s (millieseconds) is as shown in fig. 12. Time slices constitute very powerful QC (Quality Control) tool in 3D data processing and are normally generated from the cube of the 3D seismic data at intervals from shallow to deeper horizons to reveal variation in structural trends with depth and lateral stratigraphic changes. The fault patterns are also enhanced and the time sections further confirm the additional faults observed on the 3D data.

A two-way time (Seismic) map made from the 3D data indicating heavily faulted roll-over structure is as shown in fig. 14, and when compared with a previous 2D seismic time map (fig. 13) of the same area, signifies remarkable difference. Major and minor faults are better resolved on the 3D time map and most of the structral closures are well defined. These faults with different throw compartmentalize the OK-field reservoir, readily explaining the different hydrocarbon - water contacts encountered in some wells. As a result of this detailed interpretation and new structural concept, the original field development plan was drastically revised.

COMMENTS AND CONCLUSION

The areal 3D seismic technique turned out to be very effective tool for reservoir development of the OK-field. Complex fault aliasing problems were resolved and these completely changed the structural concept of the field in which several smaller faults were indentified, and the reservoir had to be partitioned into various faults compartments resulting in a completely new structural configuration. Seismic events were also better defined at both shallow and deeper horizons indicative of superior quality of the 3D data set.

The detailed 3D structural interpretation is particularly valuable in the investigating of reservoir connectivity and expected fluid flow patterns with respect to the faulting system. This led to drastic revision of the original field development plan culminating in optimal section of drilling locations, significant cost reductions and improved reserves estimates.

Other achievements include monitoring by imaging subsurface targets with increased accuracy, enabling identification of flooding projects and location of injection wells. Consequently, areal 3D survey would aid in promoting field development, avoidance of drilling dry holes and maximization of oil recovery.

The areal 3D technique is clearly superior to the more conventional CDP surveying in that it provides a cube of data, while the CDP method gives a plane information along an up - or - down dip line through the reservoir. The cost of seismic surveying is about one-tenth (or less) the cost of drilling a single well, and since one well gives just one more data point in the reservoir while an areal survey can define the entire complex, the merits of the areal technique are readily justified.

The areal 3D survey is more cost effective than CDP method especially when recorded in numerous channels in the field. McDonald, in 1979, demonstrated that twice as many traces are collected in about one-third of the time in areal survey resulting in substantial cost reduction (see Table 1).

Ideally, a 3D survey should be performed after the initial discovery and before devleopment drilling as it can significantly reduce the number of appraisal wells required and ultimately lessen the elapsed time before the field is brought to production.

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TABLE 1

LAND SURVEYS

	AREAL	LINEAR
TYPE	CROSSED ARRAYS	CDP
CHANNELS	96	96
LENGTH	∞	22 MILES
AREA	2 MILES X 4 MILES	0
GRID	50 FEET	50 FEET
REDUNDANCY	4	8
NUMBER OF TRACES	80,000	40,000
VOLUME	16 MILES^2	0
TIME	9 DAYS	29 DAYS
SOURCE	DYNAMITE	DYNAMITE

(AFTER MCDONALD, J. A. SEG. 1979)

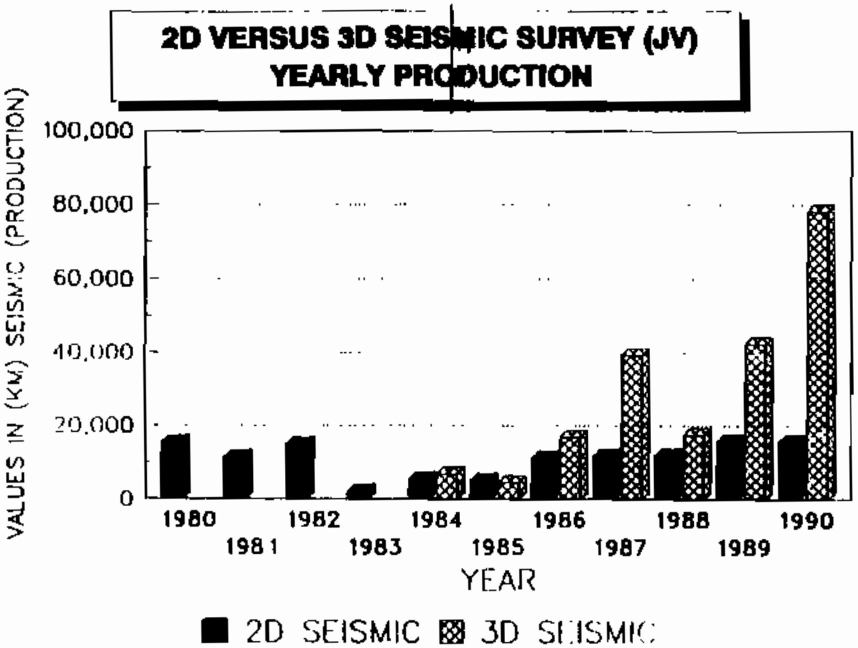


FIGURE 1

FIGURE 2 3D TECHNIQUE

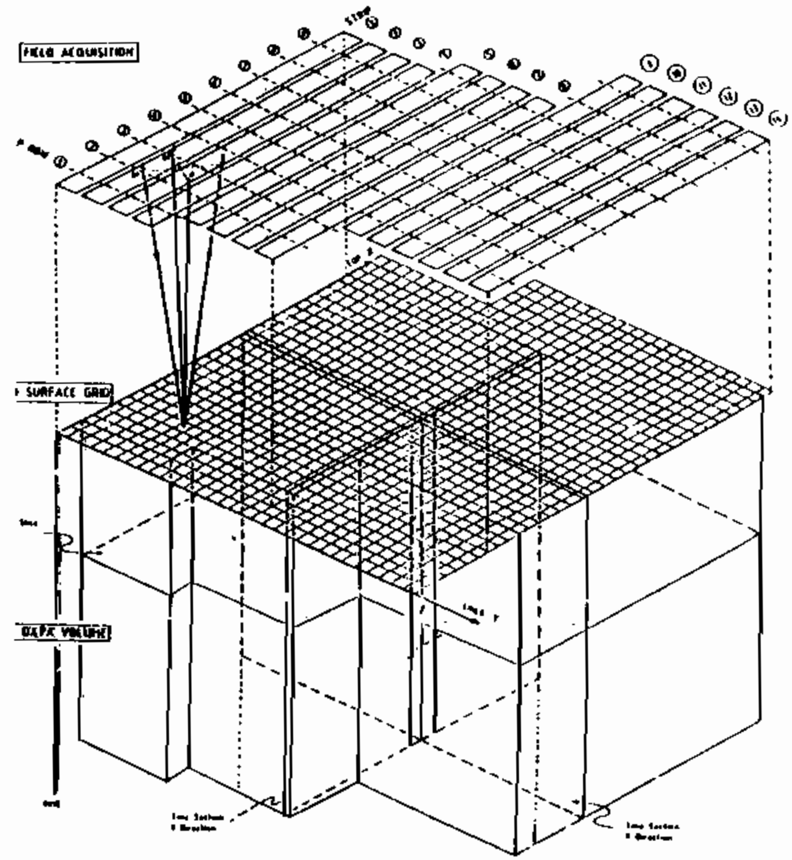
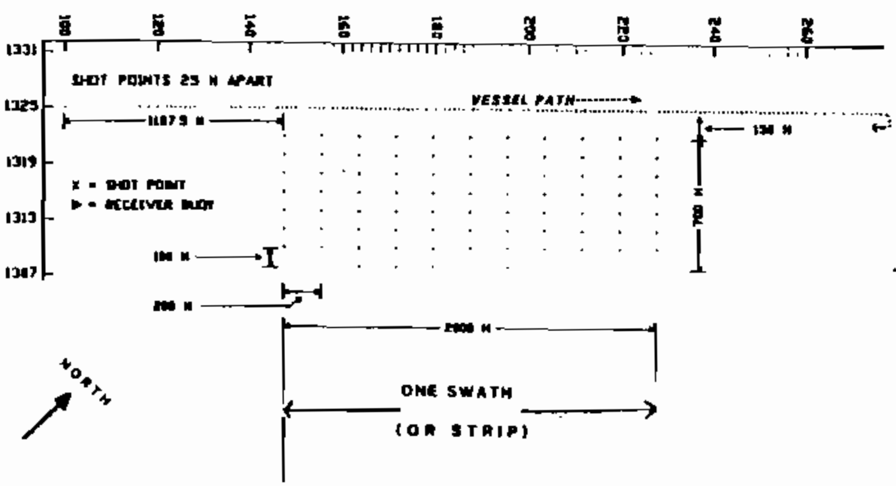


FIGURE 3 SWATH SHOOTING TECHNIQUE WITH DIGISEIS TELEMETRY SYSTEM

SHOT AND RECEIVER LINES CONFIGURATION



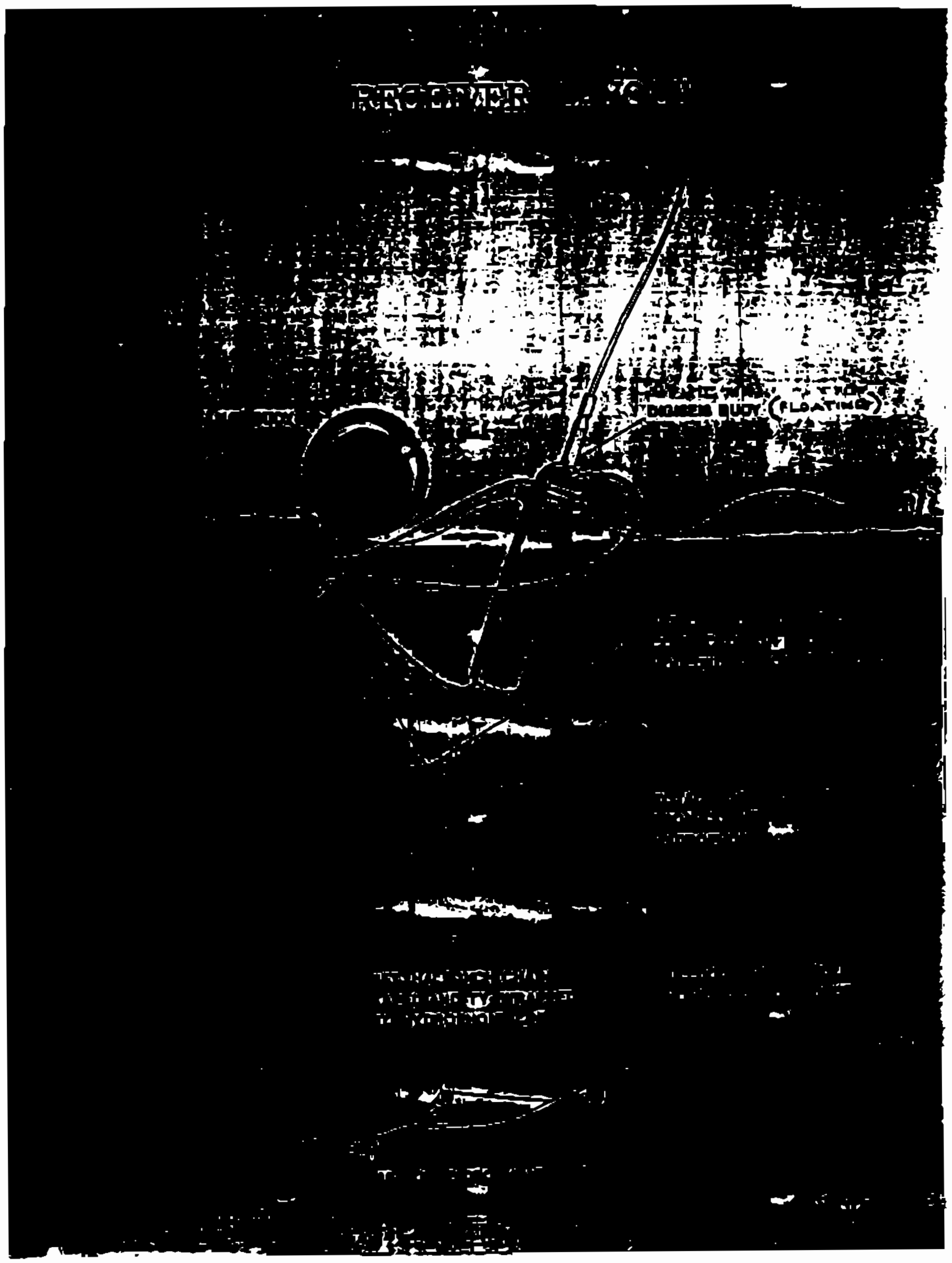


FIGURE 4

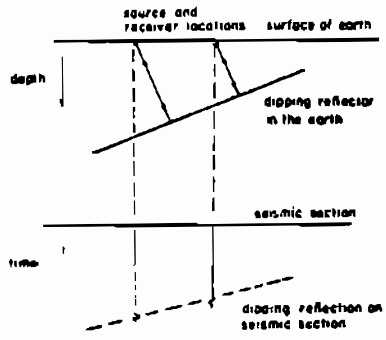


FIGURE 5 : Dipping Surface and Migration

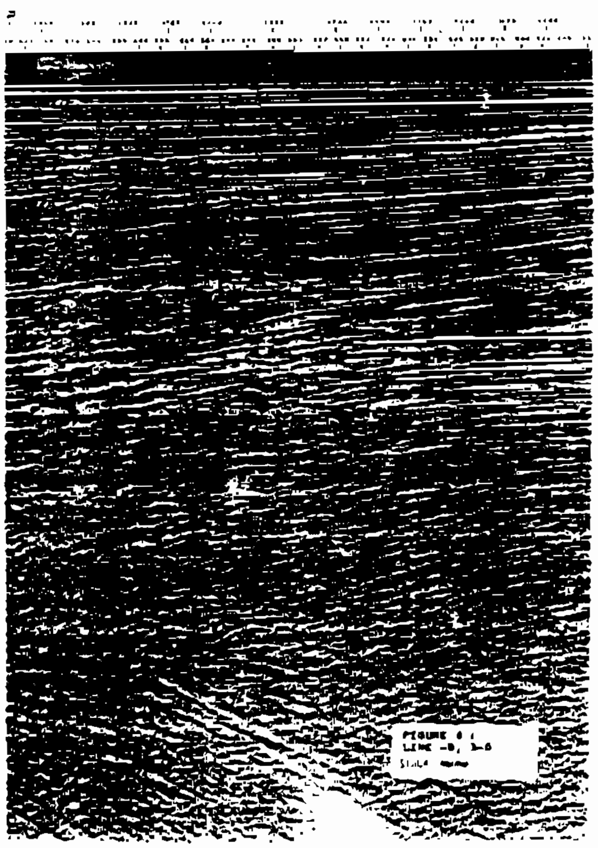


FIGURE 6 :

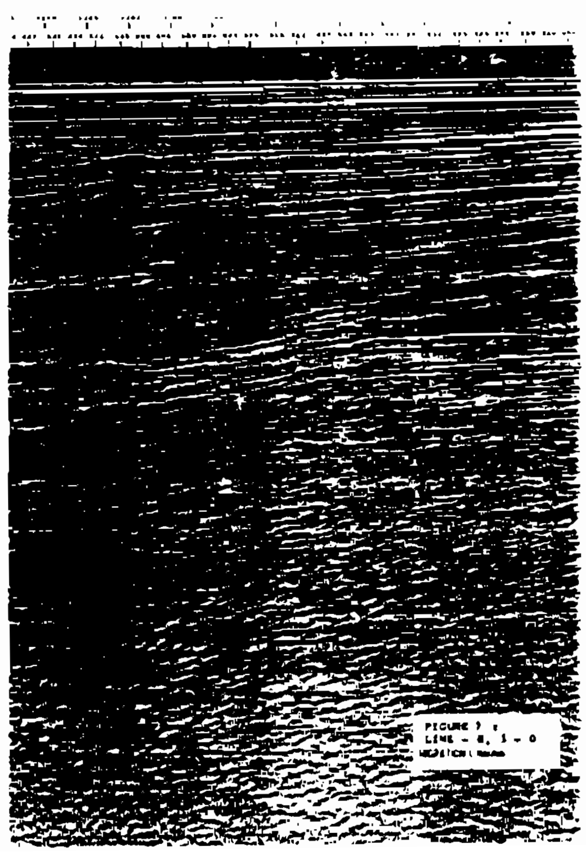
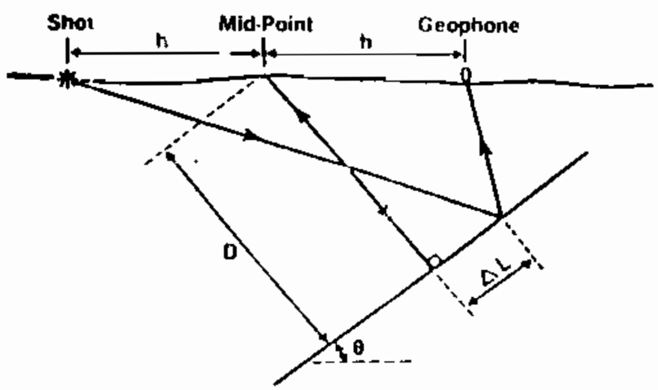


FIGURE 7 :

FIGURE 8 :

REFLECTOR POINT DISPERSAL



$$\Delta L = \frac{h^2}{D} \cos\theta \ \sin\theta$$

8. Reflector point dispersal increases as the square of the offset is inversely proportional to the travel time.

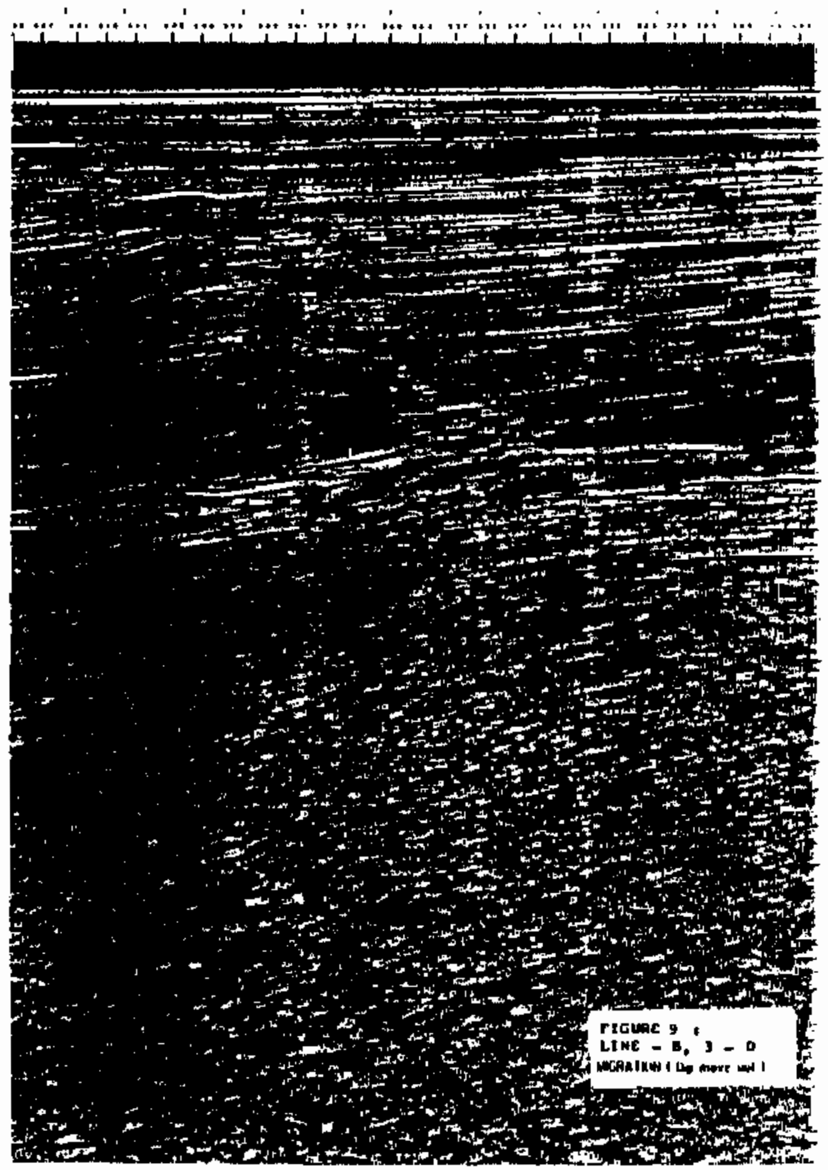


FIGURE 9 :
LINE – B, 3 – D
MIGRATION (Dip move out)

FIGURE 10: 3D SEISMIC DISPLAY

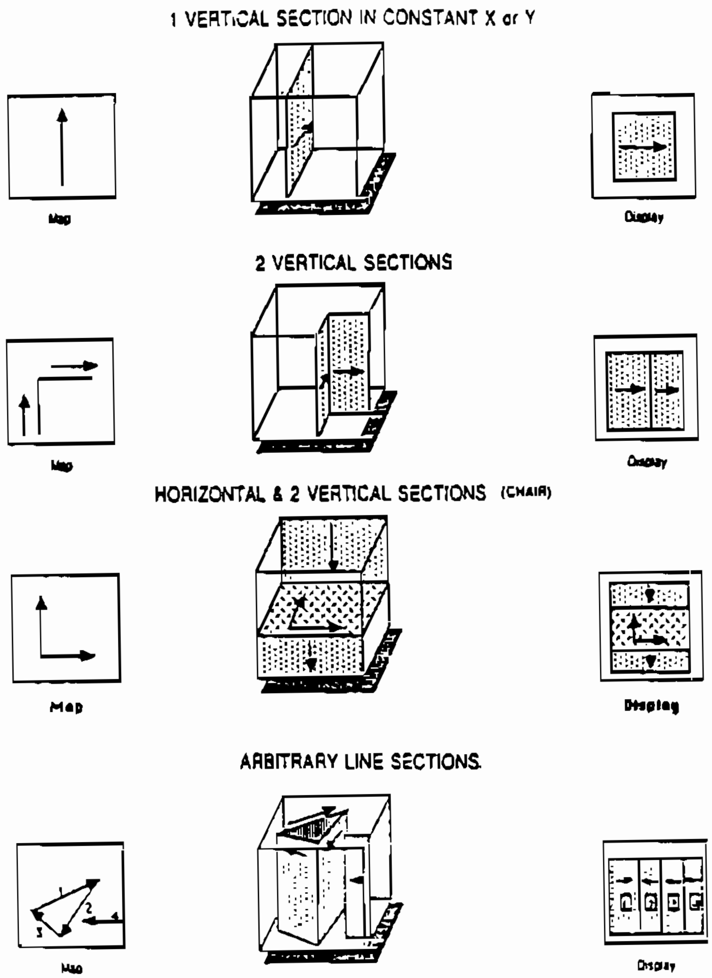


FIGURE 11: 2-D AND 3-D COMPARISON DIP LINES

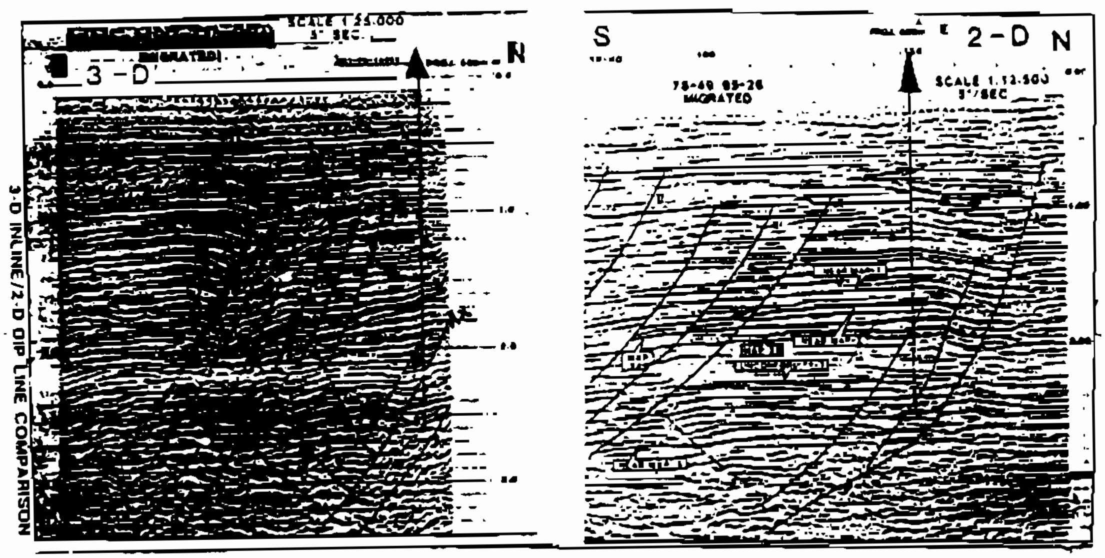


FIGURE 12: TIME SLICE: 1680 MSEC.

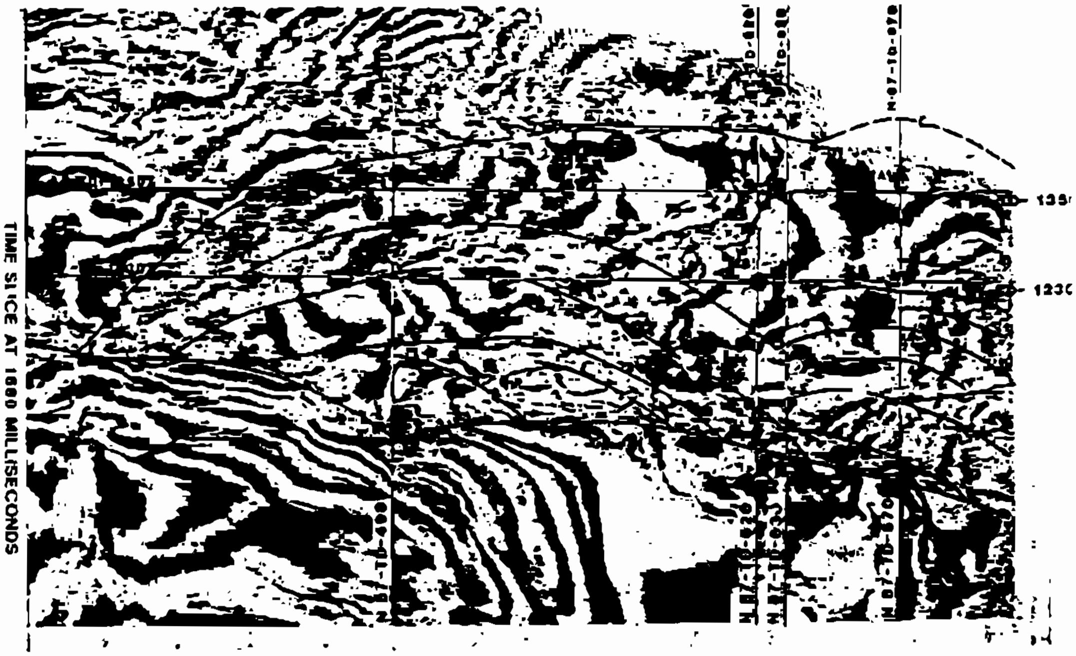


FIGURE 13 2-D TIME MAP.

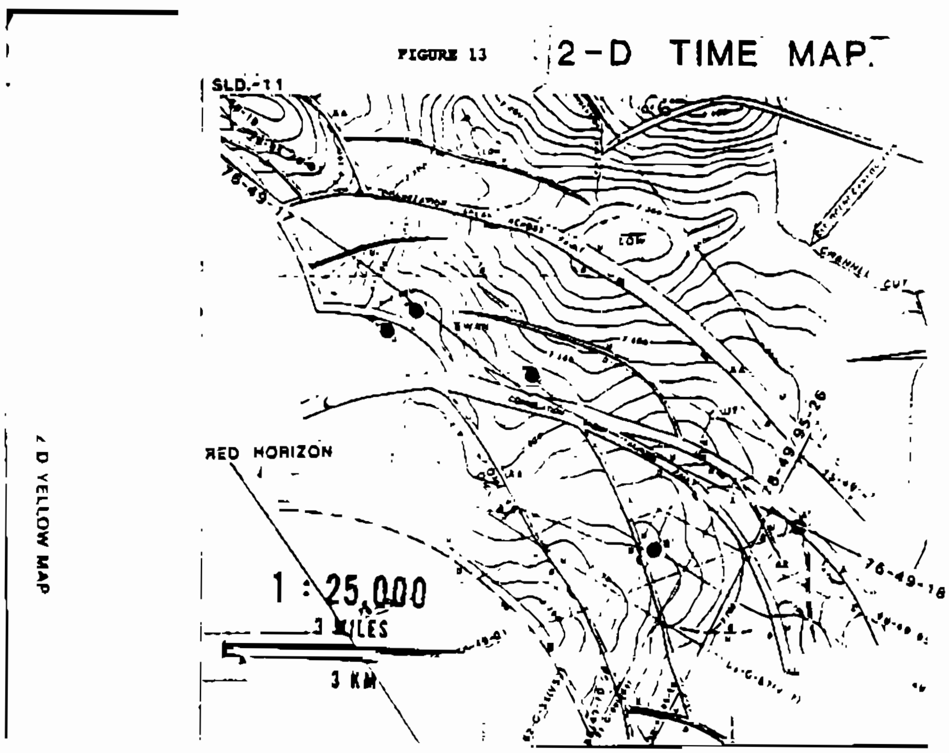
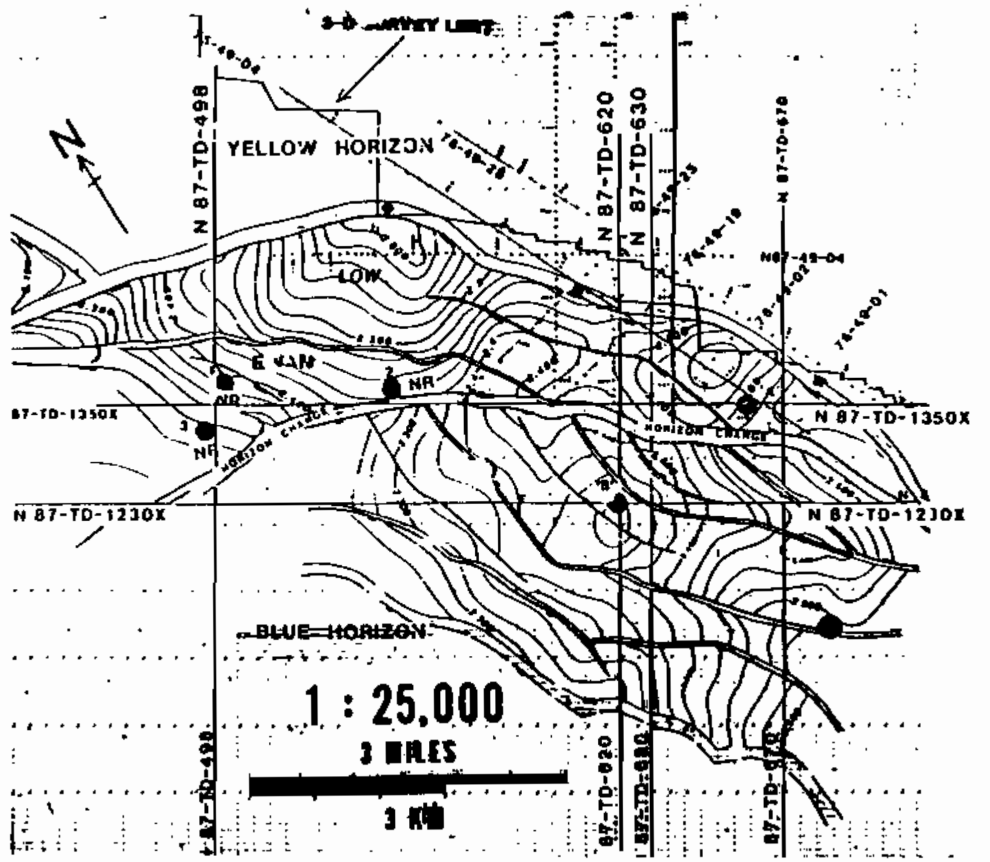


FIGURE 14 : 3-D TIME MAP.



A 3-D reflection seismic survey

over the Dollarhide field, Andrews County, Texas

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Because onshore 3-D surveys can be expensive, the results may not be considered cost-effective. This case history presents an onshore 3-D survey that was cost-effective and shows the power of 3-D seismic versus well control and 2-D data.

Discovered in 1945, the Dollarhide field is a large faulted anticline in Andrews County which is located on the Central Basin Platform in west Texas. Production in this field is from the Permian *Clearfork*, *Devonian* Thirty-one, *Silurian* Wristen, and Ordovician *Ellenburger* formations. The commonly used names for the reservoirs are in italics. Well spacing is approximately 40 acres and the Devonian formation is currently undergoing CO_2 flooding.

In August and September 1988, a 3-D survey was acquired over a 24 mi^2 area covering the Dollarhide field. The survey's primary purpose was to accurately image the location of faulting within and bounding the Devonian. This would aid in planning the CO_2 flood and possibly locate previously untested fault blocks.

Geophysicists from Unocal and Halliburton Geophysical Services (HGS) worked together to design the 3-D survey. Information (including depth of the main objective, velocity, maximum dip desired to be recorded, and reflection data quality) were compiled from previous 2-D seismic data and geologic data from well logs. Migration aperture, sweep bandwidth, source and receiver arrays, CMP fold, and offset geometry were all modeled and examined for optimum recording parameters. We determined that a subsurface bin size of 110 ft inline by 110 ft crossline would adequately sample the subsurface for processing through 3-D migration.

As mentioned earlier, the high cost of land 3-D seismic surveys has been a deterrent to their use in both exploration and production geophysics. HGS suggested two innovations to reduce costs:

• Incorporate trace interpolation into the processing sequence prior to 3-D migration. Well control in the area reveals the general dip of the target horizon. Because the dip in the north-south direction is less steep than in the east-west direction, we could relax the sampling criteria in the former. We were able to use a subsurface sample interval of 110 ft in the east-west (inline) direction and 330 ft in the north-south (crossline) direction, thus reducing the amount of data to be acquired by 66 percent. This also generated a further cost relief because the lessened number of receiver and vibrator lines meant fewer surface access permits to be obtained. And, economies were also realized in data processing because the number of records that had to go through CMP stack was reduced by 66 percent.

• The use of two vibrators to simultaneously sweep two separate lines. This technique improved the productivity of the recording crews by approximately 35 percent. The separation of the two source signals is accomplished by upsweep-downsweep and phase rotation summing. Source separation is performed in the field during the correlation and sum processes. The isolation of the two sources using this method is on the order of 40 dB.

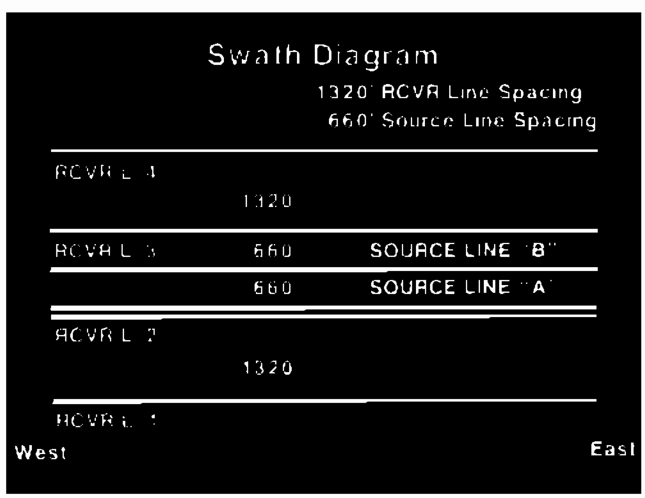

Figure 1. Swath design of the 3-D dual source survey.

A 3-D REFLECTION SEISMIC SURVEY OVER THE DOLLARHIDE FIELD, ANDREWS COUNTY, TEXAS

by
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Presented at the
60th Annual International Meeting, Society of Exploration Geophysicists
San Francisco, California, September 1990

Halliburton Geophysical Services, Inc.

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The data were acquired using a 384-channel DFS VII recording system deployed as a four-line swath. The receiver lines are spaced 1320 ft apart with two source lines per swath (Figure 1). Each swath generated eight subsurface profiles, separated by 330 ft. After each swath, the spread is moved 2640 ft (two cable lines) in the crossline direction. This geometry results in the subsurface swaths being adjacent as opposed to overlapping. This can also be described as "one fold crossline." With 12 swaths being recorded, the subsurface survey area is sampled 110 ft inline and 330 ft in the crossline directions. The source interval averaged 440 ft. The resulting effective fold is 18-24 when source-to-receiver offsets are considered relative to the depth of interest.

Data processing techniques included geometry description; field record quality control; surface-consistent deconvolution; preliminary stack; velocity analysis; residual static estimation; stack; 3-D *f-k* DMO; trace interpolation; 3-D migration.

At several steps during the processing of this survey, different parameters were tested and reviewed—including the deconvolution method, benefit of DMO, migration velocity analysis, and poststack migration algorithm. A benefit was realized by including DMO in the processing sequence in that the diffracted image of the subsurface was improved. This enabled the trace interpolation algorithm to perform better in the conversion of 110×330 ft subsurface bins to 110×110 ft bins. After 3-D migration, the data volume was moved to a workstation for interactive interpretation.

The results of this 3-D survey are impressive. Figure 2 shows the structure map of the Devonian at Dollarhide field as determined by the 40-acre-spaced well control. This map had gone through many evolutions in the 46 years since the field was discovered. Notice that the contours are relatively smooth, the anticline is cut by four simple cross faults and bounded on the east by a fault.

The structure map from the 3-D seismic survey (Figure 3) is more complex. The contouring is more detailed and the cross faults are not simple. The map shows the detail of the Devonian that the 3-D seismic has allowed us to see. This shouldn't be a surprise as our seismic data points are equivalent to a spacing of approximately four wells per acre. Considering that a seismic trace is an approximation to a synthetic seismogram from a sonic log, we indeed have a very powerful means of detail mapping subsurface structure.

There are two ways to look at the 3-D seismic data volume. One is the conventional seismic line display (Figure 4). On the crest of the structure, the top of the Clearfork formation is the strong event at approximately 780 ms. The Devonian, at approximately 1000 ms on the upthrown block and 1350 ms on the downthrown block, is colored purple. The top of the Ellenburger is a high-amplitude event at approximately 1250 ms. At about 960 ms, an unconformity can be seen which helps highlight one of the more remarkable features of the data—a fault zone showing over 2000 ft of displacement on the Devonian marker. The imaging of this fault zone demonstrates one of the shortcomings of some 3-D surveys. Due to economics, lines may not be long enough to properly image all the features (such as large faults or extremely steep dip) within the survey limits. This survey was designed to image the upthrown block, so the incomplete image east of the major fault was expected.

The other view of the 3-D data volume, and one not available with 2-D data, is the time slice. This view allows the interpreter to see subtle features which may not be apparent or as readily interpretable on conventional seismic sections. A time slice (Figure 5) through the 3-D data volume at 1008 ms (about equal to 4600 ft subsea or 7800 ft below the surface) demonstrates this. The cross faults are seen as northeast-southwest lineations. The previously undetected grabens not seen on Figure 2 are seen as easterly pullouts on the time-sliced peaks (blue) and troughs (red) in the areas of the cross-faulting. Mapping of the data is now possible in both the vertical and horizontal sense. Both offer unique perspectives of the data volume.

Because the 3-D survey gives an evenly sampled volume of data, another display of the data is possible after a horizon is interpreted. In Figure 6, a perspective view of the Devonian horizon time map as viewed from the southwest is presented. It shows the northerly plunge of the anticline which isn't readily apparent on the Devonian horizon structure map (Figure 3). The cross faults,

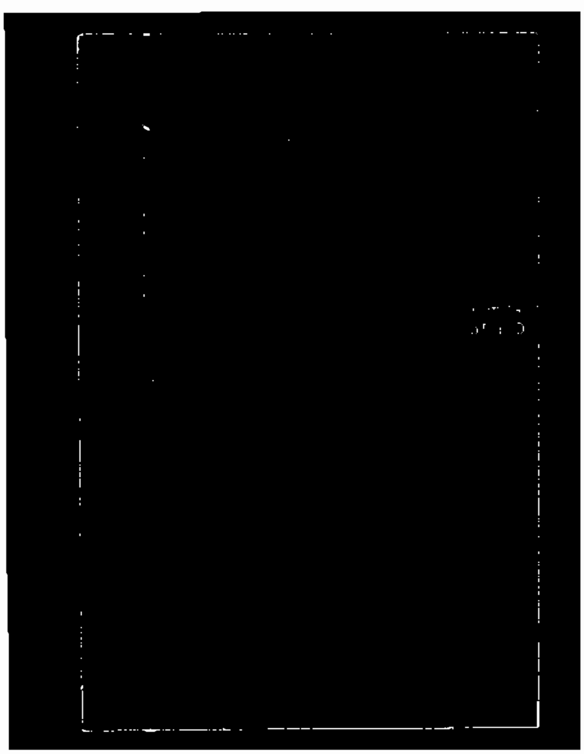

Figure 2. Simplified Devonian structure map from 40 acre well control. The unit outline is red.

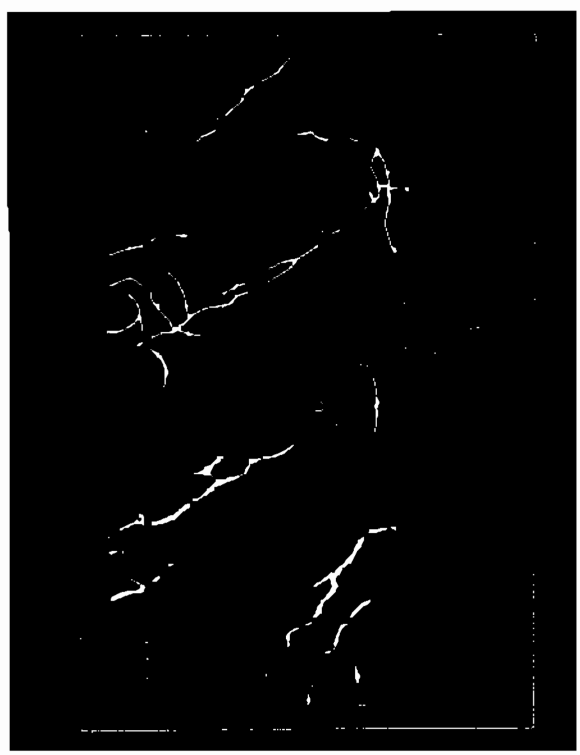

Figure 3. Simplified Devonian structure map from 3-D seismic interpretation.

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Reservoir Management Using 3D Seismic Data

James D. Robertson, SPE, Arco Oil & Gas Co.

Introduction

The geologic detail needed to develop most hydrocarbon reservoirs properly substantially exceeds the detail required to find them. This obvious, but compelling, precept has fueled the steadily increasing application of three-dimensional (3D) seismic analyses to reservoir management. A measure of the increase is that 3D surveys now account for half the seismic activity in the offshore Gulf of Mexico and North Sea, and the percentage has risen yearly since commercial 3D surveys were first shot in these areas in 1975 (Fig. 1).

Likewise, 3D seismic surveying in other offshore areas and on land is growing rapidly. My Fall 1988 SEG Distinguished Lecture addressed the general subject of managing reservoirs by use of 3D seismic data; this article is derived from that lecture. There are three parts to the article: a definition of reservoir management; a discussion of the various kinds of 3D seismic analyses that can affect the development and production of a field; and a synopsis of the history and potential of the 3D seismic technique.

Definition

A good working definition of reservoir management is *maximizing the economic value of a reservoir by optimizing recovery of hydrocarbons while minimizing capital investments and operating expenses.*

The first thing to note is that this definition is not geophysical or geological; in fact, it's not even an engineering definition. Reservoir management really is the economic process of raising the worth of a property to the highest possible level. We generally measure economic value by yardsticks like present worth, investor's rate of return, payout, and investment efficiency. The task is to maximize (minimize in the case of payout) these economic descriptors. Economic value generally increases when more reserves are proved or when the reservoir's producing rate increases. Of course, capital investments (drilling, seismic shooting, and lease bonuses) and operating expenses (lease rentals, staff costs, taxes, etc.) must be incurred to find and subsequently to develop and produce these reserves, and these expenditures themselves detract from the economic value. The reservoir manager thus trades off expenditures that drain present worth against the chance of increasing present worth by adding reserves and/or increasing production. The process is a continuous balancing act.

This paper is similar to work the author published in the Feb. 1989 issue of *The Leading Edge* of the Soc. of Exploration Geophysicists

What is the role of seismic surveying, particularly 3D, in this balance? Basically, it impacts reservoir management in two different ways. First, a 3D seismic analysis can lead to identification of reserves that will not be produced optimally, or perhaps not be produced at all, by the existing reservoir management plan. Secondly, the analysis can save costs by minimizing dry holes and poor producers, by contributing to the proper sizing and design of facilities, and by condemning leases that can then be dropped to avoid rental payments and/or to take tax write-offs. These concepts are summarized in my first major point: *3D seismic data contribute to reservoir economics by adding reserves and/or by reducing costs.* Either of these impacts can be sufficient justification for shooting a 3D seismic survey. Of course, the best situation is when both happen at once, and that is generally the case.

Process Model

One possible model of the reservoir management process, the linear system, is shown in Fig. 2. This model consists of the following sequence: a discovery, an evaluation of the discovery, implementation of a development plan leading to production of the field, and final abandonment when the field is no longer economical. In this scheme, a 3D survey is shot during the evaluation phase and is used to assist in the design of the development plan, after which development and production start up.

I suggest that this linear model is not what really happens in reservoir management, except in the very simplest cases (a discovery followed by one or two offsets that fully develop the reservoir). The real world generally is the process shown in Fig. 3, called the iterative system. This model also starts with a discovery, but then goes into a loop where data are constantly being evaluated to form the basis for development/production decisions (such as locating production and injection wells, siting and designing platforms, setting flow rates, managing pressure maintenance, performing workovers, planning waterflood and tertiary recovery strategies, etc.). When implemented, the development and production activities in turn generate new information (logs, cores, drillstem tests, pressure tests, etc.) that change maps, revise structure, alter the reservoir stratigraphic model, and so on. Most of the time spent in managing reservoirs really consists of going around this loop. Occasionally, a deeper pool or offset extension test will spin off from the evaluation, resulting in a new discovery and revitalization of the loop. This process continues until the field is finally abandoned.

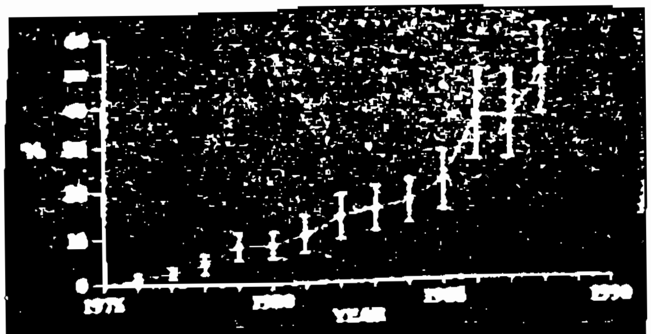

Fig. 1—3D seismic as a percentage of total seismic in the Gulf of Mexico and North Sea.

A 3D seismic survey is one tool in the evaluation tool kit An initial interpretation of the survey impacts the original development plan. As subsequent events, such as the drilling of development wells, occur, the added information is used to revise and refine the original interpretation. Often, as time passes and the data base builds, elements of the 3D data that were initially ambiguous begin to make sense, and the interpretation becomes more detailed and sophisticated. This is important enough to be a second major point: *the usefulness of a 3D seismic survey lasts for the life of a reservoir.* A 3D survey is not something shot right after the discovery, interpreted once, and then put on the shelf, never to be looked at again. It hangs around for years as an active file on one's computer system!

Geometric Framework

The interpretations that a geophysicist might perform with 3D seismic data can be grouped conveniently into those that examine the geometric framework of the hydrocarbon accumulation, those that analyze rock and fluid properties, and those that try to monitor fluid flow and pressure in the reservoir (Fig. 4). These analyses affect and, one hopes, significantly improve, decisions that must be made about reserves volume, well/platform locations, and recovery strategy. Thus, the analyses themselves are not the end products, but rather are management tools.

I am using "geometric framework" as a collective term for such spatial elements as the attitudes of the beds that form the trap, the fault and fracture patterns that guide or block fluid flow, the shapes of the depositional bodies that make up a field's stratigraphy, and the orientations of any unconformity surfaces that might cut through the reservoir. A 3D-seismic data collection samples the geometric framework on a regular 3D grid (generally 50 to 100 ft [15 to 30 m] laterally and 10 to 50 ft [3 to 15 m] vertically). By mapping travel times to selected events, displaying seismic amplitude variations across selected horizons, isochroning between events, noting event terminations, slicing through the volume at arbitrary angles, compositing horizontal and vertical sections, optimizing the use of color in displays, and using the wide variety of other interpretive techniques available on a computer workstation, a

Doing These Things leads to →

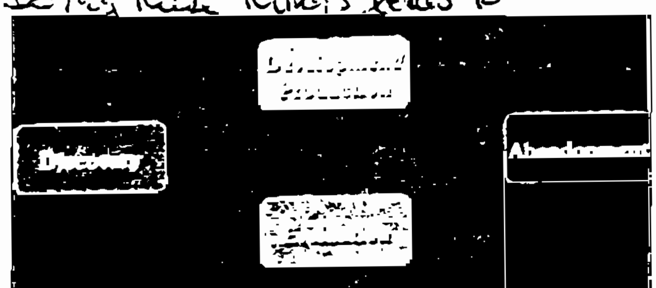

Fig. 3—Reservoir management—the iterative system.

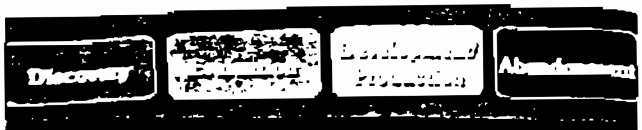

Fig. 2—Reservoir management—the linear system.

geophysicist can synthesize a coherent and quite detailed 3D picture of a field's geometry.

An example of mapping geometric framework is shown in Figs. 5 and 6. Fig. 5 is an early structure map of the Prudhoe Bay field on the northern edge of Alaska. The map, which predates any 3D seismic shooting over the field, was used in an AAPG Distinguished Lecture in the early 1970's and subsequently presented by Morgridge and Smith.[1] It shows the basic elements of the trap at Prudhoe Bay: the dip to the south and southwest, the boundary fault to the north, and the erosional truncation of the Sadlerochit reservoir to the east.

Fig. 6, prepared by David A. Fisher of Arco, is a time slice from one of the 3D seismic volumes that now exist over the field (location shown in Fig. 5). A "time slice" is a horizontal cut through the volume of seismic data that is the final, processed product of a 3D survey. It represents a plan view of the seismic response of the subsurface at a fixed seismic travel time. In Fig. 6, the reds and blues are seismic peaks and troughs, and the time slice cuts the volume at about the level of the unconformity truncating the Sadlerochit. One can clearly see the Sadlerochit subcrop imaged as a red/blue/red event traversing north-northwest to south-southeast across the right side of the image and denoted by double arrows. The northern boundary fault, denoted by single arrows, appears as a sharp, white, arcuate lineament crossing the top of the time slice. More subtle elements of the geometric framework, such as additional east/west and northwest/southeast faulting that disrupts the continuity of the red and blue seismic events, are also evident.

This example illustrates a third major point: *3D seismic data map the gross, controlling elements of a field.* This type of analysis is the traditional use for the 3D seismic technique and has contributed significantly to the geological characterization of many hydrocarbon traps.

An example of imaging stratigraphic shapes with 3D seismic data is shown in Figs. 7 and 8. The data are from the Matagorda area of the offshore Gulf of Mexico, and the example will be presented in Riese and Winkelman's forthcoming work for AAPG.[2]

A single seismic section (Fig. 7) in the 3D volume contains a variety of nearly flat events. Some appear and then disappear and others vary laterally in amplitude; the stratigraphic significance of any particular reflector is not obvious on the two-dimensional (2D) display. Note the short, black event located directly above the zero tick on the scale bar and marked by an arrow. A time slice through the 3D volume (Fig. 8) at this travel time reveals that the event is a transverse cut through a meandering stream channel, and the stratigraphic situation becomes clear when the lateral spatial sampling of the 3D volume is used. (The green bands crossing the northern

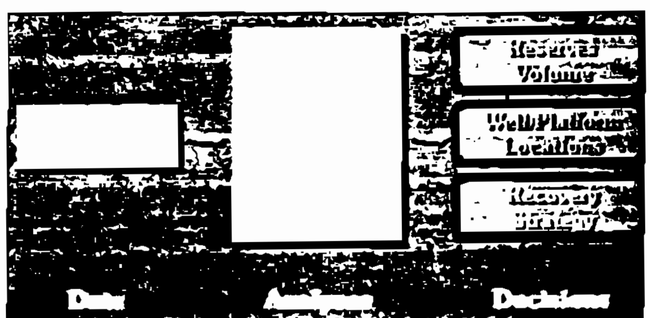

Fig. 4—Applications of 3D seismic data to reservoir management.

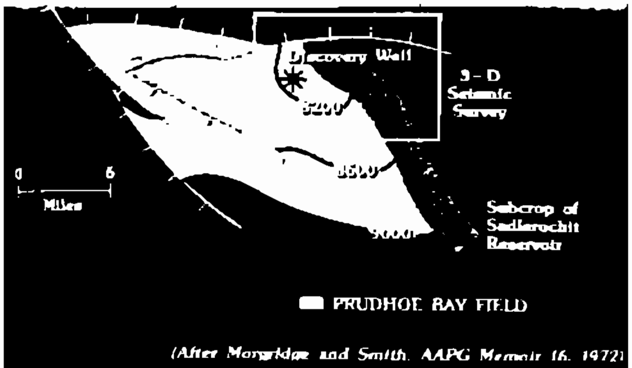

Fig. 5—Prudhoe Bay field, Alaska—1971 Sadlerochit structure map (from Ref. 1).

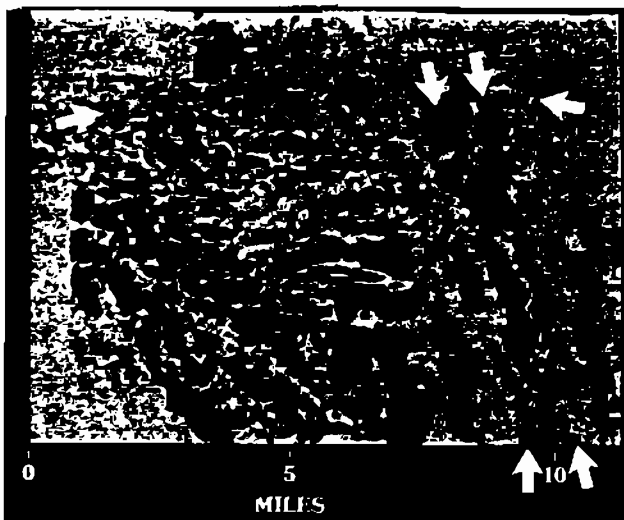

Fig. 6—Prudhoe Bay field, Alaska—time slice (courtesy of D.A. Fisher, Arco).

part of the slice are fault cuts coming up through the data). The major point here is that *minor character changes in 3D seismic data tend to correlate with real geologic changes.* The variations generally are not noise or acquisition/processing errors, and the challenge is to deduce correctly their geologic significance.

Rock Properties

The second general grouping of 3D seismic analyses (Fig. 4) encompasses those targeted at the qualitative and quantitative definition of rock properties. Amplitudes, phase changes, interval travel times between events, frequency variations, and other characteristics of the seismic data are correlated with porosity, fluid type, lithology, net pay thickness, and other reservoir properties. The correlations usually require borehole control (well logs, cuttings, cores, etc.) both to suggest initial hypotheses and to refine, revise, and test proposed relationships. An interpreter develops a hypothesis by comparing a seismic parameter in the 3D volume at the location of a well to the well's information, often through the intermediary of a synthetic seismogram match. The hypothesis is then used to predict rock properties away from the borehole control, and subsequent drilling validates (or invalidates) the concept. For example, 3D seismic surveys are commonly used in the productive Pleistocene trends of the offshore Gulf of Mexico to map gas saturation directly. One correlates seismic amplitude anomalies with gas-saturated sandstones and then maps the areal extent (and sometimes net feet of pay) of these bright spots laterally and vertically through the data volume.

Fig. 9, prepared by Stanley F. Stanulonis and Naresh Kumar of Arco, illustrates a less common type of analysis. This example is located on Alaska's North Slope and the formation of interest is the Lisburne, a carbonate that produces from below the Sadlerochit at Prudhoe Bay. The amplitude of the Lisburne seismic reflect ion was determined at points of well control and compared with Lisburne porosity-thickness measured in the same wells. This crossplot was then used to transform seismic amplitude directly into porosity-thickness values at seismic gridpoints between wells. Fig. 9 is the Lisburne reflection scaled to porosity-thickness. A number of wells drilled after this analysis have tested the quality of the porosity-thickness predictions, and the tests have matched the predictions to within a few units.

The major point here is that *3D seismic data guide interwell interpolations of reservoir properties.* Given a 3D survey, one does not have to settle for crude, linear interpolations of reservoir parameters between wells. The reservoir manager can use the seismic volume to pinpoint and understand nonlinear lateral changes, an approach that nearly always results in lower costs, fewer surprises during development, and better production.

Flow Surveillance

The third general grouping of 3D seismic analyses (Fig. 4) consists of those designed to look at the actual flow of the fluids in a reservoir. Such flow surveillance is possible if one (1) acquires a baseline 3D data volume at a point in calendar time, (2) allows fluid flow to occur through production and/or injection with attendant pressure/temperature changes, (3) acquires a second 3D data volume a few weeks or months

Fig. 7—Matagorda Block 668, offshore Texas—seismic section (courtesy of Riese and Winkelman[2]).


Fig. 8—Matagorda Block 668, offshore Texas—time slice (courtesy of Riese and Winkelman[2]).

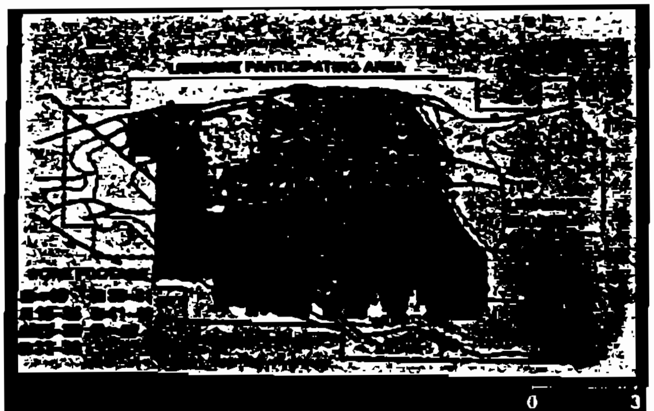

Fig. 9—Prudhoe Bay field, Alaska—Lisburne porosity-thickness from 3D seismic data (courtesy of S.F. Stanulonis and N. Kumar, Arco).

after the baseline, (4) observes differences between the seismic character of the two volumes at the reservoir horizon, and (5) demonstrates that the differences are the result of fluid-flow and pressure/temperature changes. Of course, one must be careful not to vary seismic acquisition and processing parameters drastically between surveys and thereby introduce differences that can be mistaken for fluid-flow effects. One expects that the seismic character of horizons above the reservoir would be virtually identical between the volumes (geology generally changes much more slowly than fluid flow!). Hence, an interpreted flow-induced difference can be validated indirectly by verifying that the difference occurs at the reservoir event, but not elsewhere in the 3D volume. Of course, one can acquire additional surveys and continue the surveillance by computing additional 3D difference volumes.

Flow surveillance with multiple 3D seismic surveys is at a very early stage of R&D, but its potential impact on reservoir management is enormous. Most current practice of the technique has been directed toward monitoring EOR processes. An example is shown in Fig. 10 from Greaves and Fulp.[3] An experimental, oxygen-driven, thermal EOR pilot was performed on a depleted oil field, the Holt Sand unit, in north Texas. The top section in Fig. 10 is a line through a 3D data volume acquired before the start of the pilot. The Holt sand is the event identified by the white triangles, and its seismic amplitude is low. In this color-coded display of reflection strength, the bright event is a limestone lying several hundred feet below the Holt and not associated with the reservoir. The middle section in Fig. 10 lies in the same spatial position in the 3D data volume as the top section, but was acquired a few months after the start of oxygen-injection/thermal-combustion. Likewise, the bottom section is the same line reshot about a year after startup. One can observe that the oxygen-injection/thermal-combustion process has produced a dramatic increase in the strength of the Holt sand reflection, and that the formation is affected increasingly as calendar time passes. The combination of oxygen injection and creation of combustion gases increases gas saturation in the reservoir (in effect, the experiment is creating an artificial bright spot), the thermal process is altering the state of the reservoir, and the multiple seismic data sets are monitoring the changes. The seismic monitoring also mapped an apparent vertical override of the gas some months after the start of the pilot; this and other details of the monitoring are described fully by Greaves and Fulp.[3]

The lesson here is that *3D seismic snapshots can map changes in fluid/pressure/flow regimes.* Although not yet as commercialized as mapping geometric frameworks or estimating rock properties between wells, this application of 3D seismic surveying may eventually become just as important. It has the potential to measure reservoir performance directly, to provide timely feedback that can

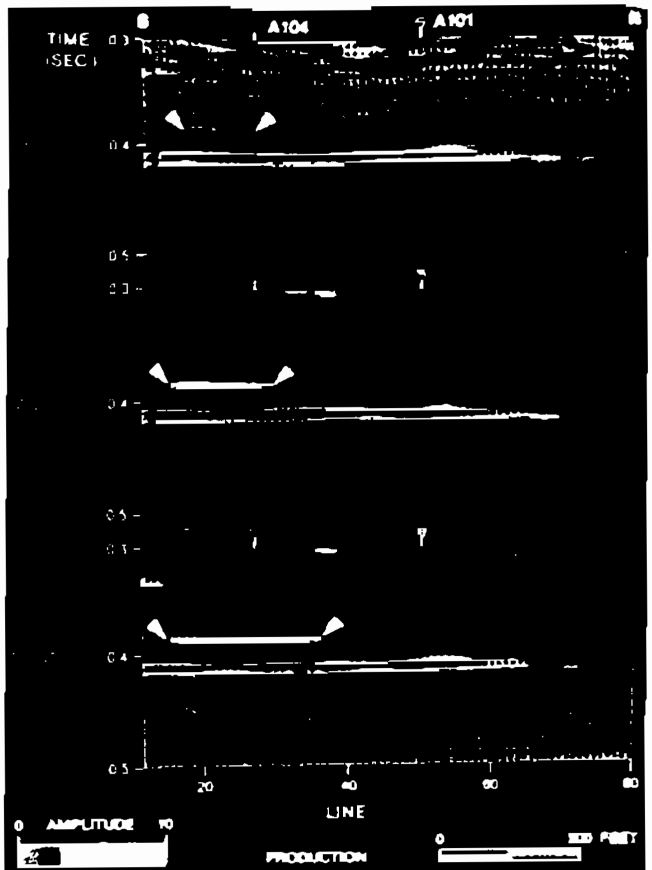

Fig. 10—Holt Sand Unit EOR pilot—seismic sections (from Greaves and Fulp[3]).

change development/production plans, and to be more spatially specific than pressure tests. In the future, the technique might be used to monitor secondary recovery operations and gas cap movements, to control production and injection rates for optimum recovery, to map pressure/temperature distributions, and even to decipher stress patterns, particularly in tectonically active areas.

Roots

The first 3D seismic survey ever shot appears to have been an experimental survey acquired by Exxon Production Research Co. in 1967 at Friendswood field near Houston. Walton[4] describes the survey and presents some of the data. During 1967–72, various petroleum companies carried out other experimental surveys, including some performed with transducers in water tanks by William S. French and coworkers at Gulf Oil Corp. about 1970. It was not until 1973, however, that the first commercial 3D seismic program was conducted—a land survey shot in Lea County, NM, by Geophysical Service Inc. for a consortium consisting of Amoco, Arco, Chevron, Mobil, Phillips, and Texaco. The first commercial marine survey followed two years later in 1975—one acquired in the High Island area of the Gulf of Mexico by Geophysical Service Inc. for Sun Oil Co. Use of the technology grew steadily from the mid-1970's onward, particularly in the marine environment, as acquisition and processing improved. The best available evidence is that more than 100 3D seismic surveys were shot worldwide by 1980. Steady innovations in acquisition and processing techniques (streamer tracking, real-time binning, 3D migration, 3D velocity analysis, etc.), the advent of supercomputers, and the explosive growth in computer-graphics workstations for interpretation have continued to fuel the use of 3D seismology. It is virtually certain that more than 1,000 3D surveys have now been acquired worldwide by the petroleum industry

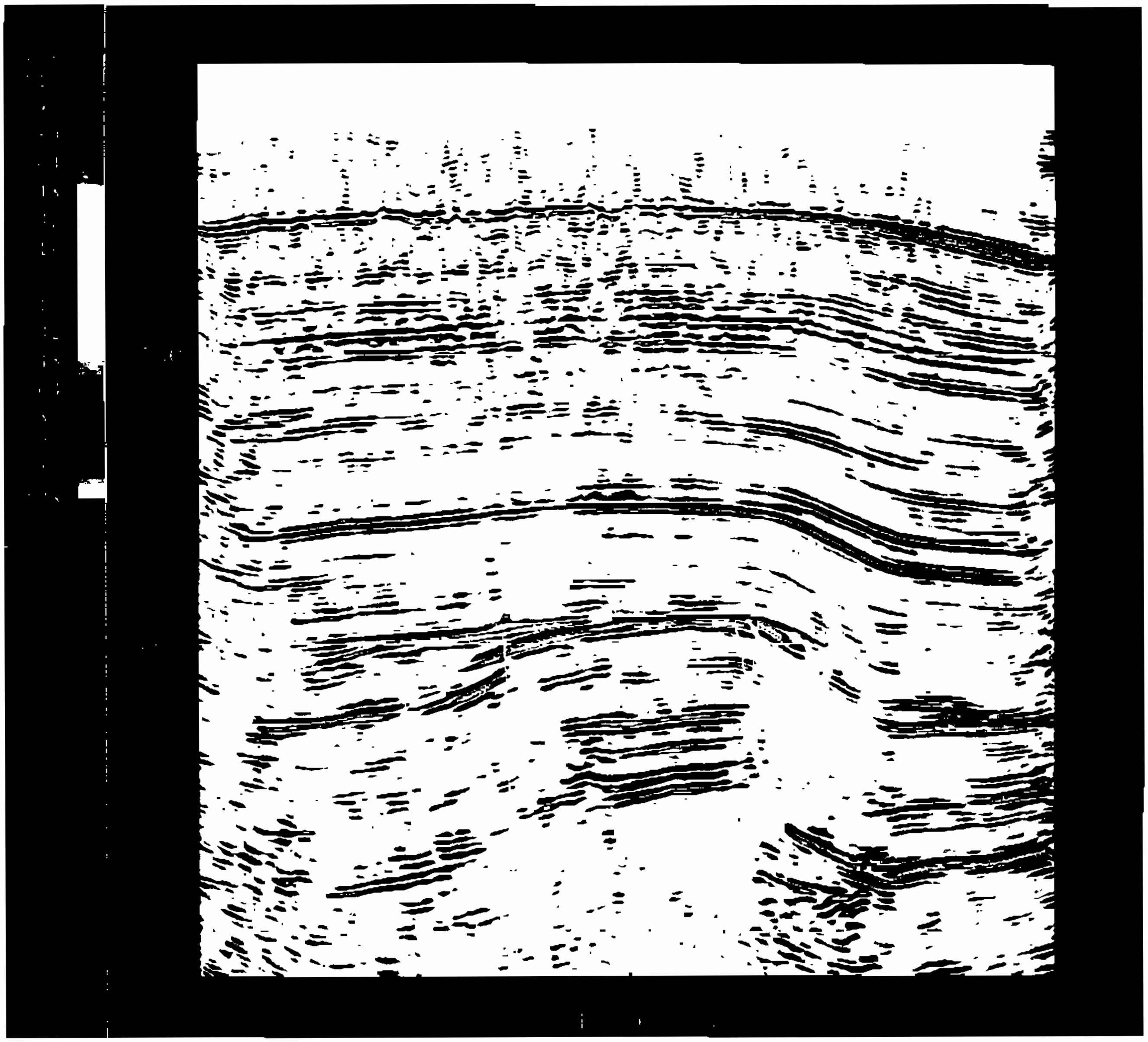

Figure 4. East-west seismic inline 110. Devonian horizon is annotated in purple and the interpreted faults are yellow.

with their associated grabens, are quite distinct and give a real feel for the relative throw of faults. This display has helped the geologists and engineers develop a better understanding of the field shape and how the faults impact the ongoing CO_2 flood project.

Having the 3-D data volume loaded on an interactive workstation allowed the interpreters to generate various attribute displays that took us beyond the traditional time interpretation. Using the seismic peak and trough associated with the producing Devonian horizon, a composite amplitude map was made (Figure 7). The hot colors, yellow and red, represent larger amplitudes and, in most cases, correspond with the better wells in the field. The cool colors, blue and green, represent lower seismic trace amplitudes along the producing Devonian. The amplitudes are interpreted to be related to the thickness of the producing zone—high amplitudes to a thick zone, low amplitudes to a thin zone. The possible exception is the linear pattern next to the north-south bounding fault where we believe the larger amplitudes are possibly related to poorly imaged steep dips. The major cross faults are seen as northeast-southwest lineations which divide the structure into four major fault blocks. The CO_2 flood is expected to have better results in the northern block which is denoted by the higher amplitudes. The flood was initiated in the northern block last year. The next block south has had the poorest flood results to date which seems related to the dominance of the lower amplitudes on the composite amplitude map. The third fault block was the first one flooded and has the best results to date, as could be predicted from the abundance of high amplitudes. The smallest fault block, located to the southeast, is faulted below the producing limits of the field to the north. However, a well drilled to the productive Devonian horizon in 1948 has recently been reentered, reevaluated, and could open up an extension to the field. The higher amplitudes indicate it could be a very productive block with good CO_2 flood potential.

Earlier in this paper, we alluded to the cost-effectiveness of this 3-D survey. One of the features that helped us to sell the concept to management was the comparison of the cost to shoot this 3-D survey to a half-mile grid of 2-D data and the dryhole cost of a Devonian test. The 2-D survey cost (including acquisition, surface permits, and processing) was estimated at \$750 000 for 150 line miles. The dryhole cost of a Devonian test is approximately \$300 000. To date, two Devonian locations have not been drilled as the 3-D results indicated they were uneconomic. Shooting conventional swath 3-D to record 110×110 ft bins was estimated at about \$1 300 000 (generating 1140 miles of 3-D data over the 24 mi^2). Using a 3-1 interpolation technique and simultaneous source recording brought the survey in at \$400 000. This cost is approximately half that for a 2-D survey, a third of a conventional 3-D survey, and only slightly more than a dry hole. The after-tax profit of a primary Devonian development well in the Dollarhide

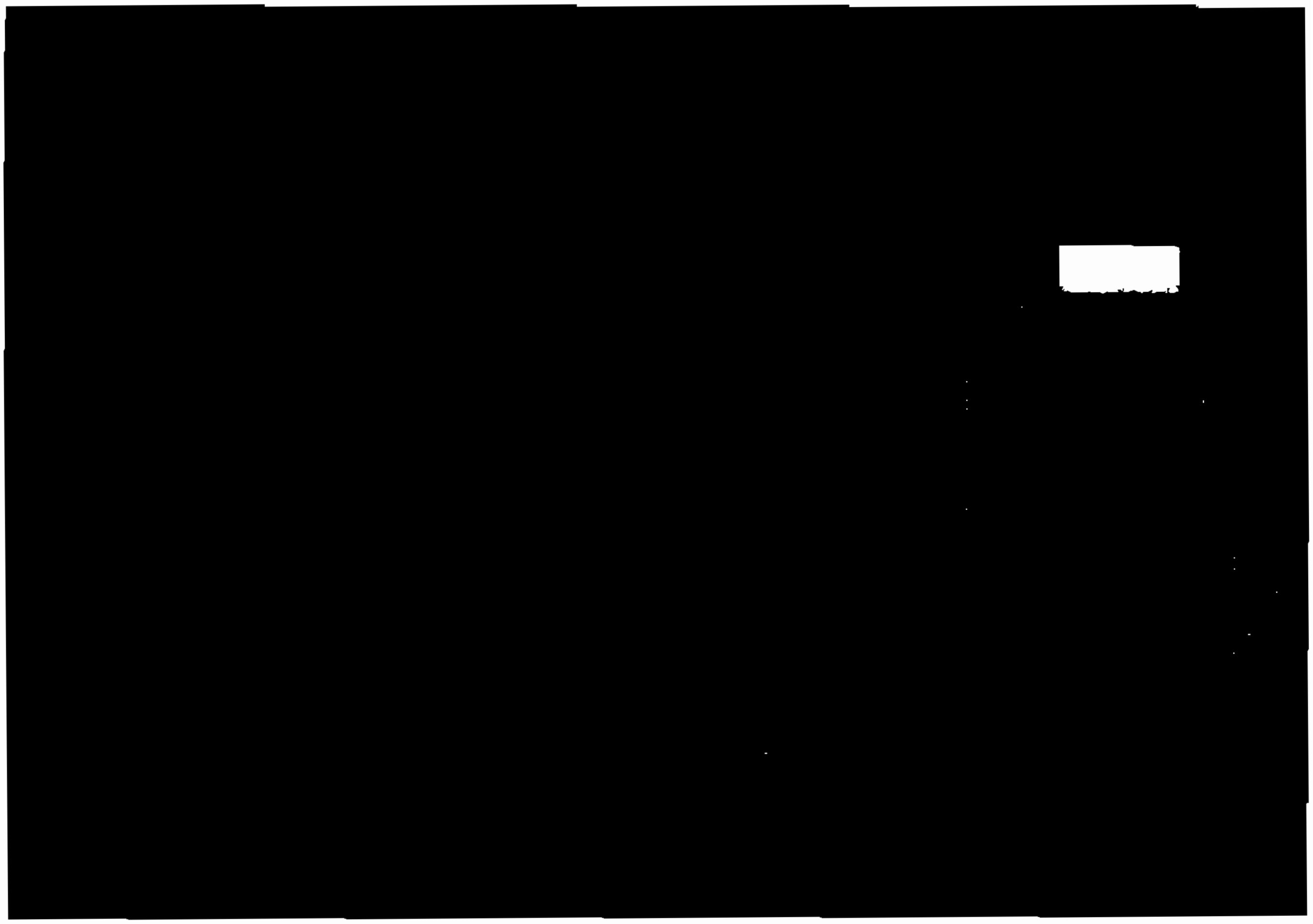

Figure 6. Northeast perspective view of the Devonian time structure map. The color change from red to green is at the same time as the time slice (Figure 5). Note the cross-fault definition.

field is about $1 000 000. By adding one well to the field, we easily recover the cost of the survey plus give the geologists and engineers a more detailed look at a reservoir that is still being developed during the tertiary recovery stage.

The results to date are multifold. The cross faulting of the Devonian producing horizon is much more extensive than previously mapped. This knowledge has influenced the location of several wells for the CO_2 flood, and the engineers continue to use the results for future programs. Some of the newly discovered faults have generated fault traps within the field that have not been drilled and are now being evaluated to determine their potential. Evidence suggests that the fault block to the southeast may be productive, although it was drilled and abandoned over 40 years ago. Lastly, preliminary studies of the Clearfork formation indicate the 3-D data will help in the development of the plan for the secondary recovery from that producing unit.

In conclusion, land 3-D surveys can be economic and may produce results well beyond the initial goals. The two acquisition techniques used here are just two examples of how to shoot cost-effective land 3-D surveys. The power of 3-D seismic is a necessary tool to use in developing new discoveries and extending the life of old fields. **LE**

Acknowledgments: The authors congratulate Unocal and its Dollarhide Unit partners for taking a leap of faith to test new technology. We thank HGS Party 1207 for taking our ideas and bringing them to life in a very efficient and professional manner. Finally, we express our appreciation to the management of Unocal and HGS for encouraging us to experiment and share our experiences with our peers.

Michael T. Reblin is a regional geophysicist for Unocal North American Oil and Gas Division. He obtained a BS in applied geophysics from Michigan Techological University and an MS in geophysics from the University of Utah. After a year with Gulf Oil, he joined Unocal International Division in 1974. After three years in Balikpapan, Indonesia, he worked for the Oil and Gas Division in Ventura, Anchorage, and Midland. He currently holds a staff position as a consultant to the line geophysicists and managers.

Gregory G. Chapel is a senior geophysicist for Unocal North American Oil and Gas Division. He graduated from Colorado School of Mines in 1980 with a degree in geophysical engineering. After joining Unocal International Division in Los Angeles, he spent several years on assignment in Balikpapan. He is currently working as a development geophysicist in Midland, specializing in 3-D seismic interpretation and workstation technology.

Steven L. Roche received his BS from the University of California-Riverside in 1978. He joined Geophysical Service Inc as a seismic processor. He later worked for HGS as an area geophysicist for the Mid-Continent Division. In 1990 Roche joined the Data Acquisition Research and Development Group within HGS. He is a member of SEG, EAEG, and PBGS.

Chuck Keller received a BS from Pittsburg State University in 1980. He joined Geophysical Service Inc as a seismic processor and from 1983-89 worked as an area geophysicist and processing party chief. In 1989 Keller was named geophysical supervisor for both data acquisition and data processing. He is a member of SEG and PBGS.

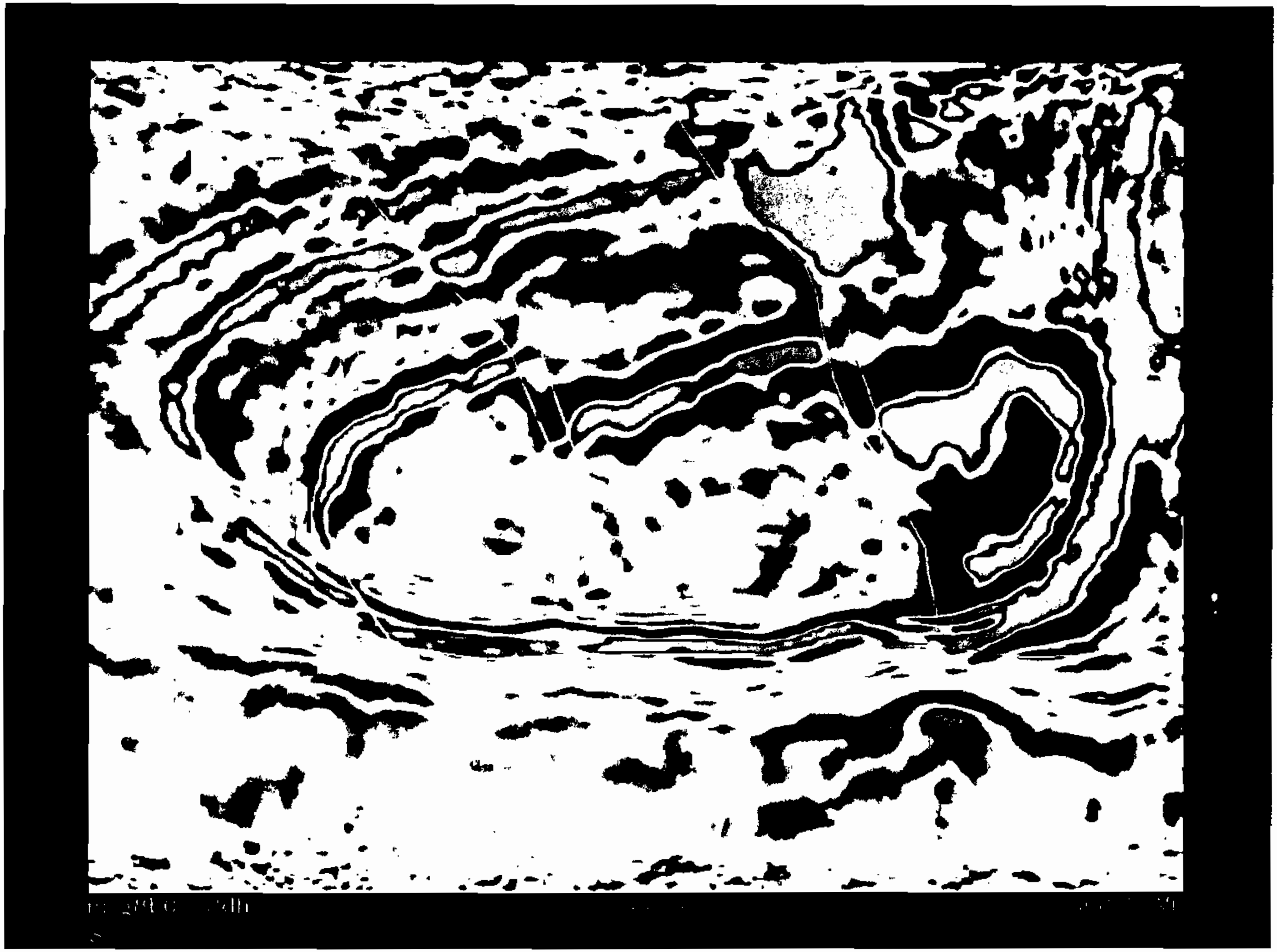

Figure 5. Time slice at 1008 ms (approximately 4600 ft subsea, and 7800 ft below the surface). Devonian horizon is annotated in purple and the interpreted faults are yellow.

AAPG National Convention (1994), Denver, CO

case forecast assuming a moderate increase in gas well completions indicates that U.S. gas production could decline as much as 2.5 Tcf/year by December 1995. Increasing gas rig utilization to 50% with 1000 active rigs could sustain U.S. production at current levels. More robust U.S. drilling activity and addition of at least 1.5 Tcf/year in Canadian imports would be required to meet the 2.0 Tcf increase in demand that is forecast by 1996. An updated forecast predicts future US drilling rates that will be required to meet increased demand.

STAUDT, WILFRIED J., GARY HEMMING, WILLIAM J. MEYERS, and MARTIN A. A. SCHOONEN, Department of Earth and Space Sciences, State University of New York, Stony Brook, NY

Constraints on the Composition of Diagenetic Fluids that Formed Burlington-Keokuk Regional Dolomites: Boron, Sodium, Chloride and Sulfate as Fluid Tracers

Based on detailed field and petrographic studies the diagenesis and relative timing of two dolomitization events (dolomite I & II) in the Mississippian Burlington-Keokuk Formation (Iowa, Illinois, Missouri) has been established. The composition and nature of the solutions that have dolomitized lime mud to form dolomite I, and partly replaced dolomite to form dolomite II have been previously constrained using various trace elements and isotopes. The use of boron isotopic compositions and boron, sodium, chloride and sulfate as fluid tracers permits us not only to distinctly differentiate between the two dolomite generations but also to further constrain the compositions of the dolomitizing solutions.

Sodium concentrations (fluid-inclusion corrected) range from 124-584 ppm ($\bar{x}$ =289 ppm) for dolomite I and from 0-186 ppm ($\bar{x}$ =58 ppm) for dolomite II. Sulfate concentration range from 1354-3521 ppm ($\bar{x}$ =2237 ppm) for dolomite I and from 150-384 ppm ($\bar{x}$ =276 ppm) for dolomite II. Dolomites I & II also have distinctly different boron concentrations which are about a factor of two higher in dolomite I.

The low sulfate and boron concentrations in dolomite II are consistent with a subsurface fluid model. The high sulfate concentrations in dolomite I, however, require near surface dolomitization under oxidizing conditions. Dolomite I samples show a distinct trend of increasing sodium and sulfate concentrations from the paleo basin towards the paleo-shoreline. These data indicate increasing fluid Na/Ca and SO_4/CO_3 ratios towards the paleo shore, and are consistent with moderately concentrated dolomitizing fluids of seawater-like origin. Observed low boron concentrations and light boron isotopic compositions compared to pristine Mississippian components may have resulted from the interaction of this evapo-concentrated marine fluid with the marine carbonate mud precursor at a somewhat lower solution pH than expected from normal marine waters.

STEWART, CINDY L. CRAWLEY, Enron Oil and Gas Company, Denver, CO

Detection of Carbonate Buildups: Aspects of a 3D Seismic Stratigraphic Interpretation of Pennsylvanian Age Upper Ismay Algal Mounds, Kiva Field, Paradox Basin, Utah

Kiva field produces oil and associated gas from carbonate buildups in the Upper Ismay zone of the Paradox formation at a depth of 5800 feet. The stratigraphic trap is formed by a lithologic change within the Upper Ismay zone from a limestone and dolomite reservoir facies to a thick offmound anhydrite facies. The estimated ultimate recovery under waterflood is 3,106 MBO + 3,689 MMcfg. Cumulative production from Kiva field as of 1/93 is 1,991 MBO + 3,023 MMcfg.

The 1984 discovery of Kiva field was the result of a geologic model that was confirmed by conventional 2D seismic data. The seismic data was carefully processed and took into consideration the cyclic nature of the geology in the Paradox formation.

After the confirmation well flowed 1050 BOPD + 750 Mcfgpd from the Upper Ismay, Meridian Oil and BWAB proceeded in January 1985 to acquire a 3D seismic survey over the possible extents of the new field. The results of that survey show that the 3D images the porous part of the algal mound and demonstrates mound morphology. The survey also demonstrates that the conventional 2D strike line images the crest of the mound from out of the plane of the section (sideswipe), and the 3D migration of the data volume is able to place the image of the mound into its proper position.

The ability to detect these prospective algal mounds using high quality seismic data makes these shallow oil reservoirs an excellent exploration target.

STONE, DONALD S., Consultant, Littleton, CO

Structure and Kinematic Genesis of the Quealy Wrench Fault Duplex: Product of Laramide Reactivation of Precambrian Shear Zones of the Cheyenne Belt in the Laramie Basin, Wyoming

The Cheyenne belt is a series of northeast-trending mylonite zones described from the Medicine Bow Mountains of southwestern Wyoming. This belt has a complex deformational history with identifiable events in Archean through Proterozoic time (>2500 through 1700 Ma). It is interpreted as a collisional suture zone separating the Wyoming Archean province on the north from accreted Proterozoic island arc terrains on the south. In the Laramie basin, footwall to the Arlington thrust which borders the Medicine Bow Mountains on the east, subsurface studies indicate that northeast-trending faults in Phanerozoic rocks extend across the basin and probably reflect Precambrian shear zones of the Cheyenne belt that were variably reactivated under probable east-west directed principal horizontal stress during several Phanerozoic deformational episodes.

A large seismic and borehole data base in the Quealy/James Lake area outlines a complex pop-up structure, which is interpreted as part of a left-stepping, dextral wrench fault duplex. This duplex is comprised of three west-dipping, north-northwest trending, basement-involved thrust faults, and one antithetic detachment (in Permian shales) thrust, confined between the east-northeast trending South Quealy and North Quealy fault zones. Along the south edge of the central Quealy pop-up, measurements based on differential shortening along either side of the South Quealy fault zone indicate that horizontal and vertical slip components are about equal (i.e., approx. 1 km). Laramide faulting and uplift produced the traps for oil accumulations in Cretaceous, Jurassic, and Permo-Pennsylvanian sandstones in the Quealy oil field. Structural details are shown with maps, cross sections, and seismic profiles. Also, an interpretive, kinematic developmental sequence is diagrammed.

STONE, W. NAYLOR, and RAYMOND SIEVER, Harvard University, Cambridge, MA

The Making of a Quartzite: Where is the Quartzose Sandstone Porosity Basement?

Studies of deeply buried quartzose sandstones and low-grade metamorphic quartzites from the Greater Green River and Anadarko basins, the Sabine Uplift (East Texas), and the Pennsylvania coal fields have led to a general model for the quartzose sandstone lithification process. Compactional processes (mechanical and pressure solution) result in intergranular volume (= intergranular porosity + cement + matrix) decline to an average of 24% within the first 2 kilometers of burial. With additional burial, the dominant porosity decline process becomes quartz cementation. Quartz cementation requires the importation of large volumes of silica-bearing fluids; therefore, two of the rate limiting steps in the porosity decline process are the aqueous fluid flow rate and the rate of supply of silica to the fluids from sources external to the sandstone.

Empirical porosity prediction models which relate observed porosity and quartz cementation to thermal maturity allow an estimate of the mean and range in porosity possible at a given thermal maturity. Our current model (and data from the literature) suggests that average porosities are less than 5% at thermal maturities shortly beyond the end of the oil window. However, since small amounts of pressure solution or small amounts of quartz cement can result in high porosity packing frameworks that are stable to great lithostatic pressures, high porosity sandstones can exist at great depth. To explore for anomalously high porosity at high thermal maturities one must identify units which (1) have had low aqueous fluid flow rates throughout their burial history; (2) are distant from potential silica sources; or, (3) have grain surface contamination which prevents quartz cement nucleation.

STONECIPHER, S. A., Marathon Oil Co., Littleton, CO; J. M. SPAW, Consultant, Denver, CO; and U. HAMMES, Consultant, Denver, CO

Diagenetic Modeling as an Exploration/Exploitation Tool. The Search for an Elusive Unconformity in the North Celtic Sea

The "A" Sand interval of the Albian-age Greensand, North Celtic Sea, is the main reservoir at Kinsale Head and Ballycotton gas fields. The "A" Sand consists of stacked coarsening-upward sequences of poorly sorted, fine-to very fine-grained, bioturbated, glauconitic quartz sands topped by sandy shell lags. These sequences are in turn overlain by a glauconite-rich transgressive sand.

Future

A very safe prediction is that the application and sophistication of 3D seismic technology will grow steadily for the foreseeable future. The following are some specific areas in which progress is occurring.

Acquisition/Processing/Interpretation Methods. At sea, operators are shooting surveys with various combinations of multiple streamers, multiple source-arrays, and multiple boats, experimenting with towing streamers in circles around targets like salt domes to improve the imaging of radial faults, and shooting into receivers fixed on the ocean bottom.

On land, where one is free from the constraints of towing a streamer, operators are deploying many innovative acquisition geometries that make full use of the multichannel capabilities of modern seismic systems. The geometries account for terrain and cultural obstacles while optimizing subsurface coverage and mixes of offsets and azimuths, all at the lowest possible cost. Some experimental work is under way to acquire 3D three-component surveys, thus adding shear- and converted-wave data volumes to the standard compressional-wave volume.

Advances in supercomputing will continue to speed processing and will permit the inclusion of more sophisticated algorithms in processing schemes. Infusion of analytical techniques from remote sensing and other image processing disciplines is beginning to affect 3D seismic interpretation. Automated information extraction (for example, algorithms that pick events after a few control points are specified) is becoming a routine part of interpretation, and many facets of 3D seismic analysis are amenable to being impacted eventually by artificial intelligence technology.

Routine Use in Exploration. A recent innovation in 3D seismic surveying has been acquisition along widely spaced lines followed by filling in of the data volume by numerical interpolation before performing 3D migration. This 3D scheme (known variously as reconnaissance, exploration, or wide-line 3D) depends on a good interpolation algorithm to be successful, and even then some steep-dip information is lost. However, the technique has the potential to reduce acquisition costs to a point where it is feasible to shoot 3D for exploration, and these types of surveys are now penetrating the seismic market.

3D Seismic With Downhole Sources/Receivers. The standard 3D seismic data volume is acquired with sources and receivers at the earth's surface. It is logistically possible to put sources and/or receivers in boreholes and to record part or all of the 3D data volume with this downhole hardware. This approach is an active area of research. Depending on the acquisition configuration, one records various kinds and amounts of reflected and transmitted seismic energy, which can then be sorted to provide information on geometric framework, rock properties, and flow surveillance, just like surface surveys. Advantages of downhole placement are that higher seismic frequencies generally can be recorded, thereby improving resolution, and surface-associated seismic noise and statics problems are lessened or avoided. The main disadvantages are that source/receiver plants are constrained by the physical locations of available boreholes; borehole seismology can be affected by tube waves and the like, so downhole placement is not noise-free; a borehole source cannot be so strong as to damage the well; and the logistics and economics of operating in boreholes are complex, though not necessarily always worse than operating on the surface. One can imagine a time when borehole seismic sources and receivers might be standard components of the hardware run into wells and accepted as routine and valuable devices for reservoir characterization and flow surveillance.

Summary

The petroleum industry's 20-year experience with 3D seismic surveying is an example of a technological and economic success. Today, the investment in a 3D survey typically results in fewer development dry holes, improved placement of drilling locations to maximize recovery, recognition of new drilling opportunities, and more accurate estimates of hydrocarbon volume and recovery rate. These outcomes improve the economics of development/production plans and make the surveys cost-effective. More skillful reservoir management will be a theme of the 1990's, and 3D seismic technology will be part of the advancement.

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SI Metric Conversion Factors

ft	× 3.048*	E−01	= m
miles	× 1.609 344*	E+00	= km

*Conversion factor is exact.

JPT

This paper is SPE 19687. Distinguished Author Series articles are general, descriptive presentations that summarize the state of the art in an area of technology by describing recent developments for readers who are not specialists in the topics discussed. Written by individuals recognized as experts in the area, these articles provide key references to more definitive work and present specific details only to illustrate the technology. Purpose: To inform the general readership of recent advances in various areas of petroleum engineering. A softbound anthology, *SPE Distinguished Author Series: Dec. 1981–Dec. 1983*, is available from SPE's Book Order Dept.

JPT

JULY 1989
VOL. 41, NO. 7

Technology

On The Cover

Operations in the hostile environment of the North Sea are always challenging. This special issue contains five papers on how Phillips Petroleum Co. solved compaction and subsidence problems in the Ekofisk field. A sixth paper tells how Amoco Production Co. addressed similar problems in the neighboring Valhall field. For a detailed look at these North Sea chalk fields, turn to the series of papers beginning on Page 709. Cover by Alex Asfar.

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6. If necessary to eliminate the effect of an ex parte communication received in violation of this section, an agency head or hearing officer in a contested case proceeding who receives the communication may be disqualified, upon good cause being shown in writing to the hearing officer or to the agency. The portions of the record pertaining to the communication may be sealed by protective order issued by the agency.
7. The agency shall, and any party may, report any willful violation of this section to the appropriate authorities for any disciplinary proceedings provided by law. In addition, an administrative agency may, by rule, provide for appropriate sanctions, including default, for any violations of this section.
8. Nothing in this section prohibits a member of the general public, not acting on behalf or at the request of any party, from communicating with an agency in cases of general interest. The agency shall disclose such written communications in contested cases.

Source: S.L. 1991, ch. 342, § 18.

Effective Date.
This section became effective July 1, 1991, pursuant to N.D. Const., Art. IV, § 13.

28-32-12.2. Separation of functions.

1. No person who has served as investigator, prosecutor, or advocate in the investigatory or prehearing stage of a contested case proceeding may serve as hearing officer.
2. No person who is subject to the direct authority of one who has served as an investigator, prosecutor, or advocate in the investigatory or prehearing stage of a contested case proceeding may serve as hearing officer.
3. Any other person may serve as hearing officer in a contested case hearing, unless a party demonstrates grounds for disqualification.
4. Any person may serve as hearing officer at successive stages of the same contested case proceeding, unless a party demonstrates grounds for disqualification.

Source: S.L. 1991, ch. 342, § 19.

Effective Date.
This section became effective July 1, 1991, pursuant to N.D. Const., Art. IV, § 13.

28-32-13. Findings of fact, conclusions of law, and order of agency — Notice.

1. Within thirty days after the evidence has been received, briefs filed, and arguments closed in a proceeding before an administrative agency, or as soon thereafter as possible, the agency shall make and state concisely and explicitly its findings of fact and its separate conclusions of law, and the order of the agency based upon its findings and conclusions.

2. If the agency head, or another person authorized by the agency head or by law to issue a final order, is presiding, the order issued is the final order.
3. If the agency head, or another person authorized by the agency head or by law to issue a final order, is not presiding, then the person presiding shall issue a recommended order which becomes final unless specifically amended or rejected by the agency head. The agency head may adopt a recommended order as the final order. The agency may allow petitions for review of a recommended order and may allow oral argument pending issuance of a final order. An administrative agency may adopt rules regarding the review of recommended orders and other procedures for issuance of a final order by the agency.
4. The agency must give notice of an order issued in any proceeding heard by it by delivering a copy of the order, and the findings and conclusions upon which it is based, to all the parties to the proceeding either personally or by certified mail. If notice is given by certified mail, the notice shall be deemed given as of the date of certification. Pursuant to agency rule, in circumstances requiring it, an agency may give notice of an order by mailing the order, and the findings and conclusions upon which it is based, to all the parties by regular mail, provided it files an affidavit of service by mail indicating upon whom the order was served.

Source: S.L. 1941, ch. 240, § 13; R.C. 1943, § 28-3213; S.L. 1991, ch. 342, § 20.

Effective Date.

The 1991 amendment of this section by section 20 of chapter 342, S.L. 1991, became effective July 1, 1991, pursuant to N.D. Const., Art. IV, § 13.

Adequacy of Findings.

Findings by an administrative agency under this section are adequate when they enable the supreme court to understand the basis of the agency's decision. In re Boschee (1984) 347 NW 2d 331.

Although the findings of fact and conclusions of law made by hearing officer were sparse and thus not examples to be followed for compliance with this section, they were nonetheless adequate, as the reviewing court was able to understand the factual basis upon which the trial court reached its conclusions. Walter v. North Dakota State Hwy. Comm'r (1986) 391 NW 2d 155.

An administrative agency's findings are adequate if they enable a reviewing court to understand the basis of the agency's decision. F.O.E. Aerie 2337 v. North Dakota Workers Comp. Bureau (1990) 464 NW 2d 197.

Constitutional Issues.

Administrative agencies have no authority to determine the constitutionality of the statutes under which they operate. Johnson v. Elkin (1978) 263 NW 2d 123.

Driver's License Suspension or Revocation.

Requirement that notice of decision, if mailed, be sent by registered or certified letter was inapplicable to motor vehicle driver's license suspension proceeding in which no pre-suspension hearing was required by statute. State v. Sinner (1973) 207 NW 2d 495, 500.

In a hearing to decide whether to revoke a motorist's driving privileges due to his refusal to take a blood test, the hearing officer's failure to draft a finding of fact on the critical issue of whether the motorist was denied a reasonable opportunity to consult an attorney before deciding whether to submit to the blood test warranted remanding for preparation of a finding on that issue. Evans v. Backes (1989) 437 NW 2d 848.

Insufficient Findings.

Where certificate was granted only upon finding of public convenience and necessity and on findings which merely referred to evidence, such findings were not explicit and were insufficient basis for order granting certificate. Hvidsten v. Northern Pac. Ry. Co. (1948) 76 ND 111, 33 NW 2d 615.

Statement by commission that zoning ordered was consistent with public interest and interest of carrier was not finding of fact within the purview of this statute. Kuhn v. North Dakota Public Service Commission (1956) 76 NW 2d 171.

Public Service Commission.

Public service commission had authority to order telephone company to change its toll-switching facilities to permit another company to operate its own toll-ticketing equipment since decision concerning equipment was not within managerial discretion exception to regulation; order was based on substantial evidence; failure to make specific findings of effect on rates or that public interest would be served was not grounds for reversal since consideration of public interest was implicit in findings of fact and conclusions of law. Northwestern Bell Telephone Co. v. Hagen (1975) 234 NW 2d 841.

Requirement to Make Findings.

Administrative agencies are required to make findings of fact and conclusions of law. That the findings are adequate when they enable the supreme court to understand the basis of the agency's decision. Dunseith Pub. School Dist. No. 1 v. State Bd. of Pub. School Educ. (1987) 401 NW 2d 704.

Statement of Findings.

An agency is required to explicitly state its findings of fact and its separate conclusions of law. Evans v. Backes (1989) 437 NW 2d 848.

State Personnel Board.

Where the state personnel board served on the dismissed employee's attorney only the first page of its findings and conclusions and the board's order, instead of serving the employee with the complete findings, conclusions, and order, it did not render the findings of fact and conclusions of law adopted by the board legally insufficient. Choukalos v. North Dakota State Personnel Bd. (1988) 429 NW 2d 441.

Where the state personnel board found that a state employee (1) was fully aware of [his] duties and responsibilities; (2) was fully aware of insurance department policies regarding rate deviations; (3) failed to consistently apply the policies of the insurance department in reviewing policies which specifically did not comply with department guidelines; (4) failed to communicate department policy to insurance companies; (5) failed to alert the commissioner or deputy commissioner of important regulatory concerns raised by rate filings; (6) failed to improve his performance in the areas shown to be deficient, and found that his actions were detrimental to the discipline and efficiency of the service in which he was engaged having an overall negative effect upon the insurance department, these failures were "cause" supporting the commissioner's decision to terminate the employee, and the board's findings adequately enabled the Supreme Court to understand its decision. Choukalos v. North Dakota State Personnel Bd. (1988) 429 NW 2d 441.

Unreasonable Delay.

Delay of public service commission in failing to render decision for over a year after all the evidence had been taken was unreasonable and mandamus would issue compelling commission to make some determination. State ex rel. Northern Pac. Transport Co. v. Public Service Commission, 82 NW 2d 597.

Workers Compensation Bureau.

Brief findings of fact made by workers compensation bureau without separate conclusion of law was not jurisdictional defect. Bernardy v. Beals (1947) 75 ND 377, 28 NW 2d 374.

Where expert medical testimony is desirable if not essential to a determination of causation of an injury, the workers compensation bureau may not simply ignore competent medical testimony without expressly setting forth in its findings of fact adequate reasons, which are supported by the record, for doing so. Satrom v. North Dakota Workmen's Compensation Bureau (1982) 328 NW 2d 824.

This section is clearly premised upon a prior evidentiary hearing having been held. A petition for rehearing of a denial of benefits following an informal hearing by the workers compensation bureau is in reality a request for an initial hearing, and a claimant should not be required to make a "further showing" before being afforded a hearing under those circumstances. Thus, this section must be applied differently in this situation. Manikowske v. North Dakota Workmen's Comp. Bureau (1985) 373 NW 2d 884.

DECISIONS UNDER PRIOR LAW

Failure to Find Facts.

Although workmen's compensation bureau did not set forth separate findings of fact and conclusions of law upon which it based its decision, case was not remanded since precedent exists for ignoring procedural defects

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

JUN 1994
RECEIVED
ND OIL & GAS
DIVISION

Respond w/in 30 days w/

CASE NO. 5933

IN THE MATTER OF A HEARING CALLED ON A MOTION OF THE COMMISSION TO CONSIDER THE PETITION OF CONOCO INC. FOR AN ORDER PROVIDING FOR THE UNITIZED MANAGEMENT, OPERATION, AND FURTHER DEVELOPMENT OF THE DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION; VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE.	)	**PETITION FOR RECONSIDERATION BY PLACID OIL COMPANY**

Placid Oil Company, pursuant to Sections 38-08-13 and 28-32-14 of the North Dakota Century Code, hereby petitions for reconsideration of the Industrial Commission's action in entering Order No. 6861 in Case No. 5933 on June 16, 1994. In support of this petition, and as its statement of specific grounds upon which relief is requested, Placid states as follows:

1. It is the owner of a working interest in Tracts 3 and 6 of the Dickinson-Lodgepole unit as approved by the Commission in Order No. 6861 and is further the owner of a working interest in lands adjacent to the unit as approved by the Commission in Order No. 6861. It appeared at the hearing of this matter on June 8, 1994, and submitted testimony in opposition to Conoco's proposal for unitization of the Dickinson-Lodgepole field. As such, it is agrieved by the Commission's action.

2. A copy of the order entered by the Commission was mailed to Placid and its counsel on June 21, 1994.

3. Certain of the findings of fact made by the Commission are not supported by the evidence in the record in this proceeding. Specifically, finding No. 16 states that "no evidence was introduced into the record to support identification of the productive portion of the mound using seismic information." In fact, Placid introduced Placid Exhibit No. 4, which consists of a synthetic seismic line recreated from well logs, to show that the

no evidence to support ϕ can be seen w/ seismic

mound feature productive in the Dickinson-Lodgepole pool can be

seismic is highly interpretive as shown by difference btn Placid & ASPRT net pay isopach maps which used same seismic data

detected by seismic information. Placid Exhibit No. 4 clearly shows the lower Lodgepole and Bakken Three Forks markers and the relationship between the thickness of the interval between those

use same statement as in ASPRT about velocity diff as ϕ & ...

the mound growth can be seen, but not the ϕ limit of the mound!

markers and the mound feature. To the extent that paragraph 17 of the Commission order attempts to discredit this information by setting forth Conoco testimony to the effect that only the general structure of a feature can be estimated from seismic information but that reservoir quality and the fluids contained in the reservoir cannot be detected, paragraph 17 is directly contrary to the entire basis upon which Conoco has proposed its unit. Testimony by Conoco personnel during the hearing established that, for purposes of calculating equity parameters, Conoco assumed constant porosity, permeability, and other reservoir conditions

we accepted this since the mound was a "growth" and it was a reasonable assumption

throughout the ~~mound feature~~. Therefore, if the Commission has determined in paragraphs 16 and 17 of Order No. 6861 that the mound feature may be present without containing reservoir quality rock,

Marv

address this

John is misinterpreting the word mound to be synonymous with reservoir. ... all of the ... con...

also have Marv look at this

... therefore

the Commission has discredited the entire basis for Conoco's proposed equity parameters, requiring the Commission to reject Conoco's proposal as not containing a fair, equitable and reasonable division of interest or formula for the apportionment and allocation of the unit product among the tracts.

4. With respect to the Commission's conclusion in paragraph 24 that the plan of unitization included in the record as Exhibits 5 and 6 contains fair, reasonable, and equitable provisions for the division of interest or formula for the apportionment and allocation of the unit product among the tracts, the same is wholly unsupported by any findings of fact. Furthermore, the evidence in the record does not support any findings which would in turn support the conclusion that Conoco's proposed allocation is fair, equitable or reasonable. Conoco's equity formula consists of 50% remaining primary reserves and 50% remaining original oil in place for Phase I and 100% original oil in place for Phase II. In calculating the original oil in place, Conoco witnesses testified that constant reservoir conditions were assumed, and that therefore only the thickness of the interval between the top of the Lodgepole mound and the oil water contact, and the contouring of such data

also used Fryburg data from 3 additional wells.

from four locations in the proposed unit area, had any effect on the calculation of original oil in place. Furthermore, because Conoco's formula assumed that no primary reserves should be allocated to tracts upon which a producing well is not located and all primary reserves were allocated to "producing tracts" in accordance with Conoco's net pay isopach, the calculation of remaining primary reserves is also dependent upon the accuracy of Conoco's depiction of the interval between the top of the Lodgepole mound and the oil water contact. Conoco's Exhibit No. 12 depicts Conoco's interpretation of the subsea top of the Lodgepole reservoir, while Conoco's Exhibit No. 13 depicts Conoco's interpretation of the isopach of Lodgepole pay. Conoco offered no evidence to establish the oil water contact for any of the four wells used as control points in its isopach. However, Conoco's allocation of 26 feet of net pay for the State A #83 well in the NW¼ of Section 5, Township 139 North, Range 96 West, when considered with Conoco's top of the Lodgepole reservoir at -7335 on Conoco's Exhibit No. 12, would equate to an oil water contact at -7361. When corrected for the Kelly Bushing elevation of 2467, -7361 subsea would equate to -9828 in the State A #83 well. Conoco's Exhibit No. 7 clearly shows, and Conoco's witness agreed, that the oil water contact as shown on Conoco's Exhibit No. 7 is approximately -9818. This is further supported by Placid's Exhibit No. 8. In fact, Conoco's Exhibit No. 13 allocates approximately 10 feet of net pay to the State A #83 well which cannot be justified by the evidence in the record. The effect is to overstate each and every one of the factors in both Phase I and Phase II of Conoco's proposed equity formula for tract 4, a tract in which the record discloses that Conoco owns 100% of the working interest, and understate the factors in each other tract within the unit boundaries, including tracts 3 and 6 in which Placid owns an

Conoco said this was their 1st proposed o/w contact, but it is a transition zone & doesn't go to 100% at one depth.

(use Lawrence's rebuttal)

interest. As Conoco's formula is admittedly inaccurate, it cannot be fair, equitable, or reasonable.

5. The Commission's findings in paragraphs 18 through 20 that Conoco's actions in contouring the isopach in close proximity to the Filipi No. 76 well are justified because of a supposed correlation between mound thickness and Fryburg structure is not supported by the evidence. Presumably, the Commission has relied upon Conoco's Exhibit No. 10 for its justification. Exhibit No. 10 contains a fundamental inconsistency in that it predicts the thickness of the interval from the top of the Fryburg to the top of the clean lime, or the mound, for the Filipi No. 76 well and the Frenzel No. 79 straight hole while Conoco steadfastly maintains that no mound was encountered in either well. It is axiomatic that if no mound was encountered, the thickness from the top of the Fryburg to the top of the nonexistent mound cannot be measured. There is simply no logical basis for Conoco's attempt to predict where the mound would have been had it existed in those wells.

Further, to the extent the Commission justifies Conoco's eastern boundary by the correlation between Conoco's material balance calculation and is volumetric calculation, nothing in the record supports the finding or conclusion that the correlation between two methods of calculating volumes of oil in place will in any way support or not support the location of such volumes of oil.

6. The Commission has further erred in failing to set forth fair, reasonable, and equitable terms for further development of the Dickinson-Lodgepole pool outside the unit boundaries. By

adopting Conoco's unit outlines, the Commission has included as tract 6 of the unit a 10-acre tract consisting of the SE¼SE¼SE¼ Section 30, Township 140 North, Range 96 West. Commission Order No. 6607, dated April 8, 1993, establishes 320 acre spacing for the Dickinson-Lodgepole field and requires that wells be located not less than 660 feet from a spacing unit boundary nor closer than 1980 feet to another well permitted to producing from the pool. Ordering paragraph No. 13 of Order No. 6861 provides that such spacing unit orders are superseded and replaced to the extent "not consistent" with Order No. 6861. However, the Commission has failed to address whether 320-acre spacing is still applicable in the remainder of Section 30 or where additional wells drilled to the Dickinson-Lodgepole pool may be located within the remainder of Section 30. Placid believes that evidence submitted to the Commission demonstrates that, in light of Conoco's depiction of the unit boundary, Placid's correlative rights will only be protected if it is allowed to drill an additional well at a location approximately 660 feet from the east line and 660 feet from the south line of said Section 30. Order No. 6861 simply fails to address the location of wells outside the unit boundary.

WHEREFORE, Placid respectfully requests that the Commission dissolve its Order No. 6861 and enter an order denying Conoco's petition for the reasons set forth herein. Alternatively, if the Commission feels that additional evidence is necessary or desirable, Placid requests that the Commission allow a new hearing as it may deem appropriate.

Respectfully submitted this 30th day of June, 1994.

FLECK, MATHER & STRUTZ, LTD.
Attorneys for Placid Oil
400 East Broadway, Suite 600
Post Office Box 2798
Bismarck, North Dakota 58502

By ______________________
JOHN W. MORRISON

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing document was on the 30th day of June, 1994, mailed to the following:

Lawrence Bender
Attorney at Law
P.O. Box 400
Bismarck, ND 58502

____
JOHN W. MORRISON

SFN5729

STATE OF NORTH DAKOTA)
)
COUNTY OF BURLEIGH)

AFFIDAVIT OF MAILING

I, Donna Bauer, being duly sworn upon oath, depose and say: That on the 21st day of June 1994, I enclosed in separate envelopes true and correct copies of the attached Order No. 6861 of the North Dakota Industrial Commission, and deposited the same with the United States Postal Service in Bismarck, North Dakota, with postage thereon fully paid, directed to the following persons, all of whom appeared at the hearing of the Industrial Commission in Case No. 5933 :

Mr. John Morrison
Fleck, Mather & Strutz Ltd.
P. O. Box 2798
Bismarck, ND 58502

Mr. Lawrence Bender
Pearce & Durick
P. O. Box 400
Bismarck, ND 58502

Mr. Doug Kadrmas
2314 25½ Ave. S.
Fargo, ND 58103

Mr. Frank R. Howell
Hunt Petroleum Corp.
3400 Thanksgiving Tower
Dallas, TX 75201

Mr. Robert O. Wefald
2800 N. Washington St.
P. O. Box One
Bismarck, ND 58502-0001

Ms. Martha Sundry
ARS Control Account Ltd. Part.
P. O. Box 22854
Denver, CO 80222

Mr. Clyde W. Jones
P. O. Drawer 1267
Parker, CO 80134

Mr. Gary D. Kalanek
3754 Kingston Dr.
Bismarck, ND 58501

Mr. R. Joe Starrett
Huntington Resources Inc.
8086 S. Yale
Suite 228
Tulsa, OK 74136

Mr. Ernest Gomez
Geologist
3609 S. Wadsworth
Suite 500
Denver, CO 80235

Ms. Joan Schmidt
RR1 Box 140
Dickinson, ND 58601

Donna Bauer
Donna Bauer
Oil & Gas Division

On this 21st day of June, 1994, before me personally appeared Donna Bauer to me known as the person described in and who executed the foregoing instrument and acknowledged that she executed the same as her free act and deed.

Evie Roberson
Notary Public
State of North Dakota County of Burleigh
My Commission expires 11-3-98

Mr. P. J. Turner
Conoco Inc.
800 Werner Court
Casper, WY 82601

Mr. Jerry Hyrkas
Conoco Inc.
800 Werner Court
Casper, WY 82601

Mr. Kevin Zorn
Conoco Inc.
800 Werner Court
Casper, WY 82601

Mr. Stephen Bressler
Placid Oil Co.
1601 Elm St.
Suite 3800
Dallas, TX 75201

Mr. R. Kevin Preston
P. O. Box 22066
Denver, CO 80222

Mr. Jimmy D. Campbell
1601 Elm St.
Suite 3800
Dallas, TX 75201

Mr. Greg Mohl
Conoco Inc.
800 Werner Court
Casper, WY 82601

Dickinson Field

Case #	Order #	Date Signed	Description
0175	0189	57-10-25	TS Dickinson-Md 80 C SW & NE Op
0210	0229	58-04-25	TS Dickinson-H 160 C NE 4/4
0318	0348	59-09-28	PS Dickinson-H 160 C NE
0566	0609	63-02-05	PS Dickinson-H-Md 160 SW
0848	0920	67-06-22	Amd Dickinson-H fld rules change Zns 160 & 320
0865	0936	67-08-24	POI Dickinson-H S/2 28-140-96 Continental
0888	0960	68-01-02	POI Dickinson-H N/2 33-140-96 Continental
0941	1019	69-03-25	Ex Dickinson NESE 24-140-96 Trend Exploration
1003	1080	70-06-24	Ex Dickinson-H NWSE 22-140-96 Continental
1004	1082	70-09-08	POI Dickinson-H 15-140-96 Cardinal & N American Roy. Cont
1005	1082	70-09-08	POI Dickinson-H 15-140-96 Cardinal & N American Roy. Cont
1041	1117	71-05-10	POI Cardinal & N Amer Roy E/2 15-140-96 Or vetoed Gov Guy
1043	1119	71-05-10	POI Dickinson-H Cardinal W/2 14-140-96
1041	1129	71-07-01	Rehearing POI Dickinson-H E/2 15-140-96
1057	1133	71-08-03	POI Dickinson-H Cardinal W/2 15-140-96
1060	1135	71-09-09	Ex Dickinson-H Continental NE 14-140-96 G
1059	1137	71-10-08	Ex Dickinson-H Cardinal SW 15-140-96
1072	1147	71-12-09	POI Dickinson-H Cardinal S/2 11-140-96
1301	1403	71-12-09	POI Dickinson-H Cardinal S/2 18-140-96 Dism
1095	1173	72-10-10	Unit Dickinson-H Continental App
1102	1179	72-11-30	Ex Dickinson-H Cardinal C SESW 11-140-96
1095	1186	72-11-30	Rehearing Unit Dickinson-H Continental App
1121	1202	73-03-13	Unit Dickinson-H Continental Ratified
1141	1224	73-08-15	Amd Dickinson-H fld to unit outline
1173	1262	74-01-08	Ex Dickinson-H Cardinal S/2 NW 11-140-96

Case #	Order #	Date Signed	Description
1208	1301	74-10-08	Ex Dickinson-H Patrick SESE 10-140-96 G
1209	1302	74-10-08	POI Dickinson-H Patrick E/2 10-140-96
1266	1365	75-07-18	EO suspend Permit 5678
1266	1366	75-09-09	Amd Dickinson-H Cont
1270	1369	75-09-09	Ex Dickinson-H Lone Star Producing NENE 6-139-96
1266	1381	75-10-15	Amd Dickinson-H Cont
1266	1382	75-11-13	Cont Amd Dickinson-H 660 from Unit Bndy
1283	1386	75-11-13	Unit Dickinson-H Allow 2 Inj Wells along Unit Bndy
1299	1402	75-12-09	Ex Dickinson-H Bloco SWSW 1-140-96
1307	1412	76-02-10	SO S Heart & Dickinson-H Reqires SI BHP's 03-76
1515	1657	78-01-12	Amd Dickinson-H Unit Inj Well SESW 11-140-96
1550	1686	78-04-20	EO direct well Dickinson-H Unit 2-139-97
1550	1687	78-05-03	Direct well Dickinson-H Unit 2-139-97
1563	1712	78-07-25	Amd Dickinson surface casing
1880	2099	80-06-24	SWD Dickinson-H Sand Unit SWSW 30-140-96 Dk
1943	2170	80-09-23	Ex Dickinson-H SWNE 13-140-96 G, SWSW 13-140-96 G
2908	3284	83-08-29	Ex Dickinson-H NW 6-139-96 G
2945	3329	83-10-18	Ex Dickinson-H S/2 13-140-96 ID
3120	3532	84-04-04	Amd Dickinson-H PS zn fld bndy
3499	3980	85-04-29	Ex Dickinson-H SWNE 26-140-96 Den
3951	4497	86-05-05	Ex 38-08-06.4 Flare Texas Petroleum Dickinson
4068	4624	86-06-09	Ex 38-08-06.4 Flare Dickinson H Sand Unit Conoco
4279	4887	87-06-12	Amd fld bndy Dickinson, PS Tyler 160
5322	6157	91-09-13	Unit Dickinson-H certify secondary recovery project Cont
5322	6182	91-10-17	Cont Dickinson-H Sand Secondary Recov Project Cont
5322	6275	91-12-30	Cont Unit Dickinson-H Sand Cert Secondary Recovery Cont
5322	6328	92-03-11	Unit Dickinson Heath Sand Unit qual secndry recov proj Cont
5322	6426	92-06-10	Cont Dickinson-Heath Sand Unit Cert Secondry recov Proj Dism

Case #	Order #	Date Signed	Description
5643	6532	92-11-03	Ex Dickinson (WC-Dwd) SWNW 32-140-96 G
5712	6607	93-04-08	TS Dickinson-L 320-660-1980, redef Heart River Field
5785	6698	93-08-18	Amd TS Dickinson-L (2/320) N/2 31-140-96 Cont
5806	6719	93-09-21	Rescind permit Dickinson Field SE 30-140-96 Placid Cont
5785	6720	93-09-21	Cont Amd TS Dickinson-L (2/320) N/2 31-140-96 Cont
5813	6728	93-10-01	Unit Dickinson Heath Sand Cert Secondary Rec
5806	6756	93-11-12	Cont resd permit Dickinson SE30-140-96 Placid Dism Admin App
5785	6757	93-11-12	Cont Amd TS Dickinson-L (2/320) N/2 31-140-96 Dism Admin App
5843	6762	93-12-03	POI Dickinson-L N/2 31-140-96 Cont Admin App
5857	6778	93-12-30	POI Dickinson-L W/2 32-140-96 Admin App
5858	6779	93-12-30	Ex 38-08-06.4 Flare Dickinson-L Conoco Admin App Cont
5859	6780	93-12-30	Cmgl CTB Dickinson-L Admin App (Cont)
5843	6788	93-12-30	Cont POI Dickinson-L N/2 31-140-96 risk penalty
AO	0258	94-01-12	CTB Dickinson-L sequential prod Conoco
5858	6797	94-02-23	Ex 38-08-06.4 Flare Dickinson-L, Conoco, tank vapors Cont
5859	6798	94-02-23	Cont cmgl CTB Dickinson-L Dism Admin App
5933	6861	94-06-16	Unit Dickinson-L unit operating agreement
5935	6862	94-06-16	Unit Dickinson-L ratification 7-1-94
5936	6863	94-06-16	UIC Dickinson-L NW NE 31-140-96 & NWNW 5-139-96
5933	6880	94-07-21	Unit Dickinson-L Cont 45 Days
5933	6893	94-08-03	Reconsider Unit Dickinson-L, Placid, ASPRT, Denied

BEFORE THE INDUSTRIAL COMMISSION

OF THE STATE OF NORTH DAKOTA

CASE NO. 5712
ORDER NO. 6607

IN THE MATTER OF A HEARING CALLED ON A MOTION OF THE COMMISSION TO CONSIDER THE TEMPORARY SPACING FOR THE DEVELOPMENT OF AN OIL AND/OR GAS POOL DISCOVERED BY THE CONOCO INC. #74 DICKINSON STATE WELL, LOCATED IN THE SW NW OF SECTION 32, T.140N., R.96W., STARK COUNTY, NORTH DAKOTA, DEFINE THE LIMITS OF THE FIELD, AND ENACT SUCH SPECIAL FIELD RULES AS MAY BE NECESSARY.

TEMPORARY ORDER OF THE COMMISSION

BY THE COMMISSION:

Pursuant to legal notice this cause came on for hearing at 9:00 a.m. on the 24th day of March, 1993, in Bismarck, North Dakota, before an examiner appointed by the Industrial Commission of North Dakota, hereinafter referred to as the "Commission."

NOW, on this 8th day of April, 1993, the Commission a quorum being present, having considered the testimony adduced and the exhibits received at said hearing, and being fully advised in the premises,

FINDS:

(1) That due public notice having been given as required by law, the Commission has jurisdiction of this cause and the subject matter thereof.

(2) That geological and engineering evidence presented to the Commission relative to the matter of well spacing indicates that the Dickinson-Lodgepole Pool, as classified and defined in this order, should be developed on a pattern of one well to 320 acres in order to drain efficiently the recoverable oil from said pool, assure rapid development, avoid the drilling of unnecessary wells, and prevent waste in a manner that will protect correlative rights.

(3) That temporary 320-acre spacing in the Dickinson-Lodgepole Pool in this field will result in the efficient and economical development of the field as a whole and will operate so as to prevent waste and provide

maximum ultimate recovery, will avoid the drilling of unnecessary wells, and will protect correlative rights.

(4) That the W/2 and SE/4 of Section 4, Township 139 North, Range 97 West is within the boundary of the Heart River Field and wells in the field produce from the Heath Pool. A dry hole in the W/2 of said Section 4 indicates that the Heart River-Heath Pool is not productive in the section. Removing said tracts from the field will not cause waste nor violate correlative rights.

(5) That the unrestricted flaring of gas produced from the Dickinson-Lodgepole Pool could be considered waste, and in order to minimize such, production from the pool should be restricted until the wells producing therefrom are connected to a gas gathering and processing facility.

(6) That the Dickinson State #74 produces from a different common source of supply than that from which the Wm. Kalanek #1 well produced.

(7) That Order No. 609, dated February 5, 1963, established 160-acre spacing for the Dickinson Madison and Heath Pools and continued in force and effect until further order of the Commission. With respects to the Heath Pool, Order No. 920 superseded Order No. 609.

The only well in the Dickinson Field to ever produce from the Madison Pool was the Leach Oil Corp. #1 Wm. Kalanek well which was plugged July 30, 1961. Order No. 609 erred by setting spacing for a pool which was not in production at the time the order was entered. Therefore, the order should be rescinded.

(8) That certain special field rules are necessary to prevent waste and protect against the contamination and pollution of surface lands and fresh waters.

IT IS THEREFORE ORDERED:

(1) That the Dickinson Field is hereby redefined as the following described tracts of land in Stark County, North Dakota:

TOWNSHIP 139 NORTH, RANGE 96 WEST, 5TH PM
ALL OF SECTION 5 AND 6,

TOWNSHIP 139 NORTH, RANGE 97 WEST, 5TH PM
ALL OF SECTIONS 1, 2, 3 AND 4,

TOWNSHIP 140 NORTH, RANGE 96 WEST, 5TH PM
ALL OF SECTIONS 8, 9, 10, 11, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 27, 28, 29, 30, 31, 32, 33,

TOWNSHIP 140 NORTH, RANGE 97 WEST, 5TH PM
ALL OF SECTIONS 13, 22, 23, 24, 25, 26, 27, 33, 34, 35 AND 36,

together with those additional quarter sections or governmental lots corresponding thereto as may be proven productive by wells drilled on lands within one mile of the boundaries of the field as set forth above, provided further that such extensions of the field boundaries shall include only sufficient acreage to form a spacing unit for such wells, and any intervening lands.

(2) That the Heart River Field is hereby redefined as the following described tracts of land in Stark County, North Dakota:

TOWNSHIP 139 NORTH, RANGE 97 WEST, 5TH PM
ALL OF SECTIONS 5, 7 AND 8.

(3) That the Dickinson-Lodgepole Pool be, and the same is hereby defined as that accumulation of oil and gas found in the interval from below the base of the Mission Canyon Formation to above the top of the Bakken Formation within the limits of the field as set forth above.

(4) That effective this date, the temporary spacing for the development of the Dickinson-Lodgepole Pool be, and the same is hereby set at one well to 320 acres.

(5) That all wells hereafter drilled to said pool shall be located not less than 660 feet from a spacing unit boundary nor closer than 1980 feet to a well permitted to or producing from the pool. Wells presently permitted to or producing from the pool that do not conform to this spacing pattern shall be considered exceptions.

(6) That spacing units in the Lodgepole Pool in the Dickinson Field shall consist of two adjacent quarter sections, or governmental lots corresponding thereto within the same section. The configuration of spacing units, either vertical or horizontal, shall be determined by the location of the first well in the section, such that the aforesaid well will be nearest to the center of the spacing unit. Spacing units for wells being equi-distant from the mid-section lines shall be designated by the operator; however, the Commission shall have continuing jurisdiction, and in the event that spacing units hereafter formed by this policy do not coincide with the geological and physical nature of the reservoir, the Commission may alter specific spacing units upon application by any interested party, after due notice and hearing. However, spacing units in Section 32, Township 140 North, Range 96 West, shall consist of the E/2 and W/2 of the section.

(7) That no well shall be drilled hereafter in the Dickinson-Lodgepole Pool except in conformity with the regulations above without special order of the Commission after due notice and hearing.

(8) That the following rules concerning the casing, tubing and equipping of the wells shall apply to the subsequent drilling and operation of wells in the Dickinson-Lodgepole Pool:

(a) The surface casing shall consist of new or reconditioned pipe that has been previously tested to 1000 pounds per square inch. The casing shall be set and cemented at a point not less than 50 feet below the base of the Fox Hills Formation. Sufficient cement shall be used to fill the annular space outside the pipe to the surface of the ground, or the bottom of the cellar, and sufficient scratchers and centralizers shall be used to assure a good cement job. Cement shall be allowed to stand a minimum of 12 hours before drilling the plug or initiating tests;

(b) The producing or oil string shall consist of new or reconditioned pipe that has been previously tested to 2000 pounds per square inch. Casing shall be set and cemented at a point not higher than the top of the producing formation, or at a point approved by the Director. Sufficient cement shall be used and applied in such manner as to adequately protect and isolate all formations containing oil and/or gas, protect the pipe through salt sections encountered, and to isolate the Dakota-Lakota Series. The cement shall be allowed to stand a minimum of 24 hours before drilling the plug or initiating tests. After cementing, the casing shall be tested by application of pump pressure of at least 2000 pounds per square inch. If, at the end of 30 minutes this pressure shall have dropped 150 pounds per square inch or more, the casing shall be repaired. Thereafter, the casing shall again be tested in the same manner. Further work shall not proceed until a satisfactory test has been obtained;

(c) All well-head fittings and connections shall have a working pressure in excess of that to which they are expected to be subjected; and,

(d) All wells shall be equipped with tubing; all tubing shall be of sufficient internal diameter to allow the passage of a bottom hole pressure gauge for the purpose of obtaining bottom hole pressure measurements.

(9) That the gas-oil ratio of each well shall be measured during the months of May and November, and the reservoir pressure of flowing wells shall be measured in the months of May and November, and in pumping wells when the rods are pulled but at least once annually and reported to the Commission within 15 days following the end of the month in which they are determined. Pressure measurements shall be made at or adjusted to a subsea datum of 7270 feet after the well has been shut in for 48 hours. All gas-oil ratios and reservoir pressure determinations shall be made under the supervision of and by methods approved by the Director. The Director is authorized to waive these requirements if the necessity therefor can be demonstrated to his satisfaction.

(10) That no salt water shall be stored in pits in this field, except in an emergency, and approved by the Director.

(11) That in accordance with Commission Order No. 2099, the Dakota-Lakota Series in and under the Dickinson Field, is hereby designated a disposal reservoir, and the Director is authorized to approve requests to utilize wells in the field, as herein defined, for salt water disposal purposes.

(12) That multiple completion of wells for the purpose of producing oil and/or gas from the various pools encountered in the Dickinson Field, is hereby authorized, subject to the following requirements:

(a) Administrative approval may be given by the Director upon the filing of an application in which the applicant states that the requirements described in (b) through (e) below and other applicable rules and orders of the Commission will be complied with;

(b) An approved production packer shall be set between each of the producing horizons in a manner which will effectively isolate each during the production process;

(c) Production from each producing horizon shall be through separate continuous strings of tubing installed in such a manner with respect to the production packers as will prevent commingling of production in the well bore;

(d) An approved well-head of a type which allows independent suspension and packing of the tubing shall be used; and,

(e) All tubing shall be of sufficient internal diameter to allow the passage of a bottom hole pressure gauge for the purpose of obtaining bottom hole pressure measurements.

(13) That for the purposes of division of production to owners of interests in spacing units established by this order, and proven productive prior to the date hereof, this order shall be retroactive to the date of first production.

(14) That the Dickinson State #74 well is hereby permitted to produce at an average rate of 600 barrels of oil per day and flare all surplus gas produced therewith until June 1, 1993. If flaring continues after June 1, 1993, oil production from the well shall not exceed an average of 100 barrels per day until the well is connected to a gas pipeline and processing plant. When the well is connected to a gas pipeline, it shall be allowed to produce at a maximum efficient rate.

That all wells hereafter completed in the Dickinson-Lodgepole Pool shall be allowed to produce at an unrestricted rate for a period of 60 days commencing on the first day oil is produced through well-head equipment into tanks from the ultimate producing interval after casing has been run; after that, oil production from such wells shall not exceed an average of 200 barrels per day for a period of 60 days; after that, oil production from such wells shall not exceed an average of 150 barrels per day for a period of 60 days, thereafter, oil production from such wells shall not exceed an average of 100 barrels of oil per day; if and when such wells are connected to a gas gathering and processing facility the foregoing restrictions shall be removed, and the wells shall be allowed to produce at a maximum efficient rate.

(15) That Order No. 609 is hereby rescinded.

(16) That if the flaring of gas produced with crude oil from the Dickinson-Lodgepole Pool causes, or threatens to cause, degradation of ambient air quality, production from the pool shall be further restricted.

(17) That this order shall be effective the date of first operations of the Dickinson State #74 well and shall cover all of the Dickinson-Lodgepole Pool, common source of supply of crude oil and/or natural gas as herein defined, and shall continue in full force and effect until the 1st day of September, 1994. That the proper spacing for the pool will be considered by the Commission on or before the regularly scheduled meeting in August, 1994.

Dated this 8th day of April, 1993.

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA

/S/ Edward T. Schafer
Edward T. Schafer, Governor

/S/ Heidi Heitkamp
Heidi Heitkamp, Attorney General

/s/Sarah Vogel
Sarah Vogel, Commissioner of Agriculture

BEFORE THE INDUSTRIAL COMMISSION

OF THE STATE OF NORTH DAKOTA

CASE NO. 5933
ORDER NO. 6861

IN THE MATTER OF A HEARING CALLED ON A MOTION OF THE COMMISSION TO CONSIDER THE PETITION OF CONOCO INC. FOR AN ORDER PROVIDING FOR THE UNITIZED MANAGEMENT, OPERATION, AND FURTHER DEVELOPMENT OF THE DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION; VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE.

ORDER OF THE COMMISSION

BY THE COMMISSION:

Pursuant to legal notice this cause came on for hearing at 9:00 a.m. on the 8th day of June, 1994, in Bismarck, North Dakota, before an examiner appointed by the Industrial Commission of North Dakota, hereinafter referred to as the "Commission."

NOW, on this 16th day of June, 1994, the Commission, a quorum being present, having considered the testimony adduced and the exhibits received at said hearing, and being fully advised in the premises,

FINDS:

(1) That an application was filed with the Commission by Conoco, Inc., for an order approving the unitized management, operation and further development of a portion of the Dickinson-Lodgepole source of supply of oil and gas located in Stark County, North Dakota, and for an order approving a plan of operation providing for the injection of water and/or other substances into the common source of supply; as a part of said application and attached to it was a plan of unitization consisting of a Unit Agreement

and Unit Operating Agreement; such application was filed in accordance with Sections 38-08-09.1 through 38-08-09.16 of the North Dakota Century Code ("NDCC").

(2) That the notice of filing of the application and petition and the time and place of hearing thereof was regularly given in all respects as by law required, and that more than 45 days prior to the hearing, Conoco, Inc., as the applicant, did give notice of the time and place of said hearing and did mail, postage prepaid, a copy of the application and the proposed plan of unitization to each affected person owning an interest of record in the unit outline at such person's last known post office address, and that the applicant did, more than 45 days prior to the hearing file with the Commission engineering, geological and other technical exhibits to be used and which were used at said hearing, and that the notice so given did specify that such material was filed with the Commission; that due public notice having been given, as required by law, the Commission has jurisdiction of this cause and the subject matter.

(3) That the plan of unitization proposed by the applicant consists of a Unit Agreement for the development and operation of the Dickinson-Lodgepole Unit in the county of Stark, state of North Dakota, together with a Unit Operating Agreement.

(4) That the unitized management, operation and further development of a common source of supply of oil and gas or portion thereof is reasonably necessary in order to effectively carry on a water injection and pressure maintenance project calculated to substantially increase the ultimate recovery of oil and gas from the common source of supply.

(5) That one or more unitized methods of operation as applied to such common source of supply or portion thereof are feasible, will prevent waste and will with reasonable probability result in the increased recovery of substantially more oil and gas from the common source of supply than would otherwise be recovered.

(6) That the estimated additional cost, if any, of conducting such operations will not exceed the value of the additional oil and gas so recovered.

(7) That such unitization and the adoption of one or more unitized methods of operation is for the common good and will result in the general advantage of the owners of the oil and gas rights within the common source of supply of portions thereof directly affected.

(8) That the unitization and unitized operation of the common source of supply described herein, upon the terms and conditions set forth in the Unit Agreement and Unit Operating Agreement, is fair, reasonable, equitable. Furthermore, the terms and conditions are necessary or proper to protect, safeguard, and adjust the respective rights and obligations of the persons affected including royalty owners, owners of overriding royalties, oil and gas payments, carried interests, mortgagees, lien claimants, and others, as well as the lessees.

(9) That the area proposed to be included within the unit area of the Dickinson-Lodgepole Unit is as follows:

TOWNSHIP 140 NORTH, RANGE 96 WEST, 5TH PM
ALL OF SECTION 31, THE S/2 S/2 SW/4 OF SECTION 29, THE SE/4 SE/4 SE/4 OF SECTION 30, THE W/2, THE W/2 W/2 SE/4, THE W/2 SW/4 NE/4 AND THE SW/4 NW/4 NE/4 OF SECTION 32,

TOWNSHIP 139 NORTH, RANGE 96 WEST, 5TH PM
THE N/2 OF SECTION 5 AND THE N/2 AND SE/4 OF LOT 1, THE N/2 OF LOT 2 AND THE NE/4 OF LOT 3 OF SECTION 6.

ALL IN STARK COUNTY AND COMPRISING 1436.45 ACRES; MORE OR LESS.

(10) That the unit area as described in paragraph (9) hereof and in the application and plan of unitization constitutes a common source of supply, and the evidence established that the area to be so included within the unit area is of such size and shape as may be reasonably required for the successful and efficient conduct of the unitized method or method of operation for which the unit is created, and that the conduct thereof will have no adverse effect upon the remainder of such common source of supply. Provided, however, that injection wells and new wells drilled in the unit area for production or injection purposes should be located an adequate distance from the unit boundary in order to fully protect correlative rights.

(11) That all working interest owners agree, that to increase the ultimate recovery of oil and gas from the pool and to prevent waste, the Dickinson-Lodgepole Pool should be unitized.

(12) That Placid Oil Company ("Placid") and Andrea Singer Pollack Revocable Trust ("ASPRT") each have an interest in the proposed Dickinson-Lodgepole Unit, Stark County, North Dakota.

(13) That both Placid and ASPRT object to Conoco's definition of the boundaries of the Lodgepole Pool reservoir. That definition is depicted on Conoco's net pay isopach map, Conoco Exhibit 13.

(14) That Placid and ASPRT each used identical seismic information, along with well data, to construct their own net pay isopach maps, ASPRT Exhibit 7 and Placid Exhibit 9. The reservoir boundary on each map, however, was based only upon seismic information.

(15) That Placid's net pay isopach map does not feature a "saddle", or a structural low, within the mound as depicted by Conoco and ASPRT, although evidence within Placid's own exhibits (e.g. Placid Exhibit 7) indicates that said saddle exists.

(16) That Placid and ASPRT believe that seismic information can be used to identify the reservoir boundaries, although no evidence was introduced into the record to support identification of the productive portion of the mound using seismic information.

(17) That testimony by Conoco indicates that seismic information is a highly interpretive exploration tool with which general structure of a feature can be estimated, but from which reservoir quality and the fluids it contains cannot be detected. Therefore, the productive portion of the Lodgepole mound cannot be determined by seismic information.

(18) That the Fryburg Interval has regional dip to the north across the Dickinson Field and evidence presented to the Commission indicates that the Fryburg interval will be deposited abnormally high, in comparison to said regional dip, because a mound has grown beneath it.

(19) That the structure of the Fryburg Interval can be a useful method to assist in determining the boundaries of the Lodgepole Pool reservoir.

(20) That the Filipi No. 76 well located in the SW NE of Section 32, Township 140 North, Range 96 West, Stark County, North Dakota, penetrated the Fryburg Interval abnormally high, although the mound was not developed under said well, suggesting that the mound edge is nearby.

(21) That Placid and ASPRT agree with Conoco's material balance calculation with which Conoco calculated an original oil in place of 18,250,000 barrels of oil in the Dickinson-Lodgepole reservoir.

(22) That Conoco's volumetric calculation of original oil in place is approximately 6% above the material balance calculation. ASPRT's volumetric calculation of original oil in place is approximately 12% below the calculated material balance calculation. Conoco's volumetric calculation of original oil in place is more in agreement with the material balance calculation. Therefore, the location of the eastern boundary of the reservoir is as asserted by Conoco.

(23) That Conoco's net pay isopach map is the most credible map presented.

(24) That the plan of unitization filed with the application and included in the record as Exhibits 5 and 6, contains fair, reasonable, and equitable provisions for:

(a) The efficient, unitized management and control of the further development and operation of the unit area for the recovery of oil and gas from the common source of supply affected.

(b) The division of interest or formula for the apportionment and allocation of the unit product among the tracts within the unit area is fair, equitable and reasonable.

(c) The manner in which the unit and the further development and operation of the unit area shall or may be financed and the basis, terms and conditions upon which cost and expense thereof shall be apportioned among and assessed against the tracts and interest made chargeable therewith, including a detailed accounting procedure governing all charges and credits incident to such operation, and makes reasonable provision for carrying or otherwise financing lessees who are unable to promptly meet their financial obligations in connection with the unit.

(d) The procedure and basis upon which wells, equipment, and other properties of the several lessees within the unit area are to be taken over and used for unit operations, including the method of arriving at the compensation therefor, or of otherwise proportionately equalizing or adjusting the investment of the several lessees in the project as of the effective date of unit operation.

(e) The creation of an operating committee to have general overall management and control of the unit and the conduct of its business and affairs and the operations carried on by it, together with the creation or designation of such other subcommittees, boards or offices to function under authority of the operating committee as may be necessary, proper or convenient in the efficient management of the unit, defining the powers and duties of all such committees, boards or officers, and prescribing their tenure and time and method for their selection.

(f) The time when the plan of unitization shall become and be effective.

(g) The time when and conditions under which and the method by which the unit shall be or may be dissolved and its affairs wound up.

(25) That the plan of unitization has been signed, ratified or approved by lessees and royalty owners owning in excess of the 70% required percentage interest in and to the unit area, as provided by NDCC Section 38-08-09.5.

(26) That such Unit Agreement and the Unit Operating Agreement are in the public interest, are protective of correlative rights and are reasonably necessary to increase ultimate recovery and to prevent waste of oil and gas, and that said plan of unitization, as contained therein, appears to conform and comply with the provisions and requirements of NDCC Sections 38-08-09.1 through 38-08-09.13.

(27) That in order to effectuate the purposes of unitization, NDCC Section 38-08-09.2, provides that the Commission is vested with continuing jurisdiction necessary or proper to enforce the provisions of this order.

(28) That in this cause there are certain rules which are necessary and appropriate to the efficient operation of the Dickinson-Lodgepole Unit, in order to promote and expedite the objective for which the unit was formed.

(29) That the rules and orders hereby promulgated for the Dickinson-Lodgepole Unit, pertaining to the injection of water and/or other substances into the reservoir, to reservoir pressure surveys, to gas-oil ratio surveys and to production tests are necessary, desirable, in the public interest, preventative of waste and protective of correlative rights.

(30) That the common source of supply which will be affected by the project has been adequately delineated.

(31) That NDCC Section 38-08-04 and Section 43-02-03-15 of the North Dakota Administrative Code ("NDAC") require each party desiring to drill or operate oil and gas wells in the state to file with the Commission a reasonable bond with good and sufficient surety, conditioned on full compliance with statutes rules and orders of the Commission.

(32) That on behalf of the Dickinson-Lodgepole Unit, the unit operator as a separate and distinct operator, should furnish a bond as provided in NDCC Section 38-08-04 and NDAC Section 43-02-03-15.

IT IS THEREFORE ORDERED:

(1) That the application filed herein be, and the same is hereby approved.

(2) That the creation of the Dickinson-Lodgepole Unit in Stark County, North Dakota, as prayed for in said application be, and is hereby authorized and approved.

(3) That the unit area of said unit shall extend to and include the land hereinbefore described in paragraph (9) of the Findings.

(4) That the plan of unitization consisting of the Unit Agreement and the Unit Operating Agreement, included in the record (as Exhibits 5 and 6) is hereby incorporated in this order by reference, and shall apply to the same extent and with the same force and effect as if actually set forth herein; that the said plan of unitization of and for said Dickinson-Lodgepole Unit is approved, all to the same extent and with the same force and effect as if set forth herein in its entirety; that if said plan of unitization does not in all respects conform to and comply with the provisions and requirements of NDCC Sections 38-08-09.1 through 38-08-09.13, the statute shall prevail.

(5) That the unitized formation shall mean the Lodgepole Formation as identified by Industrial Commission Order No. 6607, being that accumulation of oil and gas found in the interval from below the base of the Mission Canyon Formation to above the top of the Bakken Formation.

(6) That the injection of water and/or other substances into the unitized formation underlying the Dickinson-Lodgepole Unit by the unit operator for the purpose of operating an enhanced recovery project is authorized; provided, however, that prior to the commencement of such injection the operator shall obtain such permits as are required by NDAC Chapter 43-02-05.

(7) That the unit operator of the Dickinson-Lodgepole Unit may, from time to time, use certain existing wells, or wells to be drilled, for the purpose of injecting water and/or other substances into the unitized formation underlying the Dickinson-Lodgepole Unit upon approval by the Commission. The application for such approval shall be in accordance with statutes and rules of the Commission.

(8) That the unit operator shall be permitted to drill additional wells at any location within the unit area, no closer than 660 feet to the boundary of the unit, nor closer than 1980 feet to another well producing or permitted to the same pool outside the unit area.

(9) That all bottom-hole pressures and gas-oil ratios obtained by the unit operator shall be filed with the Commission. Additional bottom-hole pressure and gas-oil ratio measurements may be required by the Director, if deemed necessary.

(10) That a report of unit operations shall be filed annually with the Commission. Such report shall include but not be limited to production and injection amounts as well as recorded pressures and gas-oil ratios. Proposed plans for the unit for the coming year shall also be included in the report.

(11) That the termination of the Dickinson-Lodgepole Unit shall be as prescribed in the Unit Agreement, or as provided by NDCC Section 38-08-09.4; and that notwithstanding any provisions to the contrary, in the event the unit operator fails to commence or ceases enhanced recovery operations, the Commission upon its own motion, after notice and hearing, may consider rescinding this order so that the Dickinson-Lodgepole Unit will terminate and cease to exist.

(12) That the effective date of the Dickinson-Lodgepole Unit shall be the first day of the month following the month in which the plan of unitization has been signed, ratified, or approved by lessees and royalty owners owning the required percentage of interest in the unit area, and has been so certified by the Commission.

(13) That the provisions of this order shall supersede and replace the provisions of all previous rules and orders not consistent herewith, including without limitations all otherwise applicable spacing orders and well location rules.

(14) That the unit operator, on behalf of the Dickinson-Lodgepole Unit, shall cause to be transferred to a separate blanket bond, all wells in the unit area used in unit operations. The bond shall be in the applicable dollar amount as provided in NDAC Section 43-02-03-15.

(15) That this order shall remain in full force and effect until further order of the Commission.

Dated this 16th day of June, 1994.

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA

/s/ Edward T. Schafer, Governor

/s/ Heidi Heitkamp, Attorney General

/s/ Sarah Vogel, Commissioner of Agriculture

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NO. 5933

IN THE MATTER OF THE PETITION OF CONOCO INC. FOR AN ORDER PROVIDING FOR THE UNITIZED MANAGEMENT, OPERATION, AND FURTHER DEVELOPMENT OF THE DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION; VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE.

JUL 1994

CONSOLIDATED RESPONSE OF CONOCO INC. TO "PETITION FOR RECONSIDERATION BY PLACID OIL COMPANY" AND "PETITION FOR RECONSIDERATION BY ANDREA SINGER POLLACK REVOCABLE TRUST"

On June 16, 1994 the North Dakota Industrial Commission ("Commission") entered Order No. 6861 in Case No. 5933. Order No. 6861 granted the application of Conoco Inc. ("Conoco") in the above-captioned matter for the establishment of the Dickinson-Lodgepole Unit in Stark County, North Dakota. On June 30, 1994 and July 1, 1994, Placid Oil Company ("Placid") and the Andrea Singer Pollack Revocable Trust ("ASPRT"), respectively, filed petitions for reconsideration. Placid and ASPRT both allege that the Commission erred in approving the application of Conoco in Case No. 5933.

The record, however, clearly demonstrates that Conoco presented substantial credible evidence to establish that the plan of unitization for the Dickinson-Lodgepole Unit is fair, reasonable and equitable and will result in the greater ultimate recovery of oil and gas from the pool in a manner which will prevent waste, protect correlative rights and prevent the drilling of unnecessary wells.

I. CONTRARY TO PLACID'S CONTENTIONS, COMMISSION ORDER NO. 6861 IS FULLY SUPPORTED BY THE EVIDENCE.

A. Neither Placid nor ASPRT Introduced Seismic Data.

Placid first contends that "certain findings of fact made by the Commission are not supported by the evidence in the record." Placid's Petition at 2. Specifically, Placid points to FINDING NO. 16 which provides that "Placid and ASPRT believe that seismic information can be used to identify the reservoir boundaries, although no evidence was introduced into the record to support identification of the productive portion of the mound using seismic information". Order No. 6861 at 3. Placid argues that FINDING NO. 16 is not supported by the evidence because Placid introduced Exhibit No. 4 which "consists of a synthetic seismic line recreated from the well logs." Placid's Petition at 2.

Contrary to Placid's contention, a synthetic seismic line is not seismic information derived from seismic data. As Conoco's expert geophysicist, Mr. Greg Mohl, testified, a synthetic seismic line is not actual seismic data. Rather, it is a theoretical extrapolation of data derived from well logs. Further, as Placid's witness, Mr. Steve Bressler, testified, Placid did not introduce actual seismic data into evidence because such data was deemed proprietary. As such, Placid and ASPRT merely submitted maps based on seismic interpretations. Accordingly, FINDING NO. 16 is fully supported by the evidence in the record -- "no evidence was introduced into the record to support identification of the productive portion of the mound using seismic information." Order No. 6861 at 3.

Also without merit is Placid's argument that FINDING NO. 17 is "directly contrary to the entire basis upon which Conoco has proposed its unit." Placid's Petition at 2 - 3. Instead, the testimony of Conoco's expert, Mr. Greg Mohl, was that seismic was not an effective tool for identifying the boundaries of the Dickinson-Lodgepole reservoir because there was very little velocity contrast between productive and nonproductive Lodgepole. As such, it is impossible to differentiate between productive and nonproductive Lodgepole using seismic. The use of seismic had absolutely no bearing on the porosity, permeability and other reservoir conditions throughout the mound feature. Since FINDING NO. 17 deals exclusively with seismic and has absolutely nothing to do with porosity, permeability or other reservoir conditions, it is simply a specious argument for Placid to contend that FINDING NO. 17 "is directly contrary to the entire basis upon which Conoco has proposed its unit."

B. The Plan of Unitization for the Dickinson-Lodgepole Pool is Fair, Reasonable and Equitable.

Equally, without merit is Placid's argument that Conoco's plan of unitization for the Dickinson-Lodgepole Pool is not fair, reasonable and equitable. Placid's Petition at 3. Placid argues that FINDING NO. 24 is a conclusion "wholly unsupported by any findings of fact" or evidence in the record. Id. Placid further argues that Conoco's equity formula is not fair and equitable because "Conoco's Exhibit No. 13 allocates ten feet of net pay to the State A No. 83 well which cannot be justified by the evidence in the record." Id. Placid's argument ignores the evidence in the record.

On cross examination, Conoco's expert geologic witness, Mr. Jerry Hyrkas, witness for Conoco, testified that Conoco originally placed the top of the oil/water transition zone at -9818 feet in the State A No. 83 well. At no time did Mr. Hyrkas or any other Conoco witness testify that the oil/water contact was located at -9818 feet. The distinction is crucial because an oil/water contact is the point at which the water saturation goes to 100% whereas an oil/water transition zone is a broad interval over which the water saturation gradually increases to 100%. Since the State A No. 83 has a transition zone not an oil/water contact at -9818 feet, Placid's arguments that Conoco's plan of unitization is not equitable is also without merit.

The record also reflects that both Placid and ASPRT agreed to the oil/water contact interpretation utilized by Conoco in preparing Exhibit No. 13. Since any estimate of water saturation in rock such as the Lodgepole is very interpretative, the decision reached by unanimous consent of all the working interest owners, including Placid and ASPRT, was a fair and reasonable interpretation of the data. While Conoco prepared Exhibit No. 13 based upon what was agreed to by Placid and ASPRT at hearing, Placid presented a new interpretation completely ignoring the decision of the working interest owners which it previously supported.[1]

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[1] As later confirmed by Placid's Mr. Steve Bressler and ASPRT's Mr. Kevin Preston, Conoco's recommendation for inclusion of a transition zone in the reservoir did not receive the necessary votes to be approved by the working interest owner committee. The working interest owners agreed to adopt an oil/water contact which was midway between Conoco's transition zone and the tilted oil/water contact supported by Placid.

Finally, Placid suggest that because the fact that Conoco has 100% working interest in tract 4, Conoco attempted to benefit tract 4 by unfairly treating tracts 3 and 6 where Placid has an interest. The reverse logic also holds true. Placid has zero interest in every tract but tracts 3 and 6. As such, it is in Placid's best interest to downgrade any tract but 3 or 6. On the other hand, it should be noted that the record reflects that Conoco is the largest working interest owner in both tracts 3 and 6. The record also reflects, that 99.55067% of the royalty owners in tract 3 and 100% of the royalty owners in tract 6 have ratified the Unit Agreement and support Conoco's plan of unitization. Clearly, an overwhelming majority of the royalty owners in and under tracts 3 and 6 do not agree with Placid's conclusions that Conoco's plan of unitization for the Dickinson-Lodgepole Pool is not fair and equitable.

C. The Fryburg Interval is a Useful Tool in Determining the Lodgepole Pool Boundaries.

Also, without merit is Placid's argument that the Commission's findings in paragraphs 18 through 20 are not supported by the evidence. Placid's Petition at 5. According to Placid, the lack of mound in the Filipi 76 and Frenzel 79 wells invalidates the use of those wells in developing the relationship between Fryburg structure and mound thickness. Id. To the contrary, the quadratic mathematical relationship that Conoco developed (Conoco's Exhibit No. 10) requires that no mound be present where the thickness of non-mound rocks exceeds 1095 feet. Therefore, the lack of mound between the base of the Lodgepole

Formation and the top of the Fryburg zone in the Filipi 76 and Frenzel 79 wells provides important validation of Conoco's interpretation.[2]

Furthermore, as the Commission noted in FINDING NO. 23, "Conoco's net pay isopach map is the most credible map presented." Order No. 6861 at 4. Presumably, the Commission made such a finding because the Fryburg map offered by Conoco was the least interpretive of all the maps offered into evidence in this case. The Fryburg map offered by Conoco includes more well data than any of the other map offered into evidence in Case No. 5933. Conoco's Fryburg map was based on information from two wells in the middle of the reservoir (the DHSU 37 and the DHSU 33), as well as one well to the northeast (the DHSU 20). Furthermore, the Fryburg structure is geographically defined on four sides. Taking the geographic center of the reservoir at the DHSU 37 well, the Fryburg is defined by the Frenzel 79 on the northwest, the Walton 84 on the southwest, the State A 83 on the southeast, and the Filipi 76 on the northeast. Based on the evidence in the record, the Commission was justified in finding that "the Fryburg interval can be a useful method to assist in determining the boundaries of the Lodgepole Pool reservoir." Order No. 6861 at 4.

D. The Well Location Rules for the Dickinson-Lodgepole Unit Provide for Orderly Development of the Pool.

Finally, Placid contends that the Commission erred by failing to address the issue of well location rules outside the unit boundary. More specifically, Placid states that "the Commission has failed to address whether 320-acre spacing is still applicable in the

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[2] It is important to note that on cross examination ASPRT's geologic witness also supported use of the Fryburg structure in determining mound thickness concerning the existence of the saddle between the State 74 and Kadrmas 75 wells.

remainder of Section 30 or where additional wells drilled to the Dickinson-Lodgepole pool may be located within the remainder of Section 30". Placid's Petition at 5 - 6. Further, Placid contends that their correlative rights will only be protected if it is allowed to drill a well 660 feet from the south line and 660 feet from the east line of Section 30 (effectively on the boundary line of the unit).

Placid makes this contention in spite of the undisputed testimony of Conoco's expert land witness, Mr. Jim Turner. Mr. Jim Turner testified that Conoco would not protest an otherwise legal location drilled outside of the unit boundary in Section 30 and the creation of a non-standard 320-acre spacing unit consisting of only 310 acres. Moreover, Mr. Turner testified that Placid was advised in February 1994 that if it desired to drill a well in Section 30, it should "send us [Conoco] an AFE" and Conoco would evaluate the proposal. More than six months have elapsed since Conoco advised Placid to send an AFE for a well in Section 30. Placid has yet to make proposal to Conoco for the drilling of a well in Section 30. Since Conoco is the largest working interest owner in the Southeast Quarter of Section 30, it is logical to assume the if Placid had intended to drill a well in the Southeast Quarter of Section 30 as they alleged at the hearing and in their petition, Placid would have approached Conoco and made a drilling proposal.

II. CONTRARY TO ASPRT'S CONTENTIONS, THE FINDINGS OF COMMISSION ORDER NO. 6861 ARE NOT "CLEARLY ERRONEOUS"OR TOTALLY WITHOUT BASIS."

ASPRT requests that the Commission "reconsider and stay" Order No. 6861 arguing that certain findings of the Commission are either "clearly erroneous" or "totally without basis." ASPRT's Petition at 1 - 4. In making its arguments, ASPRT either provides no support for its arguments or entirely ignores the evidence in the record.

ASPRT objects to FINDING NOS. 9 and 10 "because they include more tracts than are necessary under the area justified by the ASPRT net isopach map." Id. at 2. Also, ASPRT objects to FINDING NOS. 8, 10, 24 and 26 because they purport to find that the proposed unit protects correlative rights and is fair, reasonable and equitable." Id. ASPRT provides absolutely no support for its conclusion other than the bald statement that FINDING NOS. 8, 10, 24 and 26 "are not justified based on the evidence and should be reconsidered and charged." Id.

In concluding that FINDING NOS. 8, 10, 24 and 26 are not justified, ASPRT ignores the testimony of Conoco's geological witness, Mr. Jerry Hyrkas. Mr. Hyrkas testified that a determination of what tracts to include in the unit were based on the net pay isopach map approved by a vote of the working interest owners using the voting procedure that was established at the first working owners' meeting. It is absurd for ASPRT to argue that the Commission's findings are clearly erroneous and not supported by the record merely because ASPRT presented evidence to the contrary. It is well settled that the Commission, as an administrative agency, is the fact finder and as such has discretion in determining the credibility of witnesses and the weight to be accorded the evidence presented. 2 Am Jur 2d Admin. Law § 363 (1994). It is clear that the Commission exercised that authority and found that Conoco's net pay isopach map was the most credible map presented. Order No. 6861 at 4.

ASPRT also claims FINDING NOS. 14 and 16 are clearly erroneous and not supported by the record because ASPRT used well data in conjunction with seismic data for defining the reservoir edge. Id at 2. Presumably, ASPRT alleges that the Commission committed error by not giving greater weight to the evidence submitted by ASPRT. As set forth above, the Commission has discretion in deciding which evidence to accept and how much weight should be accorded that evidence. Moreover, the record reflects that Conoco and not ASPRT presented the most reliable data for defining the reservoir boundaries. ASPRT's own witness, Mr. Kevin Preston, testified that Conoco's map honored all the data.

Reviewing the data, it is clear that only one point can be exactly defined as the edge of the reservoir — the edge between the Frenzel No. 79 vertical and sidetrack holes. Since ASPRT refused to recognize the relationship between the Fryburg structure and mound thickness, ASPRT was left to define the remaining reservoir limits based on seismic data. As testified by ASPRT's expert, Mr. Ernie Gomez, ASPRT used the same seismic data as Placid in preparing its maps. Even a cursory review of the maps submitted by ASPRT and Placid reveals the highly interpretive nature of seismic mapped reservoir limits. Therefore, ASPRT's and Placid's own exhibits confirm the highly interpretative nature of seismic and its unreliability for use in defining unit boundaries.

ASPRT further argues that FINDING NO. 17 is clearly erroneous and contends that industry experience supports the use of seismic for defining reservoir boundaries. Id. at 2 - 3. Conoco's expert witness, Mr. Greg Mohl, testified that defining oil accumulations and precise reservoir boundaries based on actual seismic data is theoretical and speculative. Coupled with the physical properties associated with the Lodgepole formation, it is simply unrealistic to suggest that actual seismic is a definitive tool which the Commission should recognize as a method for delineating reservoir boundaries for unitization purposes. Certainly, ASPRT is correct that the industry finds seismic a helpful tool in the exploration of other reservoirs and in other areas having more favorable rock properties. Such favorable conditions, however, do not apply to the Lodgepole. Since no one, including Conoco, has found another productive Lodgepole mound using seismic, it is simply premature to say that the use of seismic is a proven tool in the Lodgepole to define reservoir edges.

ASPRT also argues that FINDING NO. 22 is "essentially irrelevant." Id. at 4. ASPRT correctly states that volumetric calculations are estimates based on geologic interpretations. Good geologic interpretations, however, should yield volumetric calculations that match well with the material balance. ASPRT's Mr. Kevin Preston, agreed that Conoco's material balance estimate of 18.25 million barrels of oil was a very accurate estimate of the original oil in place. Since Conoco's volumetric calculation more closely matches the material balance estimate than that of ASPRT, the Commission did not error in adopting Conoco's geologic interpretation rather than ASPRT's geologic interpretation.

Finally, ASPRT argues that FINDING NO. 23 is "clearly erroneous and not supported by a fair interpretation of the evidence." Id. Once again without pointing to any evidence to support the same, ASPRT states that its net isopach map is the most credible. Id. As outlined above, Conoco's isopach map incorporated the most reliable data of all the maps presented. Moreover, Conoco introduced evidence in the record showing that it was the only working interest owner to hold an interest in all nine tracts. Since Conoco is the only working interest owner with an interest in every tract in the unit, Conoco is in the unique position of having the greatest incentive to protect the rights of all owners of interest in each of those tracts.

Furthermore, overlays of maps prepared by ASPRT, Placid, Phillips, and Conoco (which were presented at the working interest owners' meetings), introduced into the record by Conoco, indicate that Conoco's map is the most reasonable and credible interpretation of the reservoir limits. Because Conoco presented the most reasonable and credible depiction of the Dickinson-Lodgepole Pool, it secured the support of more than 76% of the working interest owners and more than 86% of the royalty owners for its Plan of Unitization. The Commission, therefore, did not err and was justified in finding that Conoco's net pay isopach map was the most credible map presented.

CONCLUSION

For all the foregoing reasons, Placid's and ASPRT's petitions for reconsideration should be denied.

DATED this 18th day of July, 1994.

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JUN 1994 RECEIVED ND OIL & GAS DIVISION

June 15, 1994

HAND DELIVERED

Mr. Charles Carvell
Assistant Attorney General
State Office Building
900 East Boulevard
Bismarck, ND 58505-0040

NDIC CASE NO. 5933
PETITION OF CONOCO INC. FOR UNITIZED MANAGEMENT, OPERATION AND FURTHER DEVELOPMENT OF DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION; VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE.

Dear Charles:

Please find enclosed herewith for filing REPLY OF CONOCO INC. TO "RESPONSE OF ANDREA SINGER POLLACK REVOCABLE TRUST".

Mr. Charles Carvell
June 15, 1994
Page 2

Should you have any questions with regard to this matter, please advise.

Sincerely,

LAWRENCE BENDER

LB/leo

Enclosure

cc: Mr. Wesley Norton - (w/enc.)
Mr. Bruce Hicks - (w/enc.)
Mr. John Morrison - (w/enc.)
Mr. Robert Wefald - (w/enc.)
Mr. Jim Turner - (w/enc.)

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JUN 1994

June 10, 1994

Mr. Charles Carvell
Assistant Attorney General
State Office Building
900 East Boulevard
Bismarck, ND 58505-0040

HAND-DELIVERED

CASE NO 5935
APPLICATION OF CONOCO INC. FOR AN ORDER DETERMINING THAT THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA, STARK COUNTY, NORTH DAKOTA, HAS BEEN SIGNED, RATIFIED, OR APPROVED BY OWNERS OF INTEREST OWNING THAT PERCENTAGE OF WORKING INTEREST AND ROYALTY INTEREST WITHIN SAID UNIT AS IS REQUIRED BY APPLICABLE STATUTES AND RULES OF THE COMMISSION.

Dear Charles:

Please find enclosed herewith the original Approval of Unit Agreement of the Dickinson-Lodgepole Unit, Stark County, North Dakota, executed by Arnold E. Kadrmas. As yo will recall at the hearing in the above-captioned matter, a photocopy of the attached document was submitted with the understanding that the original would be submitted to the Commission for inclusion in the record.

As a result of securing the enclosed ratification, royalty owner support for the proposed Dickinson-Lodgepole Unit is as follows:

PHASE I:	86.48866%
PHASE II:	86.03647%

The percentage of royalty owners that have ratified the Unit Agreement and support Conoco's plan of unitization on a tract by tract basis is as follows:

TRACT 1:	91.13126%
TRACT 2:	75.29993%
TRACT 3:	99.55067%
TRACT 4:	100.00000%
TRACT 5:	12.50000%
TRACT 6:	100.00000%
TRACT 7:	77.77778%
TRACT 8:	86.35429%
TRACT 9:	100.00000%

Should you have any questions with regard to this matter, please advise.

Sincerely,

LAWRENCE BENDER

LB/leo

Enclosure

cc: Mr. Wesley Norton - (w/enc.)
Mr. Bruce Hicks - (w/enc.)
Mr. John Morrison - (w/enc.)
Mr. Robert Wefald - (w/enc.)
Mr. Jim Turner - (w/enc.)

ERNEST GOMEZ
GEOLOGIST

PERSONAL:	Date of Birth:	November 29, 1954
	Marital Status:	Married
	Nationality:	American
	Language:	English, Spanish

EDUCATION: B.A., Geology, State University of New York at New Paltz, 1976
M.S., Geology, Northern Arizona University, Flagstaff, Arizona, Geology, 1979

QUALIFICATIONS:

Sixteen years of technical and management experience in the petroleum industry. Expertise in most domestic U.S. basins. Strong background in exploration, development and acquisition.

WORK EXPERIENCE:

INTERA Petroleum Division, Denver, Colorado: (1992 to present)
Geologist

Review of exploration potential in Northwest Basin, Argentina. Sequence stratigraphy of First Frontier, Greater Green River Basin, southwest Wyoming, Yegua Formation, southeast, Texas.

Presidio Oil Company: Dallas, Texas: (1989 to 1992)
Senior Geologist

Responsible for exploration and development of the Jurassic Cotton Valley and Bossier of the East Texas Basin. Development of several exploratory prospects. Established a successful exploratory horizontal drilling program in the Austin Chalk of south Texas using subsurface and seismic. Development of Pennsylvanian (Red Fork, Morrow and Springer) and Devonian (Hunton) prospects in the Anadarko Basin, Oklahoma. Review of several companies and properties for acquisition in the Mid Continent and Gulf Coast, U.S. Implementation of a geological computer system comprised of a database manager (Paragon), contouring (CPS/Radian) and drafting (Autocad).

Home Petroleum Corporation: Houston, Texas: (1987 to 1989)
District Geologist

Responsible for the creation and implementation of a renewed exploration program in the onshore Gulf Coast U.S. Included supervision of staff geologists, geophysicist and landman. Development of several Yegua and Vicksberg prospects in southeast Texas, resulting in a significant discovery. Participated in generation of exploration prospects and lease sales in the OCS of Texas and

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA
Date................ Case No. 5933
Introduced by ....
Exhibit 1 (pg 3 of 3)
Identified by......................

CERTIFICATIONS:

Certified Petroleum Geologist No. 4468 (AAPG)
Professional Geologist State of Wyoming (PG-1586)

INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NOS. 5933 AND 5935

ON A MOTION OF THE COMMISSION TO CONSIDER THE PETITION OF CONOCO INC. FOR AN ORDER PROVIDING FOR THE UNITIZED MANAGEMENT, OPERATION, AND FURTHER DEVELOPMENT OF THE DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION; VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE.	)	TRANSCRIPT CASE NO. 5933
ON A MOTION OF THE COMMISSION TO CONSIDER THE APPLICATION OF CONOCO INC. FOR AN ORDER DETERMINING THAT THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA, STARK COUNTY, NORTH DAKOTA, HAS BEEN SIGNED, RATIFIED OR APPROVED BY OWNERS OF INTEREST OWNING THAT PERCENTAGE OF THE WORKING INTEREST AND ROYALTY INTEREST WITHIN SAID UNIT AS IS REQUIRED BY APPLICABLE STATUTES AND RULES OF THE COMMISSION.	)	CASE NO. 5935

Brynhild Haugland Room
State Capitol Building
Bismarck, North Dakota
June 8, 1994

Met pursuant to notice at 9:00 a.m.

BEFORE THE NORTH DAKOTA STATE INDUSTRIAL COMMISSION

Governor Edward T. Schafer, Chairman, North Dakota Industrial Commission.

Charles Carvell, Assistant Attorney General and Attorney for the Commission, conducted hearing.

APPEARANCES:

Wesley Norton, Director, North Dakota Industrial Commission, Oil and Gas Division.

Bruce Hicks, Manager of Horizontal Drilling, North Dakota Industrial Commission, Oil and Gas Division.

Lawrence Bender, Attorney representing Conoco, Inc.

John Morrison, Attorney representing Placid Oil Company.

Robert Wefald, Attorney representing Andrea Singer Pollack Revocable Trust.

Jim Turner, Landman, Conoco Inc., Casper, Wyoming.

Jerry Hyrkas, Geologist, Conoco Inc., Casper, Wyoming.

Kevin Zorn, Reservoir Engineer, Conoco Inc., Casper, Wyoming.

Greg Mohl, Senior Geophysicist, Conoco Inc., Casper, Wyoming.

Stephen Bressler, Senior Geologist, Placid Oil Company, Dallas, Texas.

Robert Johnson, Consultant, Harris, Brown and Klemer, Inc., on behalf of The Wiser Oil Company.

Arthur C. Bauer, Consultant, on behalf of Lewis W. Hill, Jr.

Ernest Gomez, Geologist,

Kevin Preston, Petroleum Engineer, Aviva Inc.

MR. CARVELL: Come to order. My name is Charles Carvell, I'm an Assistant Attorney General. I'll be today's hearing officer. Up on the table to my right there are forms that you may fill out if you wish to receive a copy of any decisions that the Commission will be making in the cases heard today. You can just fill that form out and give it to anyone here at the table and we'll be sure to send you a copy of the Commission's order. With that we'll take up the first case on the docket, which is Case 5933, this is a petition of Conoco for an order providing for the unitized management, operation, and further development of the Dickinson-Lodgepole Unit Area, consisting of lands within the Dickinson Field in Stark County, for approval of the unit agreement and unit operating agreement constituting the plan of unitization for the Dickinson-Lodgepole Unit Area; for approval of the plan of operation; vacating applicable spacing orders; and for such further and additional relief as the Commission deems appropriate. All parties wishing to be heard in this case please come forward and make your appearance.

MR. BENDER: Governor and Mr. Examiner my name is Lawrence Bender, P.O. Box 400, Bismarck, North Dakota appearing in this matter on behalf of the applicant, Conoco Inc.

MR. MORRISON: Mr. Examiner and Governor Schafer my name is John Morrison. Fleck, Mather and Strutz, P.O. Box 2798, Bismarck. And I'm appearing in this matter today on behalf of Placid Oil Company.

MR. WEFALD: Governor, Examiner, my name is Bob Wefald, P.O. Box 1, Bismarck. I'm appearing on behalf of the Andrea Singer Pollack Revocable Trust.

MR. CARVELL: The witnesses that will be testifying today, I'd like all of you to raise your right hand. Do all of you promise to tell the truth in this hearing?

ALL: I do.

MR. CARVELL: Thank you. Mr. Bender, any opening comments?

MR. BENDER: Mr. Examiner, first of all I'd like to request that Case No. 5933 and 5935 be combined and consolidated for the purposes of hearing.

MR. CARVELL: Case 5935 is an application of Conoco for an order determining that the plan of unitization for the Dickinson-Lodgepole Unit Area, Stark County, has been signed, ratified or approved by owners of interest owning that percentage of the working interest and royalty interest within said unit as is required by the applicable statutes and rules of the Commission. Does anyone object to combining Case 5935 for the purposes of hearing with Case 5933?

MR. MORRISON: No objection.

MR. WEFALD: We, no objection.

MR. CARVELL: Okay, we'll do that. The witnesses that were sworn earlier will also be sworn for Case 5935. Mr. Bender?

MR. BENDER: Governor and Mr. Examiner, this matter is before the Commission on the application of Conoco Inc. requesting authorization for unitized management and operation of the Dickinson-Lodgepole Pool, which is located just northwest of the city of Dickinson. If Conoco's application is granted, Conoco will inject water into the Dickinson-Lodgepole Reservoir which will result in the recovery of an additional 2½ million barrels of oil. The Dickinson-Lodgepole Field was discovered by Conoco in February of 1993. And Conoco is the only company that operates a well in the field. And Conoco is the only company that has ever drilled any Lodgepole wells in the field. More importantly Conoco is the only company or working interest owner in the field that has an interest in nine of the tracts that are to be included in the unit. So, Conoco, unlike any of the other working interest owners that are here today, or who participated in the meetings has an obligation to each one of the royalty owners that has an interest in those tracts. At this hearing today you are going to hear from three Conoco witnesses. Mr. Jim Turner, a landman, is the team leader for Conoco's Lodgepole project. He's going to discuss the painstaking efforts that Conoco took to secure support for this plan of unitization. Jim is also going to discuss that Conoco has received support from more than 85% of the royalty owners in and under the Dickinson-Lodgepole Pool who support Conoco's application. You're also going to hear from Conoco's geologic witness, Mr. Jerry Hyrkas, and Jerry will testify that his map of the reservoir boundary was prepared on the best information available to Conoco and all the other working interest owners. And that's well data. And he's also going to testify that his map was the only map that was approved by the working interest owners. You're also going to hear from Conoco's engineering witness, Kevin Zorn, who's going to discuss the parameters that lead to the equity formula for unitization. Kevin is going to discuss the fact that the equity formula protects the correlative rights of all those owners who have wells on their property as well as those, of course, who do not have wells on their property. Kevin's also going to discuss the unique features of the reservoir and why this field has to be unitized immediately. In addition, Kevin is going to spend some time discussing the production of the field currently. The field is currently restricted to 200 barrels a day, excuse me, 600 barrels a day. It was at 200 and it's just been increased to 600. And after unitization Kevin's going to talk about how production is going to be increased to more than 2000 barrels a day. Finally, Kevin is going to testify that the ultimate recovery from the Dickinson-Lodgepole Field will be approximately 7.9 million barrels of oil which is 2½ million barrels of oil more than will be recovered from the field if it's not unitized. And this incremental recovery of 2½ million barrels of oil is going to result in approximately $9,000,000 in revenue to working interest owners and more than $2,000,000 of revenue to royalty owners. If Conoco's application for unitization in this Dickinson-Lodgepole Pool is denied there is absolutely no guarantee that the working interest owners will be able to go back and get agreement again and come to this Commission and, and seek another application. And even if the working interest owners, if this application is denied, were able to reach agreement down the road there is absolutely no guarantee that the royalty owners will once again approve the unitization project at the level that we have right now, which is 70%. If Conoco's application for unitization is denied for the Dickinson-Lodgepole Pool we believe we might very well end up with a situation which happened approximately 11 years ago when the Little Knife Field Unitization failed. When Little Knife Unitization failed the mineral owners lost, the working interest owners lost and the state of North Dakota lost by tax revenue. If, if Conoco's application for unitization of Little Knife, excuse me, of the Dickinson-Lodgepole Field is denied, we believe that those same parties will lose. Working interest owners will lose, mineral owners will lose and so will the state of North

Dakota. With that in mind I'd be ready to call my first witness.

MR. CARVELL: Mr. Morrison, do you have any opening comments?

MR. MORRISON: Just a very few comments. Let me make it perfectly clear at the outset that Placid is not here today opposing unitization. Placid supports unitization of the Dickinson-Lodgepole Reservoir. However, Placid feels it's essential that such unitization be accomplished on terms that are fair and reasonable to all parties and Placid does oppose and object to Conoco's depiction of the reservoir. In other words Conoco's maps that show the areal extent of the reservoir. As you'll see through Conoco's presentation this is a very important issue in this unit because the only variable that goes into Conoco's proposed Phase II formula for sharing unit production is the mapping of the reservoir. Conoco will tell you they assumed common reservoir characteristics throughout the field and therefore the only thing that changes the participation of the various tracts in Phase II formula is the map of the net pay or the map of the pay. So it's very important that map be accurate. We think that Conoco's depiction is not accurate and we think the evidence will confirm that. Another comment I think is appropriate, Mr. Bender, in his opening remarks made analogies to Little Knife. And I think those analogies are totally unfounded and unsupportable. I think some of the staff that was present during Little Knife will recall that there was unalterable opposition to unitization in Little Knife. The Little Knife Royalty Owners opposed the concept of unitization and opposed the concept of waterflooding. That's not the situation in this case. At least to our knowledge it's not. Placid is here supporting unitization but supporting unitization only on grounds that are fair and reasonable to Placid, to all the other working interest owners and to all the royalty owners in the field. And so the fact that the

Commission may reject and should reject Conoco's proposal certainly does not mean that unitization will not be achieved. What it will do is tell Conoco to go back and deal, in a fair manner, with the other working interest owners and with the royalty owners in the field and come up with a proposal that adequately protects all the interest owners. So I urge the Commission not to be swayed by groundless threats the state's going to lose oil if they don't approve this and do it exactly the way Conoco wants it. It does not have to be approved on Conoco's terms. It can still be unitized and the state can still benefit from the additional recovery.

MR. CARVELL: Mr. Wefald?

MR. WEFALD: Thank you. Our position is much the same as John Morrison's on this issue. The real question is, under the law the Commission is required to come up with a plan of unitization that is fair, equitable and reasonable to all the unit owners. The fact that Conoco in itself has over 70% and therefore can steer this matter right to this Commission is not the, not the deciding factor. The fact that 70% of the interest that Conoco controls says this is where we want it, is not the decisive factor. What is the decisive factor is a plan of unitization that is fair, equitable and reasonable. We will present a net pay map based on geology and that we believe more accurately represents the reserves, and the oil to be produced out of this particular formation. And so we are interested to hear what you have to say, but keep in mind that the fact that they have 70% is not at all the deciding factor. Fair, equitable and reasonable.

MR. CARVELL: Thank you. You may call your first witness Mr. Bender.

MR. BENDER: Jim would you state your name for the record please?

MR. TURNER: My name is P as in Paul, J as in James Turner. I am employed with Conoco Inc.

MR. BENDER: Could you spell your last name please?

MR. TURNER: T-U-R-N-E-R.

MR. BENDER: And Jim, have you had an opportunity to testify before the North Dakota Industrial Commission on previous occasions?

MR. TURNER: No, I have not.

MR. BENDER: Would you then briefly highlight for the Governor and the examiner your educational background and work experience?

MR. TURNER: I have a Bachelor's Degree in Business Administration from the University of Southwestern Louisiana. During my 26 year career with Conoco I've held various landman positions, including that of land director of the Lafayette Gulf Coast Division. During the past two years I've been at Casper, Wyoming where part of my responsibility was to provide land guidance and expertise to our management and lesser experienced landmen. In addition to that, during the last year I, I have been the Lodgepole Project Team Leader.

MR. BENDER: Jim, as the Lodgepole Team Leader, are you familiar with Conoco's application for unitization of the Dickinson-Lodgepole Pool?

MR. TURNER: Yes, I am.

MR. BENDER: And are you also familiar with the various working interest owner meetings that were held prior to Conoco making application for unitization of the Dickinson-Lodgepole Pool?

MR. TURNER: Yes, I am.

MR. BENDER: Describe for us briefly, Jim, the process that Conoco followed to secure support from the various working interest owners before it made application for unitization.

MR. TURNER: Well, as team leader I was responsible for directing the effort to evaluate a plan of unitization for the Lodgepole Field. Part of that responsibility included coordinating the working interest owner meetings. I was involved, excuse me, I was involved in the planning and conducting of four working interest owner meetings which resulted in the approval of the proposed plan of unitization.

MR. BENDER: Jim, when was this first meeting that you had, the working interest owner meeting?

MR. TURNER: The first meeting was held on November 10, 1993. All working interest owners were represented at that meeting. The focus of the first meeting was basically the exchange of data and preparations for plans to pursue unitization. At that meeting a voting procedure was approved by working interest owners. Conoco's original proposal for the voting procedure was to adopt the procedure included in the NDIC statutes.

MR. BENDER: What do you understand the voting procedure to be under the North Dakota statutes?

MR. TURNER: Two or more working interest owners having a combined voting interest of 70%, of at least 70%.

MR. BENDER: And what was the voting procedure that was ultimately adopted by unanimous consent of the working interest owners?

MR. TURNER: Phillips proposed a procedure which included three or more working interest owners with a combined interest of 70%. And that was adopted.

MR. BENDER: And was Placid at that meeting when that more stringent voting requirement was adopted?

MR. TURNER: Yes, they were.

MR. BENDER: And were representatives of Aviva also present when that more stringent voting requirement were adopted?

MR. TURNER: Yes, they were.

MR. CARVELL: What was the requirement?

MR. TURNER: Beg your pardon?

MR. CARVELL: What was that more stringent requirement?

MR. TURNER: Three or more with 70%.

MR. BENDER: Jim, what happened at the next meeting?

MR. TURNER: The second meeting was held on January 6th. Again all owners were represented. In addition to the exchange of new data, the primary focus of the meeting was a technical discussion of the reservoir modeling study and the approval of the input data for the study.

MR. BENDER: What happened at the third meeting, I guess?

MR. TURNER: All owners were again represented at the February 16th meeting, either in person, by absentee ballot or by proxy. The main purpose of that meeting was the approval of a structure map. Each owner had an opportunity to present its interpretation of a structure map. Four interpretations were presented. Placid presented its map and received the vote of three owners with a combined interest of 11%. Placid, Hunt and Huntington supported Placid's interpretation. Andrea Singer Trust presented an interpretation and it cast the only vote for its map. Phillips submitted a structure map by mail and by absentee ballot it cast the only vote for its map. Conoco presented its interpretation and discussed its structure map, and, which was approved by three owners with a combined interest of 75%. Conoco, Wiser and Lewis Hill, by proxy, voted for this interpretation. Since the vote exceeded the established voting procedure, the Conoco structure map was adopted.

MR. BENDER: Okay then Jim, what happened at the final meeting?

MR. TURNER: The fourth and final meeting was held on March 30th. Over 95% of the working interest ownership was represented, either in person, by absentee vote, or by proxy. At this meeting the proposed unit outline and the various equity parameters were approved by a vote of four owners with a combined interest of over 75%. Conoco, Wiser, Lewis Hill and Phillips voted for this proposal. Since again, since this vote exceeded the established voting procedure the plan of unitization we are presenting today was approved by working interest owners.

MR. BENDER: So, to briefly summarize then, Jim, all the maps that were approved by the working interest owners were approved under this more stringent voting procedure that was unanimously adopted at the first meeting. Is that correct?

MR. TURNER: That is correct.

MR. BENDER: Jim, are you also familiar with the procedure that Conoco followed in securing the ratifications for the unit agreement and unit operating agreement?

MR. TURNER: Yes, I am.

MR. BENDER: Okay. What percentage of the royalty owners have ratified the unit operating agreement?

MR. TURNER: As of this . . .

MR. BENDER: Excuse me, the unit agreement.

MR. TURNER: As of this date we've received 86.5% of royalty ownership approval for Phase I, and 86% for Phase II.

MR. BENDER: And it's true, is it not, that you have ratifications from royalty owners in every tract?

MR. TURNER: That is correct.

MR. BENDER: And what percentage of the working interest owners have ratified the unit agreement and unit operating agreement?

MR. TURNER: 76.8% of the working interest owners have executed the, the agreement.

MR. BENDER: Okay, Jim I'm going to show you what I'd like to have marked as Exhibit A in Case No. 5935. Can you tell us what that is?

MR. TURNER: Yes. This booklet reports the royalty owner approval of the unit agreement and the working interest owner approval of the unit and the unit operating agreement.

MR. BENDER: And it's broken up into sections, is it not?

MR. TURNER: That is correct.

MR. BENDER: And the first section is tabbed royalty owners. Is that correct?

MR. TURNER: That is correct.

MR. BENDER: And that contains all the ratifications of the royalty owners that Conoco has secured to date. Is that correct?

MR. TURNER: It contains all of the original copies we have secured as of yesterday. We did receive a ratification by mail in our Casper office yesterday. I have a faxed copy of that approved ratification.

MR. BENDER: Mr. Examiner, we'll include this in the packet of Exhibit A if that's okay.

MR. CARVELL: Sure.

MR. BENDER: Jim the next tab is labeled working interest owner. What's, what's under that tab?

MR. TURNER: Those are the original, that contains the original copies of the ratification agreements executed by working interest owners ratifying the unit agreement and unit operating agreement.

MR. BENDER: And the next tab is entitled Royalty Owner Summary, what's that?

MR. TURNER: That is a listing of individual royalty owner, owners listed alphabetically who have executed the ratification agreement. The last page of that exhibit indicates the total royalty owner approval as of yesterday, that figure is 82.34321 for Phase I. 82.06324% for Phase II. Adding the copy of the ratification received yesterday brings that total to 86.48866% for Phase I and 86.03647% for Phase II.

MR. BENDER: And let's go on, back to the, the last tab, entitled Working Interest Owner Summary. What's that?

MR. TURNER: That is a listing of working interest owners who have executed a ratification agreement.

MR. BENDER: And once again the total is?

MR. TURNER: The total is 76.78677% Phase I, 76.81894% for Phase II.

MR. BENDER: We'd offer Exhibit A.

MR. MORRISON: I don't have any objection to the exhibit itself, but I would ask if you have copies available for us of the summary pages?

MR. TURNER: We don't, we can have copies made.

MR. CARVELL: We can get them made.

MR. MORRISON: All right.

MR. CARVELL: Do you want them during the hearing or do you want them . . .

MR. MORRISON: I think so, just the summary sheets, four pages, three page, four pages at the end. I don't care about copies of the ratification themselves, just summary sheets

MR. CARVELL: Okay. Do you have any objection Mr. Wefald?

MR. WEFALD: Yes, there's no doubt that there's owner's approval, we would object on the grounds of foundation.

MR. CARVELL: Your objection is overruled, Exhibit A is received. Karlene will make copies for you Mr. Morrison and Mr. Wefald.

MR. BENDER: Do you, John, do you have any objections if we proceed while the copies are being made?

MR. MORRISON: No, none at all.

MR. BENDER: Jim, in preparation for today's hearing have you also prepared or had prepared under your control and supervision certain exhibits that you intend to sponsor?

MR. TURNER: Yes, I have.

MR. BENDER: Have you satisfied yourself as to the accuracy of those exhibits?

MR. TURNER: Yes, I have.

MR. BENDER: Jim, I'm going to have you turn to the packet of exhibits and go first to Exhibit

No. 1. Can you identify that exhibit and then briefly highlight what's contained upon it?

MR. TURNER: Exhibit No. 1 is a locator map showing the Williston Basin, shaded area. It also indicates, by star, the approximate location of the Dickinson Field in Stark County, North Dakota.

MR. NORTON: One question on that, that exhibit. Did your legal counsel spell Bismarck for you?

(LAUGHTER)

MR. TURNER: I'm afraid our drafting department did.

MR. BENDER: That's the German way of spelling it. Let's go on to the next exhibit Jim, Exhibit No. 2.

MR. TURNER: Exhibit No. 2 is a plat reporting the Dickinson-Lodgepole Field in Stark County. It shows the outline of the Dickinson-Lodgepole proposed unit within the field boundary of the Dickinson-Lodgepole Field.

MR. BENDER: Exhibit 3.

MR. TURNER: Number 3 is the plat showing the Dickinson-Lodgepole Unit outline and the separate nine tracts within the proposed unit. In the left-hand bottom corner of the plat is a listing of the tracts and the acreage figures which total to a unit acreage figure of 1436.45 acres.

MR. BENDER: Exhibit 4.

MR. TURNER: Exhibit 4 is the written legal description of the proposed Dickinson-Lodgepole Unit located in Townships 139 and 140 North, Range 96 West in Stark County, North Dakota.

MR. BENDER: And Exhibit 4 is nothing more than a legal description of the tracts that were contained on Exhibit 3. Is that correct?

MR. TURNER: That is correct.

MR. BENDER: Let's go on to the next exhibit then, Exhibit 5.

MR. TURNER: Exhibit No. 5 is a copy of the unit agreement for the development and operation of the Dickinson-Lodgepole Unit. The agreement outlines the plan of unitization and is basically the contract between the royalty interest owners and the working interest owners which creates the unit. The agreement defines the unit area and the unitized formation. It contains provisions for enlargement of the unit area, it designates Conoco as the unit operator and provides a mechanism for selection of a successor operator. Article 5 of the agreement provides for the allocation of unit production based on a two phase equity formula. The agreement stipulates that the effective date of the agreement is in accordance with the order issued by the NDIC. The agreement contains two or has two exhibits attached. Exhibit A is a tract by tract listing and tabulation of the ownership and tract participation for each individual tract in the proposed unit and Exhibit B is a tract map showing the individual tracts within the proposed unit outline.

MR. BENDER: And this is the agreement that more than 85% of the royalty owners have ratified. Is that correct?

MR. TURNER: That is correct.

MR. BENDER: Let's go on to the next exhibit then, Exhibit 6.

MR. TURNER: Exhibit 6 is the unit operating agreement which is the contract between working interest owners covering the operations of the unit. The agreement names Conoco as the unit operator and generally sets forth the responsibilities and duties of the operator on behalf of all the working interest owners. The agreement provides a mechanism for calling working interest owner meetings. It establishes a voting procedure. It provides audit rights for the nonoperator owners. It establishes expenditure approval guidelines and it contains provisions for the final dissolution and abandonment of operations. There are several attachments to the unit operating agreement. The first two attachments are the same, Exhibit A and B as included in the unit agreement. Exhibit No. C is a working interest summary which includes a summary of the ownership of each tract in the proposed unit. Exhibit D is the accounting schedule which governs the financial aspects of the operations of the unit. Exhibit E is a listing of the wells to be taken over by the unit operator. Exhibit F is a certificate of compliance with the EEOC statutes. Exhibit G provides insurance provisions and Exhibit H is the gas balancing agreement.

MR. BENDER: Once again Jim, what percentage of the working interest owners approved the unit operating agreement as well as the unit agreement?

MR. TURNER: 76.8% of the working interest owners approved.

MR. BENDER: That's all the questions I have for this witness at this time.

MR. CARVELL: Mr. Morrison, do you have any questions?

MR. MORRISON: Karlene's not back, is she?

MR. CARVELL: Pardon me?

MR. MORRISON: Karlene's not back? I've got a . . .

MR. CARVELL: Well we can reserve some time . . .

MR. MORRISON: I've got a few questions, but I may want to wait until Karlene's back to finish up. I have a few questions I can cover anyway until I get the summary sheets.

MR. CARVELL: All right.

MR. MORRISON: Mr. Turner, would you turn to Exhibit 3. Can you tell me what the basis is for the determination of tract size?

MR. TURNER: Our goal was to protect the correlative rights of all owners within the area underlain by reservoir, including the areas which did not have producing wellbores. We, additionally, attempted to minimize nonproductive acreage. Our, our plan, or our, we attempted to do this by including the acreage with no wellbores in ten-acre increments.

MR. MORRISON: Look at your Tract 4. Now, I know you are not a geologist and you haven't testified as to geology, but you're generally familiar with the contour figures for your net pay for the reservoir. Is that correct?

MR. TURNER: Yes, sir.

MR. MORRISON: Can you explain to me, why in Tract 4 you've included the entire 320-acre N/2 of Section 5 and only a small portion of that is underlain by reservoir in your geologic exhibits?

MR. TURNER: Tract 4 was drilled under an approved spacing order. It contained a producing wellbore. It's our understanding that, historically, the NDIC includes all of the acreage in an approved spacing order in, within the unit outline.

MR. MORRISON: And then the reason for including Tracts 5, 6, 7, 8 and 9 in ten-acre tracts is simply there was no existing spacing unit or a producing well at the time this was proposed?

MR. TURNER: The reason was to protect the rights of those parties where reservoir was underlain and no producing well was included. That is correct.

MR. MORRISON: Would the leases in the N/2 of Section 5 be held by production if not included within the unit boundary?

MR. TURNER: Yes, they would.

MR. MORRISON: Is it held by shallow production?

MR. TURNER: Yes.

MR. MORRISON: You also testified with respect to the working interest owners meeting that all owners were present at the first two meetings, November 10, 1993 and January 6, 1994?

MR. TURNER: That is correct.

MR. MORRISON: Were Lewis Hill, Mobil and Wiser Oil Company present at those meetings?

MR. TURNER: At that point in time, before the unit boundaries were agreed to, Mobil was not a party. Only parties who, with an interest in the producing tracts were included. And yes they were all represented.

MR. MORRISON: Were they present?

MR. TURNER: They were present either in person or by proxy.

MR. MORRISON: Was Wiser present at the first two meetings?

MR. TURNER: Wiser, I don't, I'd, I'd have to check my notes, I may be mistaken, maybe Wiser was not there.

MR. MORRISON: And Mobil certainly wasn't. Is that right?

MR. TURNER: Mobil was not a party at that time. I was incorrect, Wiser was not present.

MR. MORRISON: Okay. Now let's go on to the February 16th meeting. You testified that the structure map was approved by three owners with 75%. Is that right?

MR. TURNER: That is correct.

MR. MORRISON: And, and it's also correct that Lewis Hill was not present at that meeting but was represented by proxy?

MR. TURNER: By proxy, that is correct.

MR. MORRISON: And, of course, Conoco exercised that proxy. Is that right?

MR. TURNER: Yes.

MR. MORRISON: How many working interest owners are there in this proposed unit area?

MR. TURNER: At the present in the proposed unit there are, there are 14.

MR. MORRISON: And so this has been ratified by six?

MR. TURNER: Six of the 14.

MR. MORRISON: Is that right?

MR. TURNER: That is correct.

MR. MORRISON: And there, in addition, to Conoco, I mean with the exception of Conoco none of the other working interest owners who have ratified have even 1% of the unit. Is that right?

MR. TURNER: That's correct.

MR. MORRISON: Now Jim I'm going to show you what we are going to ask be marked Placid Exhibit 1, and ask if you've seen that document before.

MR. TURNER: Yes, I have.

MR. MORRISON: And, is that a listing of the working interest owners and their percentages under both Phase I and Phase II under your proposal?

MR. TURNER: Yes.

MR. MORRISON: Okay and that's something that was prepared by Conoco. Is that right?

MR. TURNER: Yes.

MR. MORRISON: Okay. I would offer Placid Exhibit 1.

MR. BENDER: No objection.

MR. CARVELL: Mr. Wefald?

MR. WEFALD: Let me just see them, I don't think I have any objections. We have no objection.

MR. CARVELL: Placid Exhibit 1 is received.

MR. MORRISON: I only have one copy but, _____. Mr. Turner, with respect to the royalty interests how may royalty interests owners are in the field?

MR. TURNER: 102.

MR. MORRISON: And how many have ratified?

MR. TURNER: 48.

MR. MORRISON: I assume that you will agree with this document we'll ask be marked as Placid Exhibit 2 is a listing prepared by Conoco of all the royalty owners and their respective interests in the field. Is that right?

MR. NORTON: Now these are Placid Exhibits?

MR. MORRISON: They are Placid Exhibits, but they are documents that were prepared by Conoco.

MR. NORTON: Okay.

MR. TURNER: Yes, that is correct.

MR. MORRISON: All right, we would offer Placid Exhibit 2.

MR. BENDER: No objection.

MR. WEFALD: No objection.

MR. CARVELL: Placid Exhibit 2 is received. Are these the photocopies from Conoco Exhibit A, the binder?

MR. MORRISON: No, no they are not. They are another presentation of Conoco. Just to clarify, the portions of the binder, that are entitled the Mineral Interest Owners Ratification Summary, Working Interest Owners Ratification Summary. You've only shown on those summaries the owners that have ratified. Is that correct?

MR. TURNER: That is correct.

MR. MORRISON: And you haven't identified the owners that have not ratified?

MR. TURNER: I have not.

MR. MORRISON: And none of the exhibits in your exhibit booklet identify those owners, except insofar as you can go through on a tract by tract basis on your Exhibit B to the Unit Agreement.

MR. TURNER: That's correct.

MR. NORTON: John, when you present your case are you going to go through the differences between your exhibits and their percentages?

MR. MORRISON: No, no. There are no differences in percentages. The only purpose of the exhibits that we've offered is to show that while Conoco's made a great deal on the percentages of owners that have ratified, the exhibits that we've offered are important to show that its a small number of the owners and with respect to the working interest owners in fact, it's Conoco and three or four very small other working interest owners. The other larger working interest owners in the area have not ratified. But we don't have any reason to dispute the, the numbers that they've given you or the fact that they are 86.5% or 76.8% have ratified, we're not disputing that, that point. But, clarification on that point, Jim. I think in your testimony you indicated 76.8% of the working interest owners had ratified. Is that under Phase I or Phase II?

MR. TURNER: 76.78677 for Phase I, 76.81894 for Phase II.

MR. MORRISON: So, substantially the same?

MR. TURNER: Right.

MR. MORRISON: Okay. I don't have any further questions of this witness. Thank you.

MR. CARVELL: Mr. Wefald.

MR. WEFALD: Thank you. What is the percent of interest that Conoco has in this hearing?

MR. TURNER: Conoco's interest is 75.13624 Phase I, 74.88075% for Phase II.

MR. WEFALD: So when you noted that the 75% of the working interest owners voted for it, in fact, the percentages of the other two that go to Wiser, Lewis Hill must be relatively small?

MR. TURNER: No, sir. When I, when I calculated the voting percentages that we were operating under a different ownership, that was prior to the approval of a structure map and a unit outline. At that point in time the working interest ownership was different.

MR. WEFALD: What was the working interest ownership of Conoco at the time of these votes?

MR. TURNER: Let's see, I have that information, Conoco's interest was, as I recall, 73%,

MR. WEFALD: Approximately 73%?

MR. TURNER: Approximately 73%.

MR. WEFALD: You indicated that at these four meetings was an exchange of data among the various working interest owners. When did Conoco ever exchange with the other working interest owners the 3D seismic data that it had for the maps based on that 3D seismic data?

MR. TURNER: That's outside of my testimony, but I, We did not, we did not exchange 3D seismic data.

MR. WEFALD: Okay. Do you know if you had 3D seismic data?

MR. TURNER: At that point in time we did not have interpreted 3D seismic, nor do we now.

MR. WEFALD: There's another witness though that would know more about that?

MR. TURNER: Yes, sir. We are going to have a geologic witness who will address the seismic issues.

MR. WEFALD: Thank you. During the course of these negotiations at these meetings, did Conoco ever accept any data from any of the other working interest owners that would have affected or would have changed Conoco's position or anything?

MR. TURNER: Accept any data?

MR. WEFALD: Yes.

MR. TURNER: There was an exchange of technical interpretations and on many occasions there were agreements reached on matters of interpretive nature and as a matter of fact, yes, I think . . .

MR. WEFALD: Did Conoco, as a result of these discussions ever, in any one of these meetings back off or change the maps that it has presented at these meetings?

MR. BENDER: Bob, I think that, you know, we are going to have a geologic witness and an engineering witness, who might be better.

MR. WEFALD: That's fine, that's fine. We'll reserve that for that. That's fine. I have no further questions.

MR. CARVELL: Any questions from the staff?

MR. NORTON: I have a few. You referred early on in your testimony to parameters discussed at the initial meeting.

MR. TURNER: I'm sorry, I didn't hear you.

MR. NORTON: You referred to parameters early on in your . . .

MR. TURNER: Yes, sir.

MR. NORTON: At a unit meeting.

MR. TURNER: Right.

MR. NORTON: Were those parameters unanimous as to porosity cutoff, software to be used for calculating reserves, etc.?

MR. TURNER: I can't answer that but I'm sure our engineering and geological people can.

MR. NORTON: And, just to correct the record, the limits you refer to of an order of the Commission, you were referring to pool limits and not field boundaries. Is that right?

MR. TURNER: Yes, yes. That is correct.

MR. NORTON: And you also refer to a dissolution procedure in the unit that would only be the unit committee procedure for a dissolving the unit and not the Commission's jurisdiction.

MR. TURNER: No, that is correct, that is correct.

MR. NORTON: Okay. Would you have, on these, a point was made on these fractional tracts that were not complete spacing units, such as Section, or Tract No. 6 in Section 30, would you have any objection if the owners of, let's say the E/2 of 30 come to the Commission and request an exception location providing it was a certain distance from the unit boundary? To protect their interests if they should think that they have reservoir under that tract?

MR. TURNER: We would more than likely oppose an exception location. We would not oppose a legal location in that area. I understand . . .

MR. NORTON: When I say exception to the Commission order I mean that it isn't a full 320-acre spacing unit.

MR. TURNER: Conoco has an interest in, a majority interest, in most of Section 30. We have 100% interest in the NE/4, 50% in the SE/4 and a third in the . . .

MR. NORTON: I'll rephrase the question.

MR. TURNER: west quarter.

MR. NORTON: I'll rephrase the question. If someone came in the W/2 of Section 29 they would not have a complete 320-acre unit. Would you object as an exception to the statutes?

MR. TURNER: I understand. No, we would not.

MR. NORTON: Okay.

MR. TURNER: We would not.

MR. NORTON: I believe that's all my questions at the present time.

MR. HICKS: Jim, I was trying to find out where you have the creation of the unit operating committee. Is it, where in your agreement does it have that?

MR. TURNER: It references, where is my, the technical committees are referenced in 3.211.

MR. HICKS: Okay, and how are they assigned? It states there that you can have the appointment of committees.

MR. TURNER: Yes.

MR. HICKS: And what procedure do you use to select the committee?

MR. TURNER: Well, that procedure would have to be agreed to by the working interest owners, as to the makeup of the committee and we have not done that yet.

MR. HICKS: Okay. Thank you.

MR. CARVELL: Any redirect Mr. Bender?

MR. BENDER: Yes, just a question or two. Jim, under cross-examination by Mr. Morrison, you indicated that Wiser probably did not participate in the first working interest owner meeting. Is that correct.

MR. TURNER: That is correct.

MR. BENDER: Did Wiser ratify the unit agreement, unit operating agreement?

MR. TURNER: Yes, they did. As a qualifier they, that was the, they did participate in other working interest owners also.

MR. BENDER: But they ratified?

MR. TURNER: And they did ratify.

MR. BENDER: And, Jim, is Conoco a royalty owner in this proposed Dickinson-Lodgepole Unit?

MR. TURNER: Yes, we are.

MR. BENDER: And what percentage royalty interest does Conoco hold?

MR. TURNER: Conoco has 3.79156% in Phase I and 3.81948% in Phase II.

MR. BENDER: So the remaining 83 and odd percentage ratifications that Conoco that has received are from entities that are not Conoco related. Is that correct?

MR. TURNER: That is correct.

MR. BENDER: That's all the questions I have.

MR. CARVELL: Any recross Mr. Morrison?

MR. MORRISON: Yes, I have a couple follow-up questions. Mr. Turner in response to a question from Mr. Norton, you indicated that Conoco probably would oppose an exception location in the SE/4 of Section 30, but would not oppose a legal location. Is that right?

MR. TURNER: That is correct.

MR. MORRISON: What, in your opinion, would be a legal location in the SE/4 of Section 30?

MR. TURNER: 660 from the unit boundary.

MR. MORRISON: From the unit boundary?

MR. TURNER: Yes.

MR. MORRISON: 1320 from the south and east section lines then. Is that right?

MR. TURNER: Yes, I don't have the scale, but that probably be correct.

MR. MORRISON: And you're aware that Placid has attempted to permit a well in the SE/4 of Section 30 aren't you?

MR. TURNER: Yes, I guess.

MR. MORRISON: And you're aware that Conoco blocked that attempt by permitting their own well. Isn't that right?

MR. TURNER: Conoco permitted a well. I am aware that Placid filed objection to that location and later withdrew their opposition.

MR. MORRISON: And Conoco retains that permit today, don't they?

MR. TURNER: It is still in effect, yes. It expires on July 3rd.

MR. MORRISON: And by including what your geologic exhibit will later show to be about 2½ acres of reservoir in the SE/4 of Section 30 your, effectively, then will try to push any well that Placid may later desire to drill in the SE/4 of Section 30, back 1320 feet from the SE/4. Is that right?

MR. TURNER: Whatever, whatever that location is.

MR. MORRISON: Your interpretation and then what you're asking for from the Commission would require a well drilled in the SE/4 of Section 30, to the Dickinson-Lodgepole, or to the Lodgepole Formation to be 660 feet away from your unit boundary. Is that right?

MR. TURNER: Yes, it is.

MR. MORRISON: Would you object to a provision in the unit order that would allow anybody to drill a well in the SE/4 of Section 30, at a distance no farther than 100 feet from the unit boundary?

MR. TURNER: I'll, I'll have to refer that to our technical people.

MR. MORRISON: When you worked on the unit agreement, did you give any consideration to inclusion of an expansion provision in the unit agreement?

MR. TURNER: As I recall there are provisions in, included in the agreement which allows expansion of the unit agreement.

MR. MORRISON: Okay. Would Conoco, if a well was later drilled and proven to be productive in the SE/4 of Section 30, oppose any expansion?

MR. TURNER: Well, we, we would be obligated to abide by statutes and agreements.

MR. MORRISON: Which requires ratification. Isn't that right?

MR. TURNER: That is correct.

MR. MORRISON: And which Conoco would be able to block. Isn't that right?

MR. TURNER: Whatever agreement provisions there are.

MR. MORRISON: Well with 75% Conoco would be able to block it. Right?

MR. TURNER: Logically, yes.

MR. MORRISON: Okay. No further questions.

MR. WEFALD: No further questions.

MR. CARVELL: Okay. Next witness.

MR. NORTON: I have one follow-up.

MR. CARVELL: Excuse me.

MR. NORTON: What does the unit agreement provide for, for location of the wells within the unit as far as distance to the unit boundary?

MR. TURNER: Gosh, I don't know.

MR. BENDER: Maybe I can answer that. I, I don't think the unit agreement addresses that at all. I think it would be governed by the Commission's order which would indicate that wells couldn't be drilled any closer to the unit boundary. There are no specific provisions in the unit agreement with respect to well location.

MR. NORTON: What, what are you going to recommend for minimum distance to the unit boundary?

MR. TURNER: 660.

MR. NORTON: 660?

MR. TURNER: Yes, sir.

MR. NORTON: Okay. Thank you.

MR. BENDER: That's prompts one follow-up question.

MR. CARVELL: Okay, go ahead.

MR. BENDER: Jim are there plans for drilling additional wells in the unit?

MR. TURNER: There are no plans.

MR. CARVELL: Do you have anything further Mr. Bender?

MR. BENDER: Yes, one follow-up question. Jim, under questions from Mr. Morrison, you indicated that Conoco held an application for permit to drill in the SE/4 of Section 30. Has Placid ever approached Conoco about drilling that well?

MR. TURNER: At a, I think the February 16th working interest owner meeting Placid indicated that it may, it might propose a well in that location. As I've stated Conoco owns 50% interest in the SE/4 of 30 and 100% in the NE/4 of 30. In essence we would have 75% of the stand-up unit there. I advised the Placid representative at the time that if they submitted an AFE for the drilling of that well we would evaluate it. That was in February and we haven't heard anything since.

MR. BENDER: That's all the questions I have.

MR. CARVELL: Mr. Morrison, anything further?

MR. MORRISON: Nothing further.

MR. CARVELL: Mr. Wefald?

MR. WEFALD: No, nothing further.

MR. CARVELL: Okay. Next witness.

MR. BENDER: Jerry, would you state your name for the record, please.

MR. HYRKAS: My name is Jerry Hyrkas.

MR. BENDER: Spell your last name please.

MR. HYRKAS: It's H-Y-R-K-A-S.

MR. BENDER: By whom are you employed and in what capacity?

MR. HYRKAS: I'm employed by Conoco as a staff geologist in the Casper Division.

MR. BENDER: And in that capacity have you had an opportunity on previous occasions to testify before the North Dakota Industrial Commission, have your qualifications accepted as that of an expert?

MR. HYRKAS: Yes, I have.

MR. BENDER: In preparation for today's hearing have you been involved in the preparation of all the geologic exhibits that will be presented here today.

MR. HYRKAS: I have.

MR. BENDER: Have you satisfied yourself as to the accuracy of those exhibits?

MR. HYRKAS: Yes.

MR. BENDER: I offer the further testimony of this witness as that of an expert.

MR. CARVELL: Mr. Morrison, any objections?

MR. MORRISON: I have no objection to the qualification as an expert. I wonder if I might ask or inquire as to the degree of his involvement in the preparation of the exhibits?

MR. CARVELL: Sure.

MR. MORRISON: Since that was intended to lay foundation for the exhibits. Jerry could you just tell me what your involvement has been in the preparation of Exhibits 7 through 14?

MR. HYRKAS: Yes. I'm the senior geoscientist on the Lodgepole Team. Conoco works in the team effort for different plays and I have prepared, if you'd like I could go through all the various exhibits. I have prepared certain exhibits and I have peer reviewed and helped prepare the remainder of these exhibits.

MR. MORRISON: So all the exhibits have either been prepared by you or with direct involvement from you. Is that right?

MR. HYRKAS: With, yes, with varying involvement, yes.

MR. MORRISON: Okay, that's all the questions I have.

MR. CARVELL: Mr. Wefald do you object to the motion?

MR. WEFALD: No.

MR. CARVELL: Motion granted.

MR. BENDER: Jerry, I'm going to have you turn first to what has been marked at Exhibit No. 7. Can you identify that exhibit and briefly highlight for the examiner the more pertinent aspects of it?

MR. HYRKAS: Exhibit 7 is an electric log from the Conoco State "A" 83, located in Section 5 of Township 139 North, 96 West. It is a gamma ray and dual induction log showing the gamma ray on the left hand curves and the dual induction on the right-hand side of the electric log. The State "A" 83 is the type log I chose for the Dickinson-Lodgepole Field showing the stratigraphic interval which encompasses the Mississippi and Lodgepole Mound or bioherm buildup typified in this field. Shown at 9802 is the top of the clean Lodgepole limestone, a clean mound. Which is typified by, generally, less than 10 API gamma ray units in the left-hand column. This is the left-hand curve on the log showing the scale for gamma ray at the bottom, zero to 100 units. So, the clean mound is typical to less than 10 API gamma ray units and this mound has a base at 9952. In the 83 then there is 150 feet of mound or bioherm buildup. Beneath the clean limestone then there is 37 feet of limey shale which is a transitional facies of Carrington shale and lower Lodgepole limestone going to the top of the upper Bakken shale at 9989.

MR. BENDER: Jerry, what's the significance of the clean limestone buildup in this particular log?

MR. HYRKAS: The clean limestone facies found in the Lodgepole here is of particular significance. Not only because it is porous and very productive in the Dickinson area, but that represents a rock facies of change in environment not seen anywhere in this area of the Basin. It is a very rare geologic occurrence that has no productive analog in the Williston Basin of North Dakota or Montana. This facies has been interpreted as a Waulsortian type mound or buildup. Typified by rock sections in Belgium where we find the type rock intervals and found in numerous U.S. basins in the same stratigraphic intervals. When I say buildup I'm talking about a development of fossils which form a mound or reef-like structure that, because of its positive nature is a higher energy environment. And at its nucleation point and because it is a positive feature it can continue to grow and spread itself in various directions. The Waulsortian mound idea for the occurrence found at Dickinson appears, is from an interpretation fostered by the fact that the mound appears to have grown on a slope break, or at the base of a slope. Typical of these mounds. And at the age of the mound 330-360 million years in age, or Mississippian Lodgepole time, is the time interval at which these type mounds tend to be found.

MR. BENDER: Jerry, is the, is the State 83, the well that you used for this particular exhibit, is that well productive of oil and gas?

MR. HYRKAS: Yes, it is. The 83 is productive and perforated from the interval 9800 to 9807 which is, which I will be showing on the next exhibit. I also would like to note that on many of my exhibits I'm going to be talking about a clean mound thickness which will be different than the thickness of pay because the mound does contain a water contact.

MR. BENDER: Okay. Jerry, let's go to the next exhibit. Can you identify that exhibit?

MR. HYRKAS: Exhibit 8 is a structural cross-section going basically north-south across the field, from on the left the Frenzel vertical well and its sidetracking through the sidetrack arm to that well, through the State 74 which was the discovery well for the field. Then through the Dickinson State 83 which I've mentioned previously and on to the Walton 84. This is basically a dip-section going across the field. South being updip or on your right and north being downdip on your left.

All the logs on the cross-section are gamma ray and resistivity logs. Once again gamma ray to the left, resistivity tools on the right-hand curve. The mound is shown by the stippled area and also shown, by well, are the perforations and IP's of the wells which encountered the mound facies. The mound has a maximum thickness of 290 feet at the 74 location. I do have three wells in the cross-section which are productive. The Frenzel Sidetrack, the Dickinson 74 and the 83. The only well not depicted on the cross-section is the Kadrmas which was a, a, basically, a look-a-like log to the 74. And for illustration purposes I chose not to use it on the cross-section. The mound has deeply dipping sides. You can see from the 74 going through to the 83 we go quickly to 150 feet from 290 and then on both sides of the mound, to the right-hand sided cross-section, the Walton with no mound and the Frenzel with no mound on the left-hand side of the cross-section. Now the, in the Frenzel straight hole, which is the well on the left-hand side of the cross-section you could possibly interpret mound from 9970 to 9990 and we first thought that that might be part of the porous productive mound and in fact we found that it was not. The Frenzel 79 was sidetracked . . .

<u>MR. BENDER</u>: Jerry, Jerry, for those of us who don't know geology as well as you do, you're going awfully fast. Can you slow down a little bit?

<u>MR. HYRKAS</u>: Okay, okay, thank you. The Frenzel 79 was sidetracked and approximately 700 feet in a southeast direction because we thought we were close to the mound feature in the Frenzel 79 straight hole, the left-hand log on the cross-section. We did encounter, in that sidetrack the porous mound facies and it is shown to be productive on that sidetrack log with the perforations shown in measured depth, from 10,050 to 10,107.

MR. BENDER: So, Jerry, part of what you said here is, in the Frenzel No. 79, when you drilled that well, the straight hole portion of that, you didn't encounter any mound. Is that correct?

MR. HYRKAS: That is correct.

MR. BENDER: But through your sidetracking operation you were able to sidetrack and did penetrate some mound?

MR. HYRKAS: Yes, that is correct.

MR. BENDER: Now, is your cross-section, with respect to the sidetrack, is that drawn to scale?

MR. HYRKAS: No, the distances across the top of the page are shown from well to well. There is a footage distance across the top of the page and this cross-section is shown in plain view, I forgot to mention, in the right-hand corner of the diagram, of this exhibit. The sidetrack could not be drawn to scale because of the size of the exhibit we presented today.

MR. BENDER: Okay, Jerry, and once again you were going relatively quickly, but you described this mound as a Waulsortian mound. Could you describe for us some of the attributes of a Waulsortian mound?

MR. HYRKAS: Yes, and I'll try to speak a little slower. Some of the attributes we see in the

Dickinson area are that the mound we have found in the area has very steeply dipping sides. Anywhere from 4 to 15 to 45° of dip has been recorded on the imaging logs that we ran in the Kadrmas 75, the State 83 and the Frenzel 79 Sidetrack. The core analysis indicated the main bioherm buildup is a carbonate wax zone with fossils making up the, the bioherm including crinoids, ostracods, brachiopods, bryozoans and corals, with some gastropods and sponge spicules. The porosity is mainly vugular and channel. Vugs range from anywhere from pinpoint in size to holes that are diameters in inches. Open stylolites and crystalline, intercrystalline porosity with some fracture porosity make up the other porosity types. The mound has an average neutron density porosity of 5.37%. As I mentioned there is a water leg and an oil column associated with the mound. Lastly, I'd like to mention that the clean, white-gray limestones associated with the mound facies in, in the stippled area do not compact as well as the surrounding Lodgepole argillaceous lines as shown in the Frenzel 79 on the left-hand side of the cross-section and the Walton 84 on the right. This differential compaction of the mound expresses itself as a positive feature. You can see the middle Lodgepole marker as shown as one of the lines across the top of the cross section, actually shows a quite large structure over the mound and because, this is because of the differential compaction effect. And this differential compaction effect goes all the way up to the Mississippian Fryburg Formation, roughly 900 to 1000 feet above the top of the mound. The compaction process has also sealed the mound both laterally and vertically. Completely encasing this mound with an impermeable rock.

MR. BENDER: So, Jerry, as I understand your testimony you have a, a clean limestone mound surrounded by this impermeable barrier. Is that correct?

MR. HYRKAS: That is correct.

MR. BENDER: So, is this, is this mound ideal for water injection?

MR. HYRKAS: Yes.

MR. BENDER: Why is that?

MR. HYRKAS: Any water that would be injected into the mound would not be able to escape into the surrounding impermeable rock.

MR. BENDER: So it's an ideal candidate for secondary recovery as well?

MR. HYRKAS: Yes, it is.

MR. BENDER: Okay, Jerry, let's go on to the next exhibit, Exhibit No. 9.

MR. HYRKAS: You may have to turn your booklet sideways to get a good view of this Exhibit No. 9. Exhibit No. 9 is a schematic cross-section B-B' which shows the relationship between the Mississippian and Fryburg Formation, which I've mentioned, and the top of the Lodgepole mound. And the cross-section is shown in map view on the right-hand corner of the, of the exhibit if you were to turn it sideways, showing B-B' going from the Frenzel straight hole, Frenzel 79 straight hole, through the Sidetrack well, on to the State 74 and through the State 83.

MR. BENDER: Now, Jerry, you just showed us a structural cross-section as Exhibit No. 8. What's the significance of this particular schematic cross-section which you have labeled as Exhibit No. 9?

MR. HYRKAS: Because there are nine Fryburg penetrations in and around the mound and only four actual clean mound penetrations, the relationship of the Fryburg structure to the mound provides critical data for the boundaries of the mound feature. The cross-section shows the top of the Mound at the 74 is also the crest of the Fryburg structure overlying it. And as this steeply dipping sides of the mound go to zero, just to the south of the 83 and at the 79 straight hole on the left-hand side of the cross-section, there is this draping effect with differential compaction of the Fryburg structure over the top of the mound.

MR. BENDER: What's the significance of the draping effect?

MR. HYRKAS: Well, it proves that there is a relationship between the Fryburg structure and the Lodgepole mound thickness.

MR. BENDER: Tell us what that relationship is.

MR. HYRKAS: The isopach thickness from Fryburg to the top of the clean mound facies in relationship to the thickness of clean mound gives evidence to mound proximity and the thickness of the mound using the Fryburg well control.

MR. BENDER: So, if I understand, what you're saying is, where you have a Fryburg high you are going to have a thick Lodgepole mound. Is that correct?

MR. HYRKAS: That is correct.

MR. BENDER: And where you have a low in the Fryburg you would anticipate a thinning in the mound or no mound at all?

MR. HYRKAS: That is correct. By using the Fryburg structure you can more adequately define the mound and its edges.

MR. BENDER: Jerry, do you have an exhibit that explains that relationship between the Fryburg and the Lodgepole mound?

MR. HYRKAS: Yes, and that is Exhibit No. 10.

MR. BENDER: We'll go to that Exhibit then and briefly discuss it.

MR. HYRKAS: If you'll keep your books turned sideways there and I'll go along and give you some input on this. The relationship of, this exhibit shows the relationship of mound thickness to the Fryburg structure. On the X axis is the thickness of clean mound or less than 10 API gamma ray units. And on the Y axis is the isopach thickness from the top of the Fryburg to the top of the clean mound. The starred data points which depict this relationship are the actual well points that you can see on the right-hand side. The 74, the State 74 discovery well and the Kadrmas 75 both have about 280 to 290 feet of clean mound and their isopach thickness from Fryburg to top of clean mound is roughly 840 to 850 feet. And then on the left-hand side of the graph you'll see the 76 which is the Filipi well in Section 32 and the 79 which is the Frenzel straight hole in Section 31. They indicate there is no mound at this location. Now, there is a star for the 79 Sidetrack location, which is a projected thickness of the mound. Because that well encountered drilling problems and was a deviated hole, we were never able to go all the way through the clean limestone section to give an exact thickness. So that is simply a projection.

MR. BENDER: Okay, Jerry, let's go on to the next exhibit then, Exhibit No. 11.

MR. HYRKAS: Exhibit No. 11 is, is a structure map on the top of the Fryburg Zone, in the Dickinson area. The contour interval is ten feet and there are nine well control points on the map for the Fryburg. These points going from Section 29 indicate the DHSU 20 had a subsea depth of 6462. There are three well points in Section 31. The Frenzel straight hole which is at the end of the arrow coming off the Frenzel oil symbol at 6452, that's where the straight hole is located. The Kadrmas 75 showing a subsea depth of 6383, the DHSU 37, formerly known as the JJ Kadrmas well before unitization, is at 6399. Three wells in Section 32, the State 74, which was the discovery well in the W/2, the DHSU 33 immediately to the north of it and the Filipi 76 in the E/2 of that Section 32. Then to the south, the State "A" 83 and in Section 6 the Walton 84, in Section 6. So there, using these nine Fryburg data control points a structure map on the Fryburg has been constructed indicating approximately 80 feet of structural closure on the Fryburg with two separate tops of the structure at the Kadrmas 75 and the State 74, 75 in Section 31, and the 74 in Section 32, with a low at the DHSU 37 between them. The significance of this closure is that it will conform to the occurrence in the underlying Lodgepole mound and, in fact, the relationship of thick mound to Fryburg highs provides a form line for some internal attributes of the Lodgepole mound. And Fryburg lows provide evidence for the Lodgepole zero edge boundaries.

MR. NORTON: Did the well in 29 penetrate the lower Lodgepole?

MR. HYRKAS: The well in 29 simply penetrated the Fryburg.

MR. NORTON: Okay.

MR. BENDER: Okay, Jerry, let's go onto the next exhibit, Exhibit No. 12.

MR. HYRKAS: Exhibit 12 is a structure map on top of the Lodgepole, the clean Lodgepole mound. The contour interval is ten feet and there is 290 feet of structure over the mound going from subsea 7500 to the top contour around the State 74 in Section 32 of 7210. There are seven Lodgepole penetrations on the map, four of which are clean mound penetrations and structural points. Those are the Frenzel 79 Sidetrack in Section 31, the Kadrmas 75 in the S/2 of Section 31, the State 74 in the W/2, W/2 of Section 32 and to the south the State "A" 83 in Section 5. Once again there are nine Fryburg penetrations in this mapping area. I'd like you to note that there is, the mound itself has very deep sides. If you look at the contour from 7400 to 7500 that is subsea 7400 to 7500, you'll see that, that 10-foot contour interval is almost a black line, indicating very steep dips on the edge of the mound. Note also that there appears to be two growth centers for the mound. One at the 75 and one at the 74 creating this saddle between them.

MR. BENDER: Jerry, on your Exhibit 11 you indicated there was a saddle on the Fryburg structure between the State 74 and the Kadrmas 75, and now on your Exhibit 12 you are also exhibiting a saddle between the State 74 and the Kadrmas 75, is there any other evidence other than the relationship between Fryburg structure and Lodgepole mound to indicate that this saddle exists?

MR. HYRKAS: Yes. We ran a dipmeter in the Kadrmas 75 and it showed northeast dip going toward the DHSU 37, indicating and further corroborating that there is a saddle or a dip in the mound structure, between the 75 and the 74.

MR. BENDER: So, in other words there is two pieces of independent evidence that demonstrate that there is a saddle. The dipmeter data and your Fryburg structure?

MR. HYRKAS: That is correct.

MR. BENDER: Jerry, what other attributes define the boundaries of this mound?

MR. HYRKAS: We also ran a dipmeter data in the State "A" 83 showing south dips in that well. We also have dip information from the Frenzel 79 in Section 31 showing north dips. Now, we know these mound edges are extremely steep. If you look to the east, the Filipi 76, we encounter no clean mound, but we felt we were relatively close to actual mound, possibly not reservoir, but we were close to the mound edge there. So that defines the control to the east, the Frenzel defines the control to the west. To the southwest we drilled the Walton 84 which was a dry hole with no mound and to the south the State "A" 83 encountered 150 feet of mound versus 280 in the Kadrmas and 290 in the State 74 indicating that this mound section was going to zero quite thickly, or quite quickly and that we also saw south dips in that well indicating we were very close to the mound edge. Honoring all the data and recognizing that there is very, a very steep nature about this structure and that the structure is generally concentric, this map indicates the boundaries of the reservoir.

MR. BENDER: Jerry, Exhibit No. 12, is that a map that was approved by the working interest owners, by a vote that was a procedure that was initially established at the first working interest owner meeting?

MR. HYRKAS: Yes. The working interest owners approved this using the approved voting procedure set aside for approval that this map was accurate for the boundaries of the Lodgepole Reservoir.

MR. BENDER: Okay, let's go on to the next exhibit then, Exhibit 13.

MR. HYRKAS: Exhibit 13 indicates the thickness of Lodgepole pay for the reservoir. The contour interval is, once again, ten feet and the maximum thickness contour is 160 feet just to the south of the State 74. The pay was defined in the various wells as the State 74, 158 feet of pay;

the Kadrmas 75, 136 feet of pay; the Frenzel 79, 76 feet of pay; and the State 83 with 26 feet of pay.

MR. BENDER: And Jerry if you, if you look at Exhibit 12 and you look at Exhibit 13, Exhibit 12, I guess, was your, your structure map and Exhibit 13 is your isopach. They seem to be very similar, why is that?

MR. HYRKAS: Well paging back from one to the other, Exhibit 12 shows the structural top of the mound. Exhibit 13 chops off all of the mound that is in the water column or the lower portion of the mound, leaving an isopach of pay, which basically mimics the mound structure shown in Exhibit 12.

MR. BENDER: So, in other words your, in other words what you are saying is Exhibit No. 13 is the, is the area, it constitutes the oil column in the area that would be productive. Is that correct?

MR. HYRKAS: Yes, and that productive area is 753 acres.

MR. BENDER: And as in the case of your Exhibit No. 12 was Exhibit No. 13 also a map that was approved by the working interest owners?

MR. HYRKAS: Yes. The pay thickness was derived from the oil-water contact which was unanimously approved at the working interest owners meeting, February 16, 1994.

MR. BENDER: Let's go on to the final exhibit then, Jerry, Exhibit No. 14.

MR. HYRKAS: Exhibit 14 is a histogram plot of all occurrences of density neutron cross plot porosity from the four producing wells in the clean mound. The X axis is the cross plot porosity and the Y axis is the number of occurrences. And simply reading from the graph is a total number of occurrences of porosity taken at one-foot intervals, 885 occurrences. With an average porosity of 5.37%, a minimum porosity of 1.7 and a maximum porosity of 14.9%. The average porosity of 5.37% was used for the volumetric calculations in the equity formula and was unanimously approved by the working interest owners.

MR. BENDER: That's all the questions I have for this witness at this time.

MR. CARVELL: Mr. Morrison?

MR. MORRISON: Thank you. Jerry, since we're on it, Exhibit 14 really shows that this reservoir is not a homogeneous reservoir, isn't it?

MR. HYRKAS: That is correct.

MR. MORRISON: But in your equity parameters, Conoco has treated it as a homogeneous reservoir. Is that right?

MR. HYRKAS: The working interest owners are treating it as that.

MR. MORRISON: And Conoco is presenting that recommendation to the Commission today?

MR. HYRKAS: That is correct.

MR. MORRISON: And, in fact, there are substantial differences in porosity throughout the reservoir, aren't there?

MR. HYRKAS: It is not a mappable phenomenon that, if there are substantial differences, it is, the working interest owners all agreed that it was not a mappable phenomenon.

MR. MORRISON: Right. But they still exist, don't they?

MR. HYRKAS: There is the existence of differences in porosity, even shown by the histogram. But the average porosity is 5.37%.

MR. MORRISON: And whether you're using oil in place, recoverable oil or any of those factors, what you've done by assuming a homogeneous reservoir is place a lot of importance on your pay map. Is that right?

MR. HYRKAS: What the working interest owners did was place a lot of importance on the pay map, yes.

MR. MORRISON: The equity parameters are only as good as those pay maps are, right?

MR. HYRKAS: That, that is the assumption.

MR. MORRISON: Okay. You didn't use any seismic information in any of your maps did you?

MR. HYRKAS: No, we did not.

MR. MORRISON: Conoco has both 2D and 3D seismic in the area, don't you?

MR. HYRKAS: That is correct.

MR. MORRISON: And it wasn't used in your interpretations?

MR. HYRKAS: It was not.

MR. MORRISON: Do you agree that seismic information is a valuable tool when developing this type of a reservoir, a Lodgepole mound, mound feature?

MR. HYRKAS: Conoco believes that seismic is a valuable tool, as an exploratory tool, but not a good tool at all for defining reservoir boundaries.

MR. MORRISON: Does it help at all?

MR. HYRKAS: Does it help in what sense?

MR. MORRISON: Defining reservoir boundaries?

MR. HYRKAS: Only to the limits of the tools.

MR. MORRISON: Do you assume to be in oil-water contact in the reservoir?

MR. HYRKAS: We have engineering testimony which will go over the oil-water contacts.

MR. MORRISON: Okay, but in preparing your map, Exhibit No. 13, you use an oil-water contact in order to determine the thickness of the pay, right?

MR. HYRKAS: We use the oil-water contact from the working interest owners who had unanimously approved all contacts.

MR. MORRISON: And what is the oil-water contact that you used?

MR. HYRKAS: For individual wells?

MR. MORRISON: Is it uniform throughout the reservoir, or throughout the unit or does it differ for wells?

MR. HYRKAS: We didn't, the working interest owners agreed that it was not uniform throughout the field and each well that had a water contact we used the approved contact by well.

MR. MORRISON: And what was that contact?

MR. HYRKAS: For which well?

MR. MORRISON: Okay, let's start with the State "A" 83.

MR. HYRKAS: I'm sorry, I missed it.

MR. MORRISON: The State "A" 83.

MR. HYRKAS: The State "A" 83, the approved contact was a depth of 9827.5 measured depth with a TVD of subsea 7360.5.

MR. NORTON: Which one was that again?

MR. HYRKAS: The State "A" 83 in Section 5 of 139 North, 96 West.

MR. MORRISON: Why don't you turn back to your Exhibit No. 7, which is a type log of the State "A" 83. Is that right?

MR. HYRKAS: Yes.

MR. MORRISON: And, again, what was your oil-water contact on that?

MR. HYRKAS: At 9827.5.

MR. MORRISON: And looking at that log do you agree that that's a depiction of the oil-water contact as shown on the log?

MR. HYRKAS: Looking at a single log does not give you an individual oil-water contact. You have to look at a suite of logs.

MR. MORRISON: Okay.

MR. HYRKAS: Of porosity, resistivity . . .

MR. MORRISON: You can't identify what you would call the oil-water contact in this particular log on the State "A" 83?

MR. BENDER: Well, he's already answered the question, that he needs a suite of logs.

MR. MORRISON: What suite of logs do you need?

<u>MR. HYRKAS</u>: A suite of, you're asking to define a water saturation calculation, I believe, is that, is that what you're asking?

<u>MR. MORRISON</u>: Whatever you are using for an oil-water contact. I don't know what you are using for your water saturation cutoff either.

<u>MR. HYRKAS</u>: You need a porosity tool log to help you with resistivity and in that combination, that's generally, a generally accepted practice to use a porosity log and a resistivity log.

<u>MR. MORRISON</u>: Okay. And you're not showing a resistivity log on Exhibit No. 7?

<u>MR. HYRKAS</u>: Yes, I am.

<u>MR. MORRISON</u>: Okay. And a porosity log?

<u>MR. HYRKAS</u>: There is no porosity log associated with any of the logs in this suite or Exhibit 7, Exhibit 8.

<u>MR. MORRISON</u>: You do have a porosity log with on the State "A" 83?

<u>MR. HYRKAS</u>: That is correct.

MR. MORRISON: And you're, again it's 9827?

MR. HYRKAS: That was the working interest owner unanimous approval of, which Placid agreed to, all, all the working interest owners approved that depth.

MR. MORRISON: Let's change the question a little bit, Jerry. What's, what's your opinion? Let's forget about working interest owners and what working interest owners approved. What's your opinion as to the oil-water contact in the State "A" 83?

MR. HYRKAS: I, I don't think that that's a proper question because opinion is not factual.

MR. MORRISON: Well, I think you qualified yourself as an expert and you've testified as to how net pay was calculated. Now I'm asking, what is your opinion as to the oil-water contact in the State "A" 83?

MR. HYRKAS: We will provide testimony for that.

MR. MORRISON: The engineer will answer that.

MR. HYRKAS: That is correct, yes.

MR. MORRISON: And you agree that, on your Exhibit No. 13, what you're showing as pay for the State "A" 83 is dependent upon the measurement of a number of feet between the top of the clean limestone and the oil-water contact in that well. Is that right?

MR. HYRKAS: That is correct.

MR. MORRISON: And you have no opinion as to what that oil-water contact actually is for the well?

MR. HYRKAS: We have testimony which will tell you what that is.

MR. MORRISON: No, no, no, Jerry, I said, you, you personally, have no opinion as to what that oil-water contact is?

MR. HYRKAS: Without looking at the exact log suite in front of me, I, I can't answer that particular question.

MR. MORRISON: Reading logs is, is part of the functions, duties and responsibilities of a geologist, isn't it?

MR. HYRKAS: That is correct.

MR. MORRISON: Do you have the porosity log with?

MR. HYRKAS: Yes, I do.

MR. MORRISON: Could you pull it out and look at it?

MR. HYRKAS: Sure.

MR. MORRISON: Ready?

MR. HYRKAS: Yes, I'm ready.

MR. MORRISON: Okay.

MR. HYRKAS: All right, the . . .

MR. MORRISON: The question is, whether or not you have an opinion as to what the oil-water contact is in the State "A" 83?

MR. HYRKAS: The actual oil-water contact that Conoco provided was at 9818, but understanding that there was a transition zone and the bulk volume, or the, there was no transition to 100% water. That is to say, there was a transition zone in most of the wells and that this transition zone could go from 100% oil production to a water cut of varying productions to an exact, well to a 100% water.

MR. MORRISON: Conoco provided the 9818 oil-water contact.

<u>MR. HYRKAS</u>: At the working interest owner meeting there were varying water contacts that were presented by, for each well, and what we provided and what was actually approved unanimously were two different things.

<u>MR. MORRISON</u>: And it was a matter of compromise to come to what was agreed to unanimously. Is that right?

<u>MR. HYRKAS</u>: It was unanimous, so I don't think this was a compromise.

<u>MR. MORRISON</u>: Well, okay, so then 9818, you were just wrong when you went and said 9818 was the oil-water contact in the State "A" 83?

<u>MR. HYRKAS</u>: The oil-water contact is a, is a relative thing because of the transition zone in all of the wells.

<u>MR. MORRISON</u>: Uh huh.

<u>MR. HYRKAS</u>: Okay, so what do you mean, do you mean 100% water, 100% oil, 40% water, 60% oil, what exactly do you mean by your water, what would you define as the water contact?

<u>MR. MORRISON</u>: Well, let me ask you, what are you using as the cut off to determine the bottom of the pay?

MR. HYRKAS: The bottom of the pay, of 100% oil on the map was 7360.5 subsea. 9827.5 measured depth.

MR. MORRISON: And is that 100% oil, 100% water, 50% of each?

MR. HYRKAS: That's where it goes to 100% water.

MR. HICKS: I'm sorry Jerry, I didn't, oil did you say?

MR. HYRKAS: At 90, subsea 7360.5 and below for the purposes of the unit were 100% water.

MR. HICKS: Okay, thank you.

MR. MORRISON: Conoco's original indication that this oil-water contact was 9818, the difference between 9818 and 9802 your top of the clean line is 16. Is that right?

MR. HYRKAS: Can you?

MR. MORRISON: 16 feet, from 9802 to 9818.

MR. HYRKAS: Math seems correct.

MR. MORRISON: Even lawyers can do that much. And if you look on your Exhibit No. 13, you said that the well was 26 feet. Is that right?

MR. HYRKAS: Yes, that is correct.

MR. MORRISON: And the effect of increasing the pay in the State "A" 83 from 16 to 26 is to pull all the pay down to the south towards the State "A" 83 well. Is that right?

MR. HYRKAS: Only at that point because there were varying contacts.

MR. MORRISON: But, throughout all of the N/2 of Section 5 it pulled all the contours down, doesn't it?

MR. HYRKAS: Yes, for the small area of reservoir associated with the well in Section 5, the State "A" 83 and that was approved by the working interest owners as the contact, you pull it down in that direction.

MR. MORRISON: And Conoco owns 100% in the N/2 of 5, don't they?

MR. HYRKAS: It was unanimously approved that that would be . . .

MR. MORRISON: No, no, no. The question was, Conoco owns 100% of the working interest in the N/2 of Section 5?

MR. HYRKAS: I would defer that to the witness who would know better. That would be our land man . . .

MR. MORRISON: Do you know?

MR. HYRKAS: I'm not qualified to answer that particular question.

MR. MORRISON: Yes, I think you are qualified, if you know. If you don't know, you simply don't know.

MR. HYRKAS: We had 100% working interest in the well.

MR. MORRISON: Okay. Let's go on to your Exhibit No. 8 a minute. This is a cross-section, right?

MR. HYRKAS: That is correct.

MR. MORRISON: Now first you indicated this included all of the wells, except the Kadrmas. Is that right?

MR. HYRKAS: I said at first it had all the producing wells except the Kadrmas.

MR. MORRISON: Okay, it doesn't have the Filipi well either, does it?

MR. HYRKAS: That is not a productive well.

MR. MORRISON: Right. On your Frenzel straight hole with the log to the very left of the exhibit . . .

MR. HYRKAS: Yes.

MR. MORRISON: If I recall your testimony it was that initially you thought there was some mound and then later you found out there wasn't. Is that right?

MR. HYRKAS: We thought there was clean, porous mound and found out later it was not porous.

MR. MORRISON: How did you find that out later?

MR. HYRKAS: We ran a porosity log in the straight hole of the Frenzel.

MR. MORRISON: When was that done, while you were drilling the straight hole, before you did this . . .

MR. HYRKAS: At the point of TD of the straight hole, it's customary to run a log suite and we did that and we found that what we thought was porous, clean mound was not. It was actually nonporous mound.

MR. MORRISON: But still mound. Is that right?

MR. HYRKAS: Well, we interpret it as mound.

MR. MORRISON: And, in fact, I think you said your interpretation of mound was a scale of 10 on the gamma ray. Is that right?

MR. HYRKAS: Yes. With porosity.

MR. MORRISON: No, okay. And you'll agree that the little section down, just above the 10,000 foot mark on the gamma ray log on the Frenzel is, is, while not clear on this log, in fact if you look at a log with all the scales on it is at that ten?

MR. HYRKAS: 9975 to 9990 is a clean gamma ray of nonporous interval which was originally interpreted to be mound.

MR. MORRISON: In fact, Conoco used that interpretation of that portion as mound to justify the sidetrack. Is that right?

MR. HYRKAS: Yes, and we are very lucky in getting the mound on the sidetrack.

MR. MORRISON: And because you drilled the straight hole and because you found what you thought was mound in the logging and on the straight hole you went ahead and did the extra expense to drill the sidetrack, right?

MR. HYRKAS: That is correct.

MR. MORRISON: And so you knew you were close, right?

MR. HYRKAS: We assumed we were close.

MR. MORRISON: Now you didn't find any mound in the logs on the Filipi well. Is that right?

MR. HYRKAS: That is correct.

MR. MORRISON: Let's go to your Exhibit 12 a minute. Now, if I'm looking at this Exhibit right you're showing the, the outer contour, the 7500 foot contour, which is your reservoir limit, so to speak. Is that right?

MR. HYRKAS: Correct, yes.

MR. MORRISON: And you're showing that closer to the Filipi well, in which there was no evidence of any mound, than it is to the straight hole Frenzel well in which there was some evidence of mound, but not porosity. Is that right?

MR. HYRKAS: That is correct.

MR. MORRISON: Why?

MR. HYRKAS: Because at, if you'll note that the structure on the Fryburg from Exhibit 11 indicates the subsea Fryburg top of 6444 and the straight hole Frenzel was 6452. Using the relationship of the Fryburg this well needed to be closer to the mound.

MR. MORRISON: What are you showing on your Fryburg map for the Walton 84 well?

MR. HYRKAS: The Walton 84 was 6445.

MR. MORRISON: Pretty much the equivalent of the Filipi. Isn't that right?

MR. HYRKAS: Not exactly. If you assume that there is a regional dip about the beds and that, that as you move deeper into the Basin your structure is going to show that the Filipi and Frenzel were closer to mound than the Walton, which is updip to the south and so the Walton was actually further away from the mound.

MR. MORRISON: What's the orientation of the dip?

MR. HYRKAS: In which well?

MR. MORRISON: In the regional orientation throughout the field, is there a, towards the Basin?

MR. HYRKAS: Generally to the south, north to the Basin. That's correct.

MR. MORRISON: Wait, generally to the south, north to the Basin?

MR. HYRKAS: North into the Basin.

MR. MORRISON: North into the Basin.

MR. HYRKAS: North into the Basin.

MR. MORRISON: But the Walton well is to the southwest of the Filipi well?

MR. HYRKAS: That is correct.

MR. MORRISON: And it still is regional dip?

MR. HYRKAS: No, it's that the Filipi is closer to mound and the differential compaction associated with that top gives you closer to mound because, it's, it should, if the, if the Walton well is at 6445 and that is approximately what the Fryburg should be less the mound, then if the Filipi is higher at 6444 it must be closer or approximal to mound. Because if you, should be at a point, somewhat deeper, the Filipi should be deeper because you're going Basinward.

MR. MORRISON: Okay and that's why you think you're closer to the mound when you didn't find any in either well. Is that right?

MR. HYRKAS: In which wells?

MR. MORRISON: In the Filipi and the Walton, for now.

MR. HYRKAS: No.

MR. MORRISON: And you really have, again, this is based on well control. Is that right?

MR. HYRKAS: Which exhibit are you on?

MR. MORRISON: Take your pick, Exhibit 11, Exhibit 12, Exhibit 13.

MR. HYRKAS: Correct.

MR. MORRISON: And you have no control whatsoever between the State 74 and the Filipi 76 for the location of your zero line?

MR. HYRKAS: No, only the Fryburg relationship.

MR. MORRISON: And even on the Fryburg you've got no control points between the State 74 and the Filipi 76, do you?

MR. HYRKAS: They serve as control points.

MR. MORRISON: But there are none in between them, is that right?

MR. HYRKAS: No.

MR. MORRISON: Now if, in fact, your 7500 foot contour or your zero line is too far to the east and should properly be located farther to the west, you have artificially pulled out the reservoir again to the east. Is that right?

MR. HYRKAS: Could you . . .

MR. MORRISON: That was probably an inarticulate question.

MR. HYRKAS: Can you repeat that question?

MR. MORRISON: All right, let's go, it will probably take a couple questions to equal that one. While I'm not asking you to agree with this will you just assume that, in fact, the 7500 foot contour is closer to the State 74 well and not as close to the Filipi, say running through the midpoint of Section 32.

MR. HYRKAS: Wait, that's not . . .

MR. MORRISON: Assumption.

MR. HYRKAS: Could you repeat that again? You said the 7500 foot contour runs through the 74?

MR. MORRISON: No, no. On Exhibit 12 assume that the 7500 foot contour really runs right through the middle of Section 32.

MR. HYRKAS: Of 32.

MR. MORRISON: And that you've pulled it out too far towards the Filipi, okay, just make that assumption. That's all I'm asking at this point in time.

MR. BENDER: You're not asking him to agree with that?

MR. MORRISON: Right.

MR. BENDER: Just to make the assumption for the purpose of your question.

MR. HYRKAS: I'll agree with the assumption.

MR. MORRISON: Okay. The effect of pulling the 7500 foot contour to the east is to allocate substantially more reservoir, not only to the E/2 of Section 32, but also to the W/2 of Section 32. Would you agree with that, if you agree with the first assumption?

MR. HYRKAS: If you agree with the first assumption and if I were to agree with what you just said, then that would be the effect.

MR. MORRISON: Because of the way the contour is oriented and the steep dips as you pull the edges out, you are spreading the top or the thicker part of the mound out. Is that right?

MR. HYRKAS: I think I need you to repeat that too.

MR. MORRISON: Okay. Because of the steep dip on the mound, as you pull the edges of the mound out, you also pull the upper contours, which are not quite as close together, and therefore pull the thicker part of the mound down. Is that right?

MR. HYRKAS: I'm not sure I'm following your concept. If what you're saying in general is that the dips will become less near the top that assumption could be put to what you've just said.

MR. MORRISON: Okay. I'm kind of curious. I'm not sure I understood the purpose of your

Exhibit No. 10. Could you explain to me what that is again?

MR. HYRKAS: Exhibit No. 10 is to show the observed relationship between Fryburg Structure and Lodgepole Reservoir. That is that a thickened section of mound corresponds to a thinned interval between the Fryburg and the top of the mound. _______________, the structure of the Fryburg is high, the mound is thick, or high and where the Fryburg is low, the mound is low or thin.

MR. MORRISON: And what's the measurement you're using on your vertical axis?

MR. HYRKAS: The vertical axis is the isopach value from the Fryburg porosity zone within the Dickinson area to the top of the clean mound.

MR. MORRISON: But I thought you didn't have any clean mound in the 79 well, for example?

MR. HYRKAS: There is zero points. If you look at the thickness of clean mound on the X axis you will see those are zero points.

MR. MORRISON: Well, how'd you find the top of the clean mound if there's no mound to give it 1100 foot value on the Y axis?

MR. HYRKAS: You, X, it's, there is, this is part of a series of equations, which defines the, the, the relationship is not linear.

MR. MORRISON: Uh huh.

MR. HYRKAS: The Y axis is the thickness from the Fryburg to the top of the clean mound, but in the equations, which we, if you like, we can go through, X is the flat, the plane of the Bakken. So you need to define a zero thickness for the interval from Fryburg to clean mound. And so you do that by, on the zero wells assuming the Bakken is plane.

MR MORRISON: Assuming the Bakken is plane?

MR. HYRKAS: Well, assuming it's directly below the, you know, if you are drilling a well, you would go through to the Fryburg top and then you anticipate a clean mound top. If you do not hit it you'll go down to the Bakken or your next available marker horizon. So, to define a zero edge of the mound and assume a thickness of Fryburg to clean mound you have to define a deeper plane for the, for the end value.

MR. MORRISON: So what have you defined as your top of the clean line, where you don't have any clean lines, is it the top of the Bakken?

MR. HYRKAS: 1095 feet from top of the Fryburg to the exact zero or one-foot point of mound.

MR. MORRISON: So your 1095 are just values that are projected values. Is that correct?

MR. HYRKAS: That would be a projected value on the far left-hand side of the equation, knowing that those wells did penetrate the Bakken giving two control points to validate the interpretation of the 1095.

MR. MORRISON: But the 1095 is not the value from the top of the Fryburg to the top of the Bakken, is it?

MR. HYRKAS: No, it is not.

MR. MORRISON: It's the value from the top of the Fryburg to some point above the Bakken that you've used.

MR. HYRKAS: That you would assume would be the one-foot point.

MR. MORRISON: And you've used an equation to back into that. Is that right?

MR. HYRKAS: Yes. The relationship is not linear but does provide a good solution using the Fryburg structure. And it is not an exact correlation. It is, what I feel is the best solution.

MR. MORRISON: And so really what you've done, is you've taken some known values, your known values were, what's shown here as 83, 79, 75, 74?

MR. HYRKAS: Yes.

MR. MORRISON: And you've projected backwards to come up with the value for 76 and 79. Is that right?

MR. HYRKAS: Knowing that they had no mound. That that would, that that's the science that you go through.

MR. MORRISON: Zero put them on the X axis, but you are projecting backwards where they fall on the Y axis. Is that right?

MR. HYRKAS: That would be, say that again, zero on the X axis.

MR. MORRISON: Your assumption they have no mound . . .

MR. HYRKAS: Yes.

MR. MORRISON: Gives them a value of zero on the X axis?

MR. HYRKAS: That is correct.

MR. MORRISON: Their location on the Y axis is simply an assumption that you made?

MR. HYRKAS: Yes, but you know within a range where it has to be and then you assume, from the two points that went down from Fryburg to top of Bakken that there is a plane directly below and that the beds are not steeply dipping. There is, there is assumption to this, but you can validate it.

MR. MORRISON: But, again, 76 the, the value, the Y value for 76 and 79 are mathematically derived values?

MR. HYRKAS: That is correct, yes.

MR. MORRISON: If you look at 79 and if you assume that there is 15 feet of mound, in other words the same assumption that Conoco made when you drilled the initial straight hole . . .

MR. HYRKAS: Yes.

MR. MORRISON: And justified the sidetrack, where would the value for 79 lie . . . feet of mound?

MR. HYRKAS: Interestingly enough I plotted that point and it falls right on the graph. It's very, very good fit.

MR. MORRISON: What's the value for the vertical axis?

MR. HYRKAS: The vertical axis is one thousand and . . .

MR. CARVELL: What was that number again?

MR. HYRKAS: 1095 feet from Fryburg top to clean mound.

MR. MORRISON: What value are you using right now?

MR. HYRKAS: 1095.

MR. MORRISON: Okay, so that is the value that is shown on your Exhibit 10, is 1095?

MR. HYRKAS: Yes. The stars could not be superimposed. They overlay each other.

MR. MORRISON: Okay on the, the Frenzel 79 straight hole log on Exhibit No. 8, where that 1095 point would be on the log. You don't have the the top of the Fryburg on this . . .

MR. HYRKAS: I said it was, yes, I said it was calculated because we did not think there was clean mound in there. I guess I could pull a Fryburg top and tell you where it is. But I can tell you it's a calculated value.

MR. MORRISON: Why don't you tell me where the top of the Fryburg is . . .

MR. HYRKAS: The top of the Fryburg?

MR. MORRISON: . . . ________ log Frenzel straight well?

MR. HYRKAS: Yes. Top of the Fryburg porosity, the top marker was 8964.

MR. MORRISON: 8964?

MR. HYRKAS: That's correct.

MR. MORRISON: And 1095, am I doing this right? You add those two together?

MR. HYRKAS: That is correct.

MR. MORRISON: 10,059. Is that right?

MR. HYRKAS: That is correct.

MR. MORRISON: That's what, somewhere around the upper Bakken shale, isn't it?

MR. HYRKAS: That is . . .

MR. MORRISON: If you look . . .

MR. HYRKAS: Yes and that leaves the interpretation that this is not mound facies.

MR. MORRISON: Okay. But you've already agreed that the, I forgot your footages and I didn't jot them down, but that the area of clean gamma ray up above the 10,000 foot marker, that, that is mound, although not porous. Is that right?

MR. HYRKAS: It is clean limestone, but probably not mound.

MR. MORRISON: Clean limestone?

MR. HYRKAS: Of 10 API gamma ray ___________ it is not porous.

MR. MORRISON: And if you use the top of that feature which is what, 9970, give or take?

MR. HYRKAS: 9975.

MR. MORRISON: 9975?

MR. HYRKAS: That's correct.

MR. MORRISON: And if you plot that, that point on your Exhibit 10 which would be, what around 1100 give or take, or excuse me, slightly over a thousand, 1011?.

MR. HYRKAS: Uh huh.

MR. MORRISON: It doesn't confirm very well with what your projections are, does it?

MR. HYRKAS: That's why it's, it's not mound. It's a possible debris slope off the mound, it is nonporous. If you agree that the mound is porous, then this is not porous mound.

MR. MORRISON: Okay. The mathematical calculations tells you that what shows on the log as limestone is not mound. Is that what you say?

MR. HYRKAS: Could, could you repeat this, the mathematical calculation?

MR. MORRISON: The mathematical calculation that you did to derive your points for 76 and 79 . . .

MR. HYRKAS: Assume that this was not mound, not part of the mound. It was a clean limestone, not associated with the mound.

MR. MORRISON: So, that's, that's why it's not mound, because it's an assumed value?

MR. HYRKAS: Value. It was not porous, it was not in the oil or water column, it was not associated.

MR. MORRISON: Okay. Let's look at your Exhibit 12 for a minute. And, and while you're doing it you may also want to have Exhibit 11 handy, because we kind of talk about the same, it may affect both maps. Would you agree with me that you have very limited control for the north end of the feature?

MR. HYRKAS: Define limited.

MR. MORRISON: What data do you have to show your contours, any place after they leave Sections 31, 32 and head to the north?

MR. HYRKAS: The concentric nature of the mound that we've seen on three boundaries indicates with the Filipi 76 well control point in Section 32 and the Frenzel straight hole in Section 31 that this is the appropriate boundary.

MR. MORRISON: The only control you're using for the northern edge of the reservoir are the Filipi, the Frenzel and then just the general shape for the rest of the contours?

MR. HYRKAS: Along with the, the Fryburg structure map in Section 29, showing the DHSU 20 at 6462 subsea being distant from the mound.

MR. MORRISON: Okay and no similar control on the, on the northwest side of the feature. Is that right?

MR. HYRKAS: I would consider control on northwest being the Frenzel.

MR. MORRISON: Is this the same type of interpretation that led Conoco to drill three dry holes?

MR. HYRKAS: I am not understanding your question. We, you don't drill dry holes for the heck of it.

MR. MORRISON: Well is this the same interpretation that told you there would be productive mound at the Filipi 76 location?

MR. BENDER: What interpretation are you talking about?

MR. MORRISON: The general regional contours and what limited well control you had before drilling the Filipi well.

MR. HYRKAS: The Filipi gave us a control point which we did not have before.

MR. MORRISON: And before drilling that you assumed that that would be productive limestone mound. Is that right?

MR. HYRKAS: Tough price to pay, huh?

MR. MORRISON: And you were wrong, right?

MR. HYRKAS: Yes.

MR. MORRISON: And you were wrong at the Frenzel straight hole location?

MR. HYRKAS: That is correct. This, this is what defines the mound boundaries.

MR. MORRISON: Okay. And you were wrong at the Walton?

MR. HYRKAS: That is correct.

MR. MORRISON: You haven't drilled one to the north where you've been wrong yet, right?

MR. HYRKAS: There's no reason to drill anymore to the north.

MR. MORRISON: Do you concede that it's possible that your contouring on the north end of the feature is incorrect?

MR. HYRKAS: Everything is subject to interpretation, but this I believe is the best and most accurate interpretation and if that is the case, and I believe that, there is no reason to drill there.

MR. MORRISON: Is it confirmed by your seismic?

MR. HYRKAS: What is confirmed by our seismic?

MR. MORRISON: Your structural interpretation or your interpretation.

MR. HYRKAS: We used no seismic in the interpretation of the mound.

MR. MORRISON: No, I asked if it was confirmed by seismic that you now have.

MR. HYRKAS: I, we don't use seismic for the interpretation of the mound boundaries.

MR. MORRISON: You have 3D seismic covering Sections 29, 30, 31, 32, 5 and 6, right?

MR. HYRKAS: We use seis, we use 3D seismic as an exploratory tool. Exploratory wise we feel that we can probably see the tops of the mounds, but by no stretch of the imagination can we see the reservoir limits on the sides.

MR. MORRISON: Is there anything in the 3D seismic coverage that you have over the area that contradicts your interpretation that you're presenting to the Commission today?

MR. HYRKAS: The 3D seismic has not even been interpreted yet.

MR. MORRISON: When was that 3D seismic shot?

MR. HYRKAS: 3D seismic was shot from December of 1993 through March of 1994. We had a series of problems with the 3D. As you know in North Dakota we had some severe weather this winter. We lost survey notes, we had to find and put them back into their correct spots. We had a very hard time with the 3D along with the, this is a, an extremely large 3D. I'm not sure if I know anybody that's shot 24 square miles of 3D. This entire, this 3D entails a tremendous work effort to get it all interpreted.

MR. MORRISON: So you haven't even looked at the 3D yet, is that what you're telling me?

MR. HYRKAS: We are in the process of interpreting it.

MR. MORRISON: Has it been processed?

MR. HYRKAS: It's only, there's portions that have been processed.

MR. MORRISON: Have portions on Sections 29 and 30 been processed?

MR. HYRKAS: I'm not sure of that. I'm not part of the interpretation. I do not interpret the 3D seismic over this.

MR. MORRISON: Why don't you explain the difference between processing seismic and interpreting seismic?

MR. HYRKAS: I'm not qualified to answer that.

MR. MORRISON: Do you know if anyone in Conoco has looked at the 3D seismic data on Sections 29, 30, 31 and 32 with relation to the matters being presented to the Commission today?

MR. HYRKAS: I cannot qualify, I cannot qualitatively say that anyone has looked at the seismic on the 3D in those particular sections.

MR. MORRISON: So is it your interpretation or the interpretation you presented today, is the best available interpretation?

MR. HYRKAS: I'd say it's, I believe it's the most accurate.

MR. MORRISON: Okay, based upon the data that's available?

MR. HYRKAS: That is correct.

MR. MORRISON: If you're wrong how are the correlative rights of the owners in, let's pick Section 30 for example, going to be protected by approving this unit?

MR. HYRKAS: If I'm wrong?

MR. MORRISON: Right.

MR. HYRKAS: We have a certain portion of Section 30 already in the unit.

MR. MORRISON: Okay.

MR. HYRKAS: You're assuming that wells be drilled outside the unit to define whether I'm wrong or not?

MR. MORRISON: You're assuming a well is going to be drilled outside the unit?

MR. HYRKAS: Well, how, how else would you define it as wrong?

MR. MORRISON: Okay. And in your opinion is there substantially more risk in drilling a well outside the unit in Section 30, at a 1320, 1320 location than there would be at a 660, 660 location?

MR. HYRKAS: According to the interpretation that would be correct.

MR. MORRISON: And yet Conoco today is asking the Commission to require that any well drilled in the SE/4 of Section 30 be 660 away from the unit outline. Is that right?

MR. HYRKAS: From the unit outline, yes.

MR. MORRISON: Then do you agree that Conoco would probably oppose any request for an exception location that would allow a well to be drilled in the SE/4 of Section 30 closer than 660 to the unit boundary?

MR. HYRKAS: Do I agree that Conoco would probably oppose it?

MR. MORRISON: Uh huh.

MR. HYRKAS: I can't speak for management on this. I, I'm not sure. I will guess we probably would, but that's, I can't make that decision.

MR. MORRISON: I don't have any further questions.

MR. CARVELL: Mr. Wefald?

MR. WEFALD: Thank you. Just so I'm clear about this, your interpretation is based principally on the well logs, the data from the well logs?

MR. HYRKAS: That is correct.

MR. WEFALD: And from that data you have picked out information about the Fryburg area and the Lodgepole. Is that correct?

MR. HYRKAS: That is correct.

MR. WEFALD: And your maps then, the exhibits that you've presented here that you've testified to, basically are strictly an interpretation of the data from the well log.

MR. HYRKAS: That is any geologic map, is an interpretation. That is correct.

MR. WEFALD: As I look at your exhibits, I believe if you take a look at Exhibit 11 and compare that to Exhibit 12, 11's the Fryburg, is it not? And 12 is the Lodgepole?

MR. HYRKAS: Correct.

MR. WEFALD: It looks to me like what you're basically suggesting here, this is almost a, there's almost a one-to-one relationship from top to bottom.

MR. HYRKAS: No, that is not what I'm suggesting. There is no one-to-one relationship. It is a, the graph in Exhibit 10 shows it to be a relationship, but it is not linear. But there is a relationship. But it is not linear. It is defined by the graph.

MR. WEFALD: But is it also true that as each of these wells have been drilled the interpretation, the maps I should say, interpreting this area that Conoco has, those maps have changed with each hole that's been drilled. Is that right?

MR. HYRKAS: That's correct, that's the nature of, of the work.

MR. WEFALD: And is it safe to assume that if there were another hole drilled, anywhere, that, in this area, that would probably result in another change to the map?

MR. HYRKAS: That's most logical.

MR. WEFALD: On that Exhibit No. 10 where was the Walton 84 set on that?

MR. HYRKAS: Exhibit No. 10, it would be at the zero thickness, Y axis in the neighborhood of 1100 feet.

MR. WEFALD: With the 76 and the 79?

MR. HYRKAS: That's correct.

MR. WEFALD: I think, what was the reason that the 84 was the, let me see, yes, the Walton 84 was the only well that was left off here?

MR. HYRKAS: Because we already had overlapping data points, 76 and 79 which was already pointed out that I couldn't superimpose the two on each other. There was no reason to superimpose an additional data point on that.

MR. WEFALD: Just so I'm clear, the 79, although there is, I think it's 15 feet of mound, you nevertheless show zero feet of mound. Is that correct?

<u>MR. HYRKAS</u>: That is subject to interpretation. I do not interpret that as mound. It's clean limestone, but not associated with the mound.

<u>MR. WEFALD</u>: It's different structure then you're saying?

<u>MR. HYRKAS</u>: Excuse me?

<u>MR. WEFALD</u>: A different structure, that 15 feet is different from the mound?

<u>MR. HYRKAS</u>: The 15 feet of clean limestone is different from the porous mound facies, that is true.

<u>MR. WEFALD</u>: Is that, is that clean lime, that limestone seen anywhere else in that Fryburg area?

<u>MR. HYRKAS</u>: In that, if you could qualify that as just any well in the stratigraphical interval, I'm not sure if I follow the exact question. There's been clean lime seen in other wells in the Williston Basin. But, are you, if you're asking me is that clean lime been seen around the Dickinson-Lodgepole Area. Is that your question?

<u>MR. WEFALD</u>: Yes.

MR. HYRKAS: That clean lime has not been seen in anything that has been associated with mound.

MR. WEFALD: There's been some discussion about a dipmeter, a dipmeter data. And, frankly, what does a dipmeter do?

MR. HYRKAS: A dipmeter measures the orientation of bedding planes, within a rock. This is general, I'm not going to, that's that's what the tool is used for, is to see what the dip of beds is.

MR. WEFALD: Is there, what kind of, what kind of dips then can be expected in each of these wells, the dry ones, even the ones that are producing.

MR. HYRKAS: What exhibit are you on sir?

MR. WEFALD: Oh I guess that you can look at No. 11, I guess that would be the one we looked at.

MR. HYRKAS: Well Exhibit No., we don't have any dipmeter data over the Fryburg.

MR. WEFALD: Well let's check No. 12 then.

MR. HYRKAS: Exhibit 12? Okay, go ahead and repeat your question, if you would please.

MR. WEFALD: What type of dips can be expected near or at the margins of this property?

MR. HYRKAS: Steep dips

MR. WEFALD: Steep dips?

MR. HYRKAS: Yes.

MR. WEFALD: What's the dipmeter in the Frenzel 79 straight hole show?

MR. HYRKAS: We have no dipmeter there. It's an imaging log.

MR. WEFALD: Okay.

MR. HYRKAS: In the sidetrack.

MR. WEFALD: Is the imaging log, is that essentially the same thing as a dipmeter?

MR. HYRKAS: I think we're confusing, are we talking about the Frenzel straight hole?

MR. WEFALD: Yes, right now we are.

MR. HYRKAS: There isn't an imaging log, I don't believe, in the straight hole.

MR. WEFALD: No imaging log, no dipmeter in the straight hole?

MR. HYRKAS: No.

MR. WEFALD: What, what about the core data, does that show anything?

MR. HYRKAS: The core data shows there are dips, yes.

MR. WEFALD: Which way?

MR. HYRKAS: It was unoriented core.

MR. WEFALD: But they were steep, I take it?

MR. HYRKAS: Steep is, define steep? I, I have my own definition for steep, but . . .

MR. WEFALD: I suppose we'd measure steep in terms of degrees of dip. What would you say it was?

MR. HYRKAS: I think the degree of dip from the unoriented core were roughly 15 to 20 degrees, slightly higher, slightly lower. There's bedding planes in there. If you're talking about an interpretation of a bedding plane as a dip now and not actual dipmeter data.

MR. WEFALD: Comparing the Filipi 76, what is the dipmeter and the data show there?

MR. HYRKAS: We have no dipmeter at the 76.

MR. WEFALD: Do you have any core data that would show you a dip there?

MR. HYRKAS: I don't believe we have any core data in the 76.

MR. WEFALD: You have nothing in 76 to show you any dip at all?

MR. HYRKAS: That's correct.

MR. WEFALD: Okay. Were you present at each of these four meetings of the working interest owners?

MR. HYRKAS: I was present at the meetings from January 1st.

MR. WEFALD: Were you present at the meeting . . .

MR. HYRKAS: I, except, there was one meeting which only Kevin Preston showed, from Aviva, which, I, I went into the meeting and everything was discussed and my name was left off of that particular, on the minutes, but I did attend that meeting. Everything since the first of January I have attended.

MR. WEFALD: There was, at one of these meetings, an agreement on the oil-water contact level, was there not?

MR. HYRKAS: Yes, there was.

MR. WEFALD: At the outset of that meeting, did various working interest owners come in with different data as to where the oil-water contact was?

MR. HYRKAS: That is correct, yes.

MR. WEFALD: In fact, what you referred to as unanimous agreement, was the result of compromise among all of the working interest owners, was it not?

MR. HYRKAS: If you were to qualify, yes, this probably . . .

MR. WEFALD: They had to agree on something, right?

MR. HYRKAS: We had to agree, yes.

MR. WEFALD: Okay, so that number was . . .

MR. HYRKAS: . . . call it compromise or call it everyone getting together and deciding it was correct. I'm not sure what you term in phraseology, but it was decided upon unanimously.

MR. WEFALD: In fact the same thing is true about this notion of porosity, is it not? Everybody said, look we might as well agree that we're going to have uniform porosity throughout this formation because that's the easiest way to do it, isn't it?

MR. HYRKAS: Well, I'm not going to characterize it as the easiest way to do it, but it was the best solution to the problem.

MR. WEFALD: I mean, it's certainly easier than to have different levels of porosity at different parts of the formation when you have to make different calculations.

MR. HYRKAS: I, I think that's correct.

MR. WEFALD: And again that was a matter of compromise, was it not?

MR. HYRKAS: Understandably that everyone agreed yes.

MR. WEFALD: And everybody had different data?

MR. HYRKAS: That's correct.

MR. WEFALD: And everybody had, in these meetings everybody had different maps showing the net pay, isn't that right?

MR. HYRKAS: ____ net, I'm not sure if everyone had a different map, but there were different, alternate solutions provided. Not everyone, but there was differences.

MR. WEFALD: And the map that was put into this unit plan here is the one that was agreed upon by, you said, 75% of the people at that vote. 75% interest of the vote.

MR. HYRKAS: Could, could you restate that, it was unanimous, I don't know if you want to say . . .

MR. WEFALD: Just a minute.

MR. HYRKAS: Okay.

MR. WEFALD: I believe this unit plan, the testimony in this case has been that, that the maps in here were agreed upon by 75% interest owners.

MR. HYRKAS: The maps?

MR. WEFALD: Yes.

MR. HYRKAS: Yes, but the contact was not a . . .

MR. WEFALD: I'm talking about a different thing now.

MR. HYRKAS: Sure, fine.

MR. WEFALD: We know the water contact and the porosity were matters of compromise in agreement among all the working interest owners.

MR. HYRKAS: Correct.

MR. WEFALD: And what my point is, that the maps that are submitted here are not the result of compromise, but are in fact the maps dictated by the people who had the 75% interest.

MR. BENDER: Which maps are you referring to, Bob?

MR. WEFALD: I would think anyone of these that shows the net pay. The net pay map is the most important one.

MR. CARVELL: Which exhibit?

MR. WEFALD: I'm going to find out. ___________________.

MR. HYRKAS: Yes, there were various maps presented at each meeting and the only map that passed was the one I'm presenting.

MR. WEFALD: And that was the one that was ___ Conoco map?

MR. HYRKAS: Yes.

MR. WEFALD: Without any compromise, that this is the map, this is the one we're going to go with.

MR. HYRKAS: Yes, but we did not have the votes to, to pass our oil-water contacts which were higher in the 83. We did not have the votes. We had to compromise on that.

MR. WEFALD: And we compromised on porosity?

MR. HYRKAS: We, consensus on porosity, there was no compromise among the groups, everyone agreed, so, I, I don't know how you compromise on total agreement.

MR. WEFALD: I guess you don't compromise on total agreement. I guess that's a good point. I'm curious as to why, why you think the relationship between the Fryburg and the mound is so critical.

MR. HYRKAS: Because it incorporates more well data than the actual mound points.

MR. WEFALD: But, in fact, it incorporates at a different level. We're talking about thousands of feet apart here, at least hundreds and hundreds of feet apart.

MR. HYRKAS: Yes, and that's why I went to great pains to express the reason that relationship exists.

MR. WEFALD: Let's see Exhibit 11 a minute. All right, Mr. Morrison asked you about this, I'm not certain I understood your response to it. This is a, 11 is the Fryburg Zone. Is that correct?

MR. HYRKAS: Fryburg porosity zone in the Dickinson area, correct.

MR. WEFALD: If I look at at the Filipi 76 and the Walton 84 you would concede that we've got a one-foot difference, isn't it?

MR. HYRKAS: Yes, and that, that was a question that Mr. Morrison brought up.

MR. WEFALD: And, tell me again, why then on 12 is the, is the 7500 foot mark basically right on top of the Filipi 76, whereas it's offset from the Walton 74, in fact we're trying to use data to interpret.

MR. HYRKAS: That's fine, yes. Going through it again, there is an assumption that the 76 is closer to mound than the 84. And that's what the map shows.

MR. WEFALD: And what is the, what's the basis of that?

MR. HYRKAS: The basis of this is that if there is a dipping slope into the Basin, going from south, at the Walton 84 to north, through the Frenzel and going off north into the Basin, there is a plane dipping into that Basin. If the Walton 84 is the same top as the Filipi then the Filipi has to be closer, or approximal to the mound because it should have a point that is lower, given any normal circumstance, okay? So, assuming that the tops are the same, which they are one foot different, in favor of the Filipi, the actual Filipi point could, could have been as low as 6452 because it's almost adjacent to, on a east-west plane with the Frenzel. So, using the relationship that there is a dipping plane beneath, in the Bakken and the base of the mound, that the Filipi has to be closer to mound.

MR. WEFALD: And the Frenzel, excuse me, in the Walton 84 I think then you must of had a dipmeter data or some type of data that indicated dip?

MR. HYRKAS: Indicating dip? No, no we did not.

MR. WEFALD: So, in the Walton 84 and the Filipi 76, from dipmeters to core logs you didn't have any indication of dip at all?

MR. HYRKAS: No.

MR. WEFALD: Then how are you coming up with an indication of dip, an assumption of dip, for the Walton 84?

MR. HYRKAS: Just what I explained. You have to assume that the Filipi is closer to mound because there is dip into the Basin. And the dip into the Basin on all beds is going north into the Basin. Therefore, a point, lets say on the south portion of the map is going to be structurally higher just because of its position than a well on the north end of the map because there is a plane dipping into the Basin. Therefore, if you have two equal points which are different because one is Basinward, it must be closer to the edge of the mound.

MR. WEFALD: Well the dip in this particular case, you say it's 2 north, 0° north?

MR. HYRKAS: No, it's, I could characterize it within 15 or 20 degrees, you know, within 10° of north to east and 10° northwest, but what it does, is it gives you a plane into the Basin. Now, I'm not going to fudge a .4° or .2°, it's, if, it's a phenomenon that is mappable that the Basin is north and it's dip is into the Basin.

MR. WEFALD: Do you have any data or any maps showing a regional dip?

MR. HYRKAS: No, I do not have a map with me that would show that regional.

MR. WEFALD: Does Conoco have any such maps at all? Whether you have them with you or not?

<u>MR. HYRKAS</u>: Yes, I would be able to show maps that show that phenomena. That particular phenomena is very, very common, common knowledge.

<u>MR. WEFALD</u>: And if there was seismic data available, is it your testimony as an expert if the seismic data is not at all as reliable as your projection about what the mound looks like, based on what the Fryburg looks like?

<u>MR. HYRKAS</u>: What I said was that the, the seismic is an exploratory tool and it can be used for the exploration to find new mounds, but you're going beyond the limits of the tools to try to use it for the boundaries of the mound.

<u>MR. WEFALD</u>: Let me ask you this. There were some questions Mr. Morrison asked about 3D seismic. Do you have any, you have 2D seismic on these four, these six tracts of land?

<u>MR. HYRKAS</u>: Yes, we do.

<u>MR. WEFALD</u>: And did you make a map of the 2D seismic?

<u>MR. HYRKAS</u>: Did I make, no I did not.

<u>MR. WEFALD</u>: There is no map that Conoco has showing us 2D seismic?

MR. HYRKAS: No, there is no map. Well, from what I've gone through there is no map. There could be, I'm trying to think if there is.

MR. BENDER: If you know.

MR. HYRKAS: I can't think of any map that we've done.

MR. WEFALD: And the 3D seismic that was shot, completed in March, still isn't mapped?

MR. HYRKAS: That is correct.

MR. WEFALD: I mean, is it you normal practice, is it Conoco's normal practice not to make maps based on seismic?

MR. HYRKAS: It is Conoco's normal practice to, in terms of exploratory or in terms of development?

MR. WEFALD: Well, let's talk about exploratory.

MR. HYRKAS: Exploratory, yes, maps are made. But risk is involved with those maps. You have to apply a certain degree of risk to any mapping that you do and that comes out of the way you drill wells, economics, etc. So any interpretation that involves seismic also has to involve a significant amount of risk.

MR. WEFALD: And, so what you're telling me is that, in fact, Conoco does have seismic exploratory maps of this area?

MR. HYRKAS: The 3D is not interpreted.

MR. WEFALD: 2D?

MR. HYRKAS: We have some 2D exploratory. And that was how the well really got drilled, the original 74 well was on a seismic anomaly we thought was deeper.

MR. WEFALD: The seismic data was good enough to find a producing hole?

MR. HYRKAS: The seismic data was good enough to find the top of structure. But was not good enough to find the edges.

MR. WEFALD: Exhibit No. 13 I, I just want to make sure that I understood this . . .

MR. HYRKAS: I'm sorry I missed, what exhibit?

MR. WEFALD: Exhibit No. 13.

MR. HYRKAS: Okay.

<u>MR. WEFALD</u>: That of course is based on the Fryburg again, is it not?

<u>MR. HYRKAS</u>: No, this is based off Exhibit No. 12 and the oil-water contact.

<u>MR. WEFALD</u>: And, when you say it's based on the oil-water contact that's based on the compromise agreement among all the working interest owners where they agreed it's what the oil-water contact was?

<u>MR. HYRKAS</u>: No, there was no compromise on the oil-water contact. That was unanimously approved.

<u>MR. WEFALD</u>: Yes, but, I mean, I thought you told me, you were at the meeting, that everybody came in with a different oil-water contact?

<u>MR. HYRKAS</u>: Yes, there is a voting procedure, that when the vote came through for the oil-water contact everyone voted for it. Now irrespective of whether we all bring maps when we vote on something that's, that's what I'm talking about. Because . . .

<u>MR. WEFALD</u>: Just so, just so I'm clear, I'm not trying to make, I'm not trying to make this, this too painful, but are you telling me there was absolutely no discussion about the oil-water contact, everybody got a vote and it turned out that everybody walked away from their points, and they wound up with the unanimous oil-water contact?

MR. HYRKAS: There was significant discussion on the oil-water contact, but when it came time to vote, everyone voted for the oil-water contact that were established by well.

MR. WEFALD: And there was someone in that group who said let's vote to make it at such and such a location?

MR. HYRKAS: That is correct.

MR. WEFALD: And that was based on all the discussion?

MR. HYRKAS: That's correct.

MR. WEFALD: Yeah, okay, sounds like a compromise to me.

MR. HYRKAS: Unanimous.

MR. WEFALD: A unanimous compromise? Everyone agrees.

MR. HYRKAS: Unanimous. It was unanimous, yes, sir.

MR. WEFALD: On the, on the Filipi 76 well, or I guess on any of the wells on the edge, the projected top of the Fryburg to the top of the mound, at that Filipi 76 location . . .

MR. HYRKAS: Mr. Wefald, and the exhibit would be?

MR. WEFALD: Well, let's try No. 13.

MR. HYRKAS: Okay . . .

MR. CARVELL: We are ready to restart. Mr. Wefald, your question.

MR. WEFALD: ______ Fryburg 76 on Exhibit 12.

MR. HYRKAS: You said Filipi 76?

MR. WEFALD: Yes, Filipi, I'm sorry, yes. If we're talking about the top of the Fryburg, we're talking about the top of the mound, is the, is the distance that uses the 1095 number, one thousand ninety five?

MR. HYRKAS: Is the distance I used the 1095 number to top of mound?

MR. WEFALD: Yes.

MR. HYRKAS: Correct. Well, that would be the, the way the equation would work, yes.

<u>MR. WEFALD</u>: Why is that, I'm just curious as to why that places it, could it be, could it be a couple hundred feet to the west?

<u>MR. HYRKAS</u>: Okay, now I'm losing you.

<u>MR. WEFALD</u>: The edge.

<u>MR. HYRKAS</u>: Could the edge be a couple hundred feet to the west of the Filipi?

<u>MR. WEFALD</u>: Yes.

<u>MR. HYRKAS</u>: There is no, yes, it's very close. This, this map is, it's probably a hundred now, could be a couple hundred by your interpretation. That's where the edge is, yes.

<u>MR. WEFALD</u>: Okay. Another question, _____. Let's assume that the State 74 wasn't there and we could drill anywhere in the section, how many, how many feet west would you want to put the Filipi 76 before it gets pay in the Lodgepole?

<u>MR. HYRKAS</u>: Well, first of course, I'd like to drill the State 74 if there was no well there.

<u>MR. WEFALD</u>: Okay.

<u>MR. HYRKAS</u>: Okay, because I, now I'm drilling the second well?

MR. WEFALD: Yes. How many feet, how many feet west does the Filipi 76 have to go before it gets into the pay?

MR. HYRKAS: Well, let's check the map. Exhibit 13?

MR. WEFALD: Okay.

MR. HYRKAS: I don't have the exact ruler, but you can see the Filipi is, I can't give you the exact number, feet west, I wish I could, but the zero boundary versus the Filipi looks to be about 400 feet, 500 feet.

MR. WEFALD: One final question about 3D then I'm all done. This 3D was taken, shot, after the wells were in and you had some indication where the producers were and where the dry holes were, is that right?

MR. HYRKAS: I'm trying to think if all the wells were . . .

MR. WEFALD: From December 19th to March 94.

MR. HYRKAS: Yes, we drilled the Walton well, I can't recall, but we had predominant well control, is what you're asking.

MR. WEFALD: Why, why would Conoco spend the money for a 3D if they don't think it does them any good for locating boundaries?

MR. HYRKAS: Well, because 3D is, as 2D is, really only works best with analogs. We know that we can see large mounds, the tops of structures, the tops of the mounds. Seismic can tell you that, but it cannot tell you these very fine wave form boundaries that are associated with the mounds because of the, the resolution of the tool. So using it as an exploratory tool and using the analog of the Lodgepole Field we intend to use the 3D as an exploratory tool.

MR. WEFALD: I have no further questions.

MR. NORTON: I can see Mr. Wefald you did listen when you were on this side of the table. (Laughter) I just have a couple questions, I think most of the ground has been covered already. Now, the oil-water contact is relatively flat, what is the, the maximum difference in elevation between the highest, highest well with an oil-water contact versus the lowest? You can talk in relative terms, it doesn't have to be exact, shall we talk about 10 foot, 20 foot?

MR. HYRKAS: The one that was approved by the working interest owners has a highest of 7360.5 at the 83 and a lowest, this is subsea depth 7369 at the Frenzel sidetrack.

MR. NORTON: So we're talking about 9-foot?

MR. HYRKAS: 9-foot.

MR. NORTON: Okay. Now, when you determine volumes of this reservoir per tract, was it only the geologic interpretation that was taken into account or was there engineering data such as a material balance, etc?

MR. HYRKAS: Yes, there was a lot of engineering data.

MR. NORTON: So that will come later with the engineering witness?

MR. HYRKAS: Yes.

MR. NORTON: Okay, thank you.

MR. HICKS: On Exhibit 14, Jerry, based on the, was it based upon the reservoir above the oil-water contact or just the perforated intervals in the well?

MR. HYRKAS: This was based on the reservoir above the oil-water contact.

MR. HICKS: Okay, as approved by everybody in . . .

MR. HYRKAS: Yes.

MR. HICKS: And you indicated that the Frenzel, when you drilled, when you ran your porosity logs in that to find out if that was mound or not, that 15 feet of clean limestone, you said that it did not have any porosity development in it.

MR. HYRKAS: That was from a sonic log.

MR. HICKS: Okay. And what was the calculated porosity?

MR. HYRKAS: The calculated porosity appeared to be 0 to 1%.

MR. HICKS: Okay. You also indicated that the other wells in the, the mound that you penetrated did not have this limestone, clean limestone associated with the mound. Did it have any clean limestone of this type, such as the Frenzel well?

MR. HYRKAS: The . . .

MR. HICKS: Below the mound?

MR. HYRKAS: The, the wells which do not define the mound, Filipi, Walton, they did not have any of this API 10 Unit gamma ray that was seen in the Frenzel.

MR. HICKS: Okay. Any, any wells that were drilled that have been found productive, did they encounter any clean limestone that was tight? In the approximate . . .

MR. HYRKAS: In the approximate interval? I can't, I can't think of any. The minimum porosity we saw was 1.7%, and I'm, I'm not sure if I'm following your questioning exactly, correctly.

MR. HICKS: No, I was just curious if this was a mappable feature across any portion of the mound?

MR. HYRKAS: Oh, as a type __________ that goes across the mound, let's say, no that is not the case. It is not a mappable feature.

MR. HICKS: Okay, thank you.

MR. CARVELL: Lawrence?

MR. BENDER: I have just a couple follow-up questions. Jerry, there was some mention about some 2D seismic that Conoco had in its possession, that was shot in the 1990's. Do you recall those questions?

MR. HYRKAS: There was questions about 2D seismic and we did shoot two lines in 1991, I believe.

MR. BENDER: What do you know about the quality of that seismic? Is it good seismic?

MR. HYRKAS: All I, I do know that the quality was 60-fold data.

MR. BENDER: And based on that seismic you drilled the State 74 well. Is that correct?

MR. HYRKAS: That is correct.

MR. BENDER: And you drilled that well as a Silurian well. Is that correct?

MR. HYRKAS: It actually went down to Winnipeg, I believe, but one of our primary objectives was the Silurian, yes.

MR. BENDER: And what did Conoco find at the Silurian?

MR. HYRKAS: We found that the zones were wet.

MR. BENDER: So it was a nonproducer. Is that correct?

MR. HYRKAS: That is correct.

MR. BENDER: That's all the questions I have.

MR. CARVELL: Any recross?

MR. MORRISON: Yes, just a very few follow-up. Jerry, you agree that in some of the wells that are productive you do have tight space. Is that right? Little or no porosity?

MR. HYRKAS: Yes, that's correct. 1.7% is the lowest we recorded.

MR. MORRISON: And nevertheless the limestone in that well that has low porosity is still considered to be part of the mound. Is that right?

MR. HYRKAS: That is correct.

MR. MORRISON: And the Frenzel portion of clean limestone is then excluded because it didn't have porosity, right?

MR. HYRKAS: Yes, that's correct.

MR. MORRISON: Okay. Also, in connection with a question from Wes, I think you said that there was some, a lot of engineering data that went into the allocation factors or the parameters.

MR. HYRKAS: Yes.

MR. MORRISON: And I think Wes used as an example, material balance, in fact there is no material balance that went into those factors, is there?

MR. HYRKAS: I would defer that question to our expert witness in reservoir modeling.

MR. MORRISON: Well, you know that the recoverable oil factors were based solely on volumetric calculations which assume constant reservoir conditions and so the only variable that went into the volumetrics was the thickness of pay, isn't that right?

MR. HYRKAS: The only variable that went into the volumetrics was the thickness of pay.

MR. MORRISON: No further questions.

MR. WEFALD: None.

MR. CARVELL: Anything further?

MR. BENDER: Nothing further.

MR. CARVELL: Any questions up here? What time is it? Well, I think we'll break and reconvene at 12:30. Okay? Good afternoon, we'll reconvene the hearing. Mr. Bender you may call your next witness.

MR. BENDER: Our next witness is Mr. Kevin Zorn. Kevin, would you state your name for the record please?

MR. ZORN: Kevin W. Zorn.

MR. BENDER: By whom are you employed and in what capacity?

MR. ZORN: I'm employed by Conoco Incorporated as a Senior Staff or as a Staff Reservoir Engineer.

MR. BENDER: And in that capacity have you ever had an opportunity to testify before the North Dakota Industrial Commission on previous occasions and had your qualifications accepted as that of an expert?

MR. ZORN: Yes, I have.

MR. BENDER: Are you familiar with Conoco's application for unitization of the Lodgepole Pool for the Dickinson Field?

MR. ZORN: Yes, I am.

MR. BENDER: And what's been your involvement in that unitization process?

MR. ZORN: I've been the reservoir engineer working on Conoco's development of the Lodgepole Reservoir since the first well was spud in November of 1992.

MR. BENDER: Kevin, since you've been involved with this field since the first well was spud and drilled, can you give us a brief summary of the history of the field starting with the drilling of that first well?

MR. ZORN: Conoco completed the Dickinson State No. 74 in the W/2 of Section 32 in the Lodgepole in February of 1993 with 129 feet of perforations in the Lodgepole. After several days of testing, the choke was increased to a 24-64th inch and was produced at a rate of over 2000 barrels of oil per day and about one million cubic feet of associated gas. Conoco then curtailed production on the well to 600 barrels a day while we constructed a nine-mile gas pipeline and this was done in order to limit the amount of gas which had to be flared during the pipeline construction. When the pipeline was connected in late May of 1993 Conoco once again opened the choke on the State 74 to a 24-64th inch and the well once again produced at an initial rate of approximately 2000 barrels of oil per day.

MR. BENDER: Okay, Kevin, after the Kadrmas, or excuse me after the State 74 well, what was the next well that Conoco drilled in the field?

MR. ZORN: Conoco then moved the rig and we drilled a well about two miles to the southwest, an exploratory well, which is not within the unit boundary. We then came up and drilled the Kadrmas No. 75, which is located in the S/2 of Section 31, this well was drilled in September of 1993. It was initially completed in a lower interval of the Lodgepole which proved to be wet on a production test. We then perforated 102 feet of Lodgepole comparable to the State No. 74 on a 24-64th inch choke the Kadrmas No. 75 produced around 1600 barrels of oil per day.

MR. BENDER: You then moved to the north, did you not?

MR. ZORN: Yes, the Frenzel No. 79 was spud at the end of August and the initial well did not encounter a productive Lodgepole zone. Conoco then sidetracked the Frenzel southeast and intersected the pay zone at approximately a 45 to a 48° angle. Initially, this well was also put on a 24/64th inch choke, like the first two wells, but within a very short period of time it began to produce water. After several days of testing we found that water production stopped if we decreased the choke size to 12/64th inch, where the well produced approximately 350 barrels of oil per day.

MR. BENDER: Where did Conoco drill its next well?

MR. ZORN: Conoco's next drilled the Filipi No. 76 in the E/2 of Section 32 and this well was a dry hole.

MR. BENDER: Why didn't Conoco sidetrack the Filipi well like it did the Frenzel well?

MR. ZORN: Well we felt very strongly that the productive pay zone was going to be located west of the Filipi straight hole location. Since the location of the Filipi was so close to the lease line, it was approximately 700 feet from the east mid-section line of the stand-up 320 unit, it was not possible to sidetrack this well and make an economic completion at a legal location. So the well was plugged and abandoned. Conoco had partners in this well, and all their partners agree with our recommendation to plug the well.

MR. BENDER: What happened next then Kevin?

MR. ZORN: Conoco then drilled the State "A" No. 83 in the NE/4 of Section 5. As previously testified to, this well just clipped the edge of the productive mound. We only perforated seven feet because of our fear of water coning as we had previously seen on the Frenzel No. 79. The State "A" No. 83 was completed in late November of 1993 and it produced about 300 barrels of oil per day on a 16/64th choke. Since this well was producing at a much lower flowing tubing pressure than the other wells we suspected it was also going to start producing water, so we made no attempt to bump the choke any higher.

MR. BENDER: Okay, after you drilled the State 83 did you then move to the west into Section 6?

MR. ZORN: Yes, the Walton No. 84 was drilled in January of 1994. And it was a dry hole.

MR. BENDER: Did Conoco give any consideration to sidetracking the Walton well?

MR. ZORN: We evaluated sidetracking the Walton No. 84 at the time we logged the dry hole. Based on our interpretation we felt the chances of making a successful completion on the sidetrack were extremely low. Since we had encountered a very thin pay section in the State 83 located to the west, we felt that if we were lucky enough to hit the Lodgepole mound it would probably be wet. Therefore, we did not feel a potential economic benefit of sidetracking was great enough to offset the risks of this drilling operation. We also had a 25% working interest partner in the well and Conoco made a recommendation to the partner to plug and abandon the well which they approved.

<u>MR. BENDER</u>: Kevin, as Conoco's reservoir engineer on this project, what kind of work have you done in preparation for today's hearing?

<u>MR. ZORN</u>: Well, as I mentioned earlier, I've been involved with the development of this field since before the first discovery well was drilled, up through the drilling of all these wells. Since I've been working on the project full-time for almost two years, I'm very familiar with the drilling, completion and production history of all the wells. During the drilling of these wells I've participated in the gathering of reservoir fluid and rock property data which has been used to conduct a reservoir study of the Lodgepole at Dickinson. The purpose of this study was to document the history of the field, make projections on the expected primary production from the field and to outline a plan for maximizing the future value of the field through secondary recovery. I worked on the study with the geoscientist and another reservoir engineer from our Houston office.

<u>MR. BENDER</u>: Now you say that Conoco acquired a lot of information about the reservoir and the Lodgepole Pool, just what did you acquire?

<u>MR. ZORN</u>: Well, since the State No. 74 discovery well was completed in the Lodgepole in February of 1993 Conoco has gathered a large amount of reservoir data in addition to the geologic information which has been previously discussed. We have conducted several core analysis

studies on cores from the Kadrmas No. 75. We've conducted black oil studies from crude oil samples from both the Kadrmas No. 74 and the Dickinson State, I'm sorry the Kadrmas 75 and the Dickinson State 74. We have also conducted an extensive pressure-transient analysis study of the four producing wells in this field including interwell interference tests. This information was used to conduct a comprehensive reservoir study of the Lodgepole and make recommendations to the working interest owners on how to best maximize the value of the field.

MR. BENDER: Now has all that reservoir information and your involvement in the development of the field gone into your preparation for today's hearing?

MR. ZORN: Yes.

MR. BENDER: And you've prepared certain exhibits that you intend to sponsor. Is that correct?

MR. ZORN: Yes, I have.

MR. BENDER: And you've satisfied yourself as to the accuracy of those exhibits?

MR. ZORN: Yes, I have.

MR. BENDER: Let's turn first to the engineering exhibits that are marked as Exhibit 15. Can you identify that exhibit and briefly explain it?

MR. ZORN: Exhibit 15 lists the reservoir properties of the, the reservoir and fluid properties of the Lodgepole Reservoir in Dickinson. The exhibit lists the reservoir property, the value that has been measured or calculated for that property and then the data source for each one of those items. I'll briefly discuss each item on this page. The initial reservoir pressure of the Lodgepole has been measured to be 4536 psia at a subsea depth of -7271 feet, which is the midpoint of the perforated interval in the State 74 in the W/2 of Section 32. This value was measured from a pressure buildup test on the State No. 74 shortly after the well was completed. The most recently observed pressure was measured on April the 7th, 1994 in the Kadrmas No. 75 and that pressure was 3638 psi at the same subsea depth. This means that over the first one year and two months of production from the field and a little over half a million barrels of oil the pressure has dropped 898 psi. The crude oil in the Lodgepole is an undersaturated original reservoir conditions and it has a bubble point of 1465 psia as measured by the PVT analysis on the Kadrmas No. 75. The oil has an initial oil formation volume factor of 1.356 reservoir barrels per stocktank barrel and B_o of 1.42 at the bubble point. The initial solution gas-oil ratio is 468 standard cubic feet per stocktank barrel and the oil is approximately 44° in API gravity. The oil has a viscosity in the reservoir of .29 centipoise and the original reservoir temperature has been measured at 224° Fahrenheit. By log analysis the average porosity has been measured at 5.372%. And through special core analysis conducted by core laboratories the connate water saturation has been calculated to be 10.6% and the residual oil saturation to water is 50.5%. The permeability of the Lodgepole is extremely high for the Williston Basin. It ranges between 100 and 2000 millidarcies. The primary drive mechanism is solution gas, although there are indications that an aquifer is present. However, Conoco believes that the aquifer is too small to provide any substantial pressure support as evidenced by the very rapid drop in reservoir pressure during the first year. Using the isopach map which has been discussed earlier, the reservoir volume in Lodgepole was calculated to be 70,693 acre feet. This yields a volumetric oil in place of 19.14 million barrels. And by material balance the original oil in place has been estimated 18.25 million barrels. This 6% difference between the volumetric oil in place and the material balance oil in place is considered an excellent match.

MR. BENDER: Now has, Conoco has drilled all the wells and currently operates all the wells in the Dickinson-Lodgepole Pool. Is that correct?

MR. ZORN: That's correct.

MR. BENDER: And, has Conoco supplied to the various working interest owners and its partners all of the information concerning those wells regardless of whether those partners have an interest in a particular well?

MR. ZORN: That's correct.

MR. BENDER: Now, with the exception of the geologic mapping, which was discussed earlier, all the information on Exhibit No. 15 was agreed to by the various working interest owners at the working interest owner meetings. Is that correct?

MR. ZORN: Yes. Conoco received approval from all working interest owners present at the meetings, that with the exception of the geologic mapping there were no unresolved _______ in the meetings concerning any of this basic reservoir data.

MR. BENDER: I believe you indicated that Conoco began the study in the Lodgepole, what, shortly after completing the State 74. Is that correct?

MR. ZORN: That's correct.

MR. BENDER: And when did you first begin thinking about forming a unit?

MR. ZORN: After drilling the Kadrmas No. 75 in the S/2 of Section 31 which is our second producing well in the field, we noticed that the reservoir pressure in the S/2 of Section 31 was the same as the reservoir pressure we were observing in the State 74 located over 3000 feet to the west. This indicated that these two wells were located in the same reservoir and that they were in pressure communication. Shortly after completing the Frenzel No. 79 in the N/2 of Section 31 in October of 1993 it became evident that with the high productivity of these wells, the reservoir pressure was going to quickly fall to dangerously low levels before we had a chance to install some form of pressure maintenance.

MR. BENDER: What do you mean by dangerously low levels?

MR. ZORN: Well, in an undersaturated oil reservoir the reservoir initially contains oil only in a liquid phase. Even though you are producing both oil and gas at the surface, the gas remains in solution in the oil until you fall below the bubble point. Once you fall below the bubble point, the gas bubbles start to form and coalesce together. As the pressure continues to fall these gas bubbles move together and in a highly permeable reservoir like the Lodgepole, quickly move updip to form a secondary gas cap. If you try to raise the reservoir pressure after this gas cap forms, the economic viability and the future recovery of oil will be severely impaired. In many cases it will be economically unfeasible to initiate any form of secondary recovery once the reservoir pressure falls too low. Especially in a relatively small oilfield like the Lodgepole at Dickinson. In the best of circumstances the amount of secondary oil recovery will be greatly reduced once the reservoir pressure is allowed to fall below the bubble point.

MR. BENDER: What steps did Conoco take to prevent the reservoir pressure from falling too quickly?

MR. ZORN: After completing the Frenzel No. 79 the three producing wells in the field were producing at a combined rate of over 3000 barrels of oil per day. Since we knew that there was chance that additional successful wells would be drilled and we had additional wells planned at that time, before the end of 1993, we were quite concerned that the pressure was going to fall too fast to unitize the field prior to reaching the bubble point. At a rate of 3000 barrels a day we were losing approximately 6 psi per day of reservoir pressure. At this rate of pressure decline and with the potential for even higher field-wide producing rates, as new wells were brought on line, we came to the conclusion that we had to curtail production from the field.

MR. BENDER: So at a rate of 3000 barrels of oil per day in November of 1993, how long would it have taken you to reach the bubble point in the reservoir?

MR. ZORN: Approximately one year.

MR. BENDER: At this time had Conoco yet begun contacting partners for unitization?

MR. ZORN: No, we had not.

MR. BENDER: All the fields in the well, excuse me all the wells in the field hadn't even been drilled at that point in time. Is that correct?

MR. ZORN: That's correct.

MR. BENDER: So, you're drilling wells, you don't know yet what the limits of the field are, but you know that the current rate of production, at the current rate of production you're going to drop below the bubble point, what did you say, in less than a year?

MR. ZORN: That's right.

MR. BENDER: So at that point Conoco decides that the most economical method to put this thing together is a, is a secondary recovery unit?

MR. ZORN: Yes, we had to finish the development of the field, conduct a secondary recovery feasibility study, meet with the working interest owners, discuss Conoco's plans with the royalty owners, we had to meet with the NDIC and get the NDIC's approval for our plan. And we were very concerned that all of this work could not be done in a short period of time. And remember, if we added new wells in the field at that time, there was the potential that the rates could come up even higher and that this one year time period could get shrunken even more.

MR. BENDER: So with all those concerns what did Conoco decide to do?

MR. ZORN: We decided that the only prudent thing to do was curtail production from this field in order to buy more time. Therefore, in November we cut production to a rate of 1500 barrels of oil per day which is about half of what the three wells were capable of producing. A month later we further reduced the rate to a maximum of 300 barrels a day, since we wanted to preserve the option of injecting natural gas as a secondary recovery process. Since the minimum pressure to maintain a miscible natural gas flood was significantly above the bubble point we decided to limit the field production to 300 barrels of oil per day until such a time as we had determined the most economic method of secondary recovery. The 300 barrel a day rate also gave us time to finish our drilling program and contact all of the working interest owners. Once these things were done we could get a better idea of how long it would take to get the field unitized without jeopardizing the ultimate recovery in the field by producing the wells too quickly. We discussed our recommendation on the curtailment with the working interest owners and all the owners agreed that that was the prudent thing to do.

MR. BENDER: And that was 300 barrels of oil per day, is that the current rate of production in the field?

MR. ZORN: No. Currently the field is producing 600 barrels a day. We completed our reservoir study, the middle to the late part of March 1994. Based on the study we recommended to waterflood the field, not to inject natural gas, and since the required startup pressure was much lower for waterflooding than natural gas, we did not see a need to continue curtailing at that rate. There are still some benefits to not dropping the pressure, but we recommended to our management, which they approved, to increase the rates in the field from 300 to 600 barrels a day. And that's, that's the rate that the wells been producing at since April of 1994.

MR. BENDER: Kevin, I'm going to refer your attention back to Exhibit No. 15. I believe you mentioned that the information contained on this exhibit was used to conduct a reservoir study. Can you tell us a little bit about how Conoco with the various working interest owners went about conducting the study.

MR. ZORN: Well we've been collecting this basic reservoir data while drilling all the wells in the field. In November of 1993 we had the first meeting of the working interest owners, as been previously discussed, and at that meeting Conoco recommended that we conduct a reservoir modeling study of the Lodgepole in order to determine the most economic way to conduct secondary recovery operations.

MR. BENDER: Kevin, why don't you briefly tell us what a modeling study is.

MR. ZORN: Well, like most major oil companies, Conoco often uses a tool referred to as a reservoir model, in order to make predictions on future oil, gas and water production from reservoirs. The tool used by Conoco is a computer software package called Eclipse, which is manufactured by Interra and it's a three-phase, three dimensional reservoir simulator. The three phases refers to oil, gas and water and the three dimensions means that the reservoir can have multiple layers in the Z direction. In computer simulation, such as that conducted by Conoco for the Lodgepole, the geologic and reservoir data is incorporated into a three dimensional grid system. The modeling work basically boils down to three steps. The first step is to input all of the reservoir data into the computer. The second step is to perform what is called a history match. During a history match you try to get the computer to accurately predict the performance history of the field. Most of the time some of the reservoir parameters must be adjusted in order to accurately portray the past. The process is basically a calibration step. Once you're satisfied that the computer is accurately representing the past, step three is to use the model to make predictions on the future, under various different operating scenarios.

MR. BENDER: Now, Kevin, have you or Conoco ever used this reservoir modeling technique on projects other than the Dickinson-Lodgepole Pool?

MR. ZORN: Yes, as a matter of fact, as the oil industry, like most industries that become more and more computer oriented, reservoir models have become more and more common. Conoco's been using Eclipse for approximately eight years and we have used it on reservoirs in all parts of the world.

MR. BENDER: What was the reason for using a reservoir simulator for the Lodgepole rather than some other method of conducting a reservoir study?

MR. ZORN: A reservoir simulator gives you the ability to evaluate a large number of alternatives in a very short period of time. Other methods, without using computers are much slower, and because of the time factor you often must limit the number of things you look at, because of the number of calculations that are involved.

MR. BENDER: Now, did Conoco share the results of the modeling study with the other working interest owners?

MR. ZORN: Yes, Conoco conducted the study, but all of the input that went into the computer model was discussed in detail with technical representatives of the different companies. The cost of the work were approved as a pre-unitization expense and will be billed to all parties after the unit is formed.

MR. BENDER: Okay, Kevin, let's turn next in the packet of exhibits to what's been marked as Exhibit No. 16. Can you tell us about that exhibit?

MR. ZORN: Exhibit 16 is a plot on a semi-log scale, which shows oil, gas and water production versus time. The oil curve is shown in green, the gas curve is shown in purple and the water curve is shown in blue. This curve is Conoco's forecast of future productions from the Lodgepole under primary recovery. This prediction is the result of the computer simulation that I talked about earlier.

MR. BENDER: Okay, then let's go to Exhibit 17.

MR. ZORN: Exhibit 17 is a forecast of the rate of pressure depletion in the Lodgepole, if the field is allowed to be depleted without pressure maintenance. As you can see, without any form of pressure support we believe that within two years the pressure would fall below the bubble point and that within six to seven years the reservoir pressure would fall below 500 psi.

MR. BENDER: Kevin, what do Exhibits 16 and 17 tell us about the future of this field without unitization?

MR. ZORN: Exhibits 16 and 17 show that without some form of pressure maintenance the pressure in the Lodgepole Reservoir will fall very rapidly. We predict that within six months of bringing the wells off curtailment all four wells would quit flowing and need to be produced with artificial lift. As the pressure in the field falls below the bubble point, the gas-oil ratio will begin to climb, resulting in gas ____ from the field approaching nine million cubic feet of gas per day. Since this gas is the reservoir energy which drives the oil, once all the gas has been produced, the field will begin to decline very rapidly. We predict in about 13 years the field will be uneconomic.

MR. BENDER: Okay, let's turn to the next exhibit, Exhibit 18.

MR. ZORN: Exhibit 18 is a plot of oil, gas and water production for the Lodgepole under a waterflood. In this simulation Conoco converted two wells to injection in the simulator, the State

"A" No. 83 in the NE, or NW/4 of Section 5 and the Frenzel No. 79 in the S/2 of Section 31 or N/2 of Section 31. The State No. 74 and the Kadrmas No. 75 are the producing wells, since they are in the middle of the reservoir and they have the thickest pay sections. We believe the best method to waterflood the Lodgepole is by injecting water below the oil-water contact on the edges and then sweeping oil up and inwards towards the two best wells.

MR. BENDER: Okay, let's go to the next exhibit, Exhibit 19.

MR. ZORN: Exhibit 19 is a plot showing water injection rates for the State 83 and the Frenzel No. 79. We anticipate injecting water at an initial rate of approximately 4000 barrels of water per day. Most of the water will probably go into the State "A" No. 83 because it has a thicker water leg in the wellbore. Since the Frenzel No. 79 was sidetracked and is drilled at a very high angle, we did not penetrate the entire Lodgepole mound in the 79, therefore there is less Lodgepole zone below the oil-water contact to perforate in the Frenzel. Over the life of the field we estimate we will inject approximately 13 million barrels of water.

MR. BENDER: Then let's go on to the next exhibit then, Exhibit 20.

MR. ZORN: Exhibit 20 is a plot of reservoir pressure versus time for the waterflood. We intend to maintain the reservoir pressure at approximately 3500 psi, by injecting water. Since the pressure is not going to fall and then come back up as we inject water, you will not see a characteristic oil bank form or a spike in oil production, which is common on many waterfloods, when the waterflood is installed late in the life. Basically the water will basically maintain the decline at a, a fairly flat level.

MR. BENDER: Okay, let's go on to the next exhibit.

MR. ZORN: Exhibit 21 is just an overlay of the oil production rate on a linear scale comparing the primary depletion case with our plan for waterflooding the field. By injecting water now we can maintain the oil rate in the field at a very high rate for five to six years or until we get water breakthrough. This will result in the recovery of an additional 2.48 million barrels of oil and extend the field economic life from about 12.3 years to 17.3 years.

MR. BENDER: And the additional 2.48 million barrels of oil, that's oil that would otherwise not be recovered, but for this unit. Is that correct?

MR. ZORN: That's is correct.

MR. BENDER: Okay, let's move on to the next exhibit then, Kevin, Exhibit No. 22.

MR. ZORN: Exhibit 22 just shows, in tabular form, what is represented graphically on Exhibits 16 through 21. Without any pressure maintenance under primary depletion we predict that approximately 5.4 million barrels of oil will be produced along with approximately 8.7 billion cubic feet of gas. This is an oil recovery factor of 27.7% of original oil in place. By installing a waterflood now, we predict the field will ultimately produce about 7.9 million barrels of oil and 3.7 billion cubic feet of gas. This results in an oil recovery factor of 40.5% of original oil in place or an incremental recovery of 12.8% of original oil in place or 2.48 million barrels.

MR. BENDER: Okay, and if I understand Exhibit 22 correctly, you will produce approximately 5 billion cubic feet of gas less under waterflooding than you will under primary depletion. Is that correct?

MR. ZORN: Yes.

MR. BENDER: Why does the gas production go down?

MR. ZORN: Well, as you remember from the first exhibit, Exhibit 15 the bubble point pressure, the Lodgepole crude oil is 1465 psia. Since we will be maintaining the reservoir pressure at 3500 pounds, or almost 2000 pounds above the bubble point, the gas will not come out of solution in the reservoir. At the end of the waterflood that gas will remain in the reservoir in solution in the oil and the water.

MR. BENDER: Why couldn't you produce the gas at the end of the life of the unit?

MR. ZORN: Well theoretically you could produce some of the gas, but since the water saturation in the reservoir will increase to very high levels as a result of the injection any gas produced would be associated with very high volumes of water. Conoco expects to inject over 13 million barrels of water into the reservoir and it's very doubtful that the gas price will be high enough in the future to justify producing such high volumes of water in order to get the gas.

<u>MR. BENDER</u>: Now, Kevin, without formation of the unit, what will be the, in your estimation, the cumulative oil produced from the Dickinson-Lodgepole Pool?

<u>MR. ZORN</u>: 5.38 million barrels of oil.

<u>MR. BENDER</u>: Okay, and if the Commission were to decide to deny Conoco's application for unitization how much of that oil will be lost?

<u>MR. ZORN</u>: Without a unit we, we can't inject water into the Lodgepole, therefore without a waterflood the field pressure will drop and result in the loss of 2.48 million barrels of oil.

<u>MR. BENDER</u>: Okay, Kevin, let's move on to the next exhibit then, Exhibit No. 23.

<u>MR. ZORN</u>: Exhibit 23 is a summary of the economic analysis which was conducted in the study comparing primary depletion and waterflooding in the Lodgepole. Using a project effective date of June 1st 1994, Conoco estimates we will spend about $178,000 in order to consolidate the facilities under primary depletion. We would spend a grand total of $343,000 in order to install the waterflood. The economics are based on 100% working interest, 87½% net revenue interest. We used an initial oil price of $11.80 a barrel which is based on a $13.00 barrel West Texas Intermediate Posting and subtracting the $1.20 per barrel price differential for the Williston Basin. The oil price is escalated at 5% per year in the analysis. The initial gas price assumed in the economics was $1.72 per MCF and its been escalated based upon Conoco's gas contract for

Dickinson with Koch. Conoco used a severance tax credit in North Dakota on the incremental oil recovery over the first five years of the project and we assumed a 37% federal income tax. The net present values are based upon an 8% discount factor.

MR. BENDER: Now, use, using this information, what do your economics show?

MR. ZORN: Well, under primary recovery the working interest owners can expect to make a combined $28,000,000 from June 1st 1994 to the end of the life. If we waterflood the field we will make an estimated $37,000,000 combined. This yields an incremental $9,000,000 as a result of the waterflood, which gives you a rate of return on the project of over 200%.

MR. BENDER: So, in other words, all the working interest owners will make an approximate additional $9,000,000 if this unit is put together. Is that correct?

MR. ZORN: That's correct.

MR. BENDER: And, you've assumed a 12½% or one-eighth royalty in your analysis?

MR. ZORN: That's correct.

MR. BENDER: Okay. So the numbers that you talked about earlier, those don't, that only reflects the working interest owners. Is that correct?

MR. ZORN: That's right, only the working interest owners.

MR. BENDER: Will the royalty owners also benefit from this unit?

MR. ZORN: Yes, they will. Using the one-eighth royalty figure and the predicted recoveries that we've done, based on the modeling study, using the same price assumptions that we've used or the initial price assumptions of $11, $11.80 a barrel, we estimate that the royalty owners will produce, will make approximately an incremental 2.6 million dollars before taxes.

MR. BENDER: Let's turn now to the next exhibit, Exhibit 24.

MR. ZORN: Exhibit 24 is Conoco's proposed equity formula for the secondary recovery unit.

MR. BENDER: Can you explain how Conoco arrived at the equity formula that is depicted on Exhibit No. 24?

MR. ZORN: Well, Conoco's philosophy for the unitization formula basically boils down to three things. First of all we needed a formula which would protect the correlative rights of all parties with an interest in the field, both royalty and working interest owners. Secondly we felt that the tracts containing the four producing wells should be compensated for the fact that they will drain the entire reservoir. And thirdly, despite the fact that Tracts 5 through 9 do not have producing wells, by bringing these nonproducing tracts into the field they also needed to receive some revenue from the unit since they will be contributing to the unit. However, we felt it important that the nonproducing tracts not be given a very large interest because, in Conoco's opinion, with the exception of Tracts 1 through 4 no other producing wells can be drilled at a legal location and be capable of producing oil.

MR. BENDER: Exhibit 24 indicates that you are recommending a two-phase formula. Why are you recommending a two-phase formula?

MR. ZORN: Well since the Lodgepole was discovered so recently in 1993 and since the field has been artificially curtailed for the last six months, the cumulative oil production at the present time is only a very small fraction of the ultimate primary recovery. We anticipate that the remaining primary reserves are over 4½ million barrels of oil and it would take at least another five years, even under the waterflood scenario, to recover that 4½ million barrels. Therefore, we felt a two-phase formula was the most equitable.

MR. BENDER: Describe for us Conoco's recommendation for the Phase I formula.

MR. ZORN: Conoco believes that a Phase I formula based on 50% remaining primary reserves and 50% remaining original oil in place is the best formula for the Lodgepole. By definition you can't have remaining primary reserves if you don't have a producing well. Therefore, the first 50% of the formula compensates the four producing wells based upon the amount of remaining primary reserves _____.

MR. BENDER: What's Conoco's Phase II formula based upon?

MR. ZORN: We recommend a Phase II formula based upon 100% original oil in place. The most secondary barrels will be located in those areas of the field where there is the largest oil in place target. Therefore, a secondary formula based upon original oil in place is the most equitable to all parties.

MR. BENDER: Okay, let's move on to Exhibit No. 25.

MR. ZORN: Exhibit 25 is merely a summary of the conclusions and recommendations of Conoco's reservoir study. Under the conclusions, No. 1 the Lodgepole is an undersaturated oil with a bubble point pressure of 1465 psia. No. 2, through the first year of production, reservoir pressure has declined almost 900 psi and without some form of pressure maintenance the reservoir will quickly fall below the bubble point resulting in a significant loss of oil reserves. No. 3, the reservoir's completely developed at this time. No. 4, Conoco has determined that the optimum form of pressure maintenance is waterflooding. A waterflooding, a waterflood using two injectors and two producers is forecasted to recover an incremental 2.48 million barrels of oil. For an investment of about $343,000 the waterflood will return approximately $9,000,000 in incremental net present value to the working interest owners. No. 5, failure to initiate a waterflood at this time would result in prolonged curtailment and a significant loss of net present value for the working and royalty interest owners. No. 6 unitization will protect the correlative rights of all owners and prevent the drilling of unnecessary wells. Under the recommendations, No. 1, the Lodgepole Reservoir at Dickinson should be unitized immediately for the purposes of initiating a waterflood. No. 2, the State "A" No. 83 in Section 5, and the Frenzel No. 79 in Section 31 should be converted to downdip injection wells and be recompleted below the oil-water contact. Water should be injected on a reservoir voidage replacement schedule to match fluid injection with oil, gas and water withdrawals. No. 3, on the last recommendation, since Conoco prepared these exhibits, we've made a small change in our recommendations, and we recommend that we not perform the remedials on the two producing wells before the waterflood is initiated. This work will still be done as described, however, since we do not expect to get water breakthrough for several years there is no need to do this work in 1994. This small change will not affect any of the reservoir predictions and will actually improve the economics of the project slightly because some of the $343,000 initial investment will be delayed until we get water breakthrough.

MR. BENDER: Kevin, in your opinion, is unitization of this Dickinson-Lodgepole Reservoir, for the purposes of installing a waterflood, the best method of maximizing the value of this field for the working interest owners, the royalty owners, and the State of North Dakota?

MR. ZORN: Yes, it is.

MR. BENDER: And Kevin, to your knowledge, are there any working interest owners who disagree that a unit should be formed and that the best method for the unit is a secondary recovery operation, including water injection?

MR. ZORN: No, as a matter of fact we've heard from all of the working interest owners that they support unitization and they agree with Conoco's technical reports. I think their disputes center around the mapping which has been discussed earlier.

MR. BENDER: Kevin, in your opinion, will Conoco's plan of unitization protect correlative rights?

MR. ZORN: Yes, it will.

MR. BENDER: Will it prevent the drilling of unnecessary wells?

MR. ZORN: Yes, it will.

MR. BENDER: That's all the questions I have for this witness. We would offer our Exhibits 1 through 25.

MR. CARVELL: Any objections to receipt of the exhibits Mr. Morrison?

MR. MORRISON: No objection.

MR. CARVELL: Bob?

MR. WEFALD: My only concern about the exhibits is that they, they be received subject to the understanding that the maps on their represent Conoco's point of view and that those interests reflected in the net pay maps and the calculations of who is going to get what is what's objected to by my client, the Andrea Singer Pollack Irrevocable Trust.

MR. BENDER: My, my only comment is that they don't represent Conoco's point of view, they represent the point of view of the majority of the working interest owners as was testified to by the landman, approximately 76%.

MR. WEFALD: Of which Conoco has 73%. _____________________.

MR. CARVELL: The exhibits are received. Mr. Morrison, cross-examination?

MR. MORRISON: Just a few questions. Sir, do you agree that the reserves in this particular common source of supply can be recovered by existing wells. Is that right?

MR. ZORN: That's correct.

MR. MORRISON: Any additional wells would be an unnecessary well?

MR. ZORN: That's right.

MR. MORRISON: You testified under your opinion Conoco's proposal would protect correlative rights, is it safe to assume that by protecting correlative rights, you mean that Conoco's proposal will assure to all owners their fair and equitable share of the oil and gas?

MR. ZORN: That's correct.

MR. MORRISON: And your opinion in that regard is contingent upon the validity of the maps in the pay. Is that correct?

MR. ZORN: Well, I believe the map, so I agree with the map, so I think it will protect correlative rights.

MR. MORRISON: And if the map is wrong it won't protect correlative rights. Isn't that right?

MR. ZORN: Under that assumption, but, like I said I, I don't agree that the map's wrong.

MR. MORRISON: But if it is, correlative rights will not be protected, is that right?

MR. ZORN: Yes, that's right.

MR. MORRISON: And, and the map is a very important part in this particular unit because of the way you've allocated your equity factors with the map accounting for 50% of the original, of the Phase I, and 100% of the Phase II allocations?

MR. ZORN: That's correct.

MR. MORRISON: I don't have any further questions.

MR. WEFALD: You indicated that the pressure is getting, at least, dangerously low. One of the ways you can maintain pressure is to restrict production. Is that correct?

MR. ZORN: Well you can't maintain pressure by restricting production, you can slow down the rate of pressure decline.

MR. WEFALD: Insofar as this, these producing wells go, if we kept, if the Commission kept the restriction on the production, we would then slow down the rate of decline in pressure?

MR. BENDER: I'm going to object, it's a mischaracterization of the evidence that's in the record. There is no evidence that the Commission is restricting production.

MR. WEFALD: I just said if the Commission restricts production.

MR. CARVELL: Can you answer that question?

MR. ZORN: I guess, it's my understanding the Commission doesn't restrict production, this is a voluntary curtailment.

MR. WEFALD: It's my understanding the Commission has the authority to restrict production if they so choose to do so. I, I guess my question is, if, if by agreement or by the Commission order, if production were restricted for a period of time, say a year or six months it's probable that we would maintain enough pressure throughout that period of time that we would still be able to get the benefit of unitization at the end of six months or a year.

MR. ZORN: If that were to happen yes. If, if there were, if it were a fact that by waiting six or eight months or a year or even two years you would result in another unit, yes.

MR. WEFALD: Okay.

MR. ZORN: And also depending on the rate that the wells are curtailed at.

MR. WEFALD: Yes. Just so it's clear, if this is unitized the extra production is going to be 2.48 million barrels on your Exhibit 21?

MR. ZORN: Yes sir, that's correct.

MR. WEFALD: And I believe you said on Exhibit 23 that represents roughly $9,000,000 to who ever's got the working interest or the royalty interest.

MR. ZORN: That incremental value, yes, that's correct.

MR. WEFALD: And, again, for instance if Conoco was in for 75% of that they would get 75% of that production from that?

MR. ZORN: Well we have a 75% working interest, we do not have a 75% net revenue interest, so

I don't have those net numbers in front of me. The $9,000,000 was a gross number. I think we have roughly 64% net revenue interest.

MR. WEFALD: I see.

MR. ZORN: So, you know, you'd have to work out that, that difference. A large majority of that obviously goes to Conoco because we have the highest interest in the field.

MR. WEFALD: Sure. I have no further questions.

MR. CARVELL: Any questions Wes, Bruce?

MR. NORTON: There isn't much difference in the equity formula between the, the difference is the amount of oil that's been produced already, and there isn't much difference as far as participation?

MR. ZORN: Yes, that's because most of the wells besides the 74 have not produced very much oil to date.

MR. NORTON: Now, you stated that you are going to inject the water near the oil-water contact, and you're going to eventually only produce from the top perforations of the 79 and the 83, pardon me, the 74 and 75 well, do you think you'll need to drill any additional recovery wells or injection wells? __________________________.

MR. ZORN: Based on our, based on our modeling study at this time we don't see any need to add any wellbores to the field.

MR. NORTON: On your modeling studies what was the difference in recoverable, incremental oil between injecting water at the base of the reservoir and recovering the oil from the top of the reservoir versus injecting gas at the top of the reservoir and producing the oil from the bottom of the oil-water contact?

MR. ZORN: About .2% of original oil in place.

MR. NORTON: So, you get 2% more . . .

MR. ZORN: .2% which would be . . .

MR. NORTON: .2%?

MR. ZORN: I can calculate that for you. Hang on a second.

MR. NORTON: You take into account economics or is that?

MR. ZORN: No, that's, that's just the oil recovery. That was your question. The question was the recovery not the money you would make. You'd recover an additional 40,000 barrels through gas injection.

MR. NORTON: Okay. And that's, that's based on no additional wells being drilled?

MR. ZORN: That correct.

MR. NORTON: Okay. It's been testified in previous hearings that the, the reservoir may be laminated or lensed or so forth, do you think that's going to have an effect on injecting at the base and, and producing the oil from the top of the reservoir?

MR. ZORN: Well, one of the, one of the problems that we have is defining exactly what the porosity matrix looks like, that's one of the reasons why we've conducted the interwell, interference test to try to get a better understanding of that. Our model is a fairly simplistic viewpoint of the reservoir. Basically what happens in the reservoir model is that, if you can picture a bathtub that has oil in it, and with a cover on it and a spout at the top and a spout at the bottom, we're injecting water because of the assumptions we've made in the reservoir model it assumes basically a piston-like displacement and you are just raising the water level in the bathtub and pushing the oil out the top. That is a, that is an oversimplification of what happens in the real world, but once you get into the field of reservoir modeling, if you try to get a whole lot more detailed than that, you create a monster in terms of solving the problem and we don't really have the data to, to go to a larger level of detail than that. So . . .

MR. NORTON: The, the modeling you did though, assumed uniform porosity and permeability?

MR. ZORN: No, we didn't assume uniform porosity. We do have eleven layers in the reservoir simulator and we have logs from each of the four wells and so we've made an attempt to adjust the porosity between the wells. It's constant within a single claim in the Z direction, but as you go laterally, it did vary slightly, but the differences are very, very small and it doesn't really have a big impact on the recovery factors from, from the reservoir.

MR. NORTON: And the software you used is standard oilfield software?

MR. ZORN: Yes.

MR. NORTON: Engineering software?

MR. ZORN: Yes.

MR. NORTON: I'd like to ask the geologic witness one more question if that's okay. When you got to the point where you determined that you were going to contour and so forth, that was contoured with the computer?

MR. HYRKAS: I believe that was contoured using the . . .

MR. NORTON: The point I'm getting to is if you use standard software for the contouring and did not use any human interpretation into it . . .

MR. HYRKAS: There is, there is certainly interpretation to this, but, the use of the computer was used, but the exact computer contouring was not used. It was edited, so the computer was used but it, there is edits to the computer contouring.

MR. NORTON: Okay, thank you.

MR. HICKS: Kevin, looking at your Exhibit 21, you show a rapid decrease in oil production around year seven, I was wondering if you could kind of explain why it comes back to the primary so quickly.

MR. ZORN: Well, if you refer to the waterflood plot and if you look at the water curve which is shown in blue, you can see that's about the point in time when the model predicts it will start getting water breakthrough. Once you get water breakthrough the relative perm. to oil around those wellbores is going to quickly fall and so the field will also start going on the decline. The other factor that goes in there is, one of the assumptions that has to be made in modeling is how you are going to handle artificial lift, both in the waterflooding scenario and in the primary completion scenario. These wells are not going to flow throughout their entire life, so you have to make some assumptions in the modeling on how you are going to handle pumping conditions. Unfortunately, there's about five different ways that you can artificially lift the wells and then there's all kinds of combinations there as well. We chose a fairly simplistic assumption that we would install the pumping units on the wells and that we would only be able to lift a maximum of 700 barrels of fluid a day with a beam pumping unit. There are other forms of artificial lift that will be studied when that case comes around. You know, in order to evaluate every kind of artificial lift method, at the time we did the study once again, would have taken much, much longer and that's the other thing that happens at about seven years, we think that when the water production hits and we get up to about a 15 to 20% water cut we are going to have to put the wells on artificial lift, when that happens we are not going to be able to pump the wells off because we physically can't lift at that depth as much water as it would take to pump off the wells at 10,000 feet with a beam pumping unit. Therefore, the rate from the field is going to drop. Since the rate drops the amount of water we have to inject in order to maintain the pressure of 3500 pounds will also drop. So, you've got both of those things happening at the same time, in about seven years on the waterflood case.

MR. HICKS: And you're assuming that you will reach your economic limit before you could produce this well and, before you could cease injection and continue production it would just, be no longer economic and you'd still be at bubble point then?

MR. ZORN: I guess I'm a little confused.

MR. HICKS: According to your charts you're showing that your reservoir pressure is going to still be around bubble point when . . .

MR. ZORN: Right.

MR. HICKS: when it becomes an uneconomic venture?

MR. ZORN: Yes, we used an economic limit of 20 barrels of oil per day, per well, for both the waterflood case and the primary production case, so whenever a well hit 20 barrels of oil per day it was shut-in, in the model because we believe it would be uneconomical to produce at rates lower than that. And that's, that's probably actually a little optimistic on the waterflood case because at the end of the waterflood these wells are going to make very, very, large volumes of water due to the high permeability. So, we did not try to simulate blowing down the reservoir on the waterflood case, you know, just depending on what the economic conditions are 17 years from now, you know, that may or may not be a feasible alternative. There's also the opportunity at the end of the life of the field to look at tertiary oil recovery and that's something that Conoco plans to do, you know, when that time arrives. If you look at Exhibit 15, the residual oil saturation to water, this is from the relative permeability data from the Kadrmas No. 75, the connate water saturation is 10.6% so the original oil saturation would be 89.4%. What the residual oil saturation to water means is at a oil saturation of 50.5% and a water saturation of 49.5% the relative perm. to oil is zero in the presence of water. So that's your waterflood target, you know, from a 90 or 89.4% oil saturation to a 50.5% oil saturation. That's the target for your waterflood. You could still drop this oil saturation to a lower level, possibly, with some form of tertiary oil recovery. And it, it becomes more of a function of what, not whether its technically feasible or not but whether it's economically feasible or not whether you can reduce that saturation any lower than that.

MR. HICKS: I may have missed it but the 74 well, are you going to go in and squeeze any of those perforations?

MR. ZORN: Not initially. Our original plan was to do that, and then after, starting to work on the plans for conducting those operations, we made the decision that, you know, there's a fair amount of risk involved in going into a well that makes 2000 barrels of oil per day and pumping cement, makes me a little nervous to tell you the truth. And, so rather than trying to fix a problem before it occurs, we, we think it's probably a better thing to do, to wait until we have a problem with water coning or water production. It's going to happen eventually, I mean there's no doubt about that, and then we'll deal with the problem at that time. So it doesn't really have an impact on the, on the predictions, it just affects the timing of when you would do that work.

MR. HICKS: On your Exhibit 18 is that what you're showing, drastic water production drop, approximately year 7½ or so you show the water production decreases substantially.

MR. ZORN: The reason for the water drop has to do again with this artificial lift assumption. I've made an assumption that once the, based on the series of studies referred to as flowing well analysis, trying to predict, at different reservoir pressures and different water cuts, at what point you have to put a well on artificial lift, it becomes an economic decision, basically. And because we've assumed that we can only lift 700 barrels of fluid a day from a single wellbore with a beam pumping unit at the point that it hits that magic spot where you have to install artificial lift the rate from the well drops, both the oil and the water rate. So that, that's the cause of some of that funny looking spiking around on the water curve and the oil curve there.

MR. HICKS: Thank you.

MR. CARVELL: Any further questions Mr. Bender?

MR. BENDER: No further questions.

MR. CARVELL: Mr. Morrison?

MR. MORRISON: No.

MR. CARVELL: Mr. Wefald?

MR. WEFALD: None.

MR. CARVELL: Any further witnesses for Conoco?

MR. BENDER: Not at this time.

MR. CARVELL: Mr. Morrison, you may call your first witness.

MR. MORRISON: Okay, thank you.

MR. NORTON: Do you want us to tape it to the wall or anything?

MR. MORRISON: It might help. It's, it's, the cross-section's pretty small it's going to get hard, I don't know, we thought we'd be in the other room with magnetic boards, but . . .

MR. NORTON: Do you have any tape with you?

MR. MORRISON: Are we on? Oh, we're on, okay. Thank you Mr. Examiner. We have one witness we intend to produce at this time. Steve would you state your name, spell your last name and provide your business address for the record, please.

MR. BRESSLER: My name is Stephen L. Bressler, B-R-E-S-S-L-E-R. I'm a senior geologist for Placid Oil Company, address 1601 Elm Street, Suite 3800, Dallas, Texas, 75201.

MR. MORRISON: In your capacity as a geologist for Placid have you previously testified before this Commission as an expert witness and had your qualifications accepted? Can you then briefly review your educational, professional background in the field of petroleum geology?

MR. BRESSLER: I have a Bachelor Degree in geology from Northern Arizona University and a Masters in Geology from the University of Arizona. I was employed for five years at the U.S. Geological Survey and then for the last 12½ I've been employed by Placid Oil Company.

MR. MORRISON: Now, you said you have a Bachelor's and a Master's in Geology, do you have any specialized training in geophysics?

MR. BRESSLER: I've taken several industry seismic interpretation courses from AAPG, 3D seismic interpretation course and I did my Master's Degree involved quite a bit of geophysics also.

MR. MORRISON: And is geophysics one of the matters with which you deal on a regular basis for Placid?

MR. BRESSLER: Yes, I routinely interpret both 2D and 3D seismic data.

MR. MORRISON: Now, are you familiar with the matters relating to the Dickinson-Lodgepole Unit?

MR. BRESSLER: Yes, sir. I've been the geologist assigned in Placid since the onset of our involvement.

MR. MORRISON: And you've been involved in the various working interest owners meetings that Conoco described earlier?

MR. NORTON: John, could you pull the mike closer?

MR. BRESSLER: Yes, sir. I attended all the meetings at which Placid attended, as they stated the last meeting, March, we just mailed in our vote. The three previous meetings I was there.

MR. MORRISON: Have you also prepared certain exhibits you intend to sponsor today?

MR. BRESSLER: Yes, I have.

MR. MORRISON: Those exhibits were all prepared either by yourself or under your control and supervision?

MR. BRESSLER: They've all been prepared by me.

MR. MORRISON: We'll offer the further testimony of this witness as that of an expert.

MR. CARVELL: Any objection, Mr. Bender?

MR. BENDER: No objection.

MR. CARVELL: Mr. Wefald?

MR. WEFALD: No objection.

MR. CARVELL: Motion granted.

MR. MORRISON: Steve, I'm going to ask you to turn to the first exhibit that we have in the packet which we'll ask be marked as Placid's Exhibit 3, since we already have 1 and 2 marked. And we have a over sized version of that on the wall behind the hearing examiner, maybe, if it's okay if you'd like to have him go out to the oversized one and describe the exhibit?

MR. CARVELL: Are we going to be able to record that?

MR. HICKS: You can take one of these.

MR. NORTON: Maybe you can grab Bruce's mike down on the end.

MR. BRESSLER: The stratigraphic process ____ every well in and immediately adjacent to the Lodgepole Pool it is flattened on the top of the Bakken Shale. So this is not a structural cross-section, it is a stratigraphic cross-section. Start from the west with the Walton well down in Section 6, goes up to the Frenzel straight hole and I've put in here, even though this is a, not a correct depth log this is the sidetrack Frenzel well, because this was at high angle, this is not true vertical thickness, this is just a measured depth log, so this does not represent the actual thickness, but it does represent what the log character looks like on the sidetrack well. The Kadrmas well, the 74, the 83 well and the Filipi 76 on the east side. The first thing we'd like to point out, as has previously been discussed, in the, both the 84 well on the southwest side of the mound and the 76 well, there is no log evidence whatsoever of any of the carbonate mound. There is no clean gamma ray. As was also mentioned in the straight hole on the Frenzel 79 we have about 17 feet of clean lime, actually about 15 feet that gets to the ten API unit. So we, we feel pretty strongly that is the toe of the mound on the northwest flank of the feature. In general, on this cross-section we agreed with the top of the mound that Conoco depicts, the other difference we have with them is the oil-water contact. I've depicted on here where, it says Conoco and the oil-water contact, that's the compromise oil-water contact that was determined at our last joint technical meeting. The higher oil-water contact is one that's depicted at the highest point in the log where you would assume just oil production. This would be the top of the transition zone, when the transition zone is present. We do agree with Conoco there is a transitional water level in 79 and in the 75, but especially in the 83 we feel there's a very sharp contact on the water level there and in fact these numbers essentially agree with the water level that Conoco had mapped at our second to the last meeting and the compromise resulted in, is the result of them desiring to put a transition zone in all the wells which would have pushed the oil-water contact, based the transition zone about 19 feet deeper in the 83 well and a compromise, pushing it up, splitting the difference. So, basically, gave back ten feet, that the logs do not support.

MR. NORTON: And that well is the only one _____.

MR. BRESSLER: It, it's just because the tilt is down to the northwest, in fact, we have an additional exhibit, maybe can go to that now. It would be the second to the last exhibit.

MR. MORRISON: Why don't we, before we do that let's identify the exhibit.

MR. BRESSLER: It would be the one that's labeled oil-water contact.

MR. MORRISON: And we'll ask that that be marked as Placid Exhibit 8.

MR. BRESSLER: Now that represents the plane defined by the highest water free log character. And basically there's 19 feet of dip with the Frenzel well having a water level 19 feet deeper than the, the 83 well. The oil-water contact being used by Conoco, basically, the compromise that was agreed on at the time was that they would take the deepest oil-water contact which was the Frenzel well, make that a flat plane and then the dipping oil-water contact which had 19 feet of relief on it and basically split the difference between the two. And that was the compromise that is it was arrived at that meeting. So that's the only thing we had the opportunity to compromise on. I think that's basically all . . .

MR. MORRISON: Okay.

MR. BRESSLER: to talk about on this one.

MR. MORRISON: Steve, maybe if you want to return the mike and come back we'll go on to the remaining exhibits from here. Now I'll ask you, Steve, to turn to the next exhibit in the packet, which we'll ask be identified as Placid Exhibit No. 4, and I'll ask you to tell us what this is and describe what it's relevance or significance at this hearing is.

MR. BRESSLER: Okay. This is a synthetic seismic model based on the sonic logs from three wells in the area. The 74, the 79 straight hole, which we're saying is on the edge of the feature and then a well several miles off the feature, Hunt Energy well. And what this basically is, if you take the sonic log and running it through some software, which is standard industry software, you generate a synthetic seismic response from that, that well log. And this model basically just takes those synthetics from each individual wellbore and puts them into a cross-sectional view. So it, it is essentially a, a hypothetical seismic line if you had a line through those wells. So, it's what the seismic response should be. I should point out, one thing I failed to mention on the cross-section on the wall, the, there was a shale marker in the, in all these wellbores, whether or not the mound is present. I've got it colored purple and labeled the lower, the top of the Lodgepole shale marker. On the synthetic seismic model I've similarly colored it in purple and you can see in the wellbores around the field, the Frenzel and the State 74, it follows in a trough. In other words, they kick in the curve to the left, which is a negative kick or a trough. The top of the mound in the State 74 corresponds with approximately the midpoint of that peak, just below that, that trough. I think you can . . .

MR. MORRISON: Below the purple line?

MR. BRESSLER: Below the purple line. I think you can clearly see that the character in this State 74 well is considerably different from the 79 well, which is, again, different from wells further west. I should point out also on this seismic model, the Bakken shale is colored brown and it would represent, basically, the base of the mound, although there is a little intervening 10 to 20 foot section there. I think you can clearly see that if you just measure the, the thickness and seismic time between the top of that shale marker to the Bakken there is clearly a thickening in that interval over the, over the mound as opposed to off the flank of it. And you can see that on the cross-section as well that the, that interval in the Filipi or the Walton is considerably thinner than over the mound proper. So what we're using this for is evidence that seismic can depict the mound.

MR. MORRISON: In your opinion is seismic geophysical information a valuable tool for use in development of a pool such as the Dickinson-Lodgepole Pool?

MR. BRESSLER: Certainly, Placid is involved in several other projects where we're using 3D seismic for further development and in today's world of high technology there are very few companies that are not using it.

MR. MORRISON: And not just for exploration but also for development?

MR. BRESSLER: Also for development. In fact, we've, we've shot 3D seismic over virtually all of our, our production in _____. We're shooting 3D over numerous properties in west Texas and in the Williston Basin.

MR. MORRISON: And have you examined geophysical or seismic information available in this area?

MR. BRESSLER: Yes I have.

MR. MORRISON: I'm going to ask you to turn to the next exhibit, which we'll ask be marked Exhibit 5, and tell us what that is.

MR. BRESSLER: This is a depiction of the structural configuration of the top of the mound. The depths are based on the well control again. The boundaries of the feature are based on two seismic lines which were shot in January of 1994 ____ seismic data that Placid was given a copy of as a result of permitting the lines through the N/2 of Section 31. Basically, and the other thing depicted on this map is the arched line, would be the outline of Conoco's 75 foot hundred, 7500 foot, Conoco's. So we're, we're showing the differences between the two maps here. The biggest differences that we see, on the east side of the reservoir, the seismic evidence shows, fairly conclusively we feel that the reservoir does not go as far east as the Filipi well. It boundaries approximately at the midpoint of Section 32 and we feel very strongly that the north-south line depicts reservoir reef mound buildup extending further north than Conoco depicts it. So we feel Sections 29 and 30 are being underrepresented in Conoco's plan.

MR. MORRISON: And, in your opinion, is that supported by both the seismic and by well control in the area?

MR. BRESSLER: Yes, yes, as we previously stated the Frenzel 79 we feel very strongly has the toe of the reef in it, whereas the Filipi 76 is, is off the reef, so the seismic data is confirmed by the well control.

MR. MORRISON: Okay, let's go to the next exhibit which is labeled Lodgepole Mound Isopach.

MR. BRESSLER: This is basically . . .

MR. MORRISON: Excuse me, we'll mark this Exhibit 6, Placid Exhibit 6, and I'll ask you to just identify and discuss this.

MR. BRESSLER: Okay, this is basically just following the shape of the mound on a previous map, taking the thickness of total clean carbonate in each wellbore and again, here one of the differences is that we're, we're putting 17 feet of mound in the Frenzel 79 straight hole whereas Conoco's not putting any in and our boundary is further, further east, excuse me further west than, Conoco puts it over by the Filipi well.

MR. MORRISON: The contouring of this exhibit is, is seismic __________?

MR. BRESSLER: It's, well, the contouring, the boundaries are controlled by the seismic. The thicknesses are controlled by the wells, more or less.

MR. MORRISON: So it's a combination of seismic and well data and _____.

MR. BRESSLER: Combination, right, which, you know, the only way to, to map this completely accurately would be with 3D seismic, which we've been unable to acquire.

MR. MORRISON: Okay, let's go on to the next one which is labeled Isochron - Lower Lodgepole Shale Marker to Bakken. Can you describe this? We'll ask this be marked as Exhibit 7.

MR. BRESSLER: Okay, this goes back into the seismic model between the shale marker and the Bakken and again where that interval is the thickest you have the mound developing and where it's thinnest, you do not have a mound and basically, you see on the ends of these lines where you have no mound, approximately 30 milliseconds of time interval between those two markers, whereas over the crest of the mound it gets 50 and a little thicker. In fact, there's, the thicker part is actually down in the SE/4 of 31, the SW/4 of 32. Again without 3D coverage the actual shape of that is, is subject to interpretation, but the boundaries that we depict on those lines, we feel very confident about. So we feel we have several independent lines of evidence that Conoco is pushing the eastern boundaries too far east and not pushing the northern boundary far enough north.

MR. MORRISON: You indicated that you've been unable to obtain 3D seismic in this area, can you tell us about that and why.

MR. BRESSLER: Following our last meeting at which we were not able to even attempt to compromise to, on the, on the outline of the mound, our management directed us to attempt to shoot 3D seismic to be able to bring before the board today. However, in our attempts to permit it we were, we were blocked, could not, could not permit the entire reef.

MR. MORRISON: And with 3D seismic is it important that you have total coverage?

MR. BRESSLER: That's correct. You need to have total coverage, that's correct. And you need to have data that goes, you can't stop the shooting right at your perceived edge of the feature, you need to have coverage a half a mile or so beyond that.

MR. MORRISON: And you said you were blocked, describe how you were blocked.

MR. BRESSLER: In attempting to, we started at the north and attempting to permit the S/2 of

Section 29 which is owned jointly by Conoco, Mobil and Phillips, Mobil, I believe, told our permit agent that they wouldn't approve it unless Conoco did and the Phillips geologist told me that their management had directed them not to approve it because they were involved in other negotiations with Conoco on some other rights in the area, that, that Conoco was going to explore. So we're basically, no permitted up there and just at the critical part for determining the northern edge of the feature we, we dropped our efforts after that.

MR. MORRISON: In your opinion, would the 3D seismic that Conoco has run in the area be a helpful tool for the Commission in analyzing this structure in determining where the boundaries of the unit should be?

MR. BRESSLER: Yes.

MR. MORRISON: And we've already covered exhibit, the next exhibit, Exhibit 8, then let's go the final exhibit, Exhibit 9, which is labeled Lodgepole Mound Net Pay Isopach.

MR. BRESSLER: This, this is essentially taking the structure map at the top of the mound which was I guess Exhibit 5, and the oil-water contact, Exhibit 8, and subtracting one from the other and basically the net pay map. And again because of the differences on the oil-water contact we're getting, for instance the State 83 well, 16 feet of net pay whereas I think Conoco's map has 26 feet. But otherwise the form of the map is, again, based on our structure map which is influenced by the seismic data.

MR. MORRISON: And this map, Placid's Exhibit No. 9 corresponds to Conoco's Exhibit No. 8. Is that right?

MR. BRESSLER: It's the same surface. That's correct.

MR. MORRISON: And, does the Placid's differing interpretation of the reservoir in the area have a substantial effect on the portions of the reservoir allocated to the various owners?

MR. BRESSLER: Yes, sir, it does. I should, one thing I should state before I get into that is it's based on total volumetrics. Placid has come up with 70,717 acre feet versus Conoco's 70,693, so that's remarkably close, so we don't disagree on the total volume of the reservoir, it's just the allocation. Based, based on the two different maps, for instance, Placid's working interest on the interpretation we've presented here, we would have a 6.404% working interest whereas on Conoco's interpretation it's 3.7. The difference would be, assuming that 7.8 million barrels recoverable would be over 200,000 barrels difference, net to Placid based on differing interpretations.

MR. NORTON: And that's the total percent or for individual tracts?

MR. BRESSLER: No, that is field-wide. Okay, for individual tracts, for instance, the N/2 of 31 where the Frenzel is located Conoco's would be 11.46%, Placid is 17.02, the S/2 of 30 Conoco has a 0.07%, Placid has .89%. So there's considerable difference in Section 30 and 31.

MR. MORRISON: But the, the roughly 3% difference in 200,000 barrels, that's unit wide. Is that correct?

MR. BRESSLER: That's correct, yes. That would include both 31 and 30.

MR. MORRISON: And that results not only from the differing interpretation on the north end in Sections 29 and 30 but also from honoring the well data from the Filipi and on the eastern boundaries. Is that correct?

MR. BRESSLER: Yes, as previously discussed pushing the eastern boundary of the well clear to the Filipi well results in, in Conoco having a full column over the large percentage of the W/2 of 32. By honoring the seismic data, essentially, the eastern part of their standup unit there has the taper in it, instead of the taper being in the E/2 of 32.

MR. MORRISON: Steve, does Placid oppose the unitization or waterflooding of the Dickinson Field?

MR. BRESSLER: No. We strongly agree that it is the proper thing to do. We believe the work Conoco's done on modeling is excellent and have had no disagreement whatsoever with them on their plans. It's the, the boundaries that are in dispute.

MR. MORRISON: And you agree that unitization and waterflooding is necessary in order to maximize recovery and prevent waste?

MR. BRESSLER: Yes, sir.

MR. MORRISON: Is it also your opinion that in order to protect correlative rights, it's essential that all of the owners in the area be allocated their fair, equitable share of production?

MR. BRESSLER: That's correct.

MR. MORRISON: Under Conoco's proposal will that occur?

MR. BRESSLER: Not according to the data we have in our possession, no sir.

MR. MORRISON: Would Conoco's revealing the 3D seismic coverage they have over the area help confirm whether or not correlative rights really would be protected?

MR. BRESSLER: We believe it is the only way to have any confidence in the interpretations, in the map.

MR. MORRISON: If Conoco's proposal is approved by the Commission, is Placid or are you prepared to recommend to Placid's management the drilling of an additional well in Section 30?

MR. BRESSLER: We've discussed with our management if we are unsuccessful in getting the unit boundaries reformed that they are prepared to drill a well to get the acreage in Section 30 included in the unit. We feel strongly enough about that north-south seismic line . . .

MR. NORTON: Where would you, where would you drill at?

MR. BRESSLER: Well, that's the problem. If you have to go to a 1320-1320, we would be hard pressed, based, we just have the one north-south line and that would put us perilously close to the edge. A 660 location we'd be very confident on. __ drill a 660 under the proposed . . .

MR. NORTON: Let's assume that tract weren't included in the unit, would you drill one 660-660?

MR. BRESSLER: Yes.

MR. MORRISON: And at that would it be Placid's preference, at this point in time, that the 2½ acres allotted by Conoco to the SE/4 of Section 30 be excluded from the unit rather than included and prevent the drilling of a well on a 660-660 location?

MR. BRESSLER: Well, I think that would be economic waste. We don't feel a well is necessary to drain the reservoir, but in order to protect our rights, Placid is prepared to do that. But that, that will only solve half the problem, in our mind. We feel the, the pushing of the boundary on the east side, too far east is also hurting correlative rights. And Conoco allocated too much reserve to their tract in 32, so, so drilling of that well in 30 is not going to correctly depict the reservoir, totally, in our minds. We feel 3D seismic is the only way that we'll be confident we have a properly depicted reservoir.

MR. MORRISON: Just to clarify, why don't you identify for the Commission where Placid owns interest in the proposed area.

MR. BRESSLER: We, we own 32, plus percent interest in the S/2 of Section 30 and the N/2 of Section 31.

MR. HICKS: Can you say that again, please. I didn't catch all that.

MR. BRESSLER: Okay, we own 32 point something in the S/2 of Section 30 and the N/2 of Section 31.

MR. NORTON: Is the ownership different in the SE/4 of 30 versus the, is it common throughout the S/2, or is it different between the two quarters?

MR. BRESSLER: I don't know.

MR. MORRISON: Jimmy, maybe just identify yourself by name.

MR. CAMPBELL: My name is Jimmy Campbell, I'm a landman with Placid Oil. I think . . .

MR. CARVELL: Well, just a minute, take the oath if you are going to testify.

MR. MORRISON: Just to respond to a question, you take the oath.

MR. CARVELL: Please raise your right hand.

MR. HICKS: Could please speak, come up to the mike?

MR. CARVELL: Promise to tell the truth in this hearing?

MR. CAMPBELL: What?

MR. CARVELL: Do you promise to tell the truth in this hearing?

MR. CAMPBELL: Yes.

MR. CARVELL: Okay, go ahead.

MR. CAMPBELL: Okay, the mineral interest is different in the SW/4 than the SE/4 of Section 30. But our interest ______ whole 640 acres to be in the S/2 of _________.

MR. MORRISON: Okay, I don't have any further questions of this witness at this time. We'd offer Placid's Exhibits 1 through 8 or 9?

MR. WEFALD: Nine.

MR. MORRISON: Nine. Thank you.

MR. ?: Got any objection?

MR. BENDER: No objection.

MR. CARVELL: Placid's Exhibits 1 through 9 are received. Cross-examination?

MR. WEFALD: Well, since I'm essentially on the same side, may I just do a little further direct?

MR. CARVELL: Well, that's fine.

MR. WEFALD: Okay, then you can . . .

MR. CARVELL: Are you going to conduct direct or cross?

MR. WEFALD: I'm going to follow-up some of the points he made. I believe that, I suppose technically we have some opposite points of view, so I suppose I'm a cross examiner as Lawrence is, but I know that the perception is we're on the same side. However you want to do it is fine with me. I can wait or do it now, makes no difference.

MR. CARVELL: Why don't you go now then you get everything out on the table that this witness has and then Mr. Bender you can, you'll have everything that you want to know.

MR. WEFALD: Mr. Bressler, did I understand you to say that 3D seismic is common in industry for accurately mapping structures?

MR. BRESSLER: It is becoming the standard method of both exploration and development, lowers the risk substantially.

MR. WEFALD: In fact, to your knowledge it is being widely used to develop structures as well as locate them in the first instance?

MR. BRESSLER: Yes, sir.

MR. WEFALD: In terms of 3D data, once it's collected, how difficult, in your experience, is it to put that data in a form where it can be interpreted and put into the, put into the form of a map?

MR. BRESSLER: The processing of the data is the first step and that's usually done by, by third party contractors, do that. And depending on the size of the survey that can take anywhere from three weeks to two to three months. Placid has, for instance, been involved in, in about 120 square miles of 3D acquisition in the last year in the Williston Basin. And those surveys have taken, typically about six to eight weeks, on average, to get processed and then they are brought in to our office for interpretation where the data is loaded on the 3D workstation. So you are not interpreting the, the old paper prints. And again, depending on the area, how, how highly faulted it is, for instance, the interpretation can take anywhere from a few days to a few weeks to a month, again depending on the size. We've shot several features, including the ____________ in the Williston for an exploration program and each of those were about ten square miles, and the average interpretation time for mapping seven or eight horizons and making isochrons that you make, it's on the order of ten days to two weeks.

MR. WEFALD: When, did I understand that Placid's dispute with Conoco's proposal relates to the boundaries, and do I understand that with the boundaries proposed by Conoco, that Placid believes that this unit would not be fair, would not be equitable or not be reasonable to the royalty owners and working interest owners?

MR. BRESSLER: That is correct.

MR. WEFALD: I have no further questions.

MR. CARVELL: Mr. Bender?

MR. BENDER: Mr. Examiner, we, this is the first time we've seen some of these exhibits and the opposition has had our exhibits in their possession for probably 45 days, could we just take a short recess so I could discuss with my clients some of the cross-examination that I may want to conduct on these matters?

MR. CARVELL: Ten minutes okay?

<u>MR. BENDER</u>: Ten to 15 should cover it.

<u>MR. WEFALD</u>: We, we would like to give them our exhibits too, so you'll have those at the same time.

<u>MR. CARVELL</u>: Okay. What time is it now? Okay, we'll reconvene in 15 minutes. We'll reconvene the hearing. Mr. Bender you may cross-examine the witness.

<u>MR. BENDER</u>: Steve, I want to first direct your attention to Exhibit No. 5. The, I believe that was a structure, top of the Lodgepole mound. Did you prepare this map by yourself?

<u>MR. BRESSLER</u>: Yes, I did.

<u>MR. NORTON</u>: Say Lawrence, the exhibits aren't numbered. What is Exhibit 5?

<u>MR. BENDER</u>: Structure of the Top of the Lodgepole Mound is what I have.

<u>MR. NORTON</u>: Okay.

<u>MR. BENDER</u>: What went into drafting this map?

<u>MR. BRESSLER</u>: As I previously testified I used the subsea tops from all the wells which had

penetrated the mound and used the seismic data to depict the boundaries on the north, south, east and west.

MR. BENDER: So the only well control on this particular map would be the wells that are on the map?

MR. BRESSLER: That is correct.

MR. BENDER: Okay, you didn't use any well control from the Fryburg wells?

MR. BRESSLER: That is correct, although as you will see, there is a, a westward, yes, westward bulge at the Kadrmas well. That does honor the, the north, northeast dip and that dipmeter and the Kadrmas well, so I am essentially honoring that, that shallow data somewhat, although it did not directly go into this map.

MR. BENDER: Which Kadrmas well are you referring to?

MR. BRESSLER: Okay, well you see there is a westward bulge at the Kadrmas well?

MR. BENDER: Uh huh.

MR. BRESSLER: Okay, so there is, as you go to the northeast of that, basically pulling the contours that direction which support the north dip, northeast dip in that, that Kadrmas well.

MR. BENDER: So, so to the extent that you used the Fryburg wells was only to use your regional dip. Is that correct?

MR. BRESSLER: Yes, essentially. But, as I said, this is a map on the top of the mound, it's not a map of the Fryburg.

MR. BENDER: So you don't subscribe to the theory of the Conoco witnesses that you can use the Fryburg to predict where the mound is?

MR. BRESSLER: That's an indirect indicator, not a direct indicator.

MR. BENDER: You don't subscribe to that theory?

MR. BRESSLER: That's correct.

MR. BENDER: When was the seismic shot?

MR. BRESSLER: I believe it was shot in January of 94.

MR. BENDER: Let me finish my questions first.

MR. BRESSLER: Oh.

MR. BENDER: There is two seismic shot lines. There's a seismic shot line that runs north and south and would that have been shot at the same time that the seismic . . .

MR. BRESSLER: I believe, I believe so. Again, we, we were not the company which shot this data, we were given a copy as part of an agreement to give them a permit. So we were not involved in the acquisition of this data and I really can't talk specifically about the acquisition.

MR. BENDER: I don't mean to be rude, but let me finish my question before you answer.

MR. BRESSLER: Okay.

MR. BENDER: So, when did you get the data, from the, after the seismic was shot?

MR. BRESSLER: I believe we received it sometime in March, I believe.

MR. BENDER: In March of 1994?

MR. BRESSLER: Yes.

MR. BENDER: Okay. And who shot the line?

MR. BRESSLER: It was West Bay Exploration.

MR. BENDER: Steve are you familiar with a map that you presented to the working interest owners at a, at a meeting in Casper, it was also a structure map of the top of the Lodgepole, it was dated 2/14 of 1994?

MR. BRESSLER: I believe so.

MR. BENDER: I'll show you what has been marked as Exhibit 29. Is that the map that you were presented at the working interest owners meetings?

MR. BRESSLER: I believe so. I may have had my dates wrong because we . . .

MR. BENDER: _____

MR. BRESSLER: I stated March, I believe we actually received that just a week or so prior to that meeting. I was mistaken, I guess it was in February not March that we received it.

MR. BENDER: The seismic data that you have on your Exhibit No. 5, is, is the data that's also on Exhibit No. 29. Is that correct?

MR. BRESSLER: That is correct.

MR. BENDER: Is Exhibit No. 29, your map that was drafted in February or has a February 1994 date on it, is this identical to Exhibit No. 5?

MR. BRESSLER: Essentially it is. I've modified the, some of the annotations a bit, and added, added the outline of Conoco's 7500 foot contour, but essentially the outline, and as I depicted it is essentially the same between the two maps.

MR. BENDER: Okay, but the contours are the same. Is that correct?

MR. BRESSLER: Yes, essentially.

MR. BENDER: Now, Steve did you, did you also attend a working interest owner meeting in Casper regarding this Lodgepole Unit on January 6 of 1993?

MR. BRESSLER: Yes, I did.

MR. BENDER: And did you also present a structure map at that meeting?

MR. BRESSLER: Yes, I did.

MR. BENDER: Now I'll show you what's been marked as Exhibit No. 30. Could you tell me if that's the map that you presented at that meeting?

MR. BRESSLER: Yes, sir, that is the map. This was made prior to having made the seismic data.

It was based on well control and I should also mention it was based on a map Conoco had, had submitted to the Commission prior to drilling the 74 well. They, the Winnipeg time structure map, which depicted the deep structure, so I attempted to honor Conoco's general structural shape at the deep level, with this well control. So that's what went into this map.

MR. BENDER: And I believe you indicated that you received the seismic from West Bay, what in February?

MR. BRESSLER: Yes, it must have been in February.

MR. BENDER: So, this map was drafted without the benefit of seismic?

MR. BRESSLER: That is correct, that is correct. Well, I mean, put it this way, ___ seismic, it was based on a seismic map of a deeper horizon that Conoco had submitted to the Commission. So indirectly you could say the shape was based on a seismic interpretation Conoco had made.

MR. BENDER: So, basically what you're saying this is an interpretation based on Conoco's map?

MR. BRESSLER: It's using the deeper structure they had presented to the, to the Commission, with the well control that we had at the Lodgepole and tried to make a map to fit both pieces of data.

MR. BENDER: Well did Conoco actually present seismic information at, at that previous hearing?

MR. BRESSLER: They had, they had presented a map that was based on seismic data. They did not depict the seismic itself.

MR. BENDER: You didn't look at any raw data?

MR. BRESSLER: No, Conoco did not reveal any data.

MR. BENDER: Steve, I'm now going to show you what I also have labeled as Exhibit No. 29, which is a overlay. It's identical to the previous Exhibit 29 only it's a transparent. Can you lay that over the top of the Exhibit 30 that you have represented to be as identical to Exhibit No. 5?

MR. BRESSLER: Okay, that's good.

MR. BENDER: Do you have it laid over?

MR. BRESSLER: Yes.

MR. BENDER: Okay. Can you tell me how your interpretations changed from December of 1993 to February of 1990? Was there any change in your interpretation to the north?

MR. BRESSLER: Very little. But again I should mention that that previous interpretation was based on a deeper seismic map. So, I'm not surprised that the new seismic data didn't severely disagree with the earlier map Conoco had made at a deeper level.

MR. BENDER: What horizon was that earlier seismic?

MR. BRESSLER: I believe it was at the Winnipeg.

MR. BENDER: Does your interpretation change from December to February to the east?

MR. BRESSLER: Not significantly, no.

MR. BENDER: Does it change to the south?

MR. BRESSLER: A very minor amount.

MR. BENDER: Where does it change?

MR. BRESSLER: The west side, there's a slight amount of change. And that was in part due to the fact at the previous, the first map Placid did not have access to that dipmeter data. Once we were given the dipmeter data from the Kadrmas that caused us to pull that contour further out to the west.

MR. BENDER: Now, also, between the times that you prepared your first map, Exhibit No. 30

and then you prepared your second map, Exhibit No. 29, which is identical to Exhibit No. 5, another well was drilled. Is that correct?

MR. BRESSLER: That's correct.

MR. BENDER: And that would, is that correct?

MR. BRESSLER: That's correct.

MR. BENDER: And that's the Walton No. 5. Is that correct?

MR. BRESSLER: That's correct.

MR. BENDER: And what did you do with your contour to the west in your second exhibit, Exhibit No.?

MR. BRESSLER: It pulled it out further to the west in Section 31, but it did not materially affect the position relative to the Walton 84 location. And that map was presented prior to the drilling of that well and as we've discussed with Conoco personnel at that time, that we were predicting a dry hole.

MR. BENDER: I, I guess I don't understand what you're saying. In, just let me finish. Let's go back again to Exhibit No. 29.

<u>MR. BRESSLER</u>: Okay.

<u>MR. BENDER</u>: In Exhibit No. 29 you have your 7500 foot contour line running nearly down the center of Section 31 in the north-south direction. Is that correct?

<u>MR. BRESSLER</u>: Section, Exhibit 30, that's correct.

<u>MR. BENDER</u>: Then, after you have a dry hole, the Walton No. 84 drilled, you pull your contour line further to the west?

<u>MR. BRESSLER</u>: That was due to the dipmeter data we then got access to. If you look at the two maps when you overlay them the distance I have from the Walton 84 to the 7500 foot contour is virtually identical on two maps. The changes in Section 31 were based on the dipmeter we got access to. I agreed that it must push off further west because you have a northeast dip on that dipmeter. That was why that change was made.

<u>MR. BENDER</u>: Let's talk a little bit more about your zero line on Exhibit No. 30, as depicted on the eastern edge, okay? You pick it in the center of Section 32 right on the midsection line. Is that correct?

<u>MR. BRESSLER</u>: That is correct.

MR. BENDER: Now, overlay it again on your Exhibit No. 5 and where is it picked after you have your seismic information?

MR. BRESSLER: In the same position. But I mentioned that the previous map was based on a Conoco deeper map which showed structures very similar to what I've depicted on my early maps.

MR. BENDER: How does the deep structure define the zero edge of the mound?

MR. BRESSLER: You make the assumption that the, the mound grew on a positive topographic feature. You can't directly say it's going to match the structure exactly. But we know from the well control that there is a four way closure at the Bakken, so presumably the, the four-way closure map seismically at the Winnipeg would also reflect the structure. We certainly, it does not agree with it in every detail. As I said I based my overall shape on my early map before we had the two seismic lines _____ of Conoco's map ___ and making changes where the new well control was provided by the, by the drilling.

MR. BENDER: What makes you think that there was deep structure that went into that previous map that you were utilizing?

MR. BRESSLER: Well, the map depicts a deep __ structure. That is what Conoco drilled the 74 well on.

MR. BENDER: And you got that information from . . .

MR. BRESSLER: It was . . .

MR. BENDER: . . . that was presented to the Industrial Commission?

MR. BRESSLER: Yes, that is correct. It was presented, made public record.

MR. BENDER: Did you look at the, the log of the State 74 after the well was drilled to determine whether there was structure?

MR. BRESSLER: Well, you didn't have that, any deep well control through the Winnipeg level other than that well so you could not with that one well determine that there was structure there.

MR. BENDER: But wasn't the State 74 drilled that deep?

MR. BRESSLER: That's correct, but a single well does not draw your structure map.

MR. BENDER: Do you know whether the well was wet or not?

MR. BRESSLER: It was wet.

MR. BENDER: So was there a structure?

MR. BRESSLER: Whether or not it's wet or not doesn't tell you whether there's a structure. We know from the well control there is structure at the Bakken level below this mound, so that, that supports the evidence that you have an underlying structure.

MR. NORTON: I was having a hard time following what you're saying. You have the _______.

MR. BENDER: Let's go to your cross-section, Steve.

MR. BRESSLER: Okay.

MR. BENDER: Could you point out for me on the State 74 where the Bakken structure is?

MR. BRESSLER: Well this map is a stratigraphic cross-section which is flattened on the Bakken so you're not going to depict structural reversal on this map, on this cross-section.

MR. BENDER: Could, can you give me a subsea top?

MR. BRESSLER: I would have to calculate those, I don't have those in front of me. In fact, Conoco had made the statement at the technical meeting that there was reversal of the Bakken. Actually, you had presented a map which shows structure at the Bakken. Introduce one of Conoco's maps if you would like which is mapped on the top Bakken.

MR. MORRISON: Your question goes to the top of the Bakken shale in any particular wellbore, is that what you are asking for _____________?

MR. ?: Well, the State 74.

MR. MORRISON: Just give them a data point for the top of Bakken Shale in the State.

MR. ?: State __________.

MR. MORRISON: The State 74?

MR. BRESSLER: There's a intervening highly tied gamma ray shale at the top or at the base of the mound in both the 74 and the 75 and depending on how you pick the Bakken, you would, I have it picked at the top, extremely high gamma ray, which is approximately 20 feet below the top of the mound, I can't read my numbers.

MR. MORRISON: Can you refer to the oversized one?

MR. BRESSLER: Yes. In the 74 we picked the top of the Bakken at a measured depth of 10,054 feet, excuse me 52 feet.

MR. BENDER: Steve, I'm going to refer you to Exhibit No. 12 that Conoco presented. Have you had a chance to look at Exhibit 12?

MR. BRESSLER: Yes.

MR. BENDER: You see on Exhibit 12 that Conoco has depicted a saddle or a low in between the State 74 and the Kadrmas 75. Is that correct?

MR. BRESSLER: That's correct.

MR. BENDER: Now, let's refer to your Exhibit No. 5. You don't show a saddle. Is that right?

MR. BRESSLER: I show a slight reentrance there northeast of the Kadrmas 75, that's not as exaggerated as Conoco's saddle, that is correct.

MR. BENDER: Did you, did you honor the dipmeter data when you constructed your Exhibit No. 5?

MR. BRESSLER: The dipmeter within the mound, shows steep northeast dips, the dipmeter above them at the top of the mound shows more gentle north, northeast dips.

MR. BENDER: Do you know of any other geologists who were part of the working interest owner group who did depict a saddle in between the Kadrmas 74 and the . . .

MR. BRESSLER: I believe the Aviva group did, yes. Let me point out that these maps were prepared at that meeting fully intending to make adjustments to accommodate all working interest owners. These were the maps which . . .

MR. BENDER: Well, let's talk about that for a moment. You've prepared maps and took them to a working interest owner meeting to make adjustments to them are you saying that these aren't your own interpretation? Let me finish the question. Are you saying these aren't . . .

MR. BRESSLER: These are interpretations.

MR. BENDER: Okay, then, but if you took them to a working interest owner meeting with the intent to make adjustments then, what are you saying?

MR. BRESSLER: I'm saying that there is not enough well control to have high confidence in the western boundary of the mound and we were prepared to, to adjust the western boundary further west in a compromise mode if we got adjustments on Conoco's position on the northeast. We were not given the opportunity to make those adjustments.

MR. BENDER: Well . . .

MR. BRESSLER: We do not have enough data to accurately depict the exact limits on the western boundary.

MR. BENDER: How about the exhibits that you've presented here today? Are those exhibits also meant to allow for compromise and adjusting down the road?

MR. BRESSLER: They are accurate at the positions of the seismic lines and the wellbores. Everything else in between is interpretation. That's why we feel 3D seismic would be the best means of adjusting those differences in interpretation.

MR. BENDER: Why wouldn't you go into a working interest owner meeting presenting your most accurate interpretation?

MR. BRESSLER: This is, this is, but, it's an interpretation based on the knowledge that there is no data on the west side of the feature to depict that boundary.

MR. BENDER: But you just told me a few moments ago that you went in and you drafted these maps with every intention of adjusting . . .

MR. BRESSLER: We, we expected a compromise would be the result of that meeting.

MR. BENDER: Mr. Examiner I'm going to ask that you admonish the witness to not answer the questions until I'm finished.

MR. CARVELL: Well, I'm not going to use the word admonish, but, just make sure that he finishes his question before you answer.

MR. MORRISON: It goes two ways, Mr. Bender might sometimes let him finish his answer before he comes in with another question.

MR. BENDER: _____ Exhibit ______ do you recognize that map?

MR. BRESSLER: I believe that was the map that Phillips presented.

MR. BENDER: Does this show a saddle between the State 74 and the Kadrmas No. 75?

MR. BRESSLER: Yes, it does.

MR. BENDER: Do you know if they took into consideration the dipmeter when they prepared this map?

MR. BRESSLER: Apparently they did, yes, sir.

MR. BENDER: I've now shown you what's been marked as Exhibit No. 31. Do you identify that?

MR. BRESSLER: Yes, that was a map that Aviva presented.

MR. BENDER: And what does it show, does it show a saddle between the State 74 and the Kadrmas 75?

MR. BRESSLER: Yes, it does.

MR. BENDER: So we have a geologist from Aviva and we have a geologist from Phillips who both show a saddle between those two wells, but you do not. Is that correct?

MR. BRESSLER: I show a slight ___, I just do not exaggerate it to the extent that the other parties did.

MR. BENDER: Steve, what happens to the equity if you have a saddle in between the State 74 and the Kadrmas 75?

MR. BRESSLER: I, I haven't calculated it based on these other two company's maps.

MR. BENDER: Do you have a thinning of the pay?

MR. BRESSLER: Over that you would have thinning over the east, northeast part of the S/2 of 31 if you put a low in there.

MR. BENDER: Steve, I now want to refer your attention to your Exhibit No. 7. That's the isochron map. Okay, everyone found it? You show on this map, as I read it, 50 milliseconds of thickness at the Conoco Dickinson State 74 well. Is that right?

MR. BRESSLER: That is correct.

MR. BENDER: And you show 304 feet of mound at that thickness. Is that correct?

MR. BRESSLER: That is correct.

MR. BENDER: Okay. Now, let's move to the north, to shotpoint 155 on the north south shotput line. Do you see that shotpoint?

MR. BRESSLER: Yes sir.

MR. BENDER: You show 51 milliseconds of thickness at that point. Is that correct?

MR. BRESSLER: That's correct.

MR. BENDER: How many feet of mound thickness do you show on your isopach map at that level? It's Exhibit No. 6.

MR. BRESSLER: Somewhere between 200 and 300. Let me point out that the isopach map was based, the contouring was based on the well control. The zero lines were based on the seismic.

MR. BENDER: Okay, then let's go to the east west shotline. You with me?

MR. BRESSLER: Yes.

MR. BENDER: Shotpoint 130. How many milliseconds of thickness do you show at that point?

MR. BRESSLER: 245 so that supports the low there, the saddle.

MR. BENDER: So your map is incorrect, isn't it?

MR. BRESSLER: I only had a single point so I couldn't put a full 45 contour, but there would be a saddle there, that's correct.

MR. BENDER: Did you look at the, the Fryburg well that was drilled very near to shotpoint 140?

MR. BRESSLER: Again, that, that does not bear on the Lodgepole.

MR. BENDER: In your opinion, it doesn't bear?

MR. BRESSLER: That's correct.

MR. BENDER: But your seismic does show it but you just refuse to honor it, is that correct?

MR. BRESSLER: I didn't refuse to honor it. I posted it on the map. It is there.

MR. BENDER: Well, let's take a look at the contouring that you did. You have your 50 millisecond contour going through the sidetrack of the Frenzel well. Is that correct?

MR. BRESSLER: That's correct.

MR. BENDER: Okay and then as you move to the east and to the south at shotpoint 130 you have 45 milliseconds of thickness. Did you honor that shotpoint in your contouring?

MR. BRESSLER: If I was to put a single point contour I wouldn't know how to orient it.

MR. BENDER: Couldn't you loop your contour down through there to honor that 45 millisecond data and show the saddle that has been . . .

MR. BRESSLER: You can do that but it would make a very strange looking map.

MR. BENDER: It would honor the saddle though if you drew your contour on that approach, wouldn't it?

MR. BRESSLER: It would, it would honor that that thinner interval there but the map would look geologically unreasonable.

MR. BENDER: So, in other words what you did, Steve, is you used some of your seismic for this map but you ignored other parts of the seismic of the map, didn't you.

MR. BRESSLER: No, that's not correct.

MR. BENDER: Well, how did you honor the 45 millisecond thickness in, on your shotpoint line, going east and west on the 130 shotpoint line?

MR. BRESSLER: There is a thin there but it's within an area of thicker fifty, to be more accurate I probably should have put a very small closed bow centered around that shotpoint. That was the only single point that I had that would fit below the 50 contour and again given just two points I can't accurately depict two lines I cannot accurately depict the total shape of that feature. Given 3D there may well be a low that you could contour in there.

MR. BENDER: Okay, you said that was the only point that you didn't honor. Let's go to the north in section, the S/2 of Section 30 and the S/2 of Section 29, shotpoint 155. What's the, what's the value you placed on that shotpoint?

MR. BRESSLER: 51.

MR. BENDER: Okay, and so you, what's the contour line you have to the north?

MR. BRESSLER: Fifty which would be.

MR. BENDER: And as you go to the south, you have what at shotpoint number 150?

MR. BRESSLER: Fifty-three.

MR. BENDER: So you didn't really honor that ________________ point either.

MR. BRESSLER: The 50 contour goes between the 51 and the 41. Everything greater than 50 is south of that contour point, everything less is north, so that's directly honoring the data.

MR. BENDER: Okay, let's go further to the south, the 145 shotpoint. Did you honor that point?

MR. BRESSLER: With a ten foot or a ten millisecond contour interval, yes. If I had mapped it at one millisecond contour interval I would have shown a contour coming in there.

MR BENDER: How did you determine the zero edge, particularly to the east with the shotpoint?

MR. BRESSLER: There is a very marked character change on the seismic data which honors synthetic seismograms made on the Filipi well and 74 well and that zero point corresponds with a point of which that seismic character change from the non-______ bearing section as in 76 to where the character change is to depict coming up onto the mound.

MR. BENDER: Can you show us that information?

MR. BRESSLER: I cannot. Unfortunately, we have not been given permission to make that seismic data a public record today.

MR. BENDER: So although you want Conoco to show their 3D information, you won't show your 2D information?

MR. BRESSLER: If it was ours and we owned it, I would be glad to. Unfortunately, we do not own the data, and we were specifically requested not to make it a public record.

MR. BENDER: And why is that? Why were you requested to not make it a public record?

MR. BRESSLER: Because, because it would then lose it's market value to the owners of the data who are actively selling the data as I understand.

MR. BENDER: Couldn't that also be the case with Conoco's 3D seismic?

MR. BRESSLER: If it was, if it was, if the actual data was presented at the hearing, that's correct. But we think maps based on the data would not jeopardize Conoco's position.

MR. BENDER: But isn't it subject to a great deal of interpretation that what you might see on a seismic line and what the Conoco people might see in a seismic line might interpret, might differ widely.

MR. BRESSLER: I think the differences would be far less than the difference based on the widely spaced wells.

MR. BENDER: Steve, early on you mentioned that you've done a lot of interpreting of 3D data in all parts of the country and in the Williston Basin as well. Is that correct?

MR. BRESSLER: That's correct.

MR. BENDER: Okay. Have you ever drilled any dry holes using 3D data?

MR. BRESSLER: Certainly.

MR. BENDER: So, it is interpretive and it can happen. You can drill a dry hole.

MR. BRESSLER: The dry holes that I've been involved in based on 3D were structurally right where predicted. We were involved in plays for the reservoir, quality changed and we drilled tight wells, but our structural depiction of our objective came in accurate based on a 3D mapping.

MR. BENDER: So, you're saying that you drilled some dry holes on 3D data because the reservoir has changed and you couldn't find the reservoir with the 3D data.

MR. BRESSLER: That's right, we were involved in in exploration plays where the reservoir was discontinuous. We could map the structure in that case but not not the porosity.

MR. BENDER: How can you represent here today that on 2D data that you can draw the zero line of this reservoir if you can't even pick reservoir with 3D data?

MR. BRESSLER: I can pick structure on the top of a reservoir horizon. I cannot predict that you're going to have 5% porosity in one location versus 10% porosity in the other, but I can in the seismic model I presented so that you can depict where the mound is present on seismic. I am not determining the reservoir qualities of that mound. I am determining where that mound is located.

MR. BENDER: So you really can't pick mound porosity with the 3D seismic, can you?

MR. BRESSLER: I can pick the mound from the well control we have to date the mound has a fairly uniform from well to well overall reservoir properties and we've all agreed to that.

MR. BENDER: You can pick the mound directly from the seismic?

MR. BRESSLER: I can, yes sir. The model I presented shows that you can determine where the mound is present.

MR. BENDER: I tried to ask this question earlier and probably didn't do a very good job. Let's look again at your Exhibit No. 5. You're drawing the structure, the edge of the structure, the 7500 foot contour somewhere between the 150 shotput, excuse me, shot line and the 155 on an east west line. Is that correct?

MR. BRESSLER: That is correct.

MR. BENDER: Can you actually give me the exact shotpoint for that particular 7500 foot contour?

MR. BRESSLER: It appears to be that 152 to 153.

MR. BENDER: That would be the mound edge. Is that right?

MR. BRESSLER: That is correct.

MR. BENDER: And you're saying with the 2D data you can define it that closely.

MR. BRESSLER: We can define it to within a couple of seismic traces which is within a couple hundred feet.

MR. BENDER: The seismic traces, how much?

MR. BRESSLER: It depends on the acquisition of the data, typically about 110 feet per trace.

MR. BENDER: How about in this particular trace, excuse me, this particular line?

MR. BRESSLER: The character changed over a space of 2 about 2 traces.

MR. BENDER: Do you know what the _______________.

MR. BRESSLER: No, I can't predict it to the exact foot but within 200 feet I can.

MR. BENDER: So you're saying you can predict it within 200 feet on the eastern edge of this structure. Is that correct?

MR. BRESSLER: That's correct.

MR. BENDER: How about to the north?

MR. BRESSLER: The same here.

MR. BENDER: What shotpoint do you pick it there?

MR. BRESSLER: Approximately 162, 63.

MR. BENDER: And once again you'd be able to pick it 100, 200 feet either side of a line? Is that correct?

MR. BRESSLER: Yeah, that's correct.

MR. BENDER: How about to the south?

MR. BRESSLER: About 107 to 108.

MR. BENDER: Once again you can pick it 100, 200 feet either side of that line?

MR. BRESSLER: That's correct.

MR. BENDER: How about to the west?

MR. BRESSLER: I have it picked at about 115, I'll point out on the west side that we cannot pick it as accurately as on the other side, and we believe that's because the you have that pull out that bulge to the west there and the seismic line is running subparallel to the edge of the reef. And because it's just 2D data as opposed to 3D data you're not properly imaging the edge of the reef because you're getting reflections from both north and south of the line. The other three boundaries are running perpendicular to the boundary of the reef so we're getting much more defined edges to it. Again, that's something where 3D would solve that problem because the data would be properly imaged in three dimensions. And again that's why I said we have the least certainty on the west side.

MR. BENDER: And once again if you if you do the overlay, you take Exhibit No. 30 and you overlay Exhibit No. 29.

MR. NORTON: You want 30 on top of 29?

MR. BENDER: Yeah, that's correct. You were able to pick the northern edge, the eastern edge and the southern edge without the benefit of your seismic that you just acquired in January of 1994.

MR. BRESSLER: That's correct, but with the benefit of Conoco's deeper structure map.

MR. BENDER: If in fact there was such a map and there was seismic done to that deeper horizon.

MR. MORRISON: I'm going to object. That is argumentative, that suggests lying on the part of the witness. Mr. Bender knows very well that there is such a map. I believe you represented Conoco at the hearing for the exception location that generated the map.

MR. CARVELL: Sustained.

MR. BENDER: Can I just have a minute to confer with my client?

MR. CARVELL: Lawrence, you might want to say that again, the tape wasn't on.

MR. BENDER: You want me to say it again. That's all the questions I have at this time.

MR. CARVELL: Redirect, John?

MR. MORRISON: Staff questions?

MR. CARVELL: Bruce or Wes?

MR. NORTON: Pardon.

MR. CARVELL: Do you have any questions, Wes?

MR. NORTON: What I'm going have to do is listen to the tape and go over these exhibits again. Now, the first exhibit you handed over to the witness was Exhibit 29.

MR. BENDER: That's correct.

MR. HICKS: The only question I had is I was wondering if you had some comment on. Were you present when Conoco gave their testimony and went through all their exhibits? Were you present at the hearing?

MR. BRESSLER: For the original . . .

MR. HICKS: Yes.

MR. BRESSLER: Spacing, no, I was not.

MR. MORRISON: Do you mean this morning, Bruce?

MR. HICKS: No, I'm talking about just when they went over their presentation this morning.

MR. BRESSLER: Oh, I was there this morning, yes.

MR. HICKS: Under Exhibit No. 9 you're showing the top of the Fryburg structure draping over the mound and when they went through their explanation of how you can determine the edge of the mound according to the thickness. I was curious on your comment on if you do or do not believe that using Exhibit 9 and 10 that you can project whether you're not whether you're close to the edge of the mound or not.

MR. BRESSLER: Well, if you believe their premise but you believe that the 79 straight hole did encounter 15 feet of mound, the line that they have drawn is no longer valid and ______ show that the 76 well is clearly further off the mound than the 79. I don't agree with their premise that this is the way to do it.

MR. HICKS: I should ask you another question then. Do you believe that the straight hole is productive?

MR. BRESSLER: No, it is not definitely below the water level so it would not be productive and it we don't have a neutron density log to compare porosity to the other logs and as Conoco did state it does appear to have _____________ porosity. But as also was stated there are intervals in the productive wells which have bow porosity.

MR. HICKS: And the Filipi well, you're showing it considerably further away from the mound than Conoco does if you look at your Exhibit No. 5.

MR. BRESSLER: That's correct.

MR. HICKS: And I was curious after you listened to Conoco's testimony if you would draw that closer to the Filipi well or not?

MR. BRESSLER: No, I wouldn't.

MR. HICKS: Okay, so you don't agree with their interpretation . . .

MR. BRESSLER: No, I don't.

MR. HICKS: Okay, thank you.

MR. NORTON: I have one more question. The contouring on Exhibits 6 and 7, is that hand drawn or was that . . .

MR. BRESSLER: These were hand interpretation but transferred to a computer software program for the actual drafting, but the actual . . .

MR. NORTON: You didn't put the data points into a computer and have it contoured?

MR. BRESSLER: No sir, these are my own interpretation of the contouring.

MR. HICKS: I do have one more question, Steve. We've had numerous exhibits on seismic and it's been shown to us on many different occasions that seismic is a tool to find, to explore for oil and gas and it's not a true exact science, therefore, when somebody wants to come in for an exception location they say they want to have a window to drill on. And what type of resolution are your claiming to have on yours.

MR. BRESSLER: Well, 3D seismic provides much greater resolution. I would agree that 2D historically because you don't have full coverage of the feature you cannot accurately depict the structure. With 3D we feel that risk is substantially reduced. All that 2D gives you is one point. It's either there or not on the case of the edge of the mound. And you also have the added problem with 3D . . . 2D when you have a mound like this that if the lines aren't positioned right perpendicular to the boundary you get what's called side swipe and that again is something 3D will eliminate a 3D migration.

MR. HICKS: Okay, I don't think that answered my questions, but what type of resolution are you claiming to have on your 2D?

MR. BRESSLER: Okay, on the 2D as I stated during my testimony several traces which is 220 feet approximately you can pick the character change.

MR. HICKS: So you're saying we could move your zero line or the edge of the mound 220 feet one way or the other . . .

MR. BRESSLER: Approximately that, yes.

MR. HICKS: And what are you claiming to be the edge of the mound. You're showing the Frenzel well to be productive if you're claiming the 7500 foot contour line as the edge of the mound.

MR. BRESSLER: No, that is not the productive limit. That the limit of the actual mound irrespective of the water level. My Exhibit No. 9 is the actual productive net pay isopach and as you see there the Frenzel 79 straight hole is not depicted in the productive reservoir, but the that productive reservoir map is made using the structure map and the oil/water contact. So it is critical to coming up with that net pay isopach map.

MR. HICKS: Okay, thank you.

MR. NORTON: I have a couple follow-up questions, I'm confused now. These lines that you got from West Bay are 3D lines?

MR. BRESSLER: No, they are 2D lines.

MR. NORTON: 2D lines. The, it was done with the thumper?

MR. BRESSLER: I'm not positive. I'd have to look, I'm not sure if it was vibrator or dynamite so we did not acquire them ourselves.

MR. NORTON: That's okay. Disregarding that. The point I'm getting to is is these data points here really don't represent where a shot gets placed, I'm not a seismic expert but I have seen many presentations and I know they aren't there many other values that go into this other than this straight line when you have 2D and 3D?

MR. BRESSLER: Well, with 3D you have a great number of lines essentially.

MR. NORTON: Right.

MR. BRESSLER: You have a total grid. With 2D you just have the single lines with shot and receivers laid out on that line.

MR NORTON: So there are no more data points in this on the 2D.

MR. BRESSLER: No sir.

MR. NORTON: Okay, thank you.

MR. CARVELL: Mr. Morrison.

MR. MORRISON: A few questions. Steve, is it correct that or let's put it this way, is it your understanding that the seismic data you relied on the West Bay lines, the north south and the east west lines have both been made available to Conoco in the past?

MR. BRESSLER: We showed them to them at that meeting and I believe they're on the market. I don't know if Conoco's purchased them or not.

MR. MORRISON: But you virtually showed it to Conoco at one of the working interest owner meetings.

MR. BRESSLER: That's correct.

MR. MORRISON: And it's also correct that you'd be willing to allow Conoco to see the lines again today but the prohibition is that you cannot make them part of the public record.

MR. BRESSLER: That's correct.

MR. MORRISON: And you'd be willing to show the examiner or any of the staff the same lines, is that right?

MR. BRESSLER: That's correct.

MR. MORRISON: You were asked some questions about the discrepancies in maps between Aviva's geologist; this is Conoco's Exhibit 31, Phillips geologist, Conoco Exhibit 32, your own map which is Placid Exhibit 9 and Conoco's depiction which I believe is Conoco's Exhibit 13. In your opinion would the information available from 3D seismic in Conoco's possession resolve the questions as to which of these four interpretations is most accurate?

MR. BRESSLER: I believe they would result in the map that most clearly, most accurately depicts the mound's geometry.

MR. MORRISON: Would you be willing to agree to some sort of review of Conoco's 3D seismic under appropriate conditions to protect the proprietary and trade secret nature of that. For example, a review of the data either at Conoco's office or at some third party's office without copying the data itself.

MR. BRESSLER: Yes.

MR. MORRISON: Would you even be willing to resolve this issue through the interpretation of that 3D seismic data by some sort of third party perhaps appointed by the Commission itself.

MR. BRESSLER: Yes.

MR. MORRISON: I don't have any further questions.

MR. WEFALD: I have none.

MR. NORTON: Now, the interpretation that you have presented is based very heavily on seismic information.

MR. BRESSLER: It's both the seismic where we have the lines and well control.

MR. NORTON: And you show two lines on Exhibit 9 I believe it is.

MR. BRESSLER: That's correct.

MR. NORTON: Were there any other seismic lines that you used in this . . .

MR. BRESSLER: Those are the only lines that we had in there. Again the other point I should keep going back to is the some of the general shape was based on earlier Conoco deeper structure map which was based on seismic.

MR. NORTON: Just to re-ask the question you didn't look at any other . . .

MR. BRESSLER: That was the only two lines I looked at. Yes sir.

MR. BENDER: Just a couple questions. Mr. Bressler, I believe it's your testimony that you agree with the structural interpretation of the Winnipeg that Conoco presented?

MR. BRESSLER: I don't have enough seismic data to confirm it or deny. I just assume that Conoco made a accurate representation of the seismic data they had in their possession.

MR. BENDER: But you utilized that information as an analog for the Lodgepole. Is that correct?

MR. BRESSLER: I used it to generally shape the contours based based using the well control based on the deeper shape that they had depicted.

MR. BENDER: But you didn't use the structural instructural interpretation of the Fryburg that Conoco presented, did you?

MR. BRESSLER: Well, again that's above the mounds.

MR. BENDER: But you didn't use it, right?

MR. BRESSLER: Not directly, no.

MR. BENDER: What's the distance in feet between the Winnipeg and the Lodgepole in this area?

MR. BRESSLER: Probably 2500 feet approximately. I don't have that exact.

MR. BENDER: Twenty-five hundred to 3000?

MR. BRESSLER: Something in that.

MR. BENDER: And, what's the distance between the Fryburg and the Lodgepole.

MR. BRESSLER: About 1000 feet.

MR. BENDER: But you still believe that the Winnipeg is a better indicator what you're going to find at the Lodgepole than the . . .

MR. BRESSLER: It just depicts the deep structure the mound grew on, but I certainly don't necessarily agree that it's going to be shaped exactly like the deep structure. I just used it for form line purposes.

MR. BENDER: Just the east side.

MR. BRESSLER: No, basically I used it wherever we didn't have any other data. Where we had well control data at the Lodgepole that data preempted the deep structure. The only place there was any deviation really in that shape was the 75 well. The other boundaries all honored the well control.

MR. BENDER: Is is true that Placid is involved in a 3D seismic shoot north of this property . . .

MR. BRESSLER: We're involved in one in Dunn County.

MR. BENDER: Is the Lodgepole the primary objective?

MR. BRESSLER: We've got multiple objectives there.

MR. BENDER: Would a 3D analog of this Lodgepole mound be helpful to Placid in its exploration activities in that area?

MR. BRESSLER: We don't necessarily feel we need it. In fact, we've it's been, I'm sure we'd be willing to have a third party work Conoco's 3D data to make a map and we wouldn't see the 3D.

MR. BENDER: Was that their ____________ to have a third party review the seismic presented previously to Conoco?

MR. BRESSLER: No.

MR. BENDER: Is is true that geoscientists many times use analogs to pick drilling locations?

MR. BRESSLER: They use it to determine the seismic character. You don't use it to pick a drilling location.

MR. BENDER: So it would be helpful in your exploration activities to the north, wouldn't it?

MR. BRESSLER: It could be but we're preparing locations to drill right now without having this analog so it's not going to affect our planning to the north.

MR. BENDER: Is the Lodgepole play in North Dakota a competitive play?

MR. BRESSLER: I guess it is. I haven't been involved in any lease acquisitions so I don't know that for a fact.

MR. BENDER: Would it give you a competitive advantage if Conoco were to show you their 3D seismic?

MR. BRESSLER: Not necessarily. We wouldn't expect the character on that 3D to look different than the character on these 2D line.

MR. BENDER: But you mentioned earlier it's common practice to use analogs to pick locations. Is that correct?

MR. BRESSLER: To pick the character that you would then use to identify a prospect to drill.

MR. BENDER: So in that respect it would be helpful?

MR. BRESSLER: It could be.

MR. BENDER: Could it lower the risk of your picking locations?

MR. BRESSLER: It might, but as I stated we're not stating that we would necessarily need to see that 3D data. We would just like to see a map based on 3D data.

MR. BENDER: That's all the questions I have.

MR. CARVELL: Anything further from the staff? Mr. Morrison?

MR. MORRISON: Nothing further at this time.

MR. CARVELL: Mr. Wefald?

MR. WEFALD: We'll call Ernest Gomez.

MR. CARVELL: Well, Mr. Morrison, do you have any more witnesses?

MR. MORRISON: No, we have no further _______________________.

MR. CARVELL: Okay Mr. Wefald.

MR. WEFALD: We'll call Ernie Gomez. Would you state your name please?

MR. GOMEZ: My name is Ernest Gomez G-O-M-E-Z.

MR. WEFALD: State your address for the record please.

MR. GOMEZ: My business address is 3609 South Wadsworth, Suite 500, Denver, Colorado.

MR. WEFALD: I have just handed to the front, Exhibit No. 1 which is your resume. Could you briefly explain to the record your qualifications and your background.

MR. GOMEZ: I have a bachelors degree in geology from the State University in New York at New Paul and a masters in geology from Northern Arizona University. I have years of professional geologic experience, 16 of those in the oil and gas industry and I'm currently employed by Interra which is a petroleum consulting company that has been retained by Singer Trust to provide a geologic review of this field.

MR. WEFALD: Have your ever testified before this Commission before?

MR. GOMEZ: Not in the State of North Dakota, no.

MR. WEFALD: You've testified before other Commissions in other states?

MR. GOMEZ: Yes, in the states of Oklahoma and Texas.

MR. WEFALD: And have you testified about matters of geology in those other states?

MR. GOMEZ: Yes, I have.

MR. WEFALD: And that's your area of expertise?

MR. GOMEZ: It is.

MR. WEFALD: I would offer the testimony of Ernie Gomez as an expert.

MR. CARVELL: Any objection?

MR. BENDER: No objection.

MR. CARVELL: Any objection?

MR. MORRISON: No objection.

MR. CARVELL: Motion granted.

MR. WEFALD: You have prepared a series of exhibits. The first one is cross section AA and we will mark that as Exhibit 2.

MR. GOMEZ: Yes, I have. This is a . . .

MR. WEFALD: Just a minute. Does everybody got that? All right, what is Exhibit 2 the cross section purport to show?

MR. GOMEZ: It's a cross section from the southwest and northeast across the field running from the Walton 84 well through the Kadrmas 74 then the State 74 and ending in the Filipi 76.

MR. WEFALD: And this is just the well logs, is it not?

MR. GOMEZ: Just the well logs, yes.

MR. WEFALD: Does it show your oil/water contact line?

MR. GOMEZ: There is an oil/water contact line on here, yes.

MR. WEFALD: What about the next exhibit, the cross section of ______________. We will mark that Exhibit 4. ________________.

MR. GOMEZ: This once again is a cross section only this time running from northwest to southeast through the field. As the previous cross section its hung on the Bakken shale. It runs from the Frenzel 79 straight hole. It does include the sidetrack well, the Frenzel 79 sidetrack and once again this is a measured log not a true vertical depth ______ true vertical depth log. Ties into the A-A prime cross section at the State 74 and finishes at the State A-83.

MR. WEFALD: These exhibits 2 and 3 and the logs listed in the GL's was this data used by you in making an analysis that you're about to present here today.

MR. GOMEZ: It's one of the parts that I could use, yes.

MR. WEFALD: Let's take a look at Exhibit No. 4, the document that states at the Bottom Gross Isopach Lodgepole Mound. What does Exhibit No. 4 purport to show?

MR. GOMEZ: It's showing just a gross thickness of the mound based on various pieces of information. The actual well control that I do have in places are depicted on here with the exception of the sidetrack well in which case I sort of do an estimate of what the thickness of that well should be. In addition I used the seismic data, I constructed an isochron from the base of the Bakken to the top of the mound. We did have access to Placid's data and we did work the data in their offices. So we incorporated not only the well control but also the isochron from the Bakken to the top of the mound in this map.

MR. WEFALD: And so these, the seismic shown here would be similar or identical to the seismics shown by Placid.

MR. GOMEZ: It's identical.

MR. WEFALD: Though some discussion on the cross examination of the Placid witness about a saddle. Does that show in this Exhibit No. 4?

MR. GOMEZ: Yes, there is a saddle that does show on the swell to the northeast of the Kadrmas well and to the southwest of the State 74 which is supported by the the Fryburg map that Conoco has presented. It's also supported by the Kadrmas No. 75 dipmeter and lastly it's supported by the seismic isochron.

MR. WEFALD: Okay. Let's take a look at the next exhibit we'll marked as number 5. That would be the top, the Structure Top Lodgepole Mound. What does Exhibit 5 purport to show?

MR. GOMEZ: Exhibit 5 shows the structural top of the mound. Once again this map was constructed using the subsurface control that existed. It also uses the isochron. I made a Bakken structure map based on primarily the well control, very closely it looks very much like the Bakken structure map that Conoco presented in their field study, and then I added the gross mound thickness to that Bakken structure and came up with a structure map on top of the mound.

MR. WEFALD: Let's take a look at the next exhibit called structure Oil/Water Contact and we'll mark that Exhibit No. 6. What is the Exhibit No. 6 purport to show?

MR. GOMEZ: Exhibit No. 6 is the oil/water contact structure. The points that are used here are solely subsurface. These are the points that were agreed to or came up with by the technical committee for the unitization. It does not show what Aviva might think the actual oil/water contacts are in these wells. It's what's agreed upon by the unit operators or the unit working interest owners.

MR. WEFALD: There's been some discussion today about Aviva and Singer Trust. Just so the record is clear, I believe that the actual client here or the actual working interest owner is the Trust. Aviva is basically sort of the holding company that manages a series of assets in the same company structure. Let's go on to Exhibit No. 7 which is called the Lodgepole Net Pay. Let's direct your attention to Exhibit No. 7. Is this exhibit been prepared on the basis as an analysis of Exhibits 2 through 6?

MR. GOMEZ: Yes, it has been.

MR. WEFALD: Okay and where does this exhibit purport to show?

MR. GOMEZ: This exhibit is our interpretation, being Singer Trust's interpretation of what the net pay is infield using the previous maps. It is a subtraction. How this map was derived was that the structure the gross map or the structure top of the Lodgepole mound which is Exhibit No. 5 was subtracted from the oil/water contact which is Exhibit No. 6 and the residual map what was left is the net pay.

MR. WEFALD: And this net pay shows that saddle in it, does it not, that was discussed earlier today?

MR. GOMEZ: Yes, it does show a thinning to the northeast of the Kadrmas into the southwest of the State No. 74.

MR. WEFALD: And this net pay map is based on seismic data and the log data. Is it not?

MR. GOMEZ: It is indirectly, yes. It's a complication of the previous maps which were based on those two items.

MR. WEFALD: Let me direct your attention to the Conoco Exhibit No. 13. As you compare that to the Trust Exhibit No. 7, perhaps you can just generally explain on the record, what's the principle difference you see between the pays as exhibited on 13 for Conoco and the net pay as exhibited on 7 for the Trust?

MR. GOMEZ: I think the biggest difference is the eastern boundary. The Trust agrees more with Placid's interpretation boundary, the eastern boundary, that's based once again primarily on the seismic data. Conoco does give the Trust more acreage in the S/2 of Section 31. They swing theirs out a little bit further to the west than I have on this map. Relatively the other is the north end we're fairly close agreement. We might have given a little bit more to Placid but the biggest difference is on the east end.

MR. WEFALD: You've heard some discussion here today about 3D seismic. Have you not?

<u>MR. GOMEZ</u>: Yes, I have.

<u>MR. WEFALD</u>: Based on your knowledge and your professional experience, would you expect that a 3D seismic of this location would yield a more accurate net pay map?

<u>MR. GOMEZ</u>: I believe it would. If the 3D seismic is indeed tied into the well control and the other control that you have in the area you should have a very complete picture of what this reef or mound should look like.

<u>MR. WEFALD</u>: Okay, let's take a look at the document Exhibit No. 8 Summary of Original Oil in Place. Can you tell us what that purports to show?

<u>MR. GOMEZ</u>: This was a planimetering of the net pay map done by one of Interra's engineers and coming up with a various oil in place or the various tracts within the unit.

<u>MR. WEFALD</u>: This is Exhibit No. 8 again I believe. We would offer into evidence Exhibits 1 through 8.

<u>MR. CARVELL</u>: What was Exhibit No. 1.

<u>MR. WEFALD</u>: That was the bio., the, his curriculum vita.

MR. CARVELL: Any objection to the exhibits?

MR. BENDER: No objection.

MR. MORRISON: No objection.

MR. WEFALD: We have no further questions.

MR. CARVELL: Those exhibits are received. Cross examination?

MR. BENDER: Just a few questions. Mr. Gomez I'm going to refer your attention to what you have marked as Exhibit No. 7. I'd also like to refer your attention at the same time to Placid's Exhibit No. 9, Placid's Exhibit No. 9.

MR. NORTON: Which one is nine.

MR. MORRISON: Lodgepole Mound Net Pay Isopach.

MR. NORTON: Okay.

MR. BENDER: Your interpretation of the net pay in the southwest quarter of Section 29 and the southeast quarter of Section 30 is significantly different from the interpretation of Placid's. Is that correct?

MR. GOMEZ: That is correct.

MR. BENDER: And you used the same data, is that correct, to draw these maps?

MR. GOMEZ: Yes, I did. I used the same seismic data.

MR. BENDER: Can you tell me from the section line of the S/2 of Section 29 what the distance is to the zero edge on your map?

MR. GOMEZ: On my map I would say it's roughly 600, 700 feet.

MR. BENDER: Now go to Placid's Exhibit No. 9. Can you tell me what the distance is from the S/2 section line of 29 or 30 to the zero edge?

MR. GOMEZ: I would say on their map its about 800-900 feet. If I can go back to mine, please, I'd say you're probably looking at about 550 to 600 feet.

MR. BENDER: So, what's the difference?

MR. GOMEZ: When I prepared my map, I cannot speak to Placid, but when I prepared my map one of things I did use was the isochron thickness and shotpoints 150 and 155 had a thicker isochron thickness in the mound which appeared to be pushing the mound a little bit up to the north. Then when I also looked at the seismic line the edge of the mound the way that I'm picking it, it was very, very abrupt and from that last control point that I had at about 155 to where I picked the edge it came off very sharply, very steeply.

MR. BENDER: Thank you. What's the footage difference though between where you picked the zero edge on your Exhibit No. 7 and where Placid picked the zero edge on their Exhibit No. 9?

MR. GOMEZ: If we can just use the shotpoint numbers, their shotpoint, their zero is at shotpoint 160. On mine it's about 157 1/2 using 110 foot. That going to be somewhere in the neighborhood of 300 feet plus or minus.

MR. BENDER: About 350 feet?

MR. GOMEZ: Something like that.

MR. BENDER: Now I'd like to refer you to Conoco's Exhibit No. 13. How does your Exhibit No. 7 compare to Conoco's Exhibit No. 13 in the S/2 of Section 29 and the S/2 of Section 30? Is it very similar?

MR. GOMEZ: Well not really having a scale here I would say that just eyeballing it the zero edge is fairly close along the section line.

MR. BENDER: Also on your Exhibit No. 7, you depict a saddle, do you not, between the State 74 and the Kadrmas No. 75?

MR. GOMEZ: Yes, I do.

MR. BENDER: In referring your attention to Placid's Exhibit No. 9, do they depict a saddle?

MR. GOMEZ: Not as abrupt or as pronounced as I have.

MR. BENDER: And once again, you were looking at the same seismic data as Placid was?

MR. GOMEZ: I was using the seismic, the well control, the dipmeter control and the Fryburg map at this point.

MR. BENDER: Let's go to your Exhibit. What number is your oil/water contact, what exhibit?

MR. GOMEZ: That would be Exhibit 6.

MR. BENDER: Is it the same as the map that Conoco used in its determination of the oil/water contact?

MR. GOMEZ: The values are the same. It might be slightly different because I contoured it myself, but the values are identical.

MR. BENDER: So you agree with Conoco's interpretation of the oil/water contact and not Placid's interpretation?

MR. GOMEZ: No sir, that's not what I said. What my charged here in this project was to compare Conoco's interpretation to what Aviva thought they had. In that case to be consistent, to be consistent to come up with a map that I can compare to Conoco's net pay I had to use a net pay map that Conoco used.

MR. BENDER: Your interpretation is more similar to the Conoco interpretation than the Placid interpretation?

MR. GOMEZ: As far as using this, yes, because I had to use this net pay.

MR. BENDER: That's all the questions I have.

MR. CARVELL: Mr. Morrison.

MR. MORRISON: You're not saying you agree with Conoco's oil and water contact. Is that right?

MR. GOMEZ: I am not saying that, no sir.

MR. MORRISON: Just an assumption you used in your other mapping?

MR. GOMEZ: Yes Sir.

MR. MORRISON: No more questions for this witness.

MR. CARVELL: Wes?

MR. NORTON: We're kind of at an impasse on interpretations and, of course, I know where your values are and I know where Placid's values are and their values. If, let's say, the Commission did not approve this unit and new unit came through with a Placid's interpretation, would you be here opposing that?

MR. GOMEZ: With Placid's interpretation? _______________ trouble here (laughter).

MR. NORTON: You see where I'm going?

MR. GOMEZ: Yes, I see where you're coming from. I guess what I would like to say is that based on what I've seen from all the work that's been done that I would be more akin to agree with Placid on the east side of this field. I think their interpretation there is much closer to reality. Mostly because they have used the seismic; they've also used some well control along those lines. If Conoco is going only with subsurface control, they're missing part of the equation. There's other evidence out there that can be used. So from the east end I would have to tend to agree more with Placid. On the other sides, on the other edges I am a little bit more conservative than Placid is on the north end. I'm more in agreement with Conoco. On west end, I think we agree almost perfectly on that and on the south end I'm also more conservative. But I think without incorporating seismic and the existing well control you cannot have a realistic picture.

MR. NORTON: What is your percentage interest in the State 74 well?

MR. GOMEZ: Aviva or Singer Trust has no interest at all in the 74 well.

MR. NORTON: Okay, thank you.

MR. CARVELL: Mr. Wefald, any redirect.

MR. WEFALD: No.

MR. CARVELL: Any recross?

MR. BENDER: No recross.

MR. CARVELL: Next witness.

MR. WEFALD: Call Kevin Preston. Could you state your name please.

MR. PRESTON: Kevin Preston P-R-E-S-T-O-N.

MR. WEFALD: Where are you employed, sir?

MR. PRESTON: I employed by Aviva Inc. which is as you described kind of the umbrella company for among other companies the Andrea Singer Pollack Revocable Trust.

MR. WEFALD: What's your general background?

MR. PRESTON: I'm a petroleum engineer.

MR. WEFALD: And have you handled the negotiations on behalf of the Trust?

MR. PRESTON: Yes, I have.

MR. WEFALD: Did you attend all four of these meetings that were referred to?

MR. PRESTON: Yes, I did.

MR. WEFALD: There was some discussion about how the oil/water contact was unanimously arrived at, agreed upon. Can you just briefly tell the Commission how that unanimous agreements resulted?

MR. PRESTON: Well, I think that the parties that were at that particular meeting all came in with different oil/water contacts. There was pretty much general agreement, I think, as to where on the logs you would go from oil to water, but there was a disagreement on how to map it. And as I remember it, Conoco ___________ everybody there thought there was evidence of the tilted oil/water contact yet they couldn't explain why there would be a tilted oil/water contact. Because Conoco could never get comfortable with the tilted oil/water contact, they proposed a flat oil/water contact with a tilted top to a transition zone. Basically flat at the 100% water point and a wedge shape transition zone. We couldn't, there was no evidence of transition zones in some of the wells so we couldn't get comfortable with that. On some of the logs the exact point from water going from high oil saturations, high water saturations were hard to pick. The Kadrmas and the State was not real definitive. On the other hand in the State 83 it's a very sharp break, there's very little doubt? I don't think anybody that did log analysis on that well would pick the water contact anywhere else than where Placid had picked it. Yet, because we were trying to reach a compromise, trying to move on with the process, we agreed to compromise, not use a tilted transition zone but a use a tilted oil/water contact and average the differences between a flat and the top of the transition and the 100% water line. And that's where we ended up.

<u>MR. WEFALD</u>: Would you explain to the Commission how in this one meeting, has been some testimony this morning that the maps that Conoco has submitted with the unit plan were approved under the voting formula by 75%. What role did the Trust have in arriving at that decision. What discussion took place.

<u>MR. PRESTON</u>: Each company presented a map and votes were taken. Basically everyone voted for their own map and against everyone else's map with a few exceptions. When Conoco's

map was presented and voted on they did because they have 73-75% depending on which factors you use of the unit they already achieved the 70% necessary to get the map approved. They only needed two additional votes to carry it out of the committee. They had proxy from one company the Lewis Hill Trust that had never attended any meetings. I don't know if they looked at any of the data that had been mailed or not so that, Conoco could vote that Lewis Hill interest any way. And then they wanted and then they also received an affirmative vote from Wiser Oil Company who is represented by a consultant at that meeting and it was the first time that they had had a representative at any of the meetings, and he had never seen any of the data. It had arrived to his office too late so it just, his information was just based on what he saw in the hour's worth of presentation before. At that meeting Placid presented the 2D seismic lines to the group. Unfortunately, you know, Lewis Hill was not there and I believe Phillips was not there at that meeting so you know it really didn't get discussed. As soon as the vote was taken and Conoco along with the proxy and Wiser's vote it was over. No discussion, no compromise, no exchange of ideas. My experience on technical committees that are working together to form a unit has been that their company supply their technical experts and there is discussion that takes place. I mean all this data is interpretive and I guarantee all of these maps that have been presented are wrong and the effort of the technical committee, and this is what we thought was going to happen at that meeting, would have been to reach some kind of a compromise, consensus opinion as to the probable shape and thickness of the reservoir. And that's not what happened at all. Conoco's support from Wiser and Lewis Hill represented, I believe, less than 1 1/2% of the total working interest. Twenty-four percent of the 25 or 26% that's not owned by Conoco voted against that map so it's far from a consensus.

MR. WEFALD: Let me ask you a couple other follow-up questions. The Trust opposes the unit as is. Is that correct

MR. PRESTON: We do just because of the equity formula.

MR. WEFALD: Okay and does the Trust believe that the proposal is not fair, equitable and reasonable to all the unit production owners?

MR. PRESTON: Yes.

MR. WEFALD: And for that reason you would like to have the unit rejected. Is that correct?

MR. PRESTON: That's correct.

MR. WEFALD: There's been some discussion about 3D seismic data. Mr. Morrison, I believe, suggested a possibility with the Trust, go along with a third party analysis of the 3D seismic data that Conoco has a map that is based on that by a third party.

MR. PRESTON: I would make that recommendation to management. I don't know that they would go for it but we had agreed to help Placid shoot 3D seismic over the field where we had ownership and we're hoping that they would but then they go no permit by Conoco, Phillips and that group so they couldn't shoot it. So at that time we made that decision to allow Placid to 3D shoot, we were pretty much convinced ourselves that the way Conoco had mapped this reservoir was absolutely as small as you could map it honoring all the data across our tract which is the S/2 of 31. We felt like that there was even though we didn't know what the 3D was going to show we felt like that there was very little chance that the 3D data would show it the reservoir any smaller on our tract than it was already mapped. We felt like we had everything to gain that, I feel like that the reservoir extends even farther to the west than any of the maps show.

MR. WEFALD: Do you believe in the industry that 3D is gaining some significant level of confidence?

MR. PRESTON: I do. I have not been using it, but based on reading the publications, it appears and announcements of discoveries, almost all new discoveries are based on 3D these days and many development wells are based on 3D.

MR. WEFALD: Would you believe that, were there an analysis of 3D data the well logs, structures, that the information that's presently available that you'd have a higher probability of getting an accurate map of the net pay.

MR. PRESTON: Based on what I've read and been told, I think it would the most exact way to do it. Given the fact that we've got wellbores that we can general synthetic seismograms in the field I think that we could have a very high degree of confidence in the 3D interpretation.

MR. WEFALD: Would you have any objection to the Commission continuing this hearing for the purpose of allowing Conoco to have its 3D data analyzed by a third party and a map prepared so that so the record could be complete on all the data that is available but not yet before the Commission?

MR. PRESTON: I would have no objection to that.

MR. WEFALD: I have no further questions.

MR. CARVELL: Mr. Bender.

MR. BENDER: Kevin, were you present at the first working interest owner meeting?

MR. PRESTON: Yes.

MR. BENDER: Did you vote in favor of the voting procedure that was established by the working interest owners.

MR. PRESTON: Yes, I did.

MR. BENDER: You've changed your mind today, though, haven't you. You didn't like the voting procedure?

MR. PRESTON: Well, I don't know if there was another way to do it. The outcome of it, is unfortunate because it was far from a consensus.

MR. BENDER: Well, how do you define a consensus? Did you want 100% agreement.

MR. PRESTON: Well, I think that more than 1 1/2% should support ______ proposal when they already have 75% interest.

MR. BENDER: Have you every worked on a working interest owner committee where you've reach 100% consensus on every issue that came before the committee.

MR. PRESTON: No.

MR. BENDER: Have you, I believe you made a statement, correct me if I'm wrong. You said every map that was presented here today is wrong.

MR. PRESTON: Um hum.

MR. BENDER: Including Aviva's maps.

MR. PRESTON: Um hum.

MR. BENDER: How do you know Conoco's maps are wrong?

MR. PRESTON: ____________________ data.

MR. BENDER: Are you a geologist?

MR. PRESTON: No.

MR. BENDER: Then how can you say that the geologic maps that Conoco presented are wrong?

MR. PRESTON: Well, I'll say this that every well that was drilled when every well was drilled the Conoco map changed. And Conoco has continued to drill dry holes, and its continued to change the shape of the reservoir and there's no doubt in my mind that if additional wells were drilled their maps would change again.

MR. BENDER: Well, what geologic data do you have to present here just today that would show that Conoco's maps are wrong?

MR. PRESTON: None.

MR. BENDER: It's just something you pulled out of thin air. Say its wrong because you say its wrong.

MR. PRESTON: No no.

MR. BENDER: No evidence to support it?

MR. PRESTON: Are you telling me that they're right?

MR. BENDER: Witnesses have testified that that's their interpretation.

MR. PRESTON: That's their interpretation. I'm just saying that none of these maps are exactly right, and I think we all know that and the Commission does too. It's everybody's best guess.

MR. BENDER: Are you familiar with the statutes and rules of the Commission for establishing a unit in the state of North Dakota?

MR. PRESTON: Yes, I am.

MR. BENDER: Does the Commission require consensus or do they require 70% vote by the working interest owners and the royalty owners to form a unit?

MR. PRESTON: They require 70% but the Commission has the ultimate say. It only took 70% why you'd have a technical committee. Conoco has this whole thing. That's just, form the unit in Section 32 and go with it so. Yeah, I'm familiar with the rules.

MR. BENDER: How many, how many royalty owners support your position that you've taken here today and the maps that you've exhibited?

MR. PRESTON: Haven't shown it to any of them.

MR. BENDER: Do you know how many royalty owners support Conoco's plan?

MR. PRESTON: Wasn't it six you said?

MR. BENDER: Pardon me.

MR. PRESTON: Six?

MR. BENDER: Eight-six, 86%.

MR. PRESTON: Oh, that's working interest, that's right.

MR. BENDER: Do you know how many of the royalty owners support Conoco's plan for unitization?

MR. PRESTON: No I don't. I heard it this morning and I took notes on it. I don't remember the number.

MR. WEFALD: Well, there's an exhibit, isn't there?

MR. BENDER: Yes.

MR. WEFALD: Yeah, okay well the exhibit speaks for itself . . . I don't __________.

MR. PRESTON: I believe 48 of 102 was the number, Mr. Bender.

MR. BENDER: I believe you stated earlier that Conoco's map that was presented at the working interest owners meeting honored all the data. Is that correct? Is that correct?

MR. PRESTON: In my opinion it honors the data?

MR. BENDER: Does Placid's map, in your opinion, honor the data?

MR. PRESTON: No, it does not.

MR. BENDER: That's all the questions I have.

MR. CARVELL: Mr. Morrison?

MR. MORRISON: I don't have any questions.

MR. CARVELL: Wes, Bruce?

MR. NORTON: I missed, are you an engineer?

MR. PRESTON: Yes, I am.

MR. NORTON: Okay. Now, referring to your Exhibit No. 7. The thickest part of the reservoir appears to be in the W/2 of 32.

MR. PRESTON: Yes.

MR. NORTON: And by moving the zero, zero line westwardly from Filipi well you are eliminating quite a bit of the reservoir.

MR. PRESTON: That's correct.

MR. NORTON: So the reservoir volume would be considerably less?

MR. PRESTON: That's right.

MR. NORTON: What, have you run a material balance on this reservoir?

MR. PRESTON: Yes, I have.

MR. NORTON: And your material balance had a considerably less recoverable for oil in place than Conoco's?

MR. PRESTON: No.

MR. NORTON: You had 18 point.

MR. PRESTON: Well, it wasn't that exact. When I did my material balance calculations it was early in the stage of the development. We had pressures on, on the Kadrmas well after the State had produced, I believe, 180,000 barrels of oil. At that time I had to make some fairly gross assumptions about porosity and other factors that went into the material balance equation, but we have been working off the figure of 15 to 20 million barrels in place, since the beginning, since we first got that pressure data from the Kadrmas. Conoco, on the other hand, was, they were in the 25 to 30 million barrel range, based on the way they were doing material balance. The 18 million barrels is based on the model and we have confidence in the model. We think it was done right.

MR. NORTON: So you agree with the 18.25?

MR. PRESTON: Yes.

MR. NORTON: Now, using the net pay they had on their exhibits, they came up with original oil in place, using the parameters they used, of 19.42 which is approximately 5% in error from the material balance.

MR. PRESTON: Right, I think they said six.

MR. NORTON: And as I looked at this map I have no numbers to work with, but by moving the zero core line to the west and eliminating a lot of the thick reservoir you're going to drop the reserves considerably using that interpretation.

MR. PRESTON: 16.1 million barrels.

MR. NORTON: 16.1?

MR. PRESTON: And that was one of our exhibits, I believe.

MR. NORTON: So that would be roughly . . .

MR. PRESTON: 12.

MR. NORTON: in excess of 10% error from the material balance.

MR. PRESTON: That's correct.

MR. NORTON: Okay, thank you.

MR. CARVELL: Bruce?

MR. WEFALD: Nothing else, sir.

MR. CARVELL: Okay. Any further exhibits Mr. Wefald?

MR. WEFALD: None.

MR. CARVELL: Witnesses? Do you have anything further, Lawrence?

MR. BENDER: I have one additional witness. A rebuttal witness.

MR. CARVELL: All right. Has he been sworn?

MR. BENDER: No, he hasn't.

MR. CARVELL: Please raise your right hand. Do you promise to tell the truth in this hearing?

MR. MOHL: Yes, I do.

MR. CARVELL: Thank you.

MR. BENDER: Greg, state your name for the record please.

MR. MOHL: Greg, excuse me, Gregory T. Mohl, M-O-H-L.

MR. BENDER: By whom are you employed and in what capacity?

MR. MOHL: I'm a Senior Geophysicist with Conoco in Casper.

MR. BENDER: And in that capacity have you had an opportunity on previous occasions to testify before the North Dakota Industrial Commission and had your qualifications accepted as that of an expert?

MR. MOHL: No, I have not.

MR. BENDER: Could you then briefly highlight for the examiner your educational background and work experience?

MR. MOHL: Yes. I have a Bachelor's of Science, and Master's of Science Degrees in Geology from Montana State University and Washington University, respectively. I also hold a PhD in Geology from Washington State University. While my advance degrees are in geology, my graduate work was actually in applied geophysics. Conoco hired me as a geophysicist and since that time I have been fully trained in operating within Conoco as a geophysicist. Professionally, I have experience in the Rocky Mountains, mid-continent, offshore Gulf of Mexico regions. While in the Gulf of Mexico I worked several of Conoco's 3D _____ including one that covered a total of 1300 square miles.

MR. BENDER: You are going awfully fast, slow down a little bit.

MR. MOHL: Okay. Most of this work, particularly the 3D work, centered upon reservoir descriptions, delineation and the application of advanced seismic methods to interpretation problems. Also, I have compiled and taught several short courses in the seismic stratigraphic interpretations, seismic waveform analysis, amplitude and analysis, amplitude analysis versus offset interpretation and the integration of seismic data and geologic interpretation.

MR. BENDER: What are your current responsibilities in Casper with Conoco?

MR. MOHL: Currently my primary responsibility is in regard to our exploration effort in northwest Colorado. However, I also serve as a Casper Division mentor and resource in advanced geophysical applications. We furnish seismic waveform analysis, synthetic modeling and amplitude versus offset work.

MR. BENDER: Is it fair to say, Greg, that on a daily basis you are looking at and interpreting seismic?

MR. MOHL: Yes, it is.

MR. BENDER: Now, Greg, do you have an opinion as to the reliability of using seismic . . . Greg, do you have an opinion as to the reliability of using seismic data as a means of determining the reservoir boundary for unitization purposes?

MR. MOHL: Yes. Based upon what I've heard today, I'm hearing a lot of, of banter thrown around with regard to 3D seismic and how much it can help in this kind of situation. And yet there has been no discussion about the physical properties of the Lodgepole Reservoir rocks themselves, whether or not they support direct seismic identification and how the synthetic modeling actually applies. Second of all, I've got a strong concern with regard to seismic wave theory and its ability to support this level of interpretation, as it defines the edges of the mounds. And finally, even if we could get over the physical properties concerns and the wave theory concerns, from my experience, this type of interpretation is highly interpretive and the interpretations are new, unique. Just from that standpoint I consider the seismic method to be totally inappropriate for an equity type of determination.

MR. BENDER: Okay, Greg, let's talk about your first concern, the physical properties of the Lodgepole and your concern in that area. Do you have an exhibit that will help you demonstrate those concerns?

MR. MOHL: Yes, I have an exhibit.

MR. BENDER: I'll show you what has been marked, for purposes of identification as Exhibit No. 26. Can you tell us what that is and then briefly discuss it?

MR. MOHL: Yes, this is the sonic log from the Kadrmas well. It has been discussed several times today.

MR. BENDER: It's actually a portion of the log.

MR. MOHL: A portion of the log. It basically covers the Lodgepole portion and then down to TD so its, you can see the scales that were applied in the sonic log. The Lodgepole section, reservoir section, runs from about 9720 down to just over or just under 10,000 feet. The reason for showing this log, as well as the companion Exhibit No. 27, is to discuss the velocity contrast between the actual reservoir itself and the surrounding country rock. The seismic method requires there must be either a velocity or a density contrast, fundamental physical properties of the rock in order to set up the conditions to be able to reflect seismic data.

MR. BENDER: You are talking about the difference between the clean limestone and the argillaceous zone, the impermeable barrier that we talked about earlier?

MR. MOHL: That is correct.

MR. BENDER: Okay, continue.

MR. MOHL: The a, there are two ways by which to calculate interval velocity off, off the logs. One way is to accept the interval transit time as shown on the right hand side of the depth track and essentially calculate, allow the log itself to calculate what the interval velocity would be for that zone. If I do that, the interval velocity for the Kadrmas well is 18,200 feet per second. The other method would be to apply an averaging over it, that averaging that, I have chosen is 55 microseconds per foot. Depending upon which camp you're following may or may not be a more accurate way to look at things. In any event, the interval velocity chosen by this method is 18,500 feet per second.

MR. NORTON: What was that number again?

MR. MOHL: 18,500.

MR. NORTON: Okay.

MR. MOHL: The importance here is that this sets up what physical properties we can realistically expect for the reservoir facies. If we move to, to Exhibit No. 27 . . .

MR. BENDER: Tell us what that exhibit is.

MR. MOHL: This is the Frenzel 79, it's an example of a well in which we did not encounter the Lodgepole mound reservoir.

MR. BENDER: It's a portion of a log from that well.

MR. MOHL: It's a portion of the log from that well. The same two techniques were applied in order to establish an interval velocity for this zone, that being using the interval transit time and using a averaged time taken off, visually picking on the log. In this case the, the interval transit time gives a calculation of 19,000 feet per second and the visual estimation gives us a transit time of 18,700 feet per second. In comparing the reservoir to a nonreservoir, this gives us a velocity difference of only 500 feet per second. Now, when you think about the model that was shown previously, the top of the reservoir was a relatively weak reflection and it was tied to the _____ Lodgepole lime marker. On Exhibit No. 27 that would be the feature that's shown from about 9790 to 9806, that's in the Frenzel 79. In the Kardamas . . .

MR. BENDER: Kadrmas.

MR. MOHL: Kadrmas, this same feature is from about 9628 to 9645. The interval velocity calculated by the same methods for these zones is about 16,000 feet per second. So you have 2500 foot per second difference in there, and that results in a weak reflection. It's my concern that when it really comes down to it, 500 feet per second, laterally, between these two zones is seismically invisible. When you look at it from the standpoint of their synthetic model that, that they submitted, the synthetic model is based upon these sonic logs. Some people may choose to put density into it, it does not appear as though density was put into that model and based upon the log response of the wells that have been penetrated in the Lodgepole area the density does not appear to be a significant contributor. The important thing to bring out, with regard to that synthetic model, is that is data that is manufactured from the sonic logs. It has no noise in it. It has none of the complicating factors the, actual field geophysics has in it. And so to look at a very subtle waveform anomaly shown on a synthetic model and extrapolate that to, to the interpretation of actual seismic data is, is a stretch. Let alone, when you have such a minor velocity.

MR. BENDER: Okay, Greg, I believe in the first part of your testimony you indicated that you had three concerns. You've just briefly discussed first your first concern, which was the velocity contrast, can you, do you have an exhibit that demonstrates your second concern, the wave theory?

MR. MOHL: Yes, I do. I believe it's Exhibit No. 28.

MR. BENDER: Greg, identify Exhibit No. 28 and tell us what it depicts.

MR. MOHL: Exhibit No. 28 has to do with seismic theory and what you can realistically expect for lateral resolution of seismic data. It brings to bear a lot of the discussion of 2D versus 3D seismic data and how it can realistically be applied in this example. To briefly go into it, it is not my intention to, to do this in detail, seismic energy itself travels to through the earth with a wave, as such it is subject to the laws of physics associated with wave theory. That includes the attenuation and transmission effects of waves passing through a semiviscous medium. It also, it also has to do with how a wave interacts with a physical surface. The top part of the exhibit graphically demonstrates how a seismic wave front would interact with a boundary zone, say the top of the Lodge, or the middle Lodgepole marker. The point to get across is that the seismic itself is not interacting with a single point, it's interacting with a zone, in effect, a seismic blind spot. This is termed the Fresnel Zone. The mathematical representation of it is indicated in the middle of the exhibit. The radius of the Fresnel Zone is what we are calculating, and that would just be the, the radius of the feature, in a 3D sense it's circular, in a 2D sense it showed up as a line. ____ velocity is the velocity that the wave had, that the wave was able to travel from the surface down to the target. The two way time in seconds relates to the depth of target as does when, when coupled with the velocity field, and then the dominant frequency of the data in hertz. When we talk about good seismic data versus bad seismic data and how it relates to this kind of a, of a calculation, these velocity fields and the two-way time are things that are reflecting the physical parameters, we have to deal with. The only thing that really is encapsulated in the quality of the data has to do with the dominant frequency. We chose not to press the, the other parties on what they thought the dominant frequency of their data might be. However, if we look at their exhibit, the seismic model, if we look at their Exhibit No. 4, up in the upper right hand corner, if you can see a seismic wavelet represented. It was chosen to be a _____ wavelet for the frequency content from 12 to 72 hertz, then tapers on to 24 at 24 and 60 hertz. Okay, visually estimating the dominant frequency that they would have in their data, it compares very favorably to a seismic data that we have in Conoco's possession of the Lodgepole feature and that being that there's a dominant frequency on the order of 40 hertz.

MR. BENDER: You are talking about the 2D seismic that was obtained in 1990?

MR. MOHL: I'm talking about the, about the 2D seismic that was obtained in 1991. The, if you applied this formula, utilizing the seismic information that Conoco does have over the fields, our average velocity is 9700 feet per second, our two-way time to the top of the feature is 1.85 seconds and our dominant frequency in hertz is 40 hertz. What this translates to if you do the map is a radius of 1043 feet, or a diameter of 2086 feet. Now the Fresnel Zone in and of itself has to do with stacked seismic data. There's been a lot of discussion with regard to migration, 2D migration versus 3D migration. Migration will improve the accuracy of the data, it will _____ the Fresnel Zone somewhat. However, it needs to be stressed that migration is a physical movement of the data based upon assumptions. These assumptions include the velocity field that we're going to migrate the data with. It also assumes within the programs that the computer is using there are several different ways you can migrate data with totally different results. When we think about 2D versus 3D, 2D data will migrate correctly only if the feature is oriented perpendicular to the line of section, perpendicular to the seismic line. Whereas 3D data has a volume we can more correctly place it in its correct spot, that being not only in the line of section but also in its position perpendicular with the section. The reason why I bring all this up is that even with migration on 3 dimensional data, we still are limited to what the resolution of the seismic method can hope to, to achieve. And that's shown on the bottom of the, of the exhibit. And that . . .

MR. BENDER: 28?

MR. MOHL: Exhibit 28. And that'd be, that lateral resolution from migrated seismic data can be approximated by the wavelength, which is the interval velocity over the dominant frequency. In the earlier part of my testimony we calculated the interval velocity for the Lodgepole Reservoir to be 18,500 feet per second. The dominant frequency in the Conoco data is 40 hertz. And that means that the best that we could possibly hope to do from a seismic wave theory standpoint is 462 feet and that's 462 feet for a single trace that's shown on the seismic data. If there is any error in the interpretation, that being any ability to move the interpretation one trace or another this error is compounded on top of that. As I indicated this calculation is sensitive to the earth properties, the property of the rocks that we're dealing with, and the data quality, but the data quality itself is tempered by the log properties. There are limits to which the highest frequency seismic data we can possibly obtain would be, as all parties concerned have spent considerable effort trying to acquire the best quality seismic data they could get. It's reasonable to assume that we have acquired the highest quality data we can acquire at this point in time.

MR. BENDER: Okay, Greg you've spent some time now discussing the problems you have in this area with velocity contrast, you've discussed some, the problems you have with the wave theory, even if you didn't have problems with those two areas, would you have problems using seismic data to interpret the zero line on a reservoir?

MR. MOHL: Yes and this is, this goes back to my experience within Conoco, in doing reservoir kind of work. I've spent the majority of my career looking at wave form type of anomalies and trying to work at or below the effective resolution of the seismic data. This has been primarily exploration work. Without exception this has been highly interpretive. It's very sensitive to the individual rock properties. It's also sensitive to the acquisition parameters of the seismic data and the processing of the seismic data. In the, in these steps there are interpretation steps that are taken in order to try to optimize your data, the data for whatever feature you are trying to, to highlight. Choosing the wrong parameter, even if you think you are doing so at the time, can totally invalidate the data. This waveform work is particularly sensitive to this and as the model shows, this is a waveform anomaly that we, we are truly looking at. Then finally, there's the post processing in the things and the things that we do with the data to make it so it is more visually interpretable. The bottom line is that work of this nature is very good for exploration. It can give you a general shape for, for what you're looking at and point you in the right directions. From the standpoint of, of trying to atone an equity, or basis, or, or exactly the fine amount, that is not going to change. The solution is not unique and it's an inappropriate use of the tool.

MR. BENDER: Greg how long have you been involved in interpreting seismic data?

MR. MOHL: Approximately seven years.

MR. BENDER: And in those seven years have you ever been asked to utilize seismic data to predict the reservoir boundary on unitization purposes?

MR. MOHL: I have been asked to predict reservoir boundaries in an exploration sense, to decide whether or not we want to be thinking about a play, from the standpoint of a unitization sense, no I have never been.

MR. BENDER: So, it's an exploration tool, in your opinion?

MR. MOHL: It's an exploration tool. It has some development applications but never as far as defining a limit that you're going to stick with.

MR. BENDER: You indicated that you have never utilized seismic, either 2D or 3D to depict a reservoir boundary for unitization purposes. Are you aware of any other, any geoscientist who may have used seismic to depict a reservoir boundary for unitization purposes?

MR. MOHL: No, I am not.

MR. BENDER: I believe that's all the questions I have for this witness at this time.

MR. CARVELL: Mr. Morrison?

MR. MORRISON: Sir, are you familiar with Conoco's 3D seismic program over the area in question today?

MR. MOHL: I am somewhat familiar.

MR. MORRISON: What's the status of interpretation of that data?

MR. MOHL: That data is currently being looked at with regard to exploration.

MR. MORRISON: Has it been looked at with regards to confirming or disproving Conoco's interpretation of the Dickinson-Lodgepole Pool as presented today?

MR. MOHL: I do not know that for sure.

MR. MORRISON: You have not done it?

MR. MOHL: I have not done that, no.

MR. MORRISON: Who else might have done it?

MR. MOHL: The individual responsible for doing that work is Ian Gordon.

MR. MORRISON: Who?

MR. MOHL: Ian Gordon.

MR. MORRISON: Has Ian Gordon had access to that 3D?

MR. MOHL: He has been looking at the, the whole volume.

MR. MORRISON: Now, Ian Gordon was responsible for all the geologic data that was presented today, wasn't he?

MR. MOHL: That is correct.

MR. BENDER: No.

MR. MOHL: No, that is not correct. He was the geoscientist primarily involved.

MR. MORRISON: Primarily involved, okay. Do you agree that seismic data at least gives you additional information, additional points of information to be considered, to be considered when making an interpretation of the reservoir boundaries?

MR. MOHL: If it is correctly acquired and processed and interpreted, and that is the big if.

MR. MORRISON: And there are interpretive differences whether you are talking about seismic or subsurface well control. Isn't that right?

MR. MOHL: The danger with interpretive differences in seismic is that you can make decisions early on the process that totally invalidate the data, and to the untrained eye you will never see them.

MR. MORRISON: Have you made a synthetic seismograms of the two logs that you have marked as Conoco's Exhibits 1 through 6 and 27?

MR. MOHL: I have not. I have looked at the ones that Ian has made, helped him with that.

MR. MORRISON: And looking at those synthetic seismograms have you seen events that correspond to the Lodgepole shale marker?

MR. MOHL: I have seen an event that corresponds to Lodgepole shale marker.

MR. MORRISON: You've seen events that correspond to the Bakken shale?

MR. MOHL: I have seen events that correspond to the Bakken shale.

MR. MORRISON: Is there a difference in the thickness between those two events, on the two different seismograms?

MR. MOHL: Between those two events, however, I'd like to state that the Lodgepole shale marker does not necessarily define the top of the reservoir.

MR. MORRISON: No further questions.

MR. CARVELL: Mr. Wefald?

MR. WEFALD: Am I to understand from your testimony that you would advise the Commission to completely disregard the seismic data here today?

MR. MOHL: I would advise the Commission to disregard seismic data as a method by which to determine equity.

MR. WEFALD: And you would think it would be better just to take that top of the Fryburg and project it down and use the well logs and that would be the best way to do it. Is that right?

MR. MOHL: Knowing the inaccuracies that can be involved in 2 dimensional or 3 dimensional data, to use the seismic data ______________ interpretation is not necessary, that is not necessary.

MR. WEFALD: Not necessary from Conoco's standpoint, because Conoco has a definition that says we're way out here to the east. Is that correct?

MR. MOHL: I am really not considering Conoco's standpoint in that regard ________________.

MR. WEFALD: You work for Conoco, don't you?

MR. MOHL: I do work for Conoco.

MR. WEFALD: Thank you. With respect to seismic, why is Conoco spending the money shooting 3D seismic over this area?

MR. MOHL: We are primarily looking at it from the standpoint of exploration, we consider it to be a very useful and viable tool in an exploration sense.

MR. WEFALD: And is Conoco willing to put that data in the hands of a third person for the purpose of making out a map?

MR. MOHL: That would not solve the problems associated with using seismic data in equity determinations and that being that fundamentally the seismic is not appropriate for that.

MR. WEFALD: Of course, there's an equity problem when we use just the Fryburg and the, the well logs, isn't it? If, if the equity is cut both ways don't they?

MR. MOHL: Could you rephrase the question or?

MR. WEFALD: You're talking about equity, you're a scientist, right?

MR. MOHL: Yes.

MR. WEFALD: Geologist?

MR. MOHL: Yes.

MR. WEFALD: Equity is fairness we're talking about, right?

MR. MOHL: Yes.

MR. WEFALD: And that's from someone's point of view. What's fair to you may not be fair to me, is that right?

MR. MOHL: It can be viewed that way.

MR. WEFALD: What's that?

MR. MOHL: It could be viewed that way.

MR. WEFALD: Of course that's why we are here, it is being viewed that way, isn't it?

MR. MOHL: All of those maps have been approved by the overall group.

MR. WEFALD: Okay. You understand that there's a dispute here today about the equity, do you not?

MR. MOHL: Yes, I do.

MR. WEFALD: All right. That's all I'm asking. And yet what you're telling us is that that dispute should be resolved by completely throwing out the seismic. Is that right?

MR. MOHL: What I'm telling you is that dispute should be resolved by the data of which has gotten the least amount of interpretation associated with it.

MR. WEFALD: But, in fact, seismic is data that this Commission can use along with the well logs, the Fryburg, just the way our witness, Mr. Gomez, put it together. It's all data that's relevant to the analysis. Is it not?

MR. MOHL: If correctly used.

MR. WEFALD: Did Mr. Gomez incorrectly use the data here today?

MR. MOHL: I did not . . .

MR. WEFALD: Let the witness answer his own questions, please.

MR. MOHL: I did not . . .

MR. WEFALD: Just a minute, I don't want anybody coaching him. You heard the witness, did he incorrectly testify today?

MR. BENDER: Mr. Wefald, I don't think you have to yell at the witness. Ask your question, but you don't have to yell.

MR. WEFALD: All right, I apologize, I don't mean to yell. But, please, when I ask you question, don't consult someone else, just answer the question, will you please?

MR. MOHL: All right.

MR. WEFALD: Then, I'll rephrase the question again. Did Mr. Gomez incorrectly interpret the data here today?

MR. MOHL: I did not have the opportunity to fully evaluate Mr. Gomez's interpretation. I have not seen how he has picked the edge of the mound. He has represented it from the standpoint that he feels he is accurate in defining the reservoir edge at a single shotpoint. I believe that is below the resolution of the tool and in that regard I believe that is an incorrect representation of the mound, if you are planning on using it in equity determination.

MR. WEFALD: Is that a yes or a no?

MR. MOHL: That is a no.

MR. WEFALD: Okay. So, no, he did not incorrectly interpret the data.

MR. MOHL: Yes, he correctly, he did not correctly interpret the data. He's trying to apply it beyond its resolutions.

MR. WEFALD: Okay, so Mr. Gomez's testimony is incorrect today?

MR. MOHL: In that sense I would say yes.

MR. WEFALD: And all the people that testified here today, they've got absolute, precise data that tells them exactly what the answer is for this underground structure that's 10,000 feet underground, right?

MR. MOHL: We have the well information, of which we can go a point on the earth and say, at this point this information exists.

MR. WEFALD: And all the rest of it between the points is interpretation, is it not?

MR. MOHL: It is.

MR. WEFALD: All right. I have no further questions.

MR. CARVELL: Wes?

MR. NORTON: I don't have any questions of this witness.

MR. CARVELL: Any redirect?

MR. BENDER: No redirect.

MR. CARVELL: Any further witnesses?

MR. BENDER: No further witnesses.

MR. CARVELL: Mr. Morrison, any witnesses?

MR. MORRISON: No.

MR. CARVELL: Mr. Wefald?

MR. WEFALD: Done.

MR. NORTON: I have a, if I can I'd like to clear up a question I have on Exhibit 7, Aviva Exhibit 7 versus the Placid Exhibit 9.

MR. CARVELL: Exhibit 7 is, which one?

MR. NORTON: The Aviva. Now you use the same data and you came up with two different interpretations. But the question I have is, whether it, I, I assume that the lines are plotted on these exhibits to scale because both of them go on the east side of the section line through most of 32, then they go on the west side of the section line through exhibit, or Section No. 6. However, the section line between 29 and 30, the Aviva exhibit has the, the data points right on the section line and the Placid exhibit has the data points, and I scaled it out here, at roughly 200 foot west of the section line. Now, my question is, was this just a drafting error on one part or the other or was that the point that the data was interpreted from?

MR. CARVELL: Who is your question addressed to, Wes?

MR. NORTON: Well, I don't know.

MR. GOMEZ: Sir, I would tend to think it's probably a drafting error. I can't explain it to you why, how it happened, but I would think that's what happened.

MR. NORTON: So, you don't know for sure.

MR. GOMEZ: I don't know for sure, but just because there is a discrepancy I would tend to agree with you that it's a drafting error, on who's part I don't know.

MR. NORTON: Thank you.

MR. CARVELL: Was there anything, any more witnesses or exhibits or any questions, Mr. Bender?

MR. BENDER: No more witnesses, no more exhibits.

MR. CARVELL: Mr. Morrison?

MR. MORRISON: No.

MR. CARVELL: Mr. Wefald?

MR. WEFALD: We got one more exhibit and I want to question Mr. Preston on the models, the Conoco's model prediction verses the ultimate recovery. This would be Exhibit No. 9. Kevin, you're still under oath, can you tell us what this is?

MR. BENDER: Is this a rebuttal testimony or . . .

MR. CARVELL: Well, I like to . . .

MR. BENDER: I'm going to object if it's not rebuttal testimony _____.

MR. CARVELL: Objection overruled. Go ahead and see what it is here.

MR. WEFALD: What is this Kevin?

MR. PRESTON: Well, this shows a comparison between primary recovery predicted by Conoco's model versus primary recovery that was used in the equity determination. And before I go into that I'd like to point out that several times during today's testimony it's been stated that the map, the oil in place map was used to derive one half of the Phase I factor and all of the Phase II factor, and actually that's incorrect. The oil in place map was directly used for both parts of Phase I and all of Phase II, because primary, remaining primary, the way that Conoco went through the formula was based on oil in place which was based on the map, so both, in that Phase I part of the formula 50% remaining primary, 50% original oil in place figures are derived from the oil in place map. Conoco, Conoco's model predicted recoveries from each of the four producing wells. And they're shown in that first column under millions of barrels. The model predicted that the State 74 would make 1.86 million barrels. The Kadrmas 2.02; the Frenzel .81; the State 83 .37. You add all those up, you get a little over 5 million barrels. Conoco took the model's ultimate recovery prediction, it's material balance, I mean it's the model's material balance oil in place, numbers 18 point something million barrels and divided that by the 5 million barrels that the model predicted to come up with a recovery factor of 27.7%. They then took that 27.7% and applied it to the map's volumes by tract to come up with primary recovery by tract, disregarding the primary recovery that had been predicted by the model. So, they were, they were willing to use the model for primary recovery predictions for the field as a whole but not for individual tracts. And, if you'll notice the State 74 well, the model predicted would produce 37% of the oil in place, I mean 37% of the primary oil, yet the number that was used for equity determination was over 50% of the primary. Conversely, the Kadrmas 75 and the other remaining wells, their recovery under the equity formula goes way down compared to what the model predicted.

MR. WEFALD: We'd offer Exhibit 9.

MR. CARVELL: Any objections to the exhibit, Mr. Bender?

MR. BENDER: I, may I ask a couple questions before I?

MR. CARVELL: Yes.

MR. BENDER: Mr. Preston, your earlier testimony was that all the exhibits here today were wrong. Is this exhibit wrong?

MR. PRESTON: I, I don't think I said all the exhibits were wrong. We could check the record, I believe I said the maps were.

MR. BENDER: Is this exhibit correct?

MR. PRESTON: Yes, it is.

MR. BENDER: Then I have no objection to the exhibit.

MR. CARVELL: Mr. Morrison, any objections to the exhibit?

MR. MORRISON: No.

MR. CARVELL: Exhibit 9 is received.

MR. WEFALD: Nothing further.

MR. CARVELL: Cross-examination?

MR. BENDER: Kevin, are you a reservoir engineer?

MR. PRESTON: Yes, I am.

MR. BENDER: Are you a, consider yourself an export, expert reservoir modeler?

MR. PRESTON: No, I wouldn't.

MR. BENDER: What, what is your experience in modeling?

MR. PRESTON: Very limited.

MR. BENDER: Tell me about it.

MR. PRESTON: I've been involved in unitizations, field development, offshore, offshore California, offshore Gulf, where the modeling was done by other majors like Shell and Exxon.

MR. BENDER: Have you ever run a reservoir model yourself?

MR. PRESTON: Never.

MR. BENDER: Don't have the software program in your office?

MR. PRESTON: No. I was relying on Conoco's abilities to run the models.

MR. BENDER: So you're not testifying today as an expert reservoir modeler?

MR. PRESTON: No, not at all. This is, these are Conoco's numbers, these aren't mine.

MR. BENDER: Were you at the working interest owner meeting when the, a decision was made that reservoir modeling would not be utilized for equity purposes?

MR. PRESTON: I don't believe that was ever decided on. Conoco just stated it many times.

MR. BENDER: You don't recall that ever coming up and you agreeing to it?

MR. PRESTON: I don't even know if it was voted on or not, but it is being used anyway. The 27.7% came from the model.

MR. BENDER: But, every tract was treated the same, was it not?

MR. PRESTON: That's right, but when you start subtracting out cums and looking at oil in place in comes into play.

MR. BENDER: So the reservoir model was never used as, for equity purposes, was it?

MR. PRESTON: Yes, it was, the 27.7% that's used in the calculation.

MR. BENDER: For the original oil in place, but it wasn't used to allocate oil to the various tracts?

MR. PRESTON: Yes, it was, indirectly. Because it comes into play in that remaining primary part of the formula. If you remember Phase I it's 50% remaining primary, 50% remaining oil in place. Remaining primary is based on 27.7% times the original oil in place less the cum production, then they allocated some of the oil _____ in tracts that didn't have wells.

MR. BENDER: Did you receive copies of the minutes from each one of the working interest owner meetings that have taken place?

MR. PRESTON: Yes.

MR. BENDER: Do you recall seeing in one of the minutes from those meetings that the reservoir model would not be utilized for equity purposes?

MR. PRESTON: I don't remember that. I remember it being said many times by Conoco. I don't know if they voted on it, but if you've got minutes and it says it was voted on I'll believe it.

MR. BENDER: Just give me a minute. So you would agree, it maybe was voted on, or do I need to show you in the minutes?

MR. PRESTON: If the minutes say it, I'll agree.

MR. BENDER: Well, if it was voted on and Aviva agreed not to use the reservoir model, why are you changing your mind now, why . . .

MR. PRESTON: Because they are using it. They are using it. They are using that 27.7% to come up with an estimate of primary recovery by tract. That number came straight from the model. Now, in normal unitizations, or in most unitizations that I've been involved in you are lengthening the life of the field, you've got production history on each well and you can go through more classical reserve determination on producing wells to come up with what remaining primary is. Maybe it's just straight decline curve analysis. In this case because it's so new you can't do that. So you, you have to come up with some other method for determining primary recovery in each well.

MR. BENDER: If it was utilized in the equity formula in this particular case why would have there been discussions not to use it at the working interest owner meetings and if it's in the minutes why would there have been a vote not to use if it was utilized anyway?

MR. PRESTON: Can't, I can't answer that.

MR. BENDER: I would like some time, can we take a short break so we can try to find this?

MR. CARVELL: What time is it? Break for ten minutes. We'll reconvene the hearing. Do you have questions?

MR. BENDER: I have no further questions of Mr. Preston.

MR. PRESTON: Was that in the minutes?

MR. CARVELL: Well, just a minute. You have no further questions?

MR. BENDER: I have no further questions of Mr. Preston.

MR. CARVELL: Mr. Morrison, any questions?

MR. MORRISON: No.

MR. CARVELL: Any redirect?

MR. WEFALD: Can we assume from that silence that it's not in the minutes?

MR. BENDER: We were unable to find it.

MR. WEFALD: All right.

MR. NORTON: I have a question on Exhibit 9.

MR. CARVELL: Go ahead.

MR. NORTON: I'm not clear on Exhibit 9, whether the model attributes the oil that the wells would produce ultimately on a rule of capture basis or whether it was allocated on the basis of the spacing unit?

MR. PRESTON: It was the rule of capture.

MR. NORTON: Okay. So it has no, no regard for lease lines or spacing unit lines? Okay.

MR. PRESTON: And I guess the reason I thought that was important was because in the regulations it says that one of the, one of the things that they are looking for as far as having a fair and equitable unit is that they have to take into account the probable productivity of oil and gas in the absence of unit operations. In the absence of unit operations we are going to be on primary basis, just like that rule.

MR. NORTON: Thank you.

MR. PRESTON: The model was applicable.

MR. CARVELL: Mr. Bender, I understand you have a witness that's going to respond to Exhibit 9?

MR. BENDER: Yes. I want to recall Kevin Zorn, please. Kevin, you've testified previously in this hearing?

MR. ZORN: Yes, I have.

MR. BENDER: And you are still under oath. Kevin, were you in the room when Mr. Preston just recently testified concerning the reservoir modeling?

MR. ZORN: Yes, I was.

MR. BENDER: Can you tell me Kevin, why the cumulative production numbers that were generated by the model were not included in the equity formula?

MR. ZORN: Well, the reservoir modeling study was not conducted in order to calculate remaining recovery by wellbores. As a matter of fact, at the second working interest owners meeting there was considerable discussion around the use of a reservoir model for that purpose. There were a couple of individuals, I believe, and my recollection is with Placid, who raised some objections to doing a modeling study because of their fear that it was going to be used for this purpose. It was never Conoco's intent to use the modeling study for equity calculations. The model parameters were not designed for that purpose. The purpose of the reservoir model was to make technical decisions on how to optimize the recovery from the field. The model is very useful in predicting approximately how much oil will be recovered from the entire field. Since all the wells in the field are in pressure communication and any production rate changes in one well are going to change the cumulative oil recoveries of all the other wells, it is very difficult to predict with any degree of accuracy how much oil will come out of individual wells. Two of the wells in the field, the State No. 74 and the Kadrmas No. 75 are capable, individually, by themselves, of draining the entire reservoir, all 753 acres. Due to the high permeability in the reservoir all four wells are like straws in one big glass of oil. Depending on the way the wells are produced, when they begin to cut water, when they are put on artificial lift, what type of artificial lift method is chosen, you are going to get a different calculation of oil in place. What we know with reasonable accuracy is that the field will produce a little over 5 million barrels from the whole field. Mr. Hicks, I think, was questioning me earlier about some of the points on the decline curve predicted from the model on the waterflood case. And I went into just a little bit of the calculations involved and why we see some of those fluctuations in the decline curve. As I mentioned at that time there's probably five, four or five different methods to put on artificial lift on these wells. We modeled one case. There is an unlimited number of scenarios on the way that they are going to be produced. And I need to indicate that this is a lot different than what you would see in a typical reservoir where you're using reservoir modeling for this purpose. For one fact we have very little production history on any of these wells. The only well that we have any history on to speak of is the State No. 74. The model prediction of what an individual well is going make is only as good as the history match. You can't do a history match on the Frenzel 79. You can't to a history match on the State 83 and you can barely do a history match, if you want to call it that, on the Kadrmas 75 because it was only on line for about three months or two months before we started artificially controlling the rates. The same reason that you can't use decline curve analysis to predict individual well productions is the reason that you can't use a reservoir model. Any attempt to use the numbers from the reservoir model to predict individual well cumulative recoveries is a gross misuse of the tool and had that been Conoco's intent or the working interest owners intent at the very beginning, the model would have been set up completely different. We have a lot of simplifications in the model as I went over, I think, in an earlier question from Mr. Norton concerning how the aquifer is treated, concerning how the permeability distribution in the reservoir is treated, the best way to allocate equity in this field is based upon where the original oil in place is. Now, obviously there's some disagreement on where oil in place is. We have an interpretation and both of the other parties have interpretations. That's where the disagreement lies, is where the oil in place is located. You cannot use, in this particular circumstance, this reservoir simulator to try to predict what individual wells are going to make. And so this comparison that Mr. Preston has done here is totally irrelevant.

MR. BENDER: No further questions.

MR. CARVELL: Cross, Mr. Morrison?

MR. MORRISON: Yes. Kevin, you agree that the 27.7% recovery factor and the 5.38 MMBO of primary recovery came from the model, right?

MR. ZORN: The 5.38 that's correct, yes. The 27.7% recovery factor came from the model. That's correct.

MR. MORRISON: Okay, both those two numbers came from the model?

MR. ZORN: That's correct.

MR. MORRISON: And how was the 5.38 million barrels of oil then allocated to existing wells for purposes of computing primary recovery under Phase I?

MR. ZORN: What I did was I took every tract, oil in place by tract, based upon the map that's in Conoco's exhibits. So the first calculation was, on any of the maps using the 5.372% average porosity, using the 10.6% connate water saturation, using the ____ at original reservoir conditions, I think it's on Exhibit 15, 1.3 something, you calculate an original oil in place in each well. Then we took the 27% recovery factor and applied this same number to every tract. We could have used 10%. We could have used 5%. We could have used 30%. We could have used any number, every tract was treated the same. The only place where the reservoir model has anything to do with the equity formula is not in the 27%, it's when you go from Phase I to Phase II. The timing of when you go from Phase I to Phase II is based upon cumulative oil recovery predicted by the model. That is the only place where it enters the equity calculation.

MR. MORRISON: You said if you used, you calculated oil in place for each tract, each producing tract? Is that right?

MR. ZORN: That's right.

MR. MORRISON: And then you applied a number. Did you apply 27.7% to it?

MR. ZORN: That's correct.

MR. MORRISON: And so the primary recovery from each tract is simply 27.7% of the oil in place calculated for the spacing unit for any particular existing well?

MR. ZORN: That's correct. And then what, as I discussed I think in the, excuse me, in the direct testimony, the tracts that did not have producing wells, Tracts 5 through 9 that oil will be recovered from the four producing wells. That oil from those nonproducing tracts was then allocated on a weighted average basis based upon the isopach map to the four producing wells. So since Conoco's isopach maps shows that the most acre feet of the reservoir is located on the W/2 of Section 32 it gets the largest chunk of that. And, in our opinion, the State No. 74 has the most oil in place and so in order to protect the correlative rights in the W/2 of 32 it should be allocated the highest equity in the field.

MR. MORRISON: Okay, so both parameters in your Phase I calculation depend upon the accuracy of your isopach of the Lodgepole?

MR. ZORN: That's exactly correct.

MR. MORRISON: All right, which I think was Mr. Zorn's point in the first place. Not Mr. Zorn, excuse me, Mr. Preston's point. Okay, no further questions.

MR. WEFALD: Nothing

MR. CARVELL: Okay. I don't know if you, the lawyers formally moved all the exhibits but all the exhibits that we've been talking about, they will be made part of the record unless anyone has an objection on any particular exhibit.

MR. WEFALD: I think they've all been moved into the record, but if not we'd certainly agree to that.

MR. CARVELL: Okay, and then we've got some letters, are they with you?

MR. WEFALD: No, I brought them up to you, you've got them right there.

MR. CARVELL: Oh, here they are. We've got a handful of letters from some of the working interest owners as well as some of the royalty owners. These will be made part of the record, if anybody wants to look at them they can just come up here and have a look. Is there anyone else here that's interested in this case and would like to make a statement or otherwise be heard?

MR. MORRISON: I have one other comment that doesn't have to do with Placid. It's really another statement of support and that is that Jeff Herman was here throughout most of the day with PetroHunt and he had to leave shortly after 3:30 and whispered in my ear that he had to leave, he did ask that I make a statement for the record that PetroHunt supports Placid's position in this matter and Placid's interpretation of the isopach.

MR. CARVELL: Okay.

MR. JOHNSON: My name is Robert Post Johnson. I'm a consultant for the firm of Harris, Brown and Klemer Inc., P.O. Box 5006, Bismarck, North Dakota. Here today making a statement on behalf of The Wiser Oil Company, Dallas, Texas, in support of Conoco's application for the unitization. I'd also like to go on record, even though Wiser was a very small working interest owner in the unit, they owned 10.6% of the royalty interest under the unit. So, I'd like to make sure that goes on record. Thank you.

MR. CARVELL: Anyone else wish to be heard?

MR. BAUER: My name is Arthur C. Bauer. I reside in Bismarck, North Dakota and I have represented Lewis W. Hill, Jr. as a consultant for approximately 30 years. Just to let you have a little background information here, Mr. Hill has been a working interest owner in the Dickinson-Tyler Unit since prior to unitization and has had many years of experience in dealing with Conoco and has, would like to state that we've been treated very fairly and all the information we've ever required has been presented to us and one reason, of course, that we don't attend all of the working interest owners meetings is that we own a very small working interest in the unit. We own .55% of the working interest and when you start adding up all these costs of attending these meetings and so forth it's been decided that we would not attend all the meetings. But, we have been furnished with all the minutes, all the mapping, all, any question that we've ever requested of Conoco and for this reason, and for the many years of past history that we've had with Conoco and the experiences all to the best side, we chose to support Conoco by proxy at the various meetings that have been held. But today I am here to strongly emphasize the fact that we favor Conoco's plan of unitization as is and we'll continue to support them. Thank you very much.

MR. CARVELL: Thank you. Anyone else? Any closing remarks, Mr. Bender?

MR. BENDER: Thank you Mr. Examiner, I'm not going to try to, in just a brief period of time, summarize all the testimony that was given here today, but let me try to highlight just a few points. If Conoco's application is granted in this matter 2½ million barrels of additional oil is going to be recovered from Dickinson-Lodgepole Pool. If the unit is not formed that's oil that will be left in the ground and will cause waste. Conoco is in a very unique situation in this particular unit, unlike Aviva, unlike Placid, unlike any other working interest owner, it owns an interest in every tract in the unit. Conoco, therefore, has a obligation to protect the correlative rights of those royalty owners in each one of those tracts. You heard the testimony early on today of Mr. Jim Turner. Jim testified the painstaking attempts that Conoco went through to keep the working interest owners involved in this process, the various meetings we held, the more stringent voting procedure that was adopted at the first meeting. Jim also testified that more than 85% of the royalty owners have thus far ratified the unit agreement and support Conoco's plans for unitization in this field. You also heard the testimony of Jerry Hyrkas, a geologist who indicated that he believes that the best information available was used in constructing the various geologic maps that were presented to the Commission. You also heard the testimony of Mr. Preston who agreed that Conoco's maps honored all of the data in the tracts. Finally you heard the testimony of Mr. Kevin Zorn and Kevin explained in great detail the benefits of unitization, the additional recovery of oil and gas that will be received as a result of the unitization, the additional revenue that will be generated for the working interest owners in the neighborhood of $9,000,000. And the additional revenue that will be generated for the royalty interest owners in the neighborhood of 2½ million dollars. I said finally, but you also heard from a rebuttal witness, Mr. Greg Mohl, who I believe, outlined in great detail the inaccuracy or the difficulty in attempting, difficulty in attempting to rely on seismic information. Greg spent a great deal of time explaining that there's problems with this particular reservoir in particular. That the resolution in these clean limestones versus the argillaceous zone outside the clean limestone that encapsulates the reservoir is such that it is very difficult to conduct seismic work, work in this area. He also discussed for you briefly the fact that the wave theory caused some problems and there's a very difficult time interpreting this. Beyond that I'll just mention one, one more thing and Mr. Morrison raised this in his opening remarks that this particular unitization hearing is very different than the Little Knife hearing because in that situation the royalty owners were vehemently opposed to unitization. I differ with Mr. Morrison. Conoco is here today with sufficient number of ratifications from the working interest owners to have this unit formed. Conoco is also here today with 86% of the royalty interest owners who have ratified the unit agreement and are ready for this field to be unitized. Well, oil, excuse me, the wells in this field have been restricted for a great deal of time, I think right now we are at approximately 600 barrels of oil per day, we were at 200 barrels of oil per day. We are here now for unitization. If this application is denied there's absolutely no assurance that the working interest owners will ever get together again and be able to come back to this Commission and submit another application. And even, even more difficult, I think, is to predict what will happen to royalty owners. I don't think there's, there's any guarantee at all that Conoco will be able to go back to these royalty owners and say well, the Commission denied the application, we've now got to take a small percentage away from you and give it to your neighbor or vise a versa and expect that these royalty owners are going to once again approve a ratification. In that respect I would urge the Commission to act upon this matter quickly, approve the application of Conoco Inc., so that Conoco can start it's injection procedure and get this field back up to 2000 barrels of oil per day in production. That's all I have, thank you.

MR. CARVELL: Mr. Morrison?

MR. MORRISON: The Commission's obligation is to approve the unit proposal that Conoco has made if it finds that the unit is for the common good and will result in the general advantage of the owners of oil and gas rights within the common source of supply and it must do so upon terms that are fair, reasonable, equitable and which are necessary or proper to protect, safeguard and adjust the respective rights and obligations of the owners of the oil and gas rights. This isn't a popular election. The fact that Conoco comes in here with its own ratification and with ratifications from five other owners owning a total of 1.6% of Phase I and less than 2% of Phase II does not mean that the Commission must approve Conoco's request. The fact that less than half of the number of royalty owners representing the 86% or 88%, whatever it is of the royalty owners have ratified, does not mean that this Commission must approve. The Commission must approve if it finds it for the common good and if it's upon terms and conditions and that are fair, reasonable and equitable. Conoco's made a great statement throughout this entire case on working interest owners meetings and actions taken at working interest owners meetings. Apparently Conoco would like this Commission to believe that because a company participates in the working interest owners meeting that somehow it's bound by actions and it forfeits its due process rights guaranteed by the constitution to come into this Commission and voice its objections. It's simply not true, it's not the law and it's not equitable, it's not fair to do that. I think what has been shown, amply demonstrated to this Commission, is that Conoco is proposing a unit upon a flawed basis. It has a net pay map that Conoco itself has admitted is inaccurate. If nothing else at least to the feet of net pay given the State "A" 83 well. It's got ten, ten feet too many. That alone is sufficient basis for the

Commission to turn down the application. There are other inaccuracies that have been described. I think it's also painfully clear to everyone in the room that there is very important data that helps the Commission, that helps the other parties understand what's going on here, that's been withheld, that's the seismic data, the 3D seismic. I think what you heard from Conoco's geophysicist is that golly we don't want to give you this seismic data because you might misinterpret it. There's a lot of problems with it, and Placid might misinterpret it, Aviva might misinterpret it, and the Commission might misinterpret it. It's the Commission's job to interpret that evidence. It's Conoco's job to present the evidence and Conoco didn't do it. They simply didn't support their application. I think Conoco is also crying wolf when they say that if you don't do what we want now, it's not going to happen, we'll lose 2½ million barrels of oil. The Commission has ample authority to order continued restricted production from the field to prevent waste. The Commission's done it before in the 1960's with the fields in the Nesson Anticline, it has the authority to do it again. What the Commission should do is deny Conoco's application. It should order that continued production restrictions remain in place in order to prevent waste, in order to give the working interest owners the encouragement and the incentive to come back with a reasonable proposal, one that protects all the owners in the field. An alternative the Commission may consider is perhaps to continue final decision on Conoco's application until sufficient evidence has been presented. That sufficient evidence is the 3D seismic which Conoco has withheld, which Conoco has refused to give the Commission. I think the Commission is entitled to demand access to that data or to interpretation by a neutral, disinterested third party before it rules on the accuracy of Conoco's interpretation of the net pay. That would be all the comments I have at this time.

MR. CARVELL: Mr. Wefald?

MR. WEFALD: With respect to the last point about the 3D I have put in my brief and response the adverse inference rule, whereas if a party has information in its control that it doesn't produce it's to the court or the hearing board is authorized to take an adverse interest, adverse inference against that party that did not produce data that was in its control. Conoco comes in here like an 800 pound gorilla, they are the biggest ones, got the most of the control and basically runs around saying well we're here, this thing has to be done and it really isn't, their maps are not a result of compromise, their maps are not a result of agreement, they just said take it or leave it, this is the way we are going to do it. Now, I suppose the sixty-four dollar question is what happens when the Commission does what Placid and the Trust want, which is to reject this unit. I guess, I don't know, they produce as much as they can when the thing produces, what it can, then shut down and the 2 point something in barrels oil is not produced, I would believe that Conoco's best interest would be served by getting that oil produced because they are going to get about 70, 75% of it. And I believe it is in their best interest to work with working interest owners that have a substantial interest in this to see to it that something comes out that's fair and equitable. The notion that they don't use seismic for this kind of thing, well, they may not, but there's been testimony by others that seismic is commonly used in the industry. And that 3D seismic has been used to accurately help define the boundaries and we have put ourselves in the position where we said show us the 3D, have some third party put a map together on it and I guess we're going to have to live with it. I just don't think all the evidence is in. It's in the possession of Conoco and I believe ___ map the way they've drawn it for their own selfish interest they've taken and put the eastern boundary right next to a dry hole when they've got another dry hole, the Walton 84, they could move it away from this. I know they've got their reasons for doing that, but in fact, I think our witnesses, that is Placid and the Trust have used more data than they have, that, by definition because we are using more data, more information, our maps have higher probability of being accurate. And I believe Mr. Preston testified correctly when he said that all of these maps are inaccurate. There's no way we can stand up here on the surface and go 10,000 feet down and figure out what's going on. We can probably, hardly figure out what's going on in the surface. We'd ask that the matter be, the unit be rejected or in the alternative that it be continued contingent upon Conoco producing the 3D data or producing it into the hands of an agreeable third party who will map it.

MR. CARVELL: With regard to this 3D, I'm curious why the Trust and why Placid did not file a motion prior to the hearing requesting that the Commission order that the seismic information be produced. Why didn't the Trust do that? And after you've answered then I'll ask why Placid didn't do that.

MR. WEFALD: I, I believe it was strictly a matter of time. The exhibits were filed in the last couple weeks, I believe, see what was there. We have been making our analysis of it, they've had that information within their control, we believe that we have a right, short of compelling them, to expect them to produce evidence that they have.

MR. CARVELL: Mr. Morrison?

MR. MORRISON: Our position is that the obligation to support Conoco's depiction lies on

Conoco. Conoco has the burden of proof and Conoco has evidence that has not been submitted and that they haven't supported the burden of proof and so the problem and how to deal with the problem really is Conoco's. What we tried to do is offer some solutions for the Commission that will enable you, some resolution ________ in short term, but nevertheless the burden of proof lies on Conoco. There is admittedly 3D seismic out there that's being reviewed by another geologist within Conoco that's had involvement with this unit and neither we nor the Commission knows what it is. They simply haven't met the burden of proof.

MR. CARVELL: Okay. Any rebuttal?

MR. BENDER: I have nothing further.

MR. CARVELL: Okay, well that will conclude the hearing in Cases 5933 and 5935. We do have one other case on the docket.

MR. NORTON: I was going to ask Bob, before we do close.

MR. WEFALD: Yes?

MR. NORTON: Let's just say the Commission ordered a third party interpret, put a unit plan together and the 800 pound gorilla doesn't agree with the interpretation? What happens then?

MR. WEFALD: I guess the Commission has the ultimate authority to reject the unit in total or I would suspect that, I know the Commission wouldn't want to get involved with it, but I would suspect that the law requires the Commission to come up with a fair, equitable and reasonable distribution that you could in fact take the data and come up with a ______________ based on what's fair, equitable and reasonable.

MR. CARVELL: Okay. Okay, that will conclude the hearing on these two cases.

STATE OF NORTH DAKOTA)
)
COUNTY OF BURLEIGH)

I CERTIFY that the record of this hearing was made under my direction, and that the foregoing is a true and correct transcript of the original tape recording of said hearing; that no alterations or additions have been made to the record; and that this transcript thereof is true and correct to the best of my knowledge and belief.

DONE at Bismarck, North Dakota, this 17th day of August, 1994.

/s/ Karlene Fine
Karlene Fine
Secretary to the North Dakota
Industrial Commission

STATE OF NORTH DAKOTA)
)
COUNTY OF BURLEIGH)

I HEREBY CERTIFY that the foregoing is a true and correct transcript of the original tape recording of said hearing; and a full and complete statement of the testimony and other proceedings which it purports to contain.

DONE at Bismarck, North Dakota, this 17th day of August, 1994.

/s/ Tracy Heilman
Tracy Heilman

DRAFT

STATE OF NORTH DAKOTA | IN DISTRICT COURT

COUNTY OF STARK | SOUTHWEST JUDICIAL DISTRICT

Andrea Singer Pollack Revocable Trust, Andrea Singer Pollack, Trustee,

Appellant,

v.

The Industrial Commission of the State of North Dakota, Conoco, Inc., and all other persons having an interest in the Dickinson-Lodgepole Unit,

Appellees.

Civil No. 94C-283

. . . .

Industrial Commission's Reply Brief and Response to Motion to Produce

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I. History of the Case

1. The Dickinson-Lodgepole pool was discovered in February of 1993 with the drilling and completion of the Dickinson State No. 74 well in Section 32, Township 140 North, Range 96 West. TR. 125-26 (Zorn Test.).

2. The productive pool is relatively small, comprising not much more than about two sections of land. <u>See</u> Tabs 7, 35 of Record. The pool lies within a unique formation, that is, it is a pronounced mound feature. Tr. ________ (Hyrkas Test.)

3. After the discovery well, five more wells were drilled by Conoco in or near the Dickinson-Lodgepole pool. Three wells were completed as producers, the Kadrmas No. 75 well, the Frenzel No. 79 well, and the State A No. 83 well. The non-producing wells, the Filipi No. 76 and the Walton No. 84, were plugged and abandoned. TR. 126-28 (Zorn Test.).

4. By October of 1993 Conoco concluded that the reservoir pressure would quickly drop and would damage the productivity of the field if some form of pressure maintenance were not undertaken. <u>Id.</u> at TR. 133, 140-41. Conoco reduced production to prevent reservoir pressure from falling too quickly. <u>Id.</u> at TR. 134, 136. Conoco also recognized that a secondary recovery program was needed to ensure that the field was efficiently developed. <u>Id.</u> at TR. 135-36.

5. Conoco estimated ~~that~~ a secondary recovery project would extend life of the field ~~form~~ from 12.3 years to 17.3 years and recover an additional 2.48 million barrels of oil. It also estimated that

an additional $9 million would be earned by working interest owners as a result of secondary recovery and that payments to royalty owners would increase by $2.6 million. Id. at TR. 142, 145-46.

6. Conoco then began working with the other 13 working interest owners in the area to put together a plan of unitization. Id. at TR. 10-13, 25. The plan of unitization was eventually ratified by 6 working interest owners. Id. at TR. 26. Other than Conoco, these working interest owners each owned less than 1% of the unit. Id. at TR. 26. Conoco's interest is about 73%. Id. at TR. 30. Conoco next sought ratification by mineral owners. Of the 102 royalty interest owners in the pool, 48 ratified the plan. Id. at TR. 27. Conoco, besides being the working interest owner, also owns a royalty interest in the pool, which amounts to about 4%. ? 77% Id. at TR. 36. About 86% of the royalty owners and about 70% of the working interest owners ratified the plan of unitization. TR. at 14 (Turner Test.).

7. In April of 1994 Conoco filed its application with the Industrial Commission requesting approval of the plan of unitization. Tab 1 of Record.

8. The unit proposed by Conoco included 1,436 acres. TR. 19 (Turner Test.). The unit is within at least a part of six different sections of land and is divided into nine different tracts. A visual depiction of the unit is at tabs 7 and 35 of the Record. A description of the mineral owners and working interest owners in each of the nine tracts is set forth at tabs 38 and 41 of the Record.

9. The Andrea Singer Pollack Revocable Trust (hereafter "the Trust") filed a response to Conoco's petition. Tab 30 of Record. The response stated that while unitization is necessary for an effective and economic recovery of hydrocarbons in the pool, Conoco's proposal is not equitable to all working and royalty interest owners.

10. A hearing on Conoco's application was held on June 8, 1994. Appearing to resist Conoco's application were Placid Oil Co. as well as the Trust.

11. Placid's interest in the area of unitization is in the S½ of Section 30 the N½ of Section 31, that is, on the NW side of the unit. TR. 180 (Bressler Test.); Tab 38 of Record. The Trust's interest lies in the S½ of the Section 31, that is, on the west side of the unit. Tab 38 of Record.

12. Placid and the Trust believe the area should be unitized, but objected to Conoco's application on the ground that the boundaries of the unit, as proposed by Conoco, do not accurately reflect the productive boundaries of the pool. TR. 178 (Bressler Test.); TR. 247 (Preston Test.).

13. At the hearing, Conoco, Placid, and the Trust all presented witnesses and exhibits in support of their positions. Placid and the Trust argued that the boundaries of the unit should be redrawn. If they were to be redrawn, Placid and the Trust would receive a greater allocation of the unit production and Conoco would receive a lesser amount. Placid and the Trust also argued that Conoco had in its possession evidence that it did not present at the hearing but should have been presented because it would shed

more light on the boundaries of the pool. That evidence is 3D seismic data.

14. Conoco submitted testimony and exhibits supporting its view of the boundaries of the productive pool. It responded to the requests for production of its 3D seismic data by presenting evidence that 3D seismic would not assist in delineating the boundaries of the pool. Conoco stated that 3D seismic is useful only as an exploration tool and not as a tool to delineate the ~~pool~~ boundaries of the Dickinson-Lodgepole Pool.

15. After the hearing, on June 15, 1994, Conoco submitted to the Commission a reply to the Trust's pre-hearing "Response" to the Conoco's application. Tab 99 of Record.

16. On June 16, 1994, the Industrial Commission issued its Order. Tab 100 of Record. The Commission found Conoco's view about the usefulness of 3D seismic and the pool boundaries to be more credible than Placid's and the Trust's view. Therefore, it granted the application.

17. The Trust and Placid then filed Petitions for Reconsideration. Tabs 101 and 102 of Record. On July 18 Conoco filed a Response to the Petitions for Reconsideration. Tab 104 of Record. On July 21 the Trust filed a Reply to Conoco's Response. Tab 105 of Record. Attached to the Trust's Reply were a number of journal articles discussing the use of seismic data. Tab 106 of Record. None of these articles had been made part of the record at the hearing.

18. The Commission had intended to make its decision on the Petitions for Reconsideration on July 21, the day on which it

received the Trust's Reply. In light of the Trust's submission, the Commission delayed its decision on the Petitions for Reconsideration to give it an opportunity to study the Trust's Reply. Tab 107 of Record.

19. On August 3, 1994, the Commission issued its Order denying the Petitions for Reconsideration. Tab 108 of Record. The Order responded to the arguments raised by Placid and the Trust in their Petitions for Reconsideration. It also declined to reopen the hearing record to allow the journal articles submitted by the Trust to become part of the record.

20. The Trust appealed the Commission's decision. Tab 109 of Record. Placid did not appeal.

II. Discussion

A. Standard of the Review.

"The court is to sustain the Commission's order 'if the Commission has regularly pursued its authority and its findings and conclusions are sustained by the law and by substantial and credible evidence.'" Hanson v. Industrial Commission, 466 N.W.2d 587, 590 (N.D. 1991). To satisfy this substantial evidence test there need only be evidence in the record that a reasonable mind would accept as adequate to support the order. Id. The evidence needed to support the order need not rise to the standard of "the greater weight of the evidence" or to the standard of a "preponderance of the evidence." Id.

The substantial evidence test is more easily met than the typical standard of review of administrative decisions. Id. Greater deference is given by courts to the Industrial Commission's decisions. Id. Because of the technical nature of the Commission's work, its decisions are "entitled to respect and appreciable deference." Id. at 591. See also Montana-Dakota Utilities Company v. Public Service Commission, 413 N.W.2d 308, 312 (N.D. 1987).

? I'm not sure you would call this results. Have they processed all the seismic data?

B. The Non-production of Conoco's 3D Seismic Data.

Conoco has in its possession the results of 3D seismic work done in the area. Conoco did not rely upon this information in putting together the plan of unitization or in presenting its evidence. The Trust argues that the 3D data could have helped to accurately locate the boundaries of the pool, and because Conoco did not produce the data, the adverse inference rule of Colgate-Palmolive Co. v. Dorgan, 225 N.W.2d 278, 281 (N.D. 1974), applies.

The adverse inference rule for non-production of evidence may no longer exist. "[T]he availability of modern discovery and other disclosure procedures serves to diminish both the justification and the need for the inference." 2 McCormick on Evidence 186-87 (4th ed. 1992). In light of modern procedural rules for discovery, the court in Jones v. Otis Elevator Co., 861 F.2d 655, 659 n.4 (11th Cir. 1988), questioned the continued need for such inferences. For the same reason the Fifth Circuit Court of Appeals referred to the similar "uncalled-witness rule" as "an anachronism" and an "archaism." Herbert v. Wall-Mart Stores, Inc., 911 F.2d

1044, 1049 (5th Cir. 1990). In Jenkins v. Bierschenk, 333 F.2d 421, 425 (8th Cir. 1964), the court affirmed the trial court's refusal to draw the inference for non-production of the defendant's son in part because "[n]o discovery procedure as to [the son] was employed."

Discovery in administrative proceeding can be as comprehensive as that available in judicial proceedings. Upon a showing of good cause, the Commission had authority to allow the Trust to undertake discovery, including interrogatories, depositions, and requests for production. N.D.C.C. § 28-32-09(4)(5). The Trust could also have asked the Commission to itself subpoena the production of the 3D seismic data for use at the hearing, which the Commission had authority to do upon a showing by the Trust of "general relevance and reasonable scope of the evidence sought." N.D.C.C. § 28-32-09(2).

The Trust did not invoke the discovery provisions of chapter 28-32. Thus, it is questionable whether the adverse inference rule applies. The Trust knew Conoco would not present the 3D data at the hearing, as it stated in its pre-hearing brief. Tab 30 of Record at 3. Thus, responsibility for non-production does not fall entirely on Conoco. The Trust should not benefit from a circumstance which it may have been able to avoid by using the procedural tools at its disposal.[1]

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[1]The Trust states that in its pre-hearing brief it "challenged the Commission to order the production of 3D seismic data." Trust Brief at 14. We are not clear what is meant by "challenging" the Commission and what its legal significance is for the purposes of this appeal, but what is clear is that in its pre-hearing brief the Trust did not request the commission to order production of the 3D seismic, all it did was state that "the Industrial Commission can

Even if the rule applies, courts "often counsel caution" in its application. 2 McCormick on Evidence 186 (4th ed. 1992). E.g. Jenkins v. Bierschenck, 333 F.2d at 425. The reason for this is because the rule creates evidence from non-evidence. Some courts decline to apply the rule because it calls for speculation about what the non-produced evidence may show. E.g. Oliphant v. Snyder, 147 S.E.2d 122, 126 (Va. 1960). Other courts state that all that can be inferred is that the non-produced evidence would not have been helpful to the party possessing it, and not that it would have been adverse. E.g. United States v. Busic, 587 F.2d 577, 586 (3rd Cir. 1978).

Assuming, however, that the inference applies, it is "open always to explanation by circumstances which make some other hypothesis a more natural one than the party's fear of exposure." 2 Wigmore on Evidence 192 (___ ed. 1979). At the hearing it was made clear that this seismic data has commercial value. TR. _____ (Bressler Test.); TR. ____ (__________ Test.). Had Conoco made the data a matter of public record, Conoco would have lost the competitive advantage of being the only operator in the area with this information.

More fundamentally, the 3D seismic data was not produced because it would not be helpful in delineating the boundaries of the productive pool and, therefore, in determining what land should be included within the unit. Conoco presented two witnesses in support of this conclusion. Jerry Hyrkas stated that seismic is "not a good tool at all for the defining reservoir boundaries."

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force its disclosure." Tab 30 of Record, Brief at 3.

TR. 61 (Hyrkas Test.). See also id. at TR. 111-13, 118. Hyrkas is a senior geoscientist with Conoco. Id. at 44. Another Conoco witness, Greg Mohl, also testified that 3D seismic has limited usefulness in detecting pool boundaries. Mohl, a senior geophysicist with Conoco, has a bachelor's, master's and doctor of philosophy degrees in geology. TR. 258 (Mohl Test.). He has worked with seismic for 7 years. Id. at 268. He has taught "several short courses" on a number of seismic related subjects and worked on seismic projects every day. Id. at 259. Mohl testified that the use of seismic is "totally inappropriate" for delineating the boundaries of ~~a pool~~ the Dickinson-Lodgepole Pool and the area to be included within ~~a~~ the unit. Id. at 260, 269. He supported his conclusions with an extensive discussion of the matter. Id. at 260-269.

Mohl set forth three reasons why 3D seismic data would not be of material use. The first concerns the physical properties of the Lodgepole. Mohl noted that although Placid and the Trust assert the usefulness of 3D seismic data in other areas of the Williston basin and the country, neither discussed the physical properties of the Lodgepole and whether its characteristics allow for an accurate interpretation of seismic. Id. at 260. To support his view that the Lodgepole's physical properties would not support accurate use of seismic, Mohl compared the sonic log of the Kadrmas well, which is in the productive pool, with the sonic log of the Frenzel well, which did not penetrate the productive pool. Id. at 261-62. Mohl found that the velocity contrast between the productive and the non-productive pool to be "seismically invisible." Id. at 263.

Mohl's second concern about using seismic dealt with seismic wave theory. Id. at 264-67. In essence, he testified that the resolution of seismic data has weaknesses. When seismic wave interacts with the edge of a pool they interact with "in effect, the seismic blind spot." Id. at 265. The resolution of 3D seismic is insufficient to pick where a productive pool begins and where it ends. The third reason Mohl found to reject the use of seismic to select land to include within a unit, is its highly interpretative nature. "Without exception this has been highly interpretive. It's very sensitive to the individual rock properties. It's also sensitive to the acquisition parameters of the seismic data and the processing of the seismic data . . . The bottom line is that work of this nature is very good for exploration. It can give you a general shape for, for what you're looking at and point you in the right directions." Id. at 268.

The uncertain nature of seismic data is proven by maps submitted by Placid and the Trust. Each used the same ~~3D~~ was actually 2D seismic information in preparing the maps. TR. 233, 240 (Gomez Test.). While the trust describes the results as "strikingly similar," Trust Brief at 21, the Commission found distinctly different. Tab 100 of Record at ¶ 15. They differ in six ways, the first two of which are they are particularly significant. (The maps are shown side by side on page 4 of the Trust's "Supplemental Record.")

1. The Trust's map depicts a "saddle" in the middle of the pool. A "saddle" is a thinning of the productive zone. Placid's map does not show a "saddle."

2. The Trust shows a high to the west of the Kadrmas well (and thus smack in the middle of

the only tract in which the Trust owns an interest). Placid shows the high to be located much farther to the east, straddling sections 31 and 32.

3. The Trust shows the pool extending farther to the west than does Placid.

4. Placid shows the pool extending farther to the north and northeast than does the Trust.

5. Placid shows the pool extending farther to the east than does the Trust.

6. The Trust's contour lines east of the State No. 74 well are drawn much more sharply than are Placid's contour lines.

Using the same seismic data, Placid and the Trust drew distinctly different maps, thus giving us an example of the limits of seismic data to determine the boundaries of a productive pool.

While Placid and the Trust presented witnesses that disagreed with Hyrkas and Mohl, the substantial evidence test is satisfied. There is in the record, evidence a reasonable mind would accept as adequate to support the Commission's conclusion that 3D seismic is not useful to locate the pool boundaries. Because of its technical nature the court is to give conclusion deference and is not to substitute its "judgment for that of the expert." Haugland v. Spaeth, 476 N.W.2d 692, 695 (N.D. 1991). In summary, Conoco's non-production of the 3D seismic data is explained and the adverse inference rule does not apply.

This dispute among the experts is not like what occurred in Hanson v. Industrial Commission where the Supreme Court reviewed conflicting expert testimony. The court ruled that since there was relevant evidence that a reasonable mind might accept, the Commission's conclusion based on that evidence would not be overturned. "The possibility of drawing two inconsistent conclusions from the evidence does not prevent the findings from being supported by substantial evidence." Hanson v. Industrial Commission, 466 N.W.2d 587, 592 (N.D. 1991).

The Trust asks the court to go outside the hearing record to draw the adverse inference. It wants the court to review journal articles the Trust attached to its second brief in support of its petition for reconsideration. Tab 106 of Record. In its order denying the petition the Commission stated: "The Trust submitted with its reply brief copies of a number of journal articles concerning the use of 3D seismic. There is no evidence that the areas discussed in the articles bear any similarity to the characteristics of the Dickinson-Lodgepole Pool. Without such evidence the articles are unhelpful, if not irrelevant. Furthermore, there is no reason why these articles could not have been submitted into evidence at the hearing. The Commission declines to reopen the case to make these part of the record." Tab 108 of Record at 3.

The Trust has gone further outside the record by filing with the court certain documents in its "supplemental record." It filed an affidavit of someone who did not appear at the hearing and exhibits and an administrative order from a Wyoming case. None of these matters were submitted for the Commission's review before, during, or after the hearing.

The court, however, may "consider only the record which was before the [agency], the transcript of the formal hearing, and any evidence presented at the hearing." Hayden v. North Dakota Workers

Compensation Bureau, 447 N.W.2d 489, 497 (N.D. 1989). *See also* N.D.C.C. § 28-32-19; *Lipp v. Job Service North Dakota*, 468 N.W.2d 133, 134 (N.D. 1991); *Smith v. North Dakota Workers Compensation Bureau*, 447 N.W.2d 250, 256-57 (N.D. 1989). In *Knutson v. North Dakota Workmens Compensation Bureau*, 120 N.W.2d 880 (N.D. 1963), the district court increased the Bureau's award to a claimant and in doing so reviewed new evidence. Since the award was not based on the record before the Bureau, *id.* at 882, and since the Bureau "had not opportunity to pass on such additional evidence," *id.* at 883, the district court was reversed.

There is a statutory procedure by which evidence not presented at a hearing can be presented to the agency. This is set forth in N.D.C.C. § 28-32-07. The Trust did not comply with this procedure. It merely submitted the journal articles. Tab 106 of Record. There is no procedure by which an appellant can petition a court for an order requesting that another party produce evidence. The court has no jurisdiction to enter what is in effect a discovery order. The court, in this case, is an appellate court. Its decision is confined to the record produced below, and that record is closed.

The Trust relies upon N.D.C.C. § 28-32-18 ~~has~~ to have authority for the court to grant its motion to compel production of the 3D seismic. That section allows the court to grant an application to *offer* additional evidence, upon a showing that the evidence is relevant and material and there was good cause for the failure to offer it at the hearing. Nothing in the statute, however, allows the court to grant a motion ordering another party to produce evidence.

C. The Boundaries of the Pool.

The Trust argues that the configuration of the unit as proposed by Conoco and approved by the Commission is in error. In particular, the Trust believes the unit's eastern boundary is located too far to the east in Section 32. ~~It also believes the west boundary should have been moved farther to the west.~~ The Trust actually has their western edge farther east than Conoco's.

The Trust argues that because Conoco has a greater interest in tract 1 of the unit, which is in Section 32, than it does in tract 2, it "has a vested interest in pushing the boundary eastward as much as possible." Trust Brief at 19. There is a bit of irony in such a statement. The Trust's only interest in the unit is in tract 2, Tab 38 of Record, which is on the west side of the unit. If the unit's ~~western~~ eastern boundary were moved farther to the west the Trust would receive a greater allocation of unit production.[2]

The Trust argues that the unit is inequitable because of the way in which the productive pool is configured. The Commission in its two orders made a number of findings related to this question. The Trust raises about six challenges to these findings. Trust Brief at 20-26. It is concerned with such matters as the location of the oil/water contract, the use of Conoco's reservoir modeling study in determining allocation of unit production, the accuracy of

[2]Likewise with Placid. Its only interest lies in tracts 2 and 3, Tab 38 of Record, which are on the northwest side of the unit. It sponsored an interpretation of the geology that would have moved the unit boundaries farther to the northwest. Tab ___ of Record.

Should this still be footnoted even though above was deleted?

the ~~perasity~~ porosity and oil saturation factors in Conoco's volumetric calculation, and the usefulness of using information from the Fryburg~~h~~ Interval to help understand the Lodgepole.

The essence of the Trust's argument on these points is that its witness should be believed rather than Conoco's. It does little, if anything, to explain why its witnesses are more credible than Conoco's and why the Commission acted unreasonably in agreeing with Conoco's interpretation of the geology.

III. Conclusion

The Trust's motion to produce should be denied. There is no authority allowing the court to issue the order requested, the information sought is not material, and the Trust neglected to use the methods given to procure such data. On appeal is not the time to put together a factual case.

The Commission's decision to approve the Dickinson-Lodgepole Unit should be upheld. The substantial evidence test has been met. It is reasonable for the Commission to have accepted Conoco's evidence over the Trust's.

e:\nr\carvell\pollack.brf

Order

On June 16, 1994, the Industrial Commission issued Order No. 6861 in this case. Two interested parties have asked the Commission to reconsider its decision. Placid Oil Company filed a petition for reconsideration on June 30, 1994. The Andrea Singer Pollack Revokable Trust (hereafter "the Trust") filed a petition for reconsideration on July 1, 1994. On July 18, 1994, Conoco Inc. filed a response to the petitions.

In their petitions, Placid and the Trust set forth the reasons why they believe the Commission erred in granting Conoco's request to unitize the Dickinson-Lodgepole Unit Area. The Commission has studied each of Placid's and the Trust's arguments and reviewed the record of the case. The Commission believes that its decision in Order No. 6861 is the best and fairest interpretation of the evidence. It declines, therefore, to withdraw or stay Order No. 6861, or to reopen the record to take additional evidence. The petitions are denied. Our reasoning follows.

The Trust argues that Findings 14 and 16 in Order No. 6861 are wrong because the Trust used not only seismic interpretation to delineate the productive boundaries of the reservoir but also well data, and that Finding 17 is wrong because seismic interpretation can identify a reservoir's productive boundaries. Findings 14 and 16 refer to the specific location of the productive reservoir, and the Commission reaffirms that the Trust interpreted, and testified that it interpreted, only seismic data to specifically identify the location of the boundaries of the productive reservoir. The Commission agrees with Conoco that seismic data is an unreliable method to locate the Dickinson-Lodgepole reservoir boundary, because there is very little velocity contrast between the productive and nonproductive Lodgepole. The Commission also agrees with Conoco's response to the petitions, that Placid and the Trust merely submitted maps based on seismic interpretations and no raw seismic data was submitted into the record.

Placid also argues that Findings 16 and 17 are erroneous. It believes Finding 16 is wrong, asserting that Placid did introduce seismic information to identify the productive reservoir. Perhaps Finding 16 should have been written more clearly, for Placid (and the Trust) seems to misunderstand it. Finding 16 states that the Commission did not receive evidence proving that seismic data can be used to identify the productive reservoir. The evidence accepted by the Commission was just the opposite, as expressed in Finding 17. Placid believes that Finding 17 is inconsistent with the basis upon which Conoco proposed the unit. Placid's argument misinterprets the word "mound" to be synonymous with "reservoir." The Commission, however, uses the word "mound" to include not only the reservoir quality rock, but also any associated deposition found around the perimeter of the reservoir quality rock.

Placid challenges Finding 24 and its conclusion that the allocation of the unit is fair. Placid did not propose what it believes would be a fair allocation. More importantly, the allocation is based on Conoco's interpretation of the geology and it is that interpretation that the Commission has found to be more reliable than Placid and the Trust's.

The Trust argues in Paragraph 7 of its petition that the Commission erred in relying on information of the Fryburg Interval to locate the boundaries of the Lodgepole Pool reservoir. In particular, the Trust states that the Fryburg map has nothing to locate its western edge. The Frenzel

79 and Walton 84 provide data points to help identify the western edge. The last two sentences of Paragraph 7 of the Trust's petition are factual assertions or interpretations not made at the hearing and the Commission will not use them as a basis to reopen this case and reconsider its decision.

The Trust argues that Findings 19 and 20 "are totally without basis." Conoco adequately explained the relationship between the Fryburg Interval and the Lodgepole Pool and how data from the Filipi No. 76 can aid in locating the eastern boundary of the productive reservoir. We will not repeat Conoco's arguments, which we found to be persuasive.

Placid also challenges Findings 19 and 20, as well as Finding 18. However, the Trust argues that Finding 22 "is essentially irrelevant" and Placid says it is unsupported. While a volumetric calculation is not definitive in locating a reservoir, it can confirm geologic interpretations and the volumetric calculation here confirms Conoco's interpretation. Its use in this way was supported by testimony from Conoco.

The Trust asks that Conoco's 3D seismic data be produced and made part of the record. This is a red herring. Since seismic data cannot identify the productive reservoir there is no purpose in requiring Conoco to produce it for consideration in this case.

Placid argues that the Commission erred by failing to set forth equitable terms for development outside the unit. Existing spacing outside the unit remains in effect and any adjustments to that spacing were not properly before the Commission in this case.

The Trust argues in Paragraph 7 of its petition, that the Commission erred in relying on information of the Fryburg Interval to locate the boundaries of the Lodgepole Pool reservoir. In particular, the Trust states that the Fryburg map has nothing to locate its western edge. The Frenzel 79 and ~~Walter~~ Welton 84 [redacted] provide data points along the western edge. The last two sentences of Paragraph 7 of the Trust's petition are factual assertions or interpretations not made at the hearing.

The Trust argues that Findings 19 and 20 "are totally without basis." Conoco adequately explained the relationship between the Fryburg Interval and the Lodgepole Pool and how data from the Filipi No. 76 can aid in locating the eastern boundary of the productive reservoir. We will not repeat Conoco's arguments, but they are persuasive.

Note Lawrence's comment incorporate his statement

The Trust argues that Find 22 "is essentially irrelevant." While Conoco's volumetric calculation is not definitive, it helps confirm geologic interpretations and here it confirms Conoco's interpretation.

The Trust asks that Conoco's 3D seismic data be produced and made part of the record. This is a red herring. Since seismic data cannot identify the productive reservoir there is not purpose in examining it.

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NO. 5933

IN THE MATTER OF THE PETITION OF CONOCO INC. FOR AN ORDER PROVIDING FOR THE UNITIZED MANAGEMENT, OPERATION, AND FURTHER DEVELOPMENT OF THE DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION; VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE.

AFFIDAVIT OF SERVICE BY MAIL

STATE OF NORTH DAKOTA)
) ss.
COUNTY OF BURLEIGH)

Lyn Entzi, being first duly sworn, deposes and says that on the *15th* day of June, 1994, she served the attached:

REPLY OF CONOCO INC. TO "RESPONSE OF ANDREA SINGER POLLACK REVOCABLE TRUST"

by placing a true and correct copy thereof in an envelope addressed as follows:

Mr. John W. Morrison, Jr.
Attorney at Law
400 E. Broadway, Suite 600
P. O. Box 2798
Bismarck, ND 58502-2798

Mr. Robert Wefald
Attorney at Law
P.O. Box 1
Bismarck, ND 58502-0001

and depositing the same, with postage prepaid, in the United States mail at Bismarck, North Dakota.

Lyn Entzi-Odden

LYN ENTZI-ODDEN

Subscribed and sworn to before me this *15th* day of June, 1994.

ROSALINDE KIENZLE, Notary Public
Burleigh County, North Dakota
My Commission expires: 05-23-95
ROSALINDE K. KIENZLE
Notary Public STATE OF NORTH DAKOTA
My Commission Expires MAY 23, 1995

Doug Kadrmas
2314 25 1/2 Avenue South
Fargo, ND 58103
June 6, 1994

Wesley McMillen
North Dakota State Industrial Commission
600 East Boulevard
Bismarck, ND 58505

Dear Mr. McMillen

I am a royalty interest owner in the Dickinson-Lodgepole formation. Conoco Inc. is proposing unitization of this formation. As I understand it, unitizing will allow the recovery of approximately one third more oil with the use of secondary recovery. Usually what is in the best interests of the oil companies is in the best interests of the royalty owners. This appears to be the case with Conoco's secondary recovery plans.

I am in favor of the unitization of the Dickinson-Lodgepole formation.

Sincerely,

Doug Kadrmas

Doug Kadrmas

ARS CONTROL ACCOUNT
LIMITED PARTNERSHIP
P.O. BOX 22854
DENVER, COLORADO 80222
(303) 756-6560

JUN 1994
RECEIVED
ND OIL & GAS
DIVISION

June 6, 1994

Mr. Wes Norton, Director
Oil & Gas Division
North Dakota Industrial Commission
600 East Boulevard
Bismarck, North Dakota 58505-0840

RE: Case No. 5933
Conoco Unitization Proposal
Dickinson-Lodgepole Unit Area
Stark County, North Dakota

Dear Mr. Norton,

ARS Control Account Limited Partnership (ARS), a working interest owner in the proposed Dickinson-Lodgepole Unit, submits the following comments for your consideration pertaining to the approval of Case No. 5933:

1) ARS agrees that unitization of the Dickinson-Lodgepole Pool area is necessary to effectively increase the ultimate recovery of hydrocarbons from the Dickinson-Lodgepole Pool.

2) ARS agrees that adoption of a secondary recovery method of operation is necessary to provide the landowners, the royalty owners, the producers, and the general public with the greatest possible economic recovery of oil and gas.

3) ARS **does not agree** with the plan of unitization presented in Conoco's Unit Agreement and Unit Operating Agreement.

4) ARS **does not agree** the plan of unitization proposed by Conoco contains fair, reasonable and equitable provisions for representation of the interests of the landowners, royalty owners, the producers, and the general public.

In summary, ARS requests that Conoco's petition for an order, Case No. 5933, either be denied or be continued until such time as a plan of unitization is presented which provides for fair, reasonable and equitable representation of the landowners, royalty owners, the producers, and the general public in accordance with NDCC 38-08-09.4 (2).

ARS believes a continuance or a denial at this time would serve the best interests of all participating owners, including the State of North Dakota. Thank you for consideration of these comments. And thank you for consideration of this request to deny or continue Case No. 5933.

Respectfully yours,

ARS CONTROL ACCOUNT LIMITED PARTNERSHIP

Martha Dixon Sundby

Martha Sundby, Vice President of
Queenstown Oil & Gas, Inc., General Partner

/bs

JUN 1994
RECEIVED
ND OIL & GAS
DIVISION

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NO. 5933

IN THE MATTER OF THE PETITION OF CONOCO INC. FOR AN ORDER PROVIDING FOR THE UNITIZED MANAGEMENT, OPERATION, AND FURTHER DEVELOPMENT OF THE DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION; VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE.

REPLY OF CONOCO INC. TO "RESPONSE OF ANDREA SINGER POLLACK REVOCABLE TRUST"

Conoco Inc. ("Conoco"), petitioner in the above-captioned matter, hereby submits this reply to the response filed on June 6, 1994 by the Andrea Singer Pollack Revocable Trust ("the Trust").

1. **There is no evidence to support the conclusion that the Dickinson-Lodgepole plan of unitization is not fair, equitable and reasonable.**

The Trust indicates its opposition to the application of Conoco as follows: "the division of the interest and the formulation for the apportionment and allocation of the unit production . . . will not allow the Tract 2 royalty owners or the Andrea Singer Pollack

Revocable Trust to receive their fair, equitable and reasonable share of the unit production or other benefits thereof."[1] Response of Trust at 2.

The Trust, however, provides absolutely no support for this conclusion. Neither its response nor the brief in support thereof submitted by the Trust points to any evidence which suggests that the plan of unitization for the Dickinson-Lodgepole Pool will not result in fair, equitable and reasonable share of production of oil and gas from the proposed unit area.

The only evidence in the record which the Trust can reasonably point to as support for its contention is the testimony, at the June 8, 1994 hearing of this matter, of its engineering witness, Mr. Kevin Preston. Mr. Preston testified as to a discrepancy between the amount of primary reserves allocated to Tracts 1-4 in Conoco's equity formula and the recovery predicted by the reservoir model.

On cross examination, however, Mr. Preston admitted that while he is familiar with the basic concepts of reservoir modeling, the extent of his experience is limited to reviewing the work of others and that he has absolutely no experience in selecting model parameters, running the computer program and adjusting the parameters for the model during the runs.

On the other hand, Mr. Kevin Zorn, Conoco's expert engineering witness, has extensive experience in reservoir simulation modeling and he testified that he was involved in all aspects of the modeling conducted on the Dickinson-Lodgepole Pool. Mr. Zorn further testified that Conoco's computer reservoir simulation model was not designed for

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1 It is interesting to note the Trust's concern for the royalty owners in and under Tract 2 considering that 75.29933% of said owners have ratified the unit agreement and support the application of Conoco in this matter.

the purposes of calculating equity. Due to the simplistic assumptions contained within the reservoir model, the model is only useful in comparing various different operating scenarios on a field-wide scale, such as water flooding, gas injection and primary depletion.

Further, Mr. Zorn testified that while the recovery factor predicted by the model was utilized in the equity formula for determining remaining primary, that recovery factor was applied uniformly to all nine tracts. Therefore, on a relative basis, any recovery factor could have been utilized and applied to the tract participation factors. The fact that the recovery factor was determined by the model is therefore not justification for utilizing the model for equity purposes.

2. **The "adverse inference rule" is inapplicable in this case.**

The Trust also asserts that because Conoco has chosen not to disclose certain 3D seismic data, the Commission must presume that the data is unfavorable to Conoco. The Trust's Brief at 3. In so asserting, the Trust relies upon the case of Colgate-Palmolive Company v. Dorgan, 225 N.W.2d 278 (N.D. 1974). The Trust misstates the rule of law established in Colgate-Palmolive.

In Colgate-Palmolive, the issue before the North Dakota Supreme Court was the application of the "adverse inference rule." Citing Wigmore on Evidence, the court held that the adverse inference rule "provides that nonproduction of relevant evidence in the control of a party permits an inference that the evidence is unfavorable to that party's cause." Colgate-Palmolive at 4. (Emphasis added.) Here, the Trust suggests that the adverse inference rule requires an automatic presumption that the seismic data is unfavorable and that Conoco "has the burden of rebutting that presumption." The Trust's Brief at 3.

Contrary to the Trust's assertion, the adverse inference rule does not create an automatic presumption. Rather, the rule permits an inference that undisclosed evidence is unfavorable, unless satisfactory explanation is offered for not disclosing the evidence. 29 Am Jur § 178 (1967).

The evidence submitted at the hearing of this matter clearly establishes Conoco's rationale for choosing not to disclose the seismic data and demonstrates why the adverse inference rule is inapplicable in this case. First, because of the physical properties of the Lodgepole formation, utilizing seismic, 3D or 2D, to pick the productive reservoir edges of the Dickinson-Lodgepole Pool is simply not possible. As Conoco's expert witness, Mr. Greg Mohl, testified, sonic logs run through the Lodgepole interval at Dickinson show no appreciable velocity contrast between productive and non-productive reservoir within the Lodgepole stratigraphic section. Because the productive reservoir is virtually invisible to seismic, a seismic interpreter must rely on wave form anomalies in order to project where the edge of the reservoir will be located. Mr. Mohl testified that basic seismic wave theory proves that there will be a radius of uncertainty which could exceed one thousand feet. Within this radius no one can pick the edge of a reservoir with reasonable certainty. Mr. Mohl therefore concluded that seismic data is an inappropriate tool for determining the reservoir edges in the Dickinson-Lodgepole Pool.

The geologic maps presented by Placid and the Trust also demonstrate the extremely interpretative nature of seismic and the inappropriateness of using such data to pick reservoir edges. Although both Placid and the Trust had experts interpreting the same seismic data, they reached totally different conclusions as to where the edges of the reservoir are located. If Conoco's 3D data were used as a basis for drawing maps for unitization, the result would be the same; each interpretation would yield a different result. Conoco was, therefore, justified in not utilizing seismic in reaching its interpretation of the reservoir boundaries.

Conoco's actions in not utilizing seismic to support its case is further justified by the fact that its 3D seismic program was conducted as an exploration tool. On direct examination, Mr. Bressler, Placid's geologist, admitted that his company is actively involved in exploration of the Lodgepole and has shot their own 3D seismic in Dunn County, North Dakota. It is common knowledge that seismic analogs over known productive fields are a useful tool to lower the geologic risk of identifying and drilling new prospects. Conoco has a distinct competitive advantage over industry competitors in the area because of its 3D data at Dickinson. Conoco would jeopardize its advantage by simply giving away its seismic analog to competitors such as Placid and the Trust.

The third reason offered by Conoco for not offering its 3D seismic data is that the data has not been completely analyzed or interpreted. Mr. Jerry Hyrkas, Conoco's geologic witness, testified that Conoco's 3D seismic data was acquired in December of 1993. Due to severe weather conditions during this time period, some of the data was mishandled. The mishandling of the data greatly lengthened the time required for computer processing of the data. Conoco did not receive the entire data set in its Casper Division Office for interpretation on a computer work station until mid-May, approximately two weeks after application for unitization of the Dickinson-Lodgepole Pool was filed with the Commission. It is simply unknown how much time will be necessary to analyze and interpret this data.

Considering the inaccuracy of seismic data, the fact that Conoco's 3D seismic was shot to give it a competitive edge in exploration activities and the fact that the data has not been completely analyzed, Conoco is justified in not utilizing this data for unitization purposes. Accordingly, the adverse inference rule is not applicable in this case.

CONCLUSION

For all the foregoing reasons, the requests of the Trust should be denied and the application of Conoco for unitization of the Dickinson-Lodgepole Pool should be granted.

DATED this *15th* day of June, 1994.

PEARCE & DURICK

By ______________________
LAWRENCE BENDER
Attorneys for Applicant,
Conoco Inc.
314 E. Thayer
P. O. Box 400
Bismarck, ND 58502-0400
(701) 223-2890

HUNTINGTON RESOURCES, INC.
8086 S. YALE, SUITE 228
TULSA, OK 74136
(918) 252-5294
FAX (918) 250-6716

June 6, 1994

Mr. Wesley Norton
North Dakota Industrial Commission
600 E. Boulevard
Bismark, ND 58505

RE: **Dickinson - Lodgepole Unit, Stark County, ND**
Case #5935

Dear Mr. Norton:

Huntington Resources, Inc. is a working interest owner in the Frenzel #79 located at N/2 Section 31-140N-96W and drilled by Conoco. HRI is in favor of unitizing the lodgepole formation but we strongly disagree with Conoco's "Lodgepole Isopach Map" used to determine ownership. There is substantial evidence showing the lodgepole trending farther north and west than shown on Conoco's map. Therefore, we are opposing the unitization of the lodgepole until further evaluation has been done to determine the proper boundaries of the lodgepole.

Please contact me should you have any questions.

Sincerely,

R. Joe Starrett

RJS:mls

Robert O. Wefald

Attorney And Counselor At Law

2800 North Washington Street
Post Office Box One
Bismarck, North Dakota 58502-0001

Phone 701-258-8945
Fax 701-255-7212

June 6, 1994

Oil and Gas Division
N.D. Industrial Commission
1022 East Divide
Bismarck ND 58501

Dear Oil and Gas Division:

Enclosed for filing in the Petition of Conoco, Inc., Case No. 5933, is the Response of the Andrea Singer Pollack Revocable Trust, the Brief in Support of the Response of the Andrea Singer Pollack Revocable Trust, and a Certificate of Service. Would you kindly file these documents. Please call me if you have any questions or comments.

Sincerely,

Robert O. Wefald

ps
enc: Response
Brief
c: Kevin Preston

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NO. 5933

IN THE MATTER OF THE PETITION OF CONOCO INC. FOR AN ORDER PROVIDING FOR THE UNITIZED MANAGEMENT, OPERATION, AND FURTHER DEVELOPMENT OF THE DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION; VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE.

RESPONSE OF THE ANDREA SINGER POLLACK REVOCABLE TRUST

The Andrea Singer Pollack Revocable Trust, by and through its attorney, Robert O. Wefald, makes this response to the above-captioned Petition of Conoco, Inc., for approval of the plan of unitization of the Dickinson-Lodgepole Pool.

1. The Andrea Singer Pollack Revocable Trust, hereby admits and concurs with the allegations of paragraphs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 15 and 16 of the Petition of Conoco, Inc.

2. Because the proposal of Conoco, Inc. is not fair, equitable or reasonable, the Andrea Singer Pollack Revocable Trust asks that the petition be denied.

3. The Andrea Singer Pollack Revocable Trust agrees in principle with the petition of Conoco, Inc., for the unitization of the Dickinson-Lodgepole Pool, because unitization would result in the most effective and economic recovery of the recoverable hydrocarbon products, but any such unitization must be done in

accordance with Section 38-08-09.4(2) of the North Dakota Century Code, so that all working interest owners and all royalty interest owners will be sure to receive their fair, equitable and reasonable share of the unit production.

4. While the proposed basic Unit Agreement and the proposed basic Unit Operating Agreement are satisfactory in their form, objective, and general provisions, Exhibit A of the Unit Agreement and Exhibit C of the Unit Operating Agreement are objected to by the Andrea Singer Pollack Revocable Trust on the grounds that the division of the interest and the formulation for the apportionment and allocation of the unit production as set forth in these exhibits, will not allow the Tract 2 royalty owners or the Andrea Singer Pollack Revocable Trust to receive their fair, equitable and reasonable share of the unit production or other benefits thereof. These exhibits as prepared and submitted by Conoco, Inc. unfairly weight the potential production away from Tract 2 in favor of Tract 1, thereby increasing the production participation of Tract 1 for the benefit of the petitioner Conoco, Inc., which owns a one hundred percent working interest in Tract 1, at the expense of Tract 2, in which Conoco, Inc., shares the working interest with the Andrea Singer Pollack Revocable Trust, each of which have a fifty percent working interest in Tract 2.

5. The supporting documentation filed by Conoco, Inc., with the Industrial Commission can also be read to substantiate a higher level of production from Tract 2.

WHEREFORE, the Andrea Singer Pollack Revocable Trust, requests that the petition of Conoco, Inc., be dismissed, or in the alternative, that the request be referred back to Conoco, Inc. and the other interested parties for the purpose of negotiating and working out a proposal which is fair, equitable and reasonable to all working interest and royalty interest owners in accordance with NDCC 38-08-09.4(2), and granting the Andrea Singer Pollack Revocable Trust such other and further relief as the Industrial Commission deems appropriate.

Dated this 6th day of June, 1994.

ROBERT O. WEFALD
Attorney for Andrea Singer Pollack
Revocable Trust
P. O. Box One
Bismarck ND 58502-0001

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NO. 5933

IN THE MATTER OF THE PETITION OF CONOCO INC. FOR AN ORDER PROVIDING FOR THE UNITIZED MANAGEMENT, OPERATION, AND FURTHER DEVELOPMENT OF THE DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION; VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE.

BRIEF IN SUPPORT OF THE
RESPONSE OF THE ANDREA SINGER POLLACK REVOCABLE TRUST

Section 38-08-01 of the North Dakota Century Code sets forth the policy of the People of North Dakota:

> It is hereby declared to be in the public interest to foster, to encourage, and to promote the development, production, and utilization of natural resources of oil and gas in the state in such a manner as will prevent waste; to authorize and to provide for the operation and development of oil and gas properties in such a manner that a greater ultimate recovery of oil and gas be had and **THAT THE CORRELATIVE RIGHTS OF ALL OWNERS BE FULLY PROTECTED**; and to encourage and to authorize cycling, recycling, pressure maintenance, and secondary recovery operations in order that the greatest possible economic recovery of oil and gas be obtained within the state to the end that the landowners, the royalty owners, the producers, and the general public realize and enjoy the greatest possible good from these vital natural resources. (Emphasis supplied)

NDCC Chapter 38-08 gives the Industrial Commission the authority to unitize the proposed Dickinson Lodgepole Unit, but the fact that the petition for a unit has been approved by seventy percent (70%) of the persons who will be required to pay the costs of the unit operation and the royalty owners (NDCC 38-08-09.5) does not relieve the Industrial Commission of its responsibility under NDCC 38-08-09.4 to see to it that ALL the royalty interest owners and ALL the working interest owners receive their "fair, equitable, and reasonable share of the unit production."

The Andrea Singer Pollack Revocable Trust agrees in principle with the petition of Conoco, Inc., for the unitization of the Dickinson-Lodgepole Pool, because unitization would result in the most effective and economic recovery of the recoverable hydrocarbon products. However, any such unitization must be done in accordance with NDCC 38-08-09.4(2), so that all working interest owners and all royalty interest owners will be sure to receive their fair, equitable and reasonable share of the unit production.

Although the basic Unit Agreement and the basic Unit Operating Agreement are satisfactory in their form, objective, and general provisions, Exhibit A of the Unit Agreement and Exhibit C of the Unit Operating Agreement do not constitute a fair, equitable or reasonable division of the unit production. These exhibits as prepared and submitted by Conoco, Inc. unfairly weight the potential production away from Tract 2 in favor of Tract 1, thereby increasing the production participation of Tract 1 for the benefit of the petitioner Conoco, Inc., which owns a one hundred percent working interest in Tract 1, at the expense of Tract 2, in which Conoco, Inc., shares the working interest with the Andrea Singer Pollack Revocable Trust, each of which have a fifty percent working interest in Tract 2.

The fact that Conoco, Inc. owns or holds proxies for more than seventy percent (70%) of the total interests does not make its proposal "fair, equitable, or reasonable." The Andrea Singer Pollack Revocable Trust participated with Conoco, Inc. and others at all meetings to develop the unit, and was at all times ready to compromise, but this final petition of Conoco, Inc. represents its decision by virtue of its more than seventy percent (70%) ownership interests and proxies.

Conoco, Inc. in these negotiations refused to show the other working interest owners or an independent third party its 3-D seismic data on this proposed unit. The Industrial Commission is justified in concluding that Conoco, Inc. is not revealing that data because it is not favorable to it. In <u>Colgate-Palmolive Company v. Dorgan</u>, 225 NW 2d 278 (ND 1974) our Supreme Court took note of the "adverse inference" rule.

> Essentially, this rule of evidence provides that nonproduction of relevant evidence in the control of a party permits an inference that the evidence is unfavorable to that party's cause. Vol. II, <u>Wigmore on Evidence</u>, 3rd Ed., §285. The rule is as much a matter of common sense and ordinary judgment as a rule of law. It has received recognition by this court. 225 NW 2d 278, 281.

Conoco, Inc. has the burden of rebutting that presumption under Rule 301 of the North Dakota Rules of Evidence. Even if Conoco, Inc. maintains that this data is its trade secret, under Rule 507 NDREv, the Industrial Commission can force its disclosure under conditions to protect Conoco, Inc.'s rights in this data.

This is a case in which the petition should be rejected, and the matter sent back to the parties to work out a mutually agreeable unitization plan.

Dated this 6th day of June, 1994.

ROBERT O. WEFALD
Attorney for Andrea Singer Pollack
Revocable Trust
P. O. Box One
Bismarck ND 58502-0001

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NO. 5933

IN THE MATTER OF THE PETITION OF CONOCO INC. FOR AN ORDER PROVIDING FOR THE UNITIZED MANAGEMENT, OPERATION, AND FURTHER DEVELOPMENT OF THE DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION; VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE.

CERTIFICATE OF SERVICE

The Response of the Andrea Singer Pollack Revocable Trust and the Brief in Support of the Response of the Andrea Singer Pollack Revocable Trust were served upon the parties listed below by hand delivering true and correct copies thereof to:

Lawrence Bender
Attorney for Conoco, Inc.
P.O. Box 400
Bismarck ND 58502-0400

John Morrison
Attorney for Placid Oil Co.
P.O. Box 2798
Bismarck ND 58502-2798

said documents having been delivered to them by the undersigned, this 6th day of June, 1994.

ROBERT O. WEFALD
Attorney for Andrea Singer Pollack
Revocable Trust
WEFALD LAW OFFICE, LTD.
P. O. Box One
Bismarck ND 58502-0001

6-2-1994

Mr. Wes Norton
ND Industrial Commission
Oil and Gas Division
600 E Boulevard
Bismarck ND 58505

Dear Mr. Norton,

I write to encourage you and the Commission to react favorably to the Conoco proposal for unitising the Dickinson Lodgepole oil reserve.

As a major mineral owner on Sec. 32, T140N, R96W, (ND State No. 74) and having reviewed the unitization plan, I feel the Conoco proposal is both equitable and prudent as they will be presented on June 8.

Thank you for your consideration in this matter.

Sincerely:

Gerald David Kalanek

Gary Kalanek
3754 Kingston Dr.
Bismarck ND 58501

HUNT PETROLEUM CORPORATION
3400 THANKSGIVING TOWER
DALLAS, TEXAS 75201
(214) 880-8800

Frank R. Howell
Vice President
Engineering

(214) 880-8960
Fax (214) 880-8951

May 27, 1994

Mr. Wes Norton
Oil and Gas Division
North Dakota Industrial Commission
600 East Boulevard
Bismarck, North Dakota 58505-0840

RE : **Case #5935**
Dickinson-Lodgepole Unitization
Stark County, North Dakota

Dear Mr. Norton,

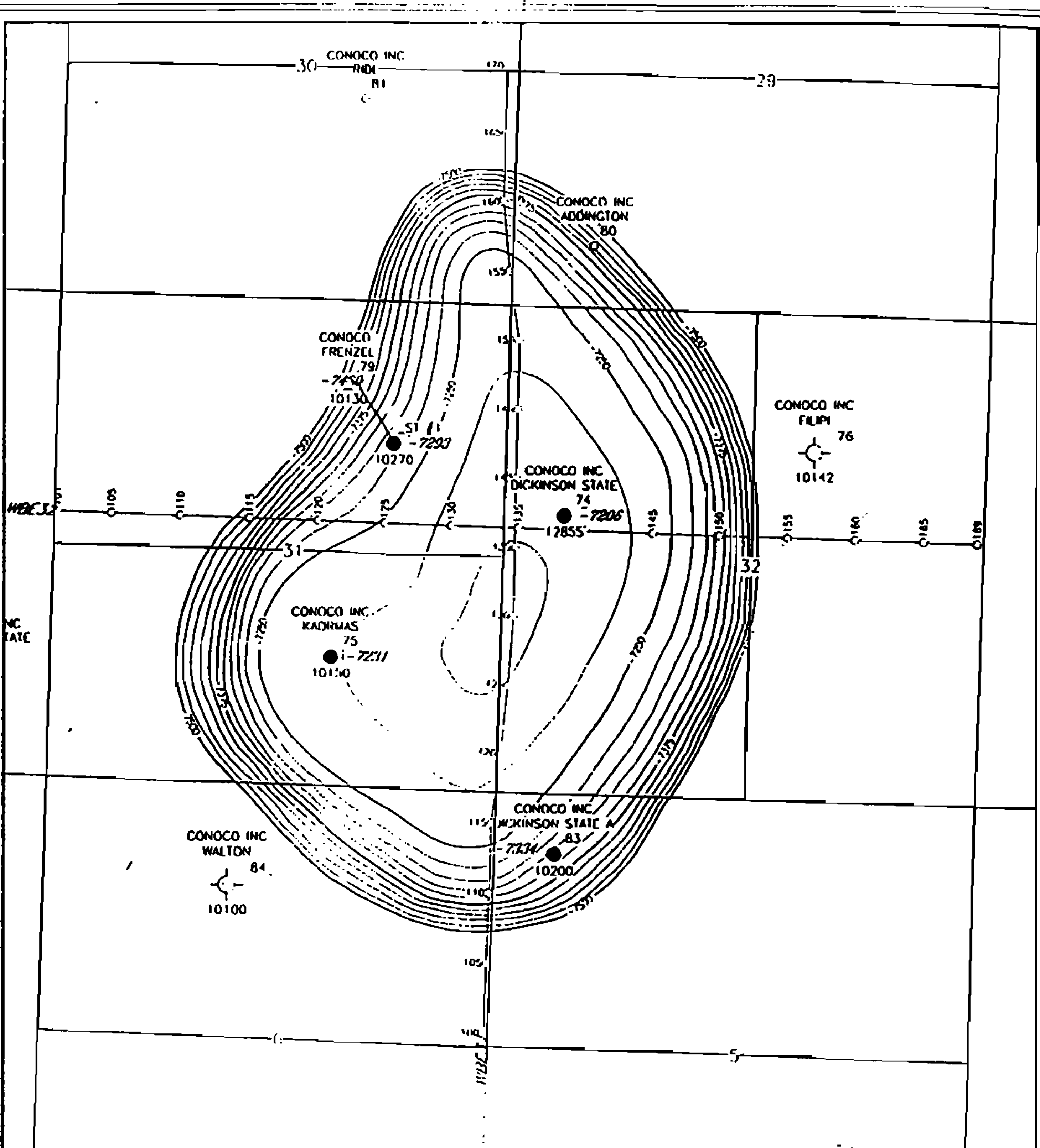
Hunt Petroleum Corporation protests Conoco's proposed unitization plan for the Dickinson-Lodgepole Field. We agree with Conoco that the field should be unitized and waterflooded. However, Hunt Petroleum strongly disagrees with the methodology used by Conoco to develop its proposed unitization plan.

Specifically, we strongly disagree with Conoco's proposed structure map. The character of their map, exhibit No. 12, with two highs and a saddle is based on an analogy to the top of the Fryburg zone that is almost a thousand feet above the Lodgepole. We find it is illogical to draw such a complex map with only four penetration points in the Lodgepole. The attached copy of Placid Oil's structure map with its single high and straight forward contours is more justified and supportable.

Since the structure map is the starting point and core of the unitization plan, Hunt Petroleum protests Conoco's entire unitization proposal. Thank you for your consideration on this subject.

Sincerely,

for Frank R. Howell,
Vice President Engineering



DICKINSON FIELD – LODGEPOLE POOL
STARK COUNTY, NORTH DAKOTA

STRUCTURE – TOP LODGEPOLE MOUND

STEVE BRESSLER
PLACID OIL COMPANY

0 0.1 0.2 0.3 0.4 0.5 MILES

CASE No. 5933

COPY

CLYDE W. JONES
POST OFFICE DRAWER 1267
PARKER, COLORADO 80134

303 - 841-4224

13 May 1994

Mr. P. J. Turner
Land Explorationist
Conoco, Inc.
800 Werner Court
Casper, Wyoming 82601

Re: Dickinson-Lodgepole Unit
Stark County, North Dakota

Dear Mr. Turner:

Pursuant to your written request of April 20, 1994, and to two separate telephone conversations with your agent, Mr. Clark Crawford, Bismarck, North Dakota, I herewith enclose two duplicate originals of the Approval of Unit Agreement covering the subject project, which instruments have been duly executed and notarized.

I do take exception to the provision for enlargement of the Unit in that you only provide for approval by working interest owners and do not include approval by royalty owners. Because future expansion of the Unit could work to dilute the interest of those royalty owners located under the more prolific wells, I feel that they should have a voice in any proposed expansion. I point this out as my only objection to your proposed Unit. However, in a spirit of cooperation I have signed your Approval of Unit Agreement and herewith hand you the same.

Very truly yours,

Clyde W. Jones

Clyde W. Jones

BEFORE THE INDUSTRIAL COMMISSION

OF THE STATE OF NORTH DAKOTA

CASE NO. 5936

IN THE MATTER OF THE APPLICATION OF CONOCO INC. FOR AN ORDER OF THE COMMISSION AUTHORIZING THE CONVERSION OF THE FRENZEL NO. 79 WELL, LOCATED IN THE NW¼ OF THE NE¼ OF SECTION 31, TOWNSHIP 140 NORTH, RANGE 96 WEST, AND THE DICKINSON STATE NO. A-83 WELL LOCATED IN THE NW¼NW¼ OF SECTION 5, TOWNSHIP 139 NORTH, RANGE 96 WEST, DICKINSON FIELD, STARK COUNTY, NORTH DAKOTA, FOR THE INJECTION OF FLUIDS IN THE PROPOSED DICKINSON-LODGEPOLE UNITIZED FORMATION PURSUANT TO CHAPTER 43-02-05 OF THE NORTH DAKOTA ADMINISTRATIVE CODE, AND PROVIDING SUCH OTHER AND FURTHER RELIEF AS THE COMMISSION DEEMS NECESSARY.

AMENDED APPLICATION OF CONOCO INC.

COMES NOW the applicant, Conoco Inc. ("Conoco"), and respectfully shows the North Dakota Industrial Commission ("Commission") as follows:

1.

That Conoco is the owner of an interest in the oil and gas leasehold estate in the Northwest Quarter of the Northeast Quarter (NW¼NE¼) of Section 31, Township 140 North, Range 96 West, Stark County, North Dakota ("Section 31").

2.

That Conoco is the owner of an interest in the oil and gas leasehold estate in the Northwest Quarter of the Northwest Quarter (NW¼NW¼) of Section 5, Township 139 North, Range 96 West, Stark County, North Dakota ("Section 5").

3.

That such lands are within the boundaries of the Dickinson Field and within the boundary of the proposed Dickinson-Lodgepole Unit.

4.

That Conoco is the operator of various wells located within the boundaries of the Dickinson Field. Stark County, North Dakota and will be the operator for the proposed Dickinson-Lodgepole Unit.

5.

That pursuant to Chapter 43-02-05 of the North Dakota Administrative Code, Conoco is desirous of converting the Frenzel No. 79 well located in the Northwest Quarter of the Northeast Quarter (NW¼NE¼) of Section 31 and the Dickinson State No. A-83 well located in the Northwest Quarter of the Northwest Quarter (NW¼NW¼) of Section 5 for the purposes of utilizing said wells for the injection of fluids into the proposed Dickinson-Lodgepole unitized formation.

6.

That attached herewith and marked Exhibit A are two plats showing the location of the proposed injection wells, all other producing wells, abandoned producers and dry holes in the Dickinson Field area.

7.

That attached herewith as Exhibit B is a list of all surface owners with the area of review to each of which will be mailed a copy of this application.

8.

That Conoco requests that the Commission enter its order authorizing the underground injection of fluids into the proposed Dickinson-Lodgepole unitized formation in the Frenzel No. 79 well located in the Northwest Quarter of the Northeast Quarter (NW¼NE¼) of Section 31, Township 140 North, Range 96 West and the Dickinson State No. A-83 well located in the Northwest Quarter of the Northwest Quarter (NW¼NW¼) of Section 5, Township 139 North, Range 96 West, Dickinson Field, Stark County, North Dakota, pursuant to Chapter 43-02-05 of the North Dakota Administrative Code and providing such other and further relief as the Commission deems necessary.

WHEREFORE, applicant requests that the matter be set for hearing at the regular Commission hearing on June 22, 1994 and that thereafter the Commission issue its Order granting the relief requested and such other and further relief as the Commission may deem appropriate.

DATED this *10th* day of May, 1994.

PEARCE & DURICK

By ______________________
LAWRENCE BENDER
Attorneys for Applicant
Conoco Inc.
314 East Thayer Avenue
Post Office Box 400
Bismarck, North Dakota 58502

STATE OF NORTH DAKOTA)
) ss.
COUNTY OF BURLEIGH)

LAWRENCE BENDER, being first duly sworn on oath, deposes and says that he is the attorney for the applicant named herein, that he has read the foregoing application, knows the contents thereof, and that the same is true to the best of this affiant's knowledge, and belief.

____
LAWRENCE BENDER

Subscribed and sworn to before me this *10th* day of May, 1994.

____
Lynette Entzi-Odden, Notary Public
Burleigh County, North Dakota
My Commission Expires: 6-26-99

1994

BEFORE THE INDUSTRIAL COMMISSION

OF THE STATE OF NORTH DAKOTA

CASE NO. _______

IN THE MATTER OF THE APPLICATION OF CONOCO INC. FOR AN ORDER OF THE COMMISSION AUTHORIZING THE CONVERSION OF THE FRENZEL NO. 79 WELL, LOCATED IN THE SW¼ OF THE NE¼ OF SECTION 31, TOWNSHIP 140 NORTH, RANGE 96 WEST, AND THE DICKINSON STATE NO. A-83 WELL LOCATED IN THE NW¼NW¼ OF SECTION 5, TOWNSHIP 139 NORTH, RANGE 96 WEST, DICKINSON FIELD, STARK COUNTY, NORTH DAKOTA, FOR THE INJECTION OF FLUIDS IN THE PROPOSED DICKINSON-LODGEPOLE UNITIZED FORMATION PURSUANT TO CHAPTER 43-02-05 OF THE NORTH DAKOTA ADMINISTRATIVE CODE, AND PROVIDING SUCH OTHER AND FURTHER RELIEF AS THE COMMISSION DEEMS NECESSARY.

AFFIDAVIT OF SERVICE BY MAIL

STATE OF NORTH DAKOTA)
) ss.
COUNTY OF BURLEIGH)

Lyn Entzi, being first duly sworn, deposes and says that on the *6th* day of May, 1994, she served the attached:

APPLICATION OF CONOCO INC.

by placing a true and correct copy thereof in an envelope addressed as follows:

See attached Exhibit A

and depositing the same, with postage prepaid, in the United States mail at Bismarck, North Dakota.

Lyn Entzi-Odden

LYN ENTZI-ODDEN

Subscribed and sworn to before me this *6th* day of May, 1994.

Rosalinde K. Kienzle

ROSALINDE KIENZLE, Notary Public
Burleigh County, North Dakota
My Commission expires: 05-23-95

ROSALINDE K. KIENZLE
Notary Public STATE OF NORTH DAKOTA
My Commission Expires MAY 23, 1995

FRENZEL NO. 79 WELL

Lester Frenzel and Marlene Frenzel
Route 1, Box 161
Dickinson, ND 58601

County of Stark, North Dakota
Box 130
Dickinson, ND 58601

City of Dickinson
c/o Ed Karsky, City Engineer
P.O. Box 1037
Dickinson, ND 58601

North Dakota State University
Dickinson Experiment Station
P.O. Box 5435
Fargo, ND 58105

Arthur J. Ridl and Dorothy A. Ridl
Route 1, Box 160
Dickinson, ND 58601

Joel L. Lupo and Josann M. Lupo
Route 1, Box 164
Dickinson, ND 58601

Douglas J. Kadrmas
2314 25-1/2 Ave. S.
Fargo, ND 58103

Mildred J. Kadrmas and Joseph J. Kadrmas
1030 4th Avenue W.
Dickinson, ND 58601

STATE A #83 WELL

State of North Dakota
State Highway Department
608 East Boulevard
Bismarck, ND 58505

EXHIBIT A

North Dakota Board of University
and School Lands
P.O. Box 5523
Bismarck, ND 58502-5523

Elizabeth Bowers
2930 Curlew St.
San Diego, CA 92110

Shirley Jean Larkin
462 South Lake Dr.
Watertown, SD 57201

William H. Walton, Trustee
3127 Highway 87-F
Billings, MT 59101

James W. Hoffman
554 Pinto Way
Eugene, OR 97401

John A. Hoffman
24608 Christina Lane
Nova, MI 48375

David E. Hoffman
c/o H.R.I. Inc.
Suite 202, 16990 Dallas Parkway
Dallas, TX 75248

William R. Hoffman
200 Greenridge Drive, #113
Lake Oswego, OR 97035

Robert Walton
118 3rd Avenue West
Dickinson, ND 58601

Benjamin Deeble
437 Eddy Avenue
Missoula, MT 59801

Julia Reynolds
3160 Meadowgrove
San Diego, CA 92110

Victoria Raynor
9451 East Carlton Oaks Drive
San Tee, CA 92071

Victor B. Walton
P.O. Box 1146
LaMesa, CA 91944

BEFORE THE INDUSTRIAL COMMISSION

OF THE STATE OF NORTH DAKOTA

CASE NO. ________

IN THE MATTER OF THE APPLICATION OF CONOCO INC. FOR AN ORDER OF THE COMMISSION AUTHORIZING THE CONVERSION OF THE FRENZEL NO. 79 WELL, LOCATED IN THE SW¼ OF THE NE¼ OF SECTION 31, TOWNSHIP 140 NORTH, RANGE 96 WEST, AND THE DICKINSON STATE NO. A-83 WELL LOCATED IN THE NW¼NW¼ OF SECTION 5, TOWNSHIP 139 NORTH, RANGE 96 WEST, DICKINSON FIELD, STARK COUNTY, NORTH DAKOTA, FOR THE INJECTION OF FLUIDS IN THE PROPOSED DICKINSON-LODGEPOLE UNITIZED FORMATION PURSUANT TO CHAPTER 43-02-05 OF THE NORTH DAKOTA ADMINISTRATIVE CODE, AND PROVIDING SUCH OTHER AND FURTHER RELIEF AS THE COMMISSION DEEMS NECESSARY.

APPLICATION OF CONOCO INC.

COMES NOW the applicant, Conoco Inc. ("Conoco"), and respectfully shows the North Dakota Industrial Commission ("Commission") as follows:

1.

That Conoco is the owner of an interest in the oil and gas leasehold estate in the Southwest Quarter of the Northeast Quarter (SW¼NE¼) of Section 31, Township 140 North, Range 96 West, Stark County, North Dakota ("Section 31").

2.

That Conoco is the owner of an interest in the oil and gas leasehold estate in the Northwest Quarter of the Northwest Quarter (NW¼NW¼) of Section 5, Township 139 North, Range 96 West, Stark County, North Dakota ("Section 5").

3.

That such lands are within the boundaries of the Dickinson Field and within the boundary of the proposed Dickinson-Lodgepole Unit.

4.

That Conoco is the operator of various wells located within the boundaries of the Dickinson Field, Stark County, North Dakota and will be the operator for the proposed Dickinson-Lodgepole Unit.

5.

That pursuant to Chapter 43-02-05 of the North Dakota Administrative Code, Conoco is desirous of converting the Frenzel No. 79 well located in the Southwest Quarter of the Northeast Quarter (SW¼NE¼) of Section 31 and the Dickinson State No. A-83 well located in the Northwest Quarter of the Northwest Quarter (NW¼NW¼) of Section 5 for the purposes of utilizing said wells for the injection of fluids into the proposed Dickinson-Lodgepole unitized formation.

6.

That attached herewith and marked Exhibit A are two plats showing the location of the proposed injection wells, all other producing wells, abandoned producers and dry holes in the Dickinson Field area.

7.

That attached herewith as Exhibit B is a list of all surface owners with the area of review to each of which will be mailed a copy of this application.

8.

That Conoco requests that the Commission enter its order authorizing the underground injection of fluids into the proposed Dickinson-Lodgepole unitized formation in the Frenzel No. 79 well located in the Southwest Quarter of the Northeast Quarter (SW¼NE¼) of Section 31, Township 140 North, Range 96 West and the Dickinson State No. A-83 well located in the Northwest Quarter of the Northwest Quarter (NW¼NW¼) of Section 5, Township 139 North, Range 96 West, Dickinson Field, Stark County, North Dakota, pursuant to Chapter 43-02-05 of the North Dakota Administrative Code and providing such other and further relief as the Commission deems necessary.

WHEREFORE, applicant requests that the matter be set for hearing on June 8, 1994 and that thereafter the Commission issue its Order granting the relief requested and such other and further relief as the Commission may deem appropriate.

DATED this *6th* day of May, 1994.

PEARCE & DURICK

By

LAWRENCE BENDER

Attorneys for Applicant
Conoco Inc.
314 East Thayer Avenue
Post Office Box 400
Bismarck, North Dakota 58502

STATE OF NORTH DAKOTA)
) ss.
COUNTY OF BURLEIGH)

LAWRENCE BENDER, being first duly sworn on oath, deposes and says that he is the attorney for the applicant named herein, that he has read the foregoing application, knows the contents thereof, and that the same is true to the best of this affiant's knowledge, and belief.

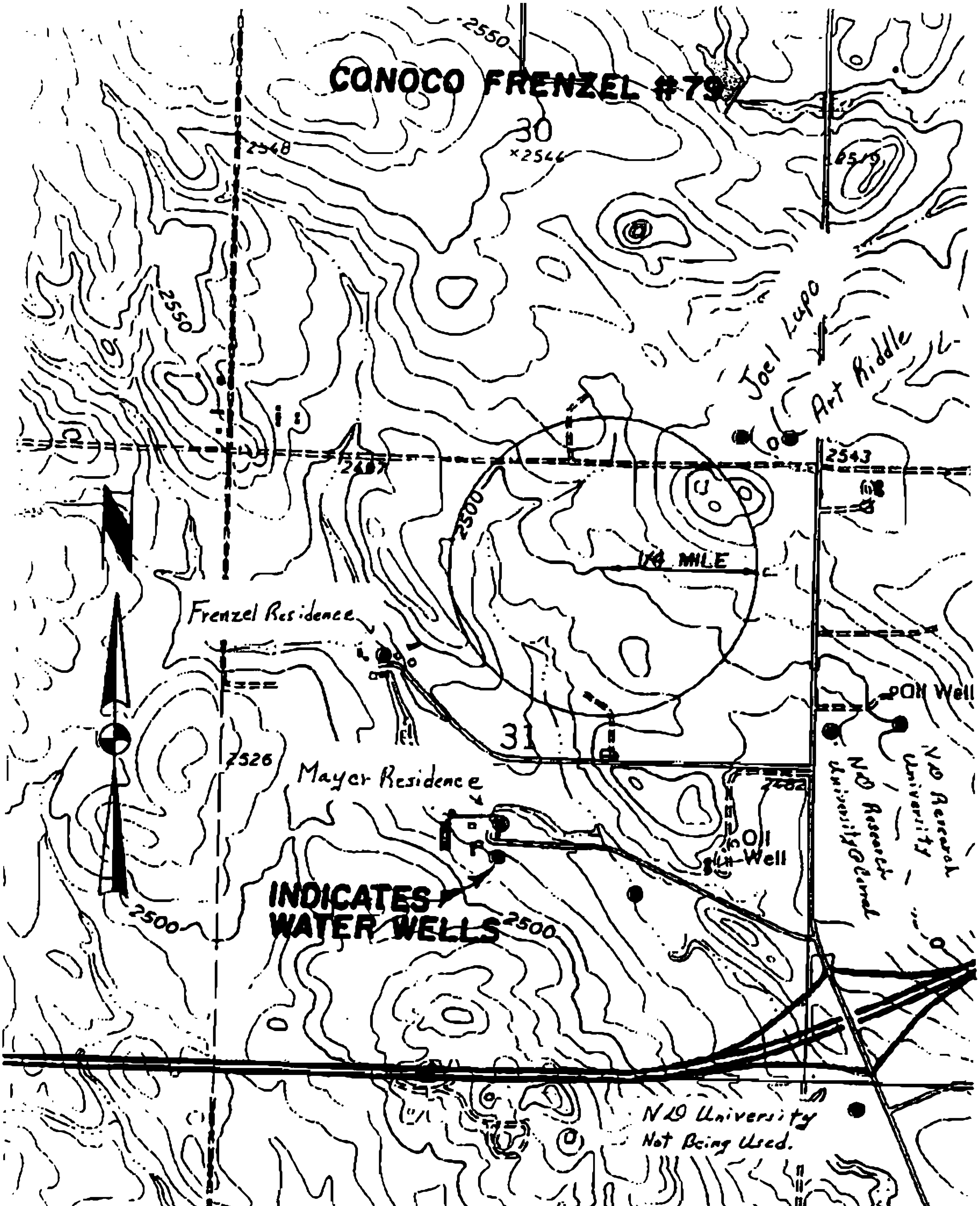
LAWRENCE BENDER

Subscribed and sworn to before me this *6th* day of May, 1994.

Lynette Entzi-Odden

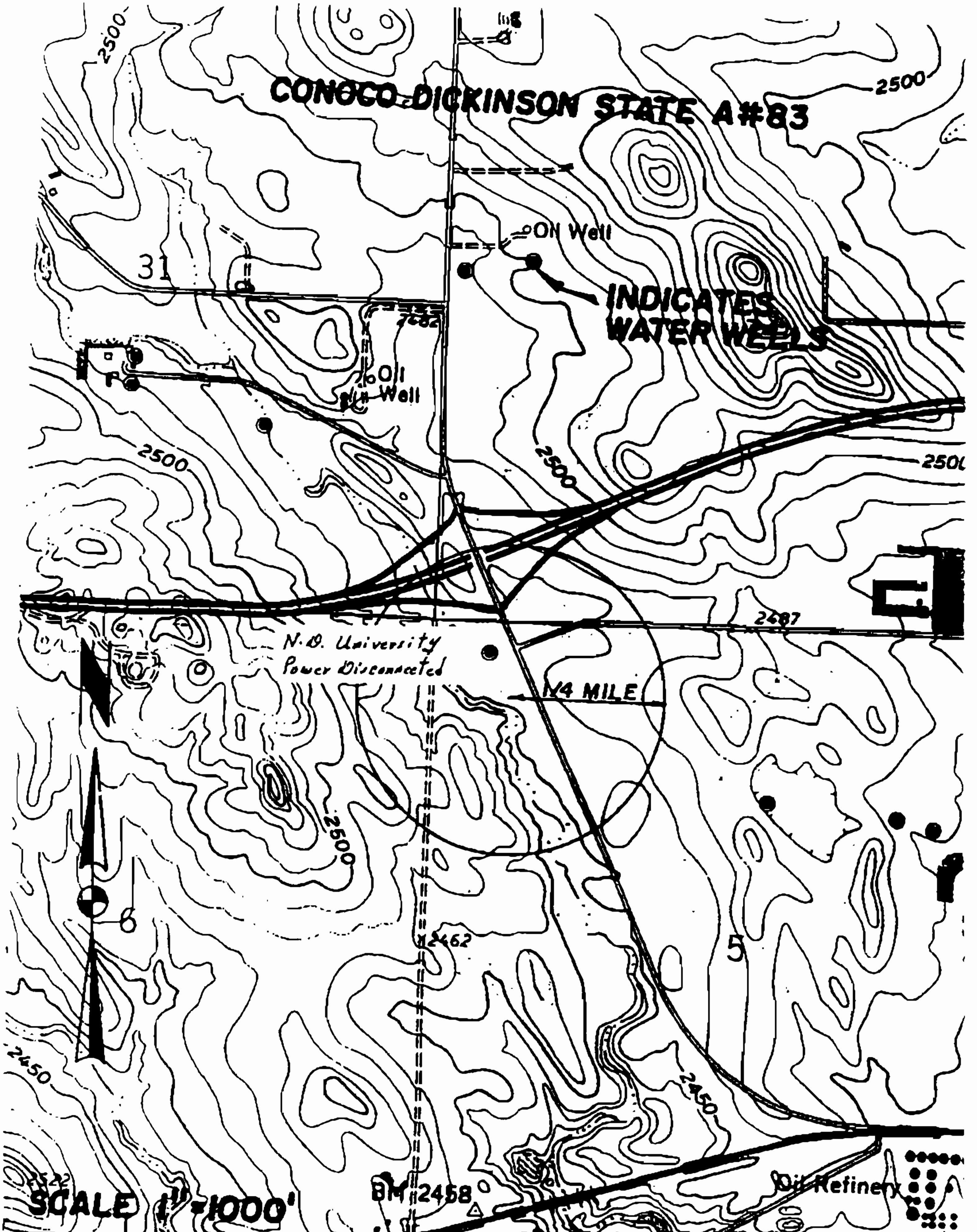
Lynette Entzi-Odden, Notary Public
Burleigh County, North Dakota
My Commission Expires: 6-26-99

LYNETTE ENTZI-ODDEN
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 26, 1999



CONOCO FRENZEL #79
2550
30
2548
×2546
2550
Joel Lupo
Art Riddle
2543
2500
1/4 MILE
Frenzel Residence
Oil Well
31
2526
Mayer Residence
Oil Well
ND Research University
ND Research University Owned
INDICATES WATER WELLS
2500
2500
ND University Not Being Used.
SCALE 1"=1000'

EXHIBIT A



CONOCO-DICKINSON STATE A#83
INDICATES WATER WELLS
Oil Well
Oil Well
31
2500
2462
2487
N.D. University
Power Disconnected
1/4 MILE
6
5
2450
2462
2522
SCALE 1"=1000'
BM 2458
Oil Refinery

SURFACE OWNERS WITHIN 1/4 MILE OF FRENZEL 79 WELL

Township 140 North, Range 96 West
Section 30: SW1/4
Section 31: N1/2
Stark County, North Dakota

Lester Frenzel and Marlene Frenzel,
Joint Tenants
Route 1, Box 161
Dickinson, ND 58601

County of Stark, North Dakota
Box 130
Dickinson, ND 58601

City of Dickinson
c/o Ed Karsky, City Engineer
P.O. Box 1037
Dickinson, ND 58601

EXHIBIT B

SURFACE OWNERS WITHIN 1/4 MILE
OF FRENZEL 79 WELL

<u>Township 140 North, Range 96 West</u>
Section 29: SW1/4
Section 32: W1/2
Stark County, North Dakota

North Dakota State University
Dickinson Experiment Station
P.O. Box 5435
Fargo, ND 58105

County of Stark, North Dakota
Box 130
Dickinson, ND 58601

City of Dickinson
c/o Ed Karsky, City Engineer
P.O. Box 1037
Dickinson, ND 58601

SURFACE OWNERS WITHIN 1/4 MILE OF FRENZEL 79 WELL

Township 140 North, Range 96 West
Section 30: SE1/4
Stark County, North Dakota

Arthur J. Ridl and Dorothy A. Ridl
Route 1, Box 160
Dickinson, ND 58601

Joel L. Lupo and Josann M. Lupo
Route 1, Box 164
Dickinson, ND 58601

County of Stark, North Dakota
Box 130
Dickinson, ND 58601

City of Dickinson
c/o Ed Karsky, City Engineer
P.O. Box 1037
Dickinson, ND 58601

SURFACE OWNERS WITHIN 1/4 MILE OF FRENZEL 79 WELL

Township 140 North, Range 96 West
Section 31: SE1/4
Stark County, North Dakota

Douglas J. Kadrmas
2314 25-1/2 Avenue South
Fargo, ND 58103

Mildred J. Kadrmas and Joseph J. Kadrmas
1030 4th Avenue West
Dickinson, ND 58601

County of Stark, North Dakota
Box 130
Dickinson, ND 58601

City of Dickinson
c/o Ed Karsky, City Engineer
P.O. Box 1037
Dickinson, ND 58601

SURFACE OWNERS WITHIN 1/4 MILE OF STATE A #83 WELL

Township 139 North, Range 96 West
Section 5: NW1/4
Stark County, North Dakota

State of North Dakota for the use and
benefit of the State Highway Department
608 East Boulevard
Bismarck, ND 58505

County of Stark, North Dakota
Box 130
Dickinson, ND 58601

City of Dickinson
c/o Ed Karsky, City Engineer
P.O. Box 1037
Dickinson, ND 58601

North Dakota Board of University and School Lands
P.O. Box 5523
Bismarck, ND 58502-5523

North Dakota State University
Dickinson Experiment Station
P.O. Box 5435
Fargo, ND 58105

SURFACE OWNERS WITHIN 1/4 MILE
OF STATE A #83 WELL

Township 139 North, Range 96 West
Section 6: NE1/4
Stark County, North Dakota

Elisabeth Bowers
2930 Curlew Street
San Diego, CA 92110

Shirley Jean Larkin
462 South Lake Drive
Watertown, SD 57201

William H. Walton, Trustee
3127 Highway 87-F
Billings, MT

James W. Hoffman
554 Pinto Way
Eugene, OR 97401

John A. Hoffman
24608 Christina Lane
Novi, MI 48375

David E. Hoffman
c/o H.R.I. Inc.
Suite 202, 16990 Dallas Parkway
Dallas, Texas 75248

William R. Hoffman
200 Greenridge Drive, #113
Lake Oswego, OR 97035

Robert Walton
118 3rd Avenue West
Dickinson, ND 58601

SURFACE OWNERS WITHIN 1/4 MILE OF STATE A #83 WELL

Township 139 North, Range 96 West
Section 6: NE1/4
Stark County, North Dakota

CONTINUATION

Benjamin Deeble
437 Eddy Avenue
Missoula, MT 59801

Julia Reynolds
3160 Meadowgrove
San Diego, CA 92110

Victoria Raynor
9451 East Carlton Oaks Drive
San Tee, CA 92071

Victor B. Walton
P.O. Box 1146
LaMesa, CA 91944

State of North Dakota for the use and
benefit of the State Highway Department
608 East Boulevard
Bismarck, ND 58505

County of Stark, North Dakota
Box 130
Dickinson, ND 58601

City of Dickinson
c/o Ed Karsky, City Engineer
P.O. Box 1037
Dickinson, ND 58601

SURFACE OWNERS WITHIN 1/4 MILE OF STATE A #83 WELL

Township 140 North, Range 96 West
Section 31: SE1/4
Stark County, North Dakota

State of North Dakota for the use and
benefit of the State Highway Department
608 East Boulevard
Bismarck, ND 58505

County of Stark, North Dakota
Box 130
Dickinson, ND 58601

City of Dickinson
c/o Ed Karsky, City Engineer
P.O. Box 1037
Dickinson, ND 58601

Douglas J. Kadrmas
2314 25-1/2 Avenue South
Fargo, ND 58103

Mildred J. Kadrmas and Joseph J. Kadrmas
1030 4th Avenue West
Dickinson, ND 58601

SURFACE OWNERS WITHIN 1/4 MILE OF STATE A #83 WELL

Township 140 North, Range 96 West
Section 32: SW1/4
Stark County, North Dakota

State of North Dakota for the use and
benefit of the State Highway Department
608 East Boulevard
Bismarck, ND 58505

County of Stark, North Dakota
Box 130
Dickinson, ND 58601

City of Dickinson
c/o Ed Karsky, City Engineer
P.O. Box 1037
Dickinson, ND 58601

North Dakota Board of University and School Lands
P.O. Box 5523
Bismarck, ND 58502-5523

North Dakota State University
Dickinson Experiment Station
P.O. Box 5435
Fargo, ND 58105

PEARCE & DURICK
ATTORNEYS AT LAW
THIRD FLOOR
314 EAST THAYER AVENUE
P O BOX 400
BISMARCK, NORTH DAKOTA 58502

TELEPHONE (701) 223-2890
FAX (701) 223-7865

OF COUNSEL
HARRY J PEARCE

WILLIAM R PEARCE 1910-1978
WILLIAM P PEARCE
PATRICK W DURICK
B TIMOTHY DURICK
CHRISTINE A HOGAN
JOEL W GILBERTSON
LAWRENCE A DOPSON
GARY R THUNE
DAVID E REICH
JEROME C KETTLESON
LARRY L BOSCHEE
LAWRENCE BENDER
JANET D SEAWORTH
MICHAEL F McMAHON
STEPHEN D EASTON

APR 1994
RECEIVED
ND OIL & GAS
DIVISION

April 22, 1994

HAND DELIVERED

Ms. Karlene Fine
Secretary
North Dakota Industrial Commission
Governor's Office
Capitol Building
Bismarck, North Dakota 58505

<u>CONOCO INC.</u>
DEVELOPMENT OF DICKINSON-LODGEPOLE UNIT

Dear Ms. Fine:

Please find enclosed herewith for filing an APPLICATION OF CONOCO INC.

If you should have any questions, please advise.

Sincerely,

L. Bender

LAWRENCE BENDER

LB/leo
Enclosure
cc: Mr. Wesley D. Norton - (w/enc.)
Mr. F. E. Wilborn - (w/enc.)
Mr. Charles Carvell - (w/enc.)
Mr. Jim Turner - (w/enc.)
Mr. William A. Jack - (w/enc.)

PEARCE & DURICK
ATTORNEYS AT LAW
THIRD FLOOR
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JOEL W GILBERTSON
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GARY R THUNE
DAVID E REICH
JEROME C KETTLESON
LARRY L BOSCHEE
LAWRENCE BENDER
JANET D SEAWORTH
MICHAEL F McMAHON
STEPHEN D EASTON

APR 1994

April 22, 1994

Ms. Karlene Fine
Secretary
North Dakota Industrial Commission
Governor's Office
Capitol Building
Bismarck, North Dakota 58505

HAND DELIVERED

<u>CONOCO INC.</u>
DEVELOPMENT OF DICKINSON-LODGEPOLE UNIT

Dear Ms. Fine:

Please find enclosed herewith for filing the following documents in regard to the above-captioned matter:

1 NOTICE OF HEARING;
2 PETITION FOR APPROVAL OF PLAN OF UNITIZATION;
3 AFFIDAVIT OF SERVICE BY MAIL; and
4 TECHNICAL EXHIBITS TO BE USED AT HEARING.

If you should have any questions, please advise.

Sincerely,

LAWRENCE BENDER

LB/leo
Enclosure
cc: Mr. Wesley D. Norton - (w/enc.)
Mr. F. E. Wilborn - (w/enc.)
Mr. Charles Carvell - (w/enc.)
Mr. Jim Turner - (w/o enc.)
Mr. William A. Jack - (w/o enc.)

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

IN THE MATTER OF THE PETITION OF CONOCO INC. FOR AN ORDER PROVIDING FOR THE UNITIZED MANAGEMENT, OPERATION, AND FURTHER DEVELOPMENT OF THE DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION; VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE.

PETITION FOR APPROVAL OF PLAN OF UNITIZATION

COMES NOW, Conoco Inc. ("Conoco"), and respectfully shows the North Dakota Industrial Commission ("Commission") as follows:

1.

That petitioner, Conoco, is a Delaware corporation with its Casper Division Office located at 800 Werner Court, Casper, Wyoming 82601.

2.

That the Dickinson-Lodgepole Pool was discovered in February of 1993 with the drilling and completing of the Dickinson State No. 74 well, located in the Northwest Quarter

Northwest Quarter (NW¼NW¼) of Section 32, Township 140 North, Range 96 West, Stark County, North Dakota.

3.

That by Order No. 6607 entered in Case No. 5712, dated April 4, 1993, the Commission established temporary spacing for the Dickinson-Lodgepole at one well to 320 acres.

4.

That since the Dickinson-Lodgepole Pool was discovered in February of 1993, a total of six wells have been drilled in or near said pool. Four wells were completed as producers and three wells were completed as dry holes after failing to penetrate reservoir rock containing commercial hydrocarbons.

5.

That through February 28, 1994, 502,004 barrels of oil have been recovered from the Dickinson-Lodgepole Pool and it is estimated that primary production practices will recover an additional 4,876,363 barrels of oil, resulting in ultimate primary production of 5,378,367 barrels of oil.

6.

That the original oil in place in the formation is estimated to be approximately 19,416,487 stock tank barrels of oil, and it is therefore estimated that primary production practices will recover approximately 27.7% of the original oil in place.

7.

That in the opinion of Conoco, a secondary recovery program conducted in accordance with the unit plan of operations will recover an additional 2,487,252 stock tank barrels of oil from the Dickinson-Lodgepole Pool, resulting in an ultimate combined primary and secondary production of 7,865,619 barrels of oil, or approximately 40.51% of the original oil in place.

8.

That Conoco anticipates that the secondary recovery project will consist of the injection of water produced from the Dakota formation from one proposed source well into two proposed injection wells.

9.

That the total investment for the secondary recovery project will be approximately $343,000.00, and the value of the additional oil to be recovered by the project exceeds the cost.

10.

That Conoco contends that the unitized management, operation and further development of the unit source of supply is reasonably necessary to effectively carry on the secondary recovery project and to substantially increase the ultimate recovery of hydrocarbons from the Dickinson-Lodgepole Pool.

11.

That the secondary recovery project as set forth above is feasible, will prevent waste and will, with reasonable probability, result in the recovery of substantially more hydrocarbons from the unit source of supply than otherwise would be recovered.

12.

That in the opinion of Conoco, the estimated additional cost of conducting such operations will not exceed the value of the additional oil and gas recovered.

13.

That the unitization and adoption of a secondary recovery method of operation is for the common good and will result in the general advantage of all owners of the oil and gas interests within the common source of supply directly affected by the project.

14.

That the proposed unit area is described on the plat attached hereto as Exhibit B to the Unit Agreement and consists of lands within the Dickinson-Lodgepole Pool located in Stark County, North Dakota. That the plan of unitization consists of a unit agreement and a unit operating agreement, copies of which are attached hereto. The plan of unitization contains fair, reasonable and equitable provisions for all matters described in Section 38-08-09.4 of the North Dakota Century Code. The unitized formation is defined in paragraph 1.2 of the unit agreement attached hereto.

15.

That this petition is filed pursuant to the provisions of Section 38-08-09.1 through 38-08-09.17 of the North Dakota Century Code.

16.

That the proposed unit area, as described on the plat attached hereto, consists of lands within the Dickinson-Lodgepole Pool located in Stark County, North Dakota. Although the entire Dickinson Field is not included within the proposed unit area, petitioner is of the opinion that the whole of the common source of supply is included within the proposed unit area.

WHEREFORE, Conoco respectfully requests that this petition be set for hearing on the 8th day of June, 1994, at the Brynhild-Haugland Room, State Capitol, Bismarck, North Dakota; and that thereafter the Commission enter an order:

(1) Providing for the unitized management, operation, and further development of the Dickinson-Lodgepole Pool, located in Stark County, North Dakota;

(2) Approving the unit agreement and unit operating agreement constituting the plan of unitization;

(3) Approving the plan of operation;

(4) Vacating the applicable spacing orders currently governing operations within the unit area; and

(5) Granting such further relief as the Commission deems appropriate.

DATED this *22nd* day of April, 1994.

PEARCE & DURICK

By [signature]
LAWRENCE BENDER
Attorneys for Applicant,
Conoco Inc.
314 E. Thayer
P. O. Box 400
Bismarck, ND 58502-0400

STATE OF WYOMING)
)SS.
COUNTY OF NATRONA)

LAWRENCE BENDER being first duly sworn on oath, deposes and says that he is the attorney for the applicant herein named, that he has read the above and foregoing application, knows the contents thereof, and that the same is true to the best of this affiant's knowledge, and belief.

[signature]
Lawrence Bender

Subscribed and sworn to before me this *22nd* day of April, 1994.

VICKI WESTBY Notary Public
County of Natrona
State of Wyoming
My commission Expires Feb 11, 1997

Vicki Westby
Vicki Westby, Notary Public
Natrona County, Wyoming
My Commission Expires: 2-11-97

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NO. 5933

IN THE MATTER OF THE PETITION OF CONOCO INC. FOR AN ORDER PROVIDING FOR THE UNITIZED MANAGEMENT, OPERATION, AND FURTHER DEVELOPMENT OF THE DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION; VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE.

APR 1994
RECEIVED
ND OIL & GAS
DIVISION

NOTICE OF HEARING

PLEASE TAKE NOTICE that Conoco Inc. has made application to the North Dakota Industrial Commission requesting an order providing for the unitized management, operation and further development of the Dickinson-Lodgepole Unit consisting of lands within and contiguous to the Dickinson Field, Stark County, North Dakota.

A hearing will be held at 9:00 a.m. on June 8, 1994 at the Brynhild-Haugland Room, State Capitol, Bismarck, North Dakota to consider the application of Conoco Inc.

The engineering, geological, and all other technical exhibits to be presented at the hearing will be filed with the Oil & Gas Division of the Industrial Commission at its offices located at 1022 East Divide Avenue, Bismarck, North Dakota, on or before April 22, 1994 and the same will be available for inspection on or before that date.

All persons interested in this matter may appear at the time and place set forth above and be heard.

DATED this *22nd* day of April, 1994.

PEARCE & DURICK

By______________________
LAWRENCE BENDER
Attorneys for Applicant,
Conoco Inc.
314 E. Thayer
P. O. Box 400
Bismarck, ND 58502-0400
(701) 223-2890

APR 1994
RECEIVED
OIL & GAS DIVISION

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

CASE NO. 5935

IN THE MATTER OF THE APPLICATION OF CONOCO INC. FOR AN ORDER OF THE COMMISSION DETERMINING THAT THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA, STARK COUNTY, NORTH DAKOTA, HAS BEEN SIGNED, RATIFIED OR APPROVED BY OWNERS OF INTEREST OWNING THAT PERCENTAGE OF THE WORKING INTEREST AND ROYALTY INTEREST WITHIN SAID UNIT AS IS REQUIRED BY APPLICABLE STATUTES AND RULES OF THE COMMISSION.

APPLICATION OF CONOCO INC.

COMES NOW the applicant, Conoco Inc., and respectfully shows the North Dakota Industrial Commission ("Commission") as follows:

1.

That Conoco Inc. has petitioned the Commission for an order providing for the unitized management, operation and further development of a unit to be known as the Dickinson-Lodgepole Unit, Stark County, North Dakota.

2.

That under the proposed plan of unitization, Conoco Inc. will be the designated operator of the Dickinson-Lodgepole Unit.

3.

That on June 8, 1994 a hearing will be held by the Commission to consider the application of Conoco Inc. for an order providing for the unitized management, operation and further development of the Dickinson-Lodgepole Unit.

4.

That Conoco Inc. anticipates that prior to the hearing on June 8, 1994, it will have obtained the execution, ratification or approval of the owners of interest owning that percent of the working interest and royalty interest as is required by applicable law to authorize the Commission to enter an order finding that Dickinson-Lodgepole Unit has been approved by said owners.

WHEREFORE, applicant respectfully requests that this matter be set for hearing on June 8, 1994, and that thereafter the Commission enter an order determining that the plan of unitization for said unit has been signed, ratified or approved by the owners of interest owning that percent of the working interest and royalty interest as required by applicable law and for such further and additional relief as the Commission may deem appropriate.

DATED this *22nd* day of April, 1994.

PEARCE & DURICK

By ______________________
LAWRENCE BENDER
Attorneys for Applicant,
Conoco Inc.
314 E. Thayer
P. O. Box 400
Bismarck, ND 58502-0400
(701) 223-2890

STATE OF NORTH DAKOTA)
)ss.
COUNTY OF BURLEIGH)

LAWRENCE BENDER, being first duly sworn on oath, deposes and says that he is the attorney for the applicant named herein, that he has read the foregoing application, knows the contents thereof, and that the same is true to the best of this affiant's knowledge, and belief.

____
LAWRENCE BENDER

Subscribed and sworn to before me this *22nd* day of April, 1994.

LYNETTE ENTZI-ODDEN
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 26, 1999

Lynette Entzi-Odden

____
Lynette Entzi-Odden, Notary Public
Burleigh County, North Dakota
My Commission Expires: 6-26-99

BEFORE THE INDUSTRIAL COMMISSION

STATE OF NORTH DAKOTA

IN THE MATTER OF THE APPLICATION OF CONOCO INC. FOR AN ORDER PROVIDING FOR THE UNITIZED MANAGEMENT, OPERATION AND FURTHER DEVELOPMENT OF THE DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION; VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE.

AFFIDAVIT OF SERVICE BY MAIL

STATE OF WYOMING)
)ss.
COUNTY OF NATRONA)

P. J. Turner, being first duly sworn, deposes and says that on the 22nd day of April, 1994, P. J. Turner, served the attached:

1 **PETITION FOR APPROVAL OF PLAN OF UNITIZATION; and**
2 **NOTICE OF HEARING.**

by placing a true and correct copy thereof in an envelope addressed as follows:

See attached Exhibit A

and depositing the same, with postage prepaid, in the United States mail at Casper, Wyoming.

P. J. Turner

P. J. TURNER

Subscribed and sworn to before me this 22nd day of April, 1994.

VICKI WESTBY Notary Public
County of Natrona
State of Wyoming
My commission Expires Feb 11, 1997

Vicki Westby

Notary Public
Natrona County, Wyoming
My Commission expires: 2-11-97

Exhibit "A"
to Affidavit of Service by Mail
Dated April 22, 1994

Working Interest Owners

Andrea Singer Pollack Revocable Trust
Andrea Singer Pollack, Trustee /
P. O. Box 22066
Denver, CO 80222-0066

ARS Control Account Limited Partnership /
Attn: Ms. Andrea Singer Pollack
P. O. Box 22854
Denver, CO 80222

Louis W. Hill, Jr. /
Trust Natural Resources, Inc.
Attn: Mr. Linn Willers
918 17th Street
Denver, CO 80202

Ruth Ray Hunt /
Attn: Mr. Gustav Svehla
2900 InterFirst One Building
1401 Elm Street
Dallas, TX 75202

Hunt Oil Co. /
Attn: Gustav Svehla
Fountain Pl.
1445 Ross at Field
Dallas, TX 75202-2785

Hunt Petroleum Corporation /
Attn: Mr. John Norman
3400 Thanksgiving Tower
1601 Elm
Dallas, TX 75201

Huntington Resources, Inc. /
Attn: Mr. Joe Starrett
8086 S. Yale, Suite 228
Tulsa, OK 74136

Louisiana-Hunt Petroleum /
2800 Thanksgiving Tower
Dallas, TX 75201

Mid-Continent Energy Investors /
3400 Mid-Continent Tower
401 South Boston
Tulsa, OK 74103-4071

Mobil Exploration & Producing /
Attn: Mr. G. M. Moffitt
12450 Greenspoint
Houston, TX 77060-1991

North American Royalties /
Attn: John Lavin
200 E. 8th Street
Chattanooga, TN 37402

Petro-Hunt Corp. /
3900 Thanksgiving Tower
1601 Elm Street
Dallas, TX 75201

Phillips Petroleum Company /
Attn: Mr. G. R. Yarrow
P. O. Box 1967
Houston, TX 77521-1967

Placid Oil Company /
Attn: Mr. Steve Bressler
3900 Thanksgiving Tower
1601 Elm
Dallas, TX 75201

Unit Four Partnership
Attn: Pete Arnett
2400 Thanksgiving Tower
1601 Elm Street
Dallas, TX 75201

The Wiser Oil Company
Attn: Mr. Gary Lauman
8115 Preston Road, Suite 400
Dallas, TX 75225

Royalty Interest Owners

Peggy Addington
1720 Bardfield Avenue
Garland, TX 75041

Agribank FCB
375 Jackson St.
P.O. Box 64949
St. Paul, MN 55164-0949

Andrews Royalty Inc.
Suite 850
5949 Sherry Lane
Dallas, TX 75225

Baytech Inc.
P.O. Box 10158
Midland, TX 79702-7158

Mary Ayala
(Address Unknown)

Martha Smart Bennett
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Cynthia A. Comeau
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Beeman Dockery
RR 1 Box 276
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Patricia & William Dowell
943 4th Avenue West
Dickinson, ND 58601-3829

Erma Lowe Trust for Carson Yost
Mary Ralph Lowe, Trustee
P. O. Box 2923
Houston, TX 77252

Erma Lowe Trust for Clayton Yost
Mary Ralph Low, Trustee
P. O. Box 2923
Houston, TX 77252

Erma Lowe Trust for Samantha Yost
Mary Ralph Lowe, Trustee
P. O. Box 2923
Houston, TX 77252

The Fasken Foundation
Acct #01-1036-00
500 West Texas, Ste 1160
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Mary Ann & Edwin A. Ficek
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Rose Frenzel
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Dickinson, ND 58601-9745

Randy Geiselman
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Midland, TX 79707-6623

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John M. Grinde, Trustee
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Chicago, IL 60614-5611

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Shreveport, LA 71119

Irene & Karl Hammann
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Portland, OR 97202-3450

Mary Daphne Hibl
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Dickinson, ND 58601

Louis W. Hill, Jr.
c/o Colorado National Bank
Trust Natural Resource Dept.
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Denver, CO 80217

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John A. Hoffman
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William R. Hoffman
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Lake Oswego, OR 97035

Ruth Ray Hunt
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WI Owner

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Lubbock, TX 79401

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Dodge Jones FDN
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Amarillo, TX 79106

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Moore & Michael H. Moore
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Seattle, WA 98146-1136

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El Paso, TX 79925-4529

Zula Mae Pugh
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Bellevue, WA 98004-4006

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Mulvane, KS 67110

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San Tee, CA 92071

Julia Reynolds
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San Diego, CA 92110

Joan Schmidt
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Dickinson, ND 58601-9639

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Abilene, TX 79605-4914

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Trustee FBO C&F Stroud Trust
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Rancho Santa Fe, CA 92067-1426

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Tulsa, OK 74102

Charles Taubman Revocable Trust
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1615 First National Building
Tulsa, OK 74102

Deborah Anne Taubman Trust
c/o J.H. Morris, Agent
1615 First National Building
Tulsa, OK 74102

Herman P. & Sophia Taubman
c/o J.H. Morris, Agent
1615 First National Building
Tulsa, OK 74102

Republic Royalty Company
P. O. Box 840-127
Dallas, TX 75284-0127

Lillian Ridl
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Dickinson, ND 58601

Karen P. Shalom Management Trust
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Tulsa, OK 74102

Virginia L. Sherron
1101 W. Greenough #F9
Missoula, MT 59802-3734

State of North Dakota
Board of Univ. & School Lands
Attn: Timothy L. Kingstad
918 E. Divide Ave., Suite 410
Bismarck, ND 58501

Adina Taubman Trust
c/o Jassoy, Graff & Douglas
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La Jolla, CA 92037

Barbara Taubman Living Trust
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Tulsa, OK 74102

Claudia P. Taubman Rev. Trust
c/o J.H. Morris, Agent
1615 First National Building
Tulsa, OK 74102

Henrik Perry Taubman Family Trust
c/o Jassoy, Graff & Douglas
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La Jolla, CA 92037

Hilary Lu Taubman Rev. Trust
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Tulsa, OK 74102

Janice L. Taubman Revocable Trust
c/o J.H. Morris, Agent
1615 First National Building
Tulsa, OK 74102

Louis Taubman Trust
1615 First National Building
Tulsa, OK 74102

same

Bank of OK, Tulsa, Maurine Taubman
Co-Trustee, c/o J.H. Morris
1615 First National Building
Tulsa, OK 74102

National Bank Tulsa, Trustee
c/o J.H. Morris, Agent
1615 First National Building
Tulsa, OK 74102

Richard J. Taubman Trust
c/o J.H. Morris, Agent
1615 First National Building
Tulsa, OK 74102

Rosalie Taubman Management Trust
c/o J.H. Morris, Agent
1615 First National Building
Tulsa, OK 74102

Estate of William David Taubman
c/o Mary Saxon Taubman
1615 First National Building
Tulsa, OK 74102

E.E. & Mildred E. Trumbell
3117 Lakeside Drive
Oklahoma City, OK 73120-2314

Robert R. Walton
118 3rd Ave. West
Dickinson, ND 58601

Dr. William H. Walton, Jr.
3127 Highway 87-F
Billings, MT 59101

L. N. Taubman Revocable Trust
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Tulsa, OK 74102

Louis Taubman Trust
c/o J.H. Morris, Agent
1615 First National Building
Tulsa, OK 74102

Morris B. Taubman Revocable Trust
c/o J.H. Morris, Agent
1615 First National Building
Tulsa, OK 74102

Rebecca M. Taubman Revocable Trust
c/o J.H. Morris, Agent
1615 First National Building
Tulsa, OK 74102

Robert M. Taubman Rev. Trust
c/o J.H. Morris, Agent
1615 First National Building
Tulsa, OK 74102

Sara K. Taubman Revocable Trust
c/o J.H. Morris, Agent
1615 First National Building
Tulsa, OK 74102

J. R. & Katherine A. Taylor
Co-Trustees of J. R. Taylor Trust
Route 2, Box 244
Douglas, KS 67039

Hunter S. Trunk
Tony J. Trunk, Guardian
Box 7556
Tacoma, WA 98407

Victor B. Walton
5549 Kiowa Dr.
La Mesa, CA 91944

Elizabeth H. Welch
725 Briarwood
Abilene, TX 79603-5703

Gerald C. Wiseman
Box 1
Maple Hill, KS 66507

Viola L. & Virginia Younger
1700 Lancaster Canterbury
Box 85
Big Spring, TX 79720

The Wiser Oil Company
8115 Preston Road, Suite 400
Dallas, TX 75225

Overriding Royalty Interest Owners

Andrea Singer Pollack Revocable Trust
Andrea Singer Pollack, Trustee
P. O. Box 22066
Denver, CO 80222-0066

Louis W. Hill, Jr.
Trust Natural Resources
(CNDT2311)
P. O. Box 17532
Denver, CO 80217

Mobil Exploration & Production
Attn: Diana Fickinger
12450 Greenspoint
Houston, TX 77060-1991

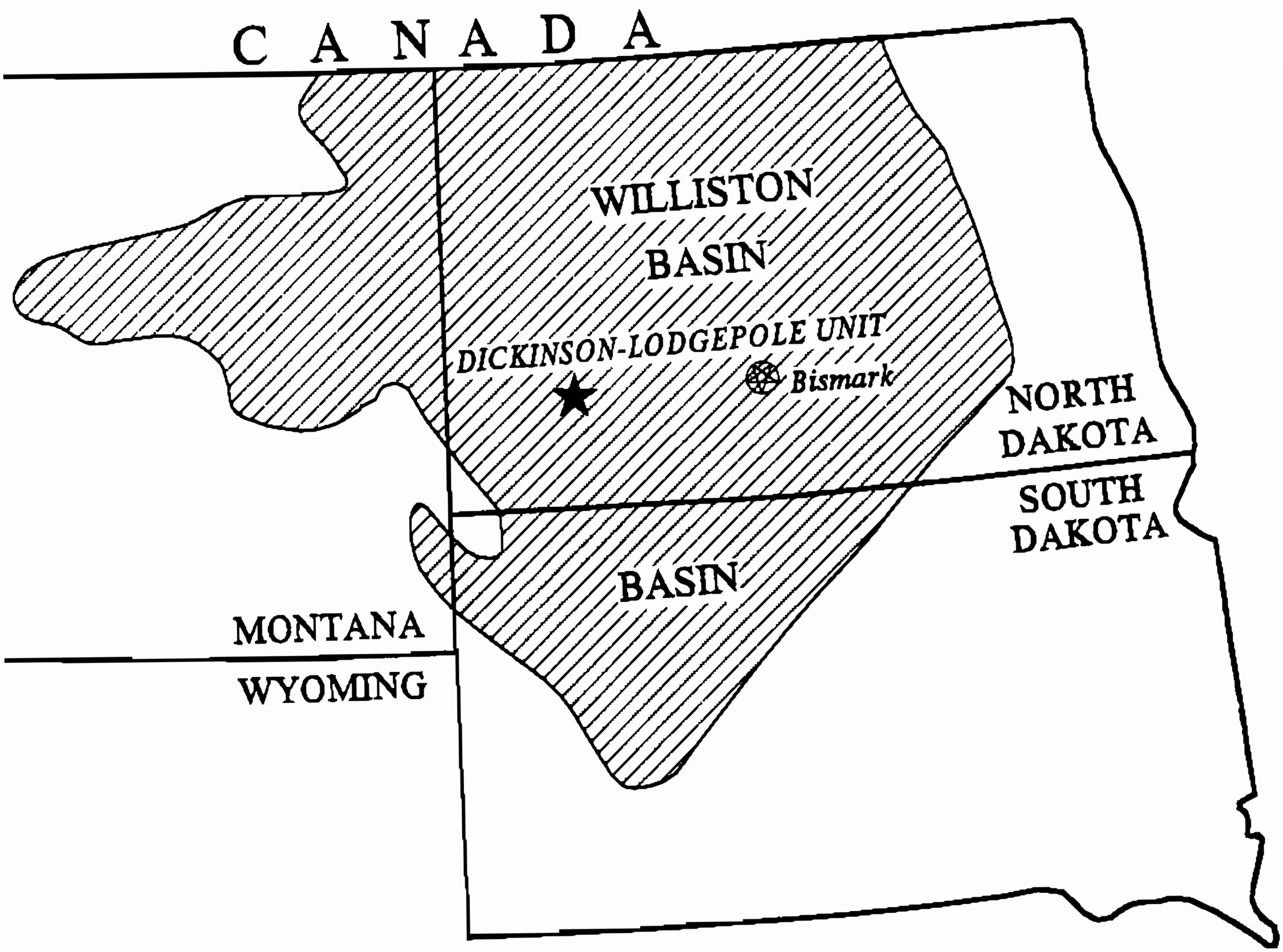
R. E. & Mildred Moore
P. O. Box 1181
Dickinson, ND 58601

Phillips Petroleum
Attn: Deborah Richardson
P. O. Box 1967
Houston, TX 77521-1967

Torch Oil & Gas Company
Attn: Stan Coddou
P. O. Box 201629
Houston, TX 77216-1629

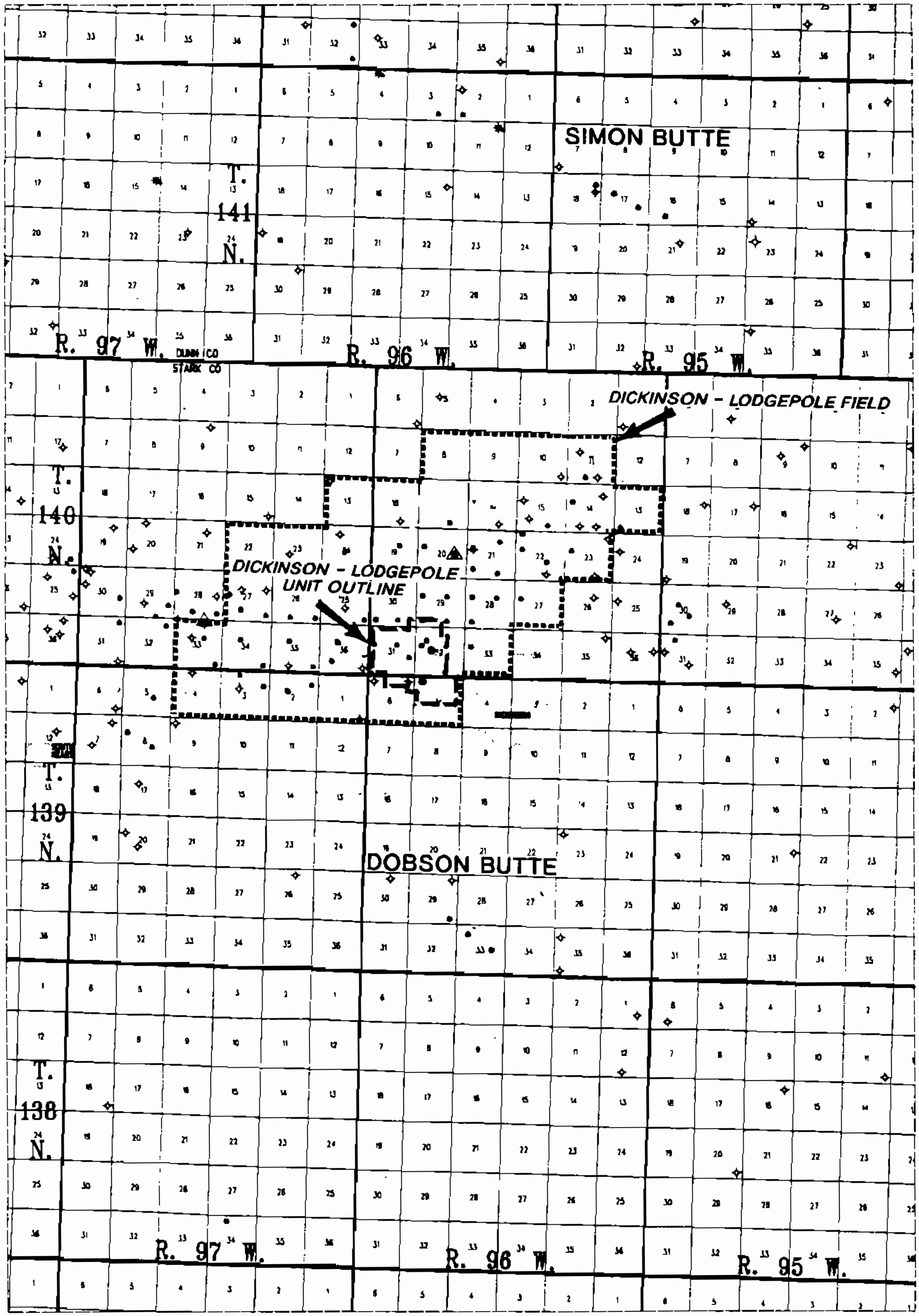
TWR, Inc.
100 North 27th Street, #200
Billings, MT 59101

DICKINSON-LODGEPOLE UNIT
Location Map



CONOCO INC.

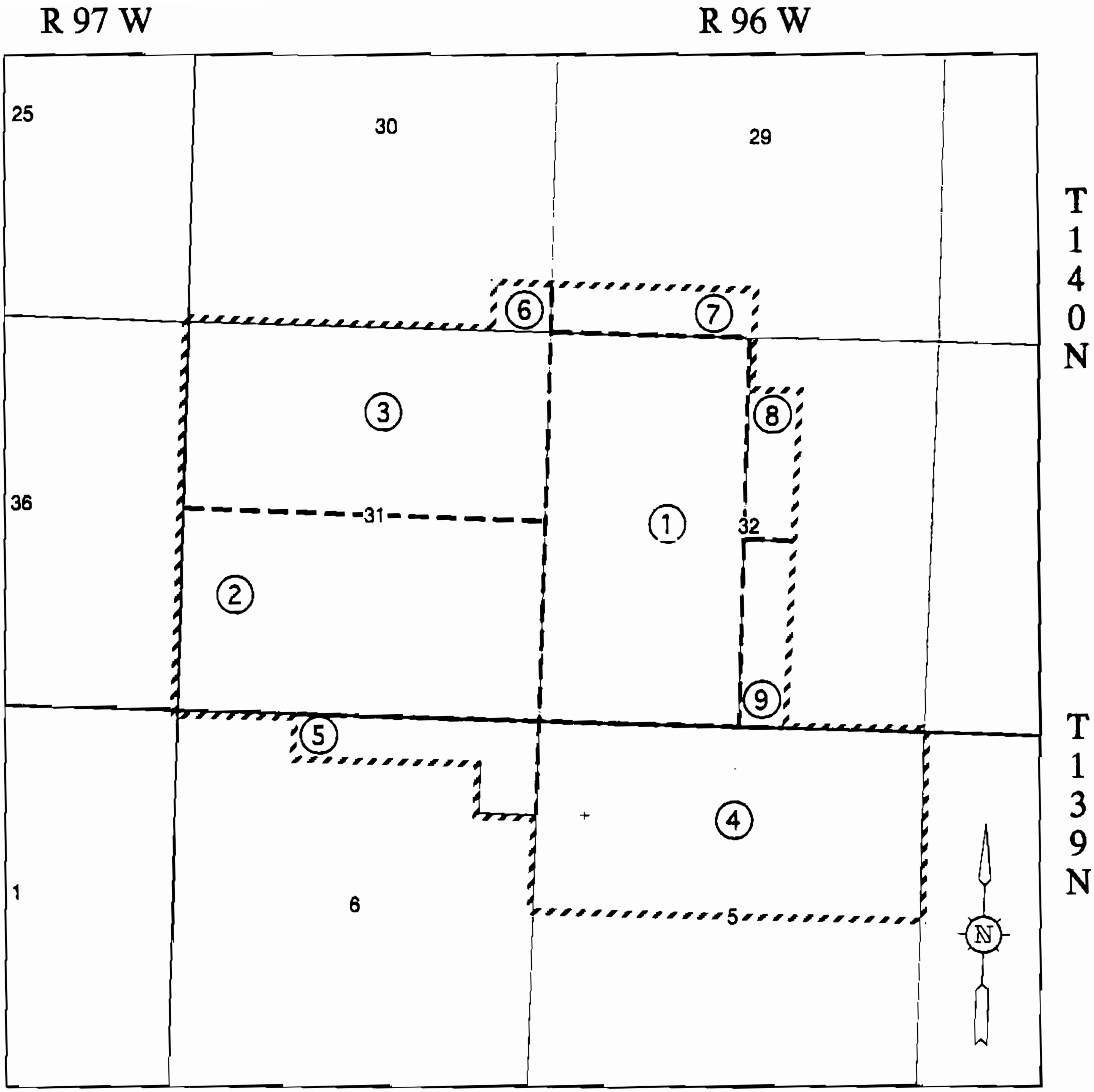
Case No.
Exhibit No. 1



DICKINSON AREA

Stark Co. North Dakota

CONOCO INC.
Case No.
Exhibit No. 2



Unit Boundary

Tract Boundary

1 Tract No.

Scale
1000'

TRACT	ACRES
1	320.00
2	308.49
3	303.65
4	323.78
5	60.27
6	10.01
7	40.15
8	30.06
9	40.04
TOTAL	1436.45

DICKINSON LODGEPOLE UNIT
Stark Co., North Dakota

CONOCO INC.
Case No.
Exhibit No. 3

DICKINSON-LODGEPOLE UNIT DESCRIPTION

Township 140 North, Range 96 West
Section 29: S½S½SW¼
Section 30: SE¼SE¼SE¼
Section 31: Lots 1, 2, 3, 4, E½W½, E½
Section 32: W½, W½W½SE¼, W½SW¼NE¼, SW¼NW¼NE¼

Township 139 North, Range 96 West
Section 5: Lots 1, 2, 3, 4, S½N½
Section 6: N½ of Lot 1, SE¼ of Lot 1, N½ of Lot 2, NE¼ of Lot 3

Stark County, North Dakota

CONOCO INC.
Case No.
Exhibit No. 4

UNIT AGREEMENT

FOR THE DEVELOPMENT AND OPERATION

OF THE

DICKINSON LODGEPOLE UNIT

COUNTY OF STARK

STATE OF NORTH DAKOTA

[Statutory Unit formed pursuant to the North Dakota Century Code, Sections 38-08-09.1 through 38-08-09.16, as amended]

DATED THIS 15TH DAY OF APRIL, 1994

CONOCO INC.

Case No.
Exhibit No. 5

UNIT AGREEMENT

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UNIT AGREEMENT

Dickinson Lodgepole Unit

Stark County, North Dakota

THIS AGREEMENT, entered into as of the 15th day of April, 1994.

WITNESSETH:

WHEREAS, in the interest of the public welfare and to promote conservation and increase the ultimate recovery of Unitized Substances from the Dickinson Field, in Stark County, North Dakota, and to protect the rights of the owners of interests therein, it is deemed necessary and desirable to unitize the Oil and Gas Rights in and to the Unitized Formation in order to conduct Unit Operations as herein provided, pursuant to Sections 38-08-09.1 through 38-08-09.16 of the North Dakota Century Code.

NOW, THEREFORE, it is provided as follows:

ARTICLE 1

DEFINITIONS

As used in this Agreement:

1.1 **Unit Area** is the land identified by Tracts in Exhibit A and shown on Exhibit B, containing 1,436.45 acres, more or less.

1.2 **Unitized Formation** is the common source of supply of hydrocarbons underlying the Unit Area described as the Lodgepole Formation as defined by the North Dakota Industrial Commission, by Order #6607, being that accumulation of oil and gas found in the interval from below the base of the Mission Canyon Formation to above the top of the Bakken Formation.

1.3 **Unitized Substances** are all oil, gas, gaseous substances, sulphur contained in gas, condensate, distillate, and all associated and constituent substances other than Outside Substances within or produced from the Unitized Formation.

1.4 **Working Interest** is an interest in Unitized Substances by virtue of a lease, operating agreement, fee title or otherwise, including a carried interest, the owner of which is primarily obligated to pay, either in cash or out of production or otherwise, a portion of the Unit Expense; however, Oil and Gas Rights that are free of lease or other instrument creating a Working Interest shall be regarded as a Working Interest to the extent of seven-eighths (7/8) thereof and a Royalty Interest to the extent of the remaining one-eighth (1/8) thereof.

1.4a **Carved-out Interests.** Any overriding royalty, production payment, net proceeds interest, carried interest or any other interest carved out of a Working Interest.

1.5 **Royalty Interest** is a right to or interest in any portion of the Unitized Substances or proceeds thereof other than a Working Interest.

1.6 **Royalty Owner** is a Person who owns a Royalty Interest.

1.7 **Working Interest Owner** is a Person who owns a Working Interest.

1.8 **Tract** is the land identified as such and given a tract number in Exhibit A.

1.9 **Unit Operating Agreement** is the agreement having the same Effective Date as this Agreement, entitled "Unit Operating Agreement, Dickinson Lodgepole Unit, Stark County, North Dakota", and with this Agreement constitutes the Plan of Unitization.

1.10 **Unit Operator** is the Working Interest Owner designated by Working Interest Owners under the Unit Operating Agreement to conduct Unit Operations, acting as operator and not as a Working Interest Owner.

1.11 **Tract Participation** is the percentage shown on Exhibit A for allocating Unitized Substances to a Tract.

1.12 **Unit Participation** of a Working Interest Owner is the sum of the percentages obtained by multiplying the Working Interest of such Working Interest Owner in each Tract by the Tract Participation of such Tract.

1.13 **Outside Substances** are substances purchased or otherwise obtained for a consideration by Working Interest Owners and injected into the Unitized Formation.

1.14 **Oil and Gas Rights** are the rights to explore, develop, and operate lands within the Unit Area for the production of Unitized Substances, or to share in the production so obtained or the proceeds thereof.

1.15 **Unit Operations** are all operations conducted pursuant to this Agreement and the Unit Operating Agreement.

1.16 **Unit Equipment** is all personal property, lease and well equipment, plants, and other facilities and equipment taken over or otherwise acquired for the joint account for use in Unit Operations.

1.17 **Unit Expense** is all cost, expense, or indebtedness incurred by Working Interest Owners or Unit Operator pursuant to this Agreement and the Unit Operating Agreement for or on account of Unit Operations.

1.18 **Effective Date** is the time and date this Agreement becomes effective as provided in Article 15.

1.19 **Person** is any individual, corporation, partnership, association, receiver, trustee, curator, executor, administrator, guardian, tutor, fiduciary, or other representative of any kind, any department, agency, or instrumentality of the state, or any governmental subdivision thereof, or any other entity capable of holding an interest in the Unitized Formation.

1.20 **Phase I** means the period of time beginning on March 1, 1994 and continuing until 7:00 a.m. of the first day of the calendar month next following the date on which 4,876,363 barrels of oil have been produced, as determined from the oil production reports submitted by the Operator to the North Dakota State Industrial Commission.

1.21 **Phase II** means the period of time beginning after the end of Phase I and continuing for the remainder of the term of this Agreement.

1.22 **Natural Gas** shall mean methane and that portion of ethane contained in the Natural Gas after conventional mechanical lease separation.

1.23 **Liquified Petroleum Gases, or LPG,** shall mean propane, butane, isobutane, pentane and any ethane contained in any mix of such LPG.

1.24 **Liquid Hydrocarbons** shall mean all liquids contained in any raw or unprocessed stream of clear hydrocarbon liquids (condensate) that exist as a liquid at atmospheric pressure.

1.25 **Blow Down** shall mean that point in time when Outside Substances are no longer injected into the reservoir.

1.26 **Operating Committee** is the Working Interest Owners and the Unit Operator acting through their designated representatives. Where appropriate, reference in this agreement and the Unit Operating Agreement to collective action by the Working Interest Owners to supervise Unit Operations means action by the Operating Committee.

ARTICLE 2

EXHIBITS

2.1 **Exhibits.** The following exhibits, which are attached hereto, are incorporated herein by reference:

2.1.1 **Exhibit A** is a schedule that identifies each Tract in the Unit Area and shows its Tract Participation.

2.1.2 **Exhibit B** is a map or plat that shows the boundary lines of the Unit Area, the Tracts therein, and wells completed in the Unitized Formation.

2.2 **Reference to Exhibits.** When reference is made to an exhibit, it is to the original exhibit or, if revised, to the last revision.

2.3 **Exhibits Considered Correct.** Exhibits A and B shall be considered to be correct until revised as herein provided.

2.4 **Correcting Errors.** The shapes and descriptions of the respective Tracts have been established by using the best information available. If any Tract, because of diverse royalty or working interest ownership on the Effective Date, should have been divided into more than one Tract, or if any mechanical miscalculation or clerical error has been made, Unit Operator shall correct the mistake by revising the exhibits to conform to the facts. The revision shall not include any re-evaluation of engineering or geological interpretations used in determining Tract Participation. Each such revision of an exhibit made prior to thirty (30) days after the Effective Date shall be effective as of the Effective Date. Each such revision thereafter made shall be effective at 7:00 a.m. on the first day of the calendar month next following the filing for record of the revised exhibit or on such other date as may be determined by Working Interest Owners and set forth in the revised exhibit.

2.5 **Filing Revised Exhibits.** If an exhibit is revised, Unit Operator shall execute an appropriate instrument with the revised exhibit attached and file the same with the North Dakota Industrial Commission, and for record in any county or counties in which this Agreement is filed.

ARTICLE 3

CREATION AND EFFECT OF UNIT

3.1 **Oil and Gas Rights Unitized.** All Oil and Gas Rights of Royalty Owners in and to the lands identified in Exhibit A, and all Oil and Gas Rights of Working Interest Owners in and to said lands, are hereby unitized insofar as the respective Oil and Gas Rights pertain to the Unitized Formation, so that Unit Operations may be conducted with respect to the Unitized Formation as if the Unit Area had been included in a single lease executed by all Royalty Owners, as lessors, in favor of all Working Interest Owners, as lessees, and as if the lease contained all of the provisions of this Agreement.

3.2 **Statutory Unitization.** It is the intent of the Working Interest Owners to utilize the statutory unitization provisions of the North Dakota Century Code Sections 38-08-09.1 through 38-08-09.16, as amended, in the formation of this unit. When the Unit Operator receives the approval of the Unit Agreement and Unit Operating Agreement by Working Interest Owners owning a combined Phase I Unit Participation of at least seventy percent (70%) and a combined Phase II Unit Participation of at least seventy percent (70%), an application will be made to the North Dakota Industrial Commission for statutory unitization of the uncommitted interests. Upon approval of the Unit Agreement and the Unit Operating Agreement as a plan of unitization and operating plan and upon approval of statutory unitization by the order of the North Dakota Industrial Commission, all uncommitted lands and all Oil and Gas Rights of Royalty Owners and Working Interest Owners insofar as rights pertain to the Unitized Formation shall be deemed committed to the unit as if approved in writing by all the parties.

3.3 **Personal Property Excepted.** All lease and well equipment, materials, and other facilities heretofore or hereafter placed by any of the Working Interest Owners on the lands covered hereby shall be deemed to be and shall remain personal property belonging to and may be removed by Working Interest Owners. The rights and interests therein as among Working Interest Owners are set forth in the Unit Operating Agreement.

3.4 **Amendment of Leases and Other Agreements.** The provisions of the various leases, agreements, division and transfer orders, or other instruments pertaining to the respective Tracts or the production therefrom are amended to the extent necessary to make them conform to the provisions of this Agreement, but otherwise shall remain in effect.

3.5 **Continuation of Leases and Term Interests.** Except as provided by Section 38-08-09.9 of the North Dakota Century Code, production from any part of the Unitized Formation, except for the purpose of determining payments to Royalty Owners, which is further specifically provided for in this Agreement, or other Unit Operations, as contemplated by this Agreement, shall be considered as production from or operations upon each Tract, and such production or operations shall have the same effect under the terms of each lease or mineral or royalty interest grant as to all lands and formations covered thereby just as if there were production from or operations upon each Tract.

3.6 **Titles Unaffected by Unitization.** Nothing herein shall be construed to result in any transfer of title to Oil and Gas Rights.

3.7 **Injection Rights.** Working Interest Owners are hereby granted the right to inject into the Unitized Formation any substances in whatever amounts Working Interest Owners deem expedient for Unit Operations, together with the right to drill, use, and maintain injection wells in the Unit Area, and to use for injection purposes any nonproducing or abandoned wells or dry holes, and any producing wells completed in the Unitized Formation.

3.8 **Development Obligation.** Nothing herein shall relieve Working Interest Owners from any obligation to reasonably develop the lands and leases committed hereto.

3.9 **Enlargements.** The Unit Area may be enlarged at any time, with the approval of the North Dakota Industrial Commission, to include adjoining portions of the same common source of supply. In such enlargements there shall be no retroactive allocation or adjustment of Unit Expense or of interests in the Unitized Substances produced, or proceeds thereof; however, this limitation shall not prevent an adjustment of investment by reason of the enlargement. In addition, the revised Tract Participations of the respective Tracts included within the Unit Area prior to such enlargement shall remain in the same ratio one to another. Such enlargement shall be effected in the following manner:

(a) The Working Interest Owner or Owners of the Tract or Tracts proposed to be added to the Unit Area shall file an application therefor with Unit Operator requesting such enlargement.

(b) Unit Operator shall circulate a notice of the proposed enlargement to each Working Interest Owner in the Unit Area and in the Tract or Tracts proposed to be added to the Unit Area, setting out the basis for admission, the Tract Participation to be assigned to each Tract in the enlarged Unit Area and other pertinent data, all of which shall be agreed upon by the Working Interest Owners of the Tract or Tracts to be added prior to the circulation of such notice. If Working Interest Owners having in the aggregate at least seventy percent (70%) of the Unit Participation then in effect agree to the inclusion of such Tract or Tracts in the Unit Area on the terms proposed, the Unit Operator shall make application for approval by the North Dakota Industrial Commission in accordance with Section 38-08-09-9 of the North Dakota Century Code.

The enlargement shall become effective on the first day of the month following the approval of the enlargement by the North Dakota Industrial Commission or such other date as may be established by order of the Commission. The effective date of the enlargement shall be set out in the certificate of effectiveness, which shall be filed of record as set forth in Article 15 hereof.

ARTICLE 4

UNIT OPERATIONS

4.1 **Unit Operator.** Conoco Inc. is hereby designated as the initial Unit Operator. Unit Operator shall have the exclusive right to conduct Unit Operations, which shall conform to the provisions of this Agreement and the Unit Operating Agreement. If there is any conflict between such agreements, this Agreement shall govern.

4.2 **Resignation or Removal.** Unit Operator may resign at any time. Unit Operator may be removed at any time by the affirmative vote of Working Interest Owners having fifty-one percent (51%) or more of the voting interest. Such resignation or removal shall not become effective for a period of three (3) months after the resignation or removal, unless a successor Unit Operator has taken over Unit Operations prior to the expiration of such period.

4.3 **Selection of Successor.** Upon the resignation or removal of Unit Operator, a successor Unit Operator shall be selected by Working Interest Owners. If the removed Unit Operator fails to vote or votes only to succeed itself, the successor Unit Operator shall be selected by the affirmative vote of Working Interest Owners having seventy percent (70%) or more of the voting interest remaining after excluding the voting interest of the removed Unit Operator.

4.4 **Method of Operation.** To the end that the quantity of Unitized Substances ultimately recoverable may be increased and waste prevented, Working Interest Owners shall, with diligence and in accordance with good engineering and production practices, engage in a water injection program and/or other future enhanced oil recovery programs designed for improved economic oil recovery.

4.5 **Change of Method of Operation.** Nothing herein shall prevent Working Interest Owners from discontinuing or changing in whole or in part any method of operation which, in their opinion, is no longer in accord with good engineering and production practices.

ARTICLE 5

TRACT PARTICIPATIONS

5.1 **Tract Participations.** The Tract Participation of each Tract is shown in Exhibit A. Beginning at 7:00 a.m. on the Effective Date hereof and continuing during the term hereof, all Unitized Substances shall be allocated on the basis of Tract Participation as shown in Exhibit A, determined under the following formula:

PHASE I - 50% Remaining Primary Recovery as of March 1, 1994.
- 50% Remaining Original Oil in Place as of March 1, 1994.

PHASE II - 100% Original Oil in Place at the Initial Reservoir Pressure of 4536 psia.

5.2 **Relative Tract Participations.** If the Unit Area is changed, the revised Tract Participations of the Tracts in the Unit Area and which were within the Unit Area prior to the change shall remain in the same ratio one to another.

ARTICLE 6

ALLOCATION OF UNITIZED SUBSTANCES

6.1 **Allocation to Tracts.** All Unitized Substances produced and saved shall be allocated to the several Tracts in accordance with the respective Tract Participations effective hereunder during the respective period that the Unitized Substances were produced. The amount of Unitized Substances allocated to each Tract, regardless of whether the amount is more or less than the actual production of Unitized Substances from the well or wells, if any, on such Tract, shall be deemed for all purposes to have been produced from such Tract.

6.2 Distribution Within Tracts. The Unitized Substances allocated to each Tract shall be distributed among, or accounted for to, the Persons entitled to share in the production from such Tract in the same manner, in the same proportions, and upon the same conditions as they would have participated and shared in the production from such Tract, or in the proceeds thereof, had this Agreement not been entered into, and with the same legal effect. If any Oil and Gas Rights in a Tract hereafter become divided and owned in severalty as to different parts of the Tract, the owners of the divided interests, in the absence of an agreement providing for a different division, shall share in the Unitized Substances allocated to the Tract, or in the proceeds thereof, in proportion to the surface acreage of their respective parts of the Tract. Any royalty or other payment which depends upon per well production or pipeline runs from a well or wells on a Tract shall, after the Effective Date, be determined by dividing the Unitized Substances allocated to the Tract by the number of wells on the Tract capable of producing Unitized Substances on the Effective Date; however, if any Tract has no well thereon capable of producing Unitized Substances on the Effective Date, the Tract shall, for the purpose of this determination, be deemed to have one such well thereon.

6.3 Taking Unitized Substances in Kind. The Unitized Substances allocated to each Tract shall be delivered in kind to the respective Persons entitled thereto by virtue of the ownership of Oil and Gas Rights therein or by purchase from such owners. Such Persons shall have the right to construct, maintain, and operate within the Unit Area all necessary facilities for that purpose, provided they are so constructed, maintained, and operated as not to interfere with Unit Operations. Any extra expenditures incurred by Unit Operator by reason of the delivery in kind of any portion of Unitized Substances shall be borne by the owner of such portion. If a Royalty Owner has the right to take in kind a share of Unitized Substances and fails to do so, the Working Interest Owner whose Working Interest is subject to such Royalty Interest shall be entitled to take in kind such share of Unitized Substances.

6.4 Failure to Take in Kind. If any Person fails to take in kind or separately dispose of such Person's share of Unitized Substances, Unit Operator shall have the right, but not the obligation, for the time being and subject to revocation at will by the Person owning the share, to purchase or sell to others such share; however, all contracts of sale by Unit Operator of any other Person's share of Unitized Substances shall be only for such reasonable periods of time as are consistent with the minimum needs of the industry under the circumstances, but in no event shall any such contract be for a period in excess of one year. The proceeds of the Unitized Substances so disposed of by Unit Operator shall be paid to the Working Interest Owners of each affected Tract or a Person designated by such Working Interest Owners who shall distribute such proceeds to the Persons entitled thereto.

6.5 Responsibility for Royalty Settlements. Any Person receiving in kind or separately disposing of all or part of the Unitized Substances allocated to any Tract shall be responsible for the payment of all royalties, overriding royalties, production payments, and all other payments chargeable against or payable out of such Unitized Substances, and shall indemnify all Persons, including Unit Operator, against any liability for such payment.

6.6 Rental or Minimum Royalty Settlement. Rental or minimum royalties due on leases committed hereto shall be paid by Working Interest Owners responsible therefor under existing contracts, laws, and regulations, provided that nothing herein contained shall operate to relieve the lessees of any land from their respective lease obligations for the payment of any rental or minimum royalty in lieu thereof due under their leases.

6.7 Royalty on Outside Substances. No payment shall be due or payable to any Royalty Owner, and no production, severance, or other tax will be payable to any taxing authority on Outside Substances injected into the Unitized Formation, and subsequently produced or sold with the Unitized Substances.

If Natural Gas is injected into the Unitized Formation as an Outside Substance, one hundred percent (100%) of the Natural Gas contained in Unitized Substances subsequently produced and sold, or used for other than Unit Operations, shall be deemed an Outside Substance until the total volume of Natural Gas deemed to be an Outside Substance equals the total volume of Natural Gas injected as an Outside Substance. If LPG or Liquid Hydrocarbons are injected into the Unitized Formation as an Outside Substance (either separately or mixed with Natural Gas), one hundred percent (100%) of all Unitized Substances other than Natural Gas subsequently produced, sold, or used for purposes other than Unit Operations, shall be deemed an Outside Substance until the total volume of such production of the LPG or Liquid Hydrocarbons injected as an Outside Substance. If more than one Outside Substance is injected into the Unitized Formation, each Outside Substance will be treated separately under this provision and the recovery percentages stated above will apply cumulatively.

The Unit Operator will account monthly for each Outside Substance injected into and produced from the Unitized Formation. In any accounting month, if the quantity of an Outside Substance injected into the Unitized Formation exceeds the quantity of the like substance produced from the Unitized Formation and deemed to be an Outside Substance, the difference in these quantities will be carried over to succeeding accounting months until the total quantity of the Outside Substance injected into the Unitized Formation has been recovered. If Natural Gas produced from the Unitized Formation is processed in a plant in the vicinity of the unit for the purpose of separating Natural Gas from LPG or Liquid Hydrocarbons, then the amount of Natural Gas, LPG and Liquid Hydrocarbons recovered by such processing and allocated to the unit will be the basis for accounting for Outside Substances under this provision.

6.8 Carved Out Interests. Those leasehold interest owners whose leases are subject to any Carved Out Interests shall bear the burden of payment for said interests in the proportion in which they have contributed said leases to the Unit Area.

ARTICLE 7

PRODUCTION AS OF THE EFFECTIVE DATE

7.1 **Oil or Liquid Hydrocarbons in Lease Tanks.** Unit Operator shall gauge or otherwise determine the amount of merchantable oil or other liquid hydrocarbons produced from the Unitized Formation that are in lease tanks as of 7:00 a.m. on the Effective Date. Oil or other liquid hydrocarbons in oil sale tanks below pipeline connections and in treating vessels and separation equipment shall not be considered merchantable. Any such merchantable oil or other liquid hydrocarbons not promptly removed may be sold by Unit Operator for the account of the Working Interest Owners entitled thereto who shall pay royalty due thereon under the provisions of applicable leases or other contracts. Any oil or liquid hydrocarbons in excess of that attributable to the prior allowable of the wells from which they were produced shall be credited to all Tracts as if they were Unitized Substances.

ARTICLE 8

USE OR LOSS OF UNITIZED SUBSTANCES

8.1 **Use of Unitized Substances.** Working Interest Owners may use or consume Unitized Substances for Unit Operations, including but not limited to the injection thereof into the Unitized Formation.

8.2 **Royalty Payments.** No royalty, overriding royalty, production, or other payments shall be payable on account of Unitized Substances used, lost, or consumed in Unit Operations.

8.3 **Storage of Unitized Substances.** The Working Interest Owners are hereby granted the right to inject Unitized Substances and Outside Substances into the Unitized Formation for storage. Unitized Substances so injected shall be excluded in allocating Unitized Substances to Tracts, and no royalty or other payment shall be payable in respect thereof until they are recovered from the Unitized Formation and sold or used for operations other than operations hereunder.

ARTICLE 9

TITLES

9.1 Warranty and Indemnity. Each Person who, by acceptance of produced Unitized Substances or the proceeds thereof, may claim to own a Working Interest or Royalty Interest in and to any Tract or in the Unitized Substances allocated thereto, shall be deemed to have warranted its title to such interest, and, upon receipt of the Unitized Substances or the proceeds thereof to the credit of such interest, shall indemnify and hold harmless all other Persons in interest from any loss due to failure, in whole or in part, of its title to any such interest.

9.2 Production Where Title is in Dispute. If the title or right of any Person claiming the right to receive in kind all or any portion of the Unitized Substances allocated to a Tract is in dispute, Unit Operator at the direction of Working Interest Owners shall either:

(a) require that the Person to whom such Unitized Substances are delivered or to whom the proceeds thereof are paid furnish security for the proper accounting therefor to the rightful owner if the title or right of such Person fails in whole or in part, or

(b) withhold and market the portion of Unitized Substances with respect to which title or right is in dispute, and impound the proceeds thereof until such time as the title or right thereto is established by a final judgment of a court of competent jurisdiction or otherwise to the satisfaction of Working Interest Owners, whereupon the proceeds so impounded shall be paid to the Person rightfully entitled thereto.

9.3 Payment of Taxes to Protect Title. If any taxes are not paid when due by or for any owner of surface rights to lands within the Unit Area, or severed mineral interests or Royalty Interests in such lands, or lands outside the Unit Area on which Unit Equipment is located, Unit Operator may, with approval of Working Interest Owners, at any time prior to tax sale, or expiration of period of redemption after tax sale, pay the tax and redeem or purchase such rights, interests, or property. Any such payment shall be an item of Unit Expense. Unit Operator shall, if possible, withhold from any proceeds derived from the sale of Unitized Substances otherwise due any delinquent taxpayer an amount sufficient to defray the costs of such payment, such withholding to be credited to Working Interest Owners. Such withholding shall be without prejudice to any other remedy available to Unit Operator or Working Interest Owners.

9.4 **Transfer of Title.** Any conveyance of all or any part of any interest owned by a Person with respect to any Tract shall be subject to this Agreement. No change of title shall be binding upon Unit Operator, or upon any Person other than the Person so transferring, until 7:00 a.m. on the first day of the calendar month next succeeding the date of receipt by Unit Operator of a photocopy or a certified copy of the recorded instrument evidencing such change in ownership.

ARTICLE 10

EASEMENTS OR USE OF SURFACE

10.1 **Grant of Easements.** Working Interest Owners shall have the right to use as much of the surface of the land within the Unit Area as may be reasonably necessary for Unit Operations and the removal of Unitized Substances from the Unit Area.

10.2 **Use of Water.** Working Interest Owners shall have and are hereby granted free use of water from the Unit Area for Unit Operations, except water from any well, lake, pond, or irrigation ditch of a Royalty Owner.

10.3 **Surface Damages.** Working Interest Owners shall pay the owner for damages to growing crops, timber, fences, improvements, and structures on the Unit Area that result from Unit Operations in accordance with the provisions of Chapter 38-11.1 of the North Dakota Century Code.

ARTICLE 11

CHANGES AND AMENDMENTS

11.1 **Changes and Amendments.** Any change of the Unit Area or any amendment to this Agreement or the Unit Operating Agreement shall be in accordance with Section 38-08-09.1 through 38-08-09.16 of the North Dakota Century Code.

ARTICLE 12

RELATIONSHIPS OF PERSONS

12.1 No Partnership. All duties, obligations, and liabilities arising hereunder shall be several and not joint or collective. This Agreement shall not be construed to create an association or trust, or to impose a partnership or fiduciary duty, obligation, or liability. Each Person affected hereby shall be individually responsible for its own obligations.

12.2 No Joint Refining or Marketing. This Agreement shall not be construed to provide, directly or indirectly, for any joint refining or marketing of Unitized Substances.

12.3 Royalty Owners Free of Costs. This Agreement shall not be construed to impose upon any Royalty Owner any obligation to pay Unit Expense unless such Royalty Owner is otherwise so obligated; provided, however, that any interest created out of a Working Interest, shall be subject to the security rights provided by the Unit Operating Agreement. The owner of any such interest shall be subrogated to the security rights available against the Working Interest out of which such interest was created.

ARTICLE 13

BORDER AGREEMENTS

13.1 Border Agreements. Unit Operator, subject to the provisions of the Unit Operating Agreement may enter into an agreement or agreements with the working interest owners of adjacent lands with respect to operations and allocation of production, which agreements are designed to increase the ultimate recovery of oil and/or gas from the Unitized Formation, prevent waste, and protect the correlative rights of the parties.

ARTICLE 14

FORCE MAJEURE

14.1 Force Majeure. All obligations arising hereunder, except for the payment of money, shall be suspended while compliance is prevented, in whole or in part, by a labor dispute, fire, war, civil disturbance, act of God; by Federal, state, or municipal laws; by any rule, regulations, or order of a governmental agency; by inability to secure materials; or by any other cause or causes, whether similar or dissimilar, beyond reasonable control of the Person. No Person shall be required against his will to adjust or settle any labor dispute. Neither this Agreement nor any lease or other instrument subject hereto shall be terminated by reason of suspension of Unit Operations due to any one or more of the causes set forth in this Article.

ARTICLE 15

EFFECTIVE DATE

15.1 Effective Date. This Agreement shall become effective as of the date determined by Working Interest Owners in accordance with the voting provisions of the Unit Operating Agreement. Such determination by Working Interest Owners shall be made in accordance with an order approving this Unit by the North Dakota State Industrial Commission.

15.2 Ipso Facto Termination. If this unit is not made effective on or before January 1, 1995, this Agreement shall ipso facto terminate on that date (hereinafter called "termination date") and thereafter be of no further effect, unless prior thereto Working Interest Owners owning a combined Unit Participation of at least seventy percent (70%) have approved this Agreement and Working Interest Owners owning seventy percent (70%) or more of that percent have decided to extend the termination date for a period not to exceed twelve (12) months. If the termination date is so extended and this unit is not made effective on or before the extended termination date, this Agreement shall ipso facto terminate on the extended termination date and thereafter be of no further effect. For the purpose of this Section, Unit Participation shall be as calculated on the basis of Tract Participations for Phase I shown on the original Exhibit A.

15.3 Certificate of Effectiveness. Unit Operator shall file with the North Dakota State Industrial Commission and for record in the county or counties in which the land affected is located a certificate stating the Effective Date.

ARTICLE 16

TERM

16.1 Term. Except as provided in Section 38-08-09.4(7) of the North Dakota Century Code, this Agreement shall remain in effect so long as Unitized Substances are produced in paying quantities without a cessation of more than ninety (90) days, or so long as other Unit Operations are conducted without a cessation of more than ninety (90) days, unless sooner terminated by Working Interest Owners owning a combined Unit Participation, in effect at the time of voting, of seventy percent (70%) or more whenever such Working Interest Owners determine that Unit Operations are no longer economically feasible.

16.2 Effect of Termination. Upon termination of this Agreement, the further development and operation of the Unitized Formation as a unit shall cease. The relationships among owners of Oil and Gas Rights shall thereafter be governed by the terms and provisions of the leases and other instruments, not including this Agreement, affecting the separate Tracts.

16.3 Salvaging Equipment Upon Termination. If not otherwise granted by the leases or other instruments affecting the separate Tracts, Working Interest Owners shall have a period of six (6) months after the date of termination of this Agreement within which to salvage and remove Unit Equipment.

16.4 Certificate of Termination. Upon termination of this Agreement, Unit Operator shall file with the North Dakota State Industrial Commission and for record in the county or counties in which the land affected is located a certificate that this Agreement has terminated, stating its termination date.

ARTICLE 17

APPROVAL

17.1 Original, Counterpart, or Other Instrument. A Working Interest Owner or a Royalty Owner of Oil and Gas Rights may approve this Agreement by signing the original, a counterpart thereof, or other instrument approving this Agreement. The signing of any such instrument shall have the same effect as if all Persons had signed the same instrument and shall constitute approval of the entire Plan of Unitization composed of this Agreement and the Unit Operating Agreement.

17.2 Commitment of Interests to Unit. The approval of this Agreement by a Person shall bind that Person and commit all interests owned or controlled by that Person as of the date of such approval, and additional interests thereafter acquired.

ARTICLE 18

DETERMINATIONS BY WORKING INTEREST OWNERS

18.1 Determinations by Working Interest Owners. All decisions, determinations, or approvals by Working Interest Owners hereunder shall be made pursuant to the voting procedure of the Unit Operating Agreement unless otherwise provided herein.

ARTICLE 19

SUCCESSORS AND ASSIGNS

19.1 Successors and Assigns. This Agreement shall extend to, be binding upon, and inure to the benefit of the Royalty Owners and Working Interest Owners and their respective heirs, devisees, legal representatives, successors, and assigns, and shall constitute a covenant running with the lands, leases, and interests covered hereby.

IN WITNESS WHEREOF, the Persons hereto have approved this Agreement on the dates opposite their respective signatures.

Date of Execution:
April 15, 1994

CONOCO INC.

By: Roger B. Brown

Roger B. Brown
Division Manager
Attorney-in-Fact

04/21/94

Exhibit A to Unit Agreement dated April 15, 1994

DICKINSON LODGEPOLE UNIT
STARK COUNTY, NORTH DAKOTA

Tract No.	Description & Acres in Tract	Working Interest Owner & Percentage		Net Acres	Mineral Owner & Percentage		Overriding Royalty Owner & Percentage		PHASE I TRACT PERCENTAGE	PHASE II TRACT PERCENTAGE
1	W½ - Sec. 32 - T140N - R96W	Conoco Inc.	100.000%	320.000	J. H. Smart Jr.	3.12500%	Torch Oil & Gas Company	0.46875%	50.12991%	50.35218%
	320.000 acres		100.000%	320.000	Peggy Addington	6.25000%	Louis W. Hill Jr	0.15381%		
					The Wiser Oil Company	0.97656%	Mobil Exploration & Production	1.87500%		
					Beeman Dockery	1.79688%	Philips Petroleum	1.84326%		
					The Fasken Foundation	0.15625%		4.34082%		
					Agribank FCB	25.00000%				
					Republic Royalty Company	2.32187%				
					Louis W. Hill Jr	5.66406%				
					Erma Lowe Trust for Carson Yost, Mary Ralph Lowe Trustee	0.01148%				
					Clark E. Jones	0.31250%				
					Clyde W. Jones	0.78125%				
					Dodge Jones FDN	0.24272%				
					Linda R. Jones a/k/a Linda R. Branting	0.78125%				
					Gerald David Kalanek	12.50000%				
					Darlene McKinley Lane	3.12500%				
					Martha Smart Bennett	3.12500%				
					Julia Jones Matthews	0.05283%				
					Hunter S. Trunk	1.56250%				
					J. Hiram Moore, Betty Jane Moore & Michael H. Moore Trust U/I/TR dated 7/1/71	3.35938%				
					Matt-Tex L.L.P	0.07500%				
					Pacific West Lease Company	0.78125%				
					Randy Geiselman	0.05625%				
					Baytech Inc.	0.12500%				
					Mary Margarett Pugh	2.34375%				
					Zula Mae Pugh	0.31250%				
					E. E. & Mildred E. Trumbell as Joint Tenants	3.12500%				
					Mary Pearl Lake	3.12500%				
					Leslie J. May	1.56250%				
					Virginia L. Sherron	6.25000%				
					John A. Matthews Jr.	0.03750%				
					Fayette K. Stroud MO, Trustee FBO C & F Stroud Trust Fund JT U/D/T dated 12/18/73	0.46875%				
					Andrews Royalty Inc	0.02313%				
					Erma Lowe Trust for Clayton Yost, Mary Ralph Lowe, Trustee	0.01148%				
					Erma Lowe Trust for Samantha Yost, Mary Ralph Lowe, Trustee	0.01148%				
					Elizabeth H. Welch	3.12500%				
					Conoco Inc.	7.42186%				
						100.00000%				

Exhibit A to Unit Agreement dated April 15, 1994

DICKINSON LODGEPOLE UNIT
STARK COUNTY, NORTH DAKOTA

Tract No.	Description & Acres in Tract	Working Interest Owner & Percentage		Net Acres	Mineral Owner & Percentage		Overriding Royalty Owner & Percentage		PHASE I TRACT PERCENTAGE	PHASE II TRACT PERCENTAGE
2	S½ – Sec. 31 – T140N – R96W	Andrea Singer Pollack Revocable Trust	50.00000%	154.245	The Wiser Oil Company	25.00000%	Andrea Singer Pollack Revocable Trust	12.50000%	33.16362%	31.78581%
	308.49 acres	Conoco Inc.	50.00000%	154.245	The Fasken Foundation	1.24654%		12.50000%		
			100.00000%	308.490	Republic Royalty Company	18.57500%				
					Erma Lowe Trust for Carson Yost, Mary Ralph Lowe, Trustee	0.09187%				
					Dodge Jones FDN	1.94172%				
					Douglas Kadrmas	12.50000%				
					Arnold L. Kadrmas	12.50000%				
					Linda Kadrmas	12.50000%				
					Julia Jones Matthews	0.42266%				
					Matt - Tex L.L.P.	0.60154%				
					Randy Geiselman	0.15000%				
					Baytech Inc	1.00000%				
					Joan Schmidt	12.50000%				
					John A. Matthews Jr	0.29993%				
					Andrews Royalty Inc	0.16500%				
					Erma Lowe Trust for Clayton Yost, Mary Ralph Lowe, Trustee	0.09167%				
					Erma Lowe Trust for Samantha Yost, Mary Ralph Lowe, Trustee	0.09167%				
						100.00000%				
3	N½ – Sec. 31 – T140N – R96W	The Wiser Oil Company	1.74958%	5.313	The Wiser Oil Company	14.79315%			12.36350%	11.64830%
	303.65 acres	Louis W. Hill Jr	4.13910%	12.568	Patricia & William Dowell	1.94818%				
		Hunt Petroleum Company	8.40336%	25.517	Agribank FCB	50.00000%				
		Huntington Resources Inc.	4.72689%	14.353	Mary Ann & Edwin A. Ficek	1.94818%				
		Placid Oil Company	32.14286%	97.602	John M. Grande Trust, William J. Grande, Trustee	2.24664%				
		Phillips Petroleum Company	4.38126%	13.304	Lester & Marlene Frenzel	1.94818%				
		Conoco Inc. **	44.45695%	134.991	Rose Frenzel	12.44275%				
			100.00000%	303.650	Irene & Karl Hammann	1.94818%				
					Louis W. Hill, Jr	8.23316%				
					Clyde W. Jones	0.82237%				
					Linda R. Jones, a/k/a Linda R. Branting	0.82237%				
					Paul Karow	0.44933%				
					Diane & Kenneth Mayer	1.94818%				
					Conoco Inc.	0.44933%				
						100.00000%				

**BPO

04/21/94

Exhibit A to Unit Agreement
dated April 15, 1994

DICKINSON LODGEPOLE UNIT
STARK COUNTY, NORTH DAKOTA

Tract No.	Description & Acres in Tract	Working Interest Owner & Percentage		Net Acres	Mineral Owner & Percentage		Overriding Royalty Owner & Percentage	PHASE I TRACT PERCENTAGE	PHASE II TRACT PERCENTAGE
4	N½ – Sec. 5 – T139N – R96W	Conoco Inc.	100.00000%	323.780	State of North Dakota	100.00000%		2.23917%	2.11507%
	323.780 acres		100.00000%	323.780		100.00000%			
5	N½ – Sec. 6 – T139N – R96W	Conoco Inc	3.63393%	2.190	Victor B. Walton	25.00000%		0.6465[illegible]%	1.64933%
	60.270 acres	A R S Limited Partnership	96.36607%	58.080	Robert R. Walton	12.50000%			
			100.00000%	60.270	Dr. William H. Walton, Jr.	12.50000%			
					Shirley Jean Larkin	12.50000%			
					Julia Reynolds	6.25000%			
					Elizabeth Bowers	6.25000%			
					Benjamin Deeble	6.25000%			
					James W. Hoffman	3.12500%			
					John A. Hoffman	3.12500%			
					David L. Hoffman	3.12500%			
					William R. Hoffman	3.12500%			
					Victoria Raynor	6.25000%			
						100.00000%			
6	SE¼ – Sec. 30 – T140N – R96W	Conoco Inc.	50.00000%	5.005	Laudie L. Ridl	10.00000%		0.01840%	0.03584%
	10.010 acres	Placid Oil Company	32.14286%	3.216	Irene Ridl Wilson	10.00000%			
		Louisiana–Hunt Petroleum	8.40336%	0.841	Angie Ridl Kadrmas	10.00000%			
		Mid–Continent Energy Investors	4.72689%	0.473	Arthur J. Ridl	10.00000%			
		Huntington Resources Inc	4.72689%	0.473	Blanche Ridl Mack	10.00000%			
			100.00000%	10.010	Agribank FCB	50.00000%			
						100.00000%			

Exhibit A to Unit Agreement dated April 15, 1994

DICKINSON LODGEPOLE UNIT
STARK COUNTY, NORTH DAKOTA

Tract No.	Description & Acres in Tract	Working Interest Owner & Percentage		Net Acres	Mineral Owner & Percentage		Overriding Royalty Owner & Percentage		PHASE I TRACT PERCENTAGE	PHASE II TRACT PERCENTAGE
7	SW¼ – Sec. 29 – T140N – R96W	Phillips Petroleum Company	25.00000%	10.038	E. E. Trumbull	6.25000%			0.32677%	0.63664%
	40.150 acres	Conoco Inc	25.00000%	10.038	Darlene McKinley Lane	6.25000%				
		Mobil Exploration & Producing NA	50.00000%	20.075	Mary Margaret Pugh	4.68750%				
			100.00000%	40.150	Elizabeth H. Welch	6.25000%				
					Virginia L. Sherron	12.50000%				
					Mary Pearl Lake	6.25000%				
					Beeman Dockery	3.59375%				
					Zula Mae Pugh	0.62500%				
					C & F Stroud Trust – Fund JT UDT, Fayette K. Stroud M.D., Trustee FBO	0.93750%				
					Clark F. Jones	0.62500%				
					Pacific West Lease Company	1.56250%				
					J. Hiram Moore, Betty Jane Moore and Michael Harrison Moore, Trustees	6.71875%				
					Gerald David Kalanek	5.55556				
					Vivian Miller	9.72222%				
					Mary Daphne Hibl	9.72222%				
					Hunter S. Trunk	3.12500%				
					Leslie F. May	3.12500%				
					Peggy Addington	12.50000%				
						100.00000%				
8	NE¼ – Sec. 32 – T140N – R96W	Ruth Ray Hunt	1.25000%	0.376	Barbara M. Comeau	1.25000%	R. E. & Mildred Moore **	1.00000%	0.11111%	0.80156%
	30.060 acres	Unit Four Partnership	0.20833%	0.063	Cynthia A. Comeau	1.25000%	TWR, Inc **	1.00000%		
		Petro-Hunt Corporation	0.20833%	0.063	J. Hiram Moore, Betty Jane Moore and Michael Harrison Moore, Trustees	7.29169%		2.00000%		
		Hunt Oil Company	0.83333%	0.251						
		Phillips Petroleum Company	62.50000%	18.788	Dewitt Lands Jr	0.52085%	** The above ORRI burdens the Phillips Petroleum WI only			
		North American Royalties Inc	9.01957%	2.711	Charles Lands	0.52085%				
		Louis W. Hill Jr	8.11625%	2.440	Gerald C. Wiseman	0.26041%				
		Conoco Inc	16.19752%	4.869	Marilyn Kay Ralston	0.26041%				
		The Wiser Oil Company	1.66667%	0.501	J. R. & Katherine A. Taylor	0.52081%				
			100.00000%	30.060	Viola L. & Virginia Younger	1.04169%				
					Janice S. Haffey	0.52081%				
					Elaine G. Konzelman	0.52081%				
					Johnnie Beth Huskey	1.04169%				
					Conoco Inc.	3.75000%				
					Mary H. Ayala	3.75000%				
					Lois Eby Budbill	1.16669%				
					The Wiser Oil Company	6.66669%				
					Stephen Filipi	62.50000%				
					Charles Taubman Revocable Trust	0.61406%				
					Henrik Perry Taubman Family Trust	0.01619%				
					Adina Taubman Trust	0.01619%				

Exhibit A to Unit Agreement dated April 15, 1994

DICKINSON LODGEPOLE UNIT
STARK COUNTY, NORTH DAKOTA

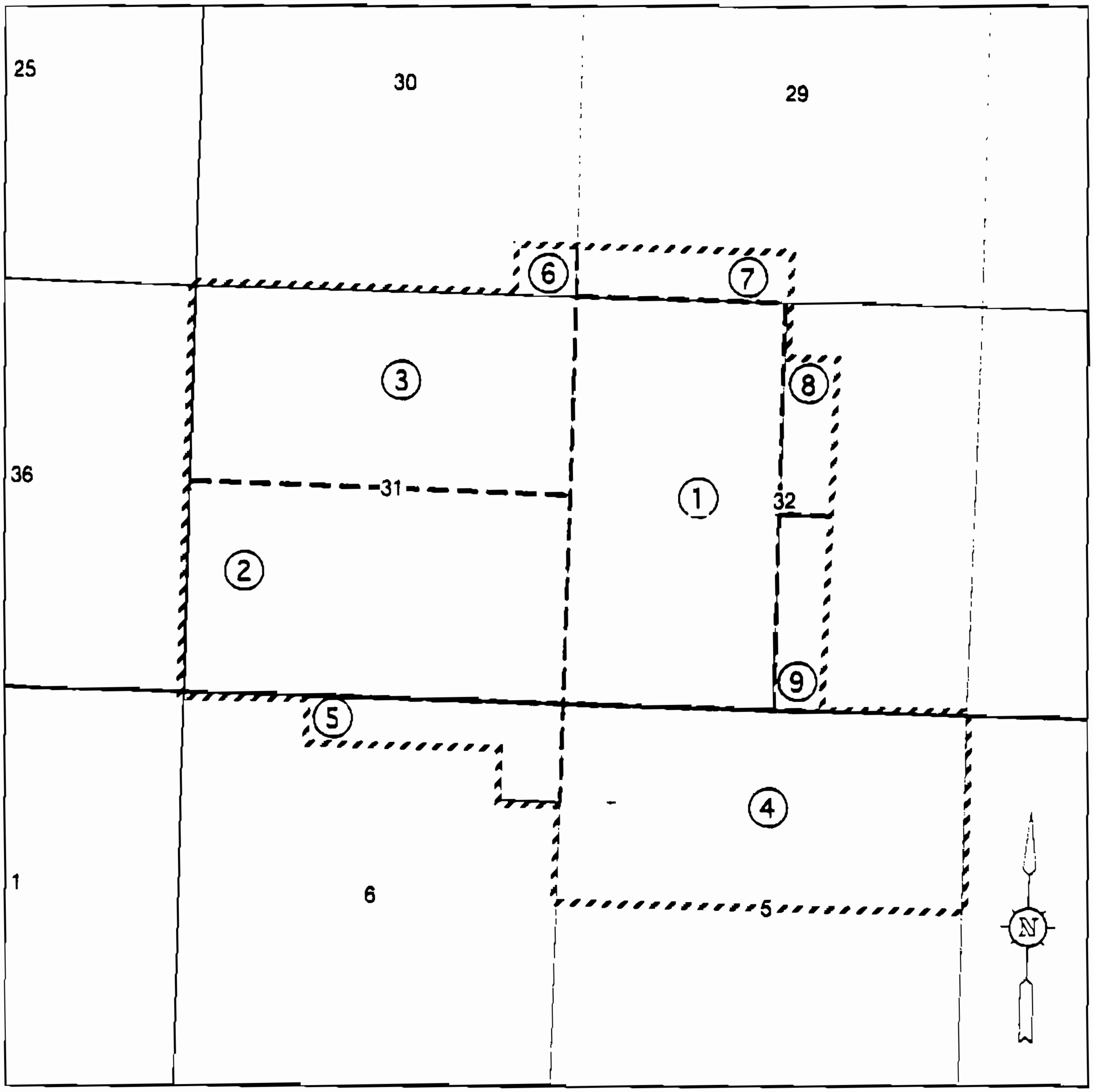
Tract No.	Description & Acres in Tract	Working Interest Owner & Percentage		Net Acres	Mineral Owner & Percentage		Overriding Royalty Owner & Percentage	PHASE I TRACT PERCENTAGE	PHASE II TRACT PERCENTAGE
8	NE¼ – Sec. 32 – T140N – R96W 30.060 acres (continued)				Louis Taubman Trust	0.785755%			
					L. N. Taubman Revocable Trust	0.055755%			
					Bank of Oklahoma, Tulsa, Maurine Taubman Co–Trustee certain Trust dated 12/4/86	0.055755%			
					Herman P. & Sophia Taubman	0.006060%			
					National Bank Tulsa, Trustee, Trust Indenture dated 11/12/69	0.56150%			
					Estate of William David Taubman	0.00725%			
					Barbara Taubman Living Trust	0.01456%			
					Deborah Anne Taubman Trust	0.00725%			
					Hilary Lu Taubman Revocable Trust	0.00725%			
					Andrea Taubman Ouqano Revocable Trust	0.00731%			
					Rebecca M. Taubman Revocable Trust	0.00725%			
					Claudia P. Taubman Revocable Trust	0.00725%			
					Robert M. Taubman Revocable Trust	0.55425%			
					Sara K. Taubman Revocable Trust	0.00731%			
					Rosalie Taubman Management Trust	0.47425%			
					Karen P. Shalom Management Trust	0.02906%			
					Jonathan Z. Shalom Management Trust	0.02906%			
					Morris B. Taubman Revocable Trust	0.81238%			
					Anne C. Taubman Trust	0.04119%			
					Janice L. Taubman Revocable Trust	0.00850%			
					Richard J. Taubman Trust	0.04119%			
						100.00000%			
9	SE¼ Sec. 32 – T140N – R96W	Conoco Inc.	100.00000%	40.040	State of North Dakota	100.00000%		0.500568%	0.975277%
	40.040 acres		100.00000%	40.040		100.00000%			
							TOTAL:	100.00000%	100.00000%

EXHIBIT "B"
to Unit Agreement Dated April 15, 1994

R 97 W R 96 W

T 140 N

T 139 N



Unit Boundary
Tract Boundary
1 Tract No.

Scale
1000'

DICKINSON LODGEPOLE UNIT
Stark Co., North Dakota

TRACT	ACRES
1	320.00
2	308.49
3	303.65
4	323.78
5	60.27
6	10.01
7	40.15
8	30.06
9	40.04
TOTAL	1436.45

UNIT OPERATING AGREEMENT

FOR THE DEVELOPMENT AND OPERATION

OF THE

DICKINSON LODGEPOLE UNIT

COUNTY OF STARK

STATE OF NORTH DAKOTA

[Statutory Unit formed pursuant to the North Dakota Century Code, Sections 38-08-09.1 through 38-08-09.16, as amended]

DATED THIS 15TH DAY OF APRIL, 1994

CONOCO INC.

Case No.
Exhibit No. 6

UNIT OPERATING AGREEMENT

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ARTICLE 14
NONDISCRIMINATION

UNIT OPERATING AGREEMENT

Dickinson Lodgepole Unit

Stark County, North Dakota

THIS AGREEMENT is entered into as of the 15th day of April, 1994,

W I T N E S S E T H :

WHEREAS, an agreement entitled "Unit Agreement, Dickinson Lodgepole Unit, Stark County, North Dakota", herein referred to as "Unit Agreement", has been made which, among other things, provides for a separate agreement to provide for Unit Operations as therein defined,

NOW, THEREFORE, it is provided as follows:

ARTICLE 1

CONFIRMATION OF UNIT AGREEMENT

1.1 **Confirmation of Unit Agreement.** The Unit Agreement is hereby confirmed and by reference made a part of this Agreement. The definitions in the Unit Agreement are adopted for all purposes of this Agreement. If there is any conflict between the Unit Agreement and this Agreement, the Unit Agreement shall govern.

ARTICLE 2

EXHIBITS

2.1 **Exhibits.** The following exhibits are incorporated herein by reference or attachment:

2.1.1 **Exhibits A and B** of the Unit Agreement.

2.1.2 **Exhibit C,** attached hereto, is a schedule showing the Working Interest of each Working Interest Owner in each Tract, the portion of each Working Interest

Owner's Unit Participation attributable to each such interest, and the Unit Participation of each Working Interest Owner.

2.1.3 **Exhibit D,** attached hereto, is the Accounting Procedure applicable to Unit Operations. If there is any conflict between this Agreement and Exhibit D, this Agreement shall govern.

2.1.4 **Exhibit E,** attached hereto, contains a list of wells to be taken over by the Unit Operator.

2.1.5 **Exhibit F,** Certificate of Compliance with Federal Contract Requirements.

2.1.6 **Exhibit G,** Insurance Provisions

2.1.7 **Exhibit H,** Gas Balancing Provision, which contains the gas balancing provisions applicable to Unit Operations.

2.2 **Reference to Exhibits.** When reference is made herein to an exhibit, it is to the original exhibit or, if revised, to the last revision.

ARTICLE 3

SUPERVISION OF OPERATIONS BY WORKING INTEREST OWNERS

3.1 **Overall Supervision.** Working Interest Owners shall exercise overall supervision and control of all matters pertaining to Unit Operations. In the exercise of such authority, each Working Interest Owner shall act solely in its own behalf in the capacity of an individual owner and not on behalf of the owners as an entirety.

3.2 **Specific Authority and Duties.** The matters with respect to which Working Interest Owners shall decide and take action shall include, but not be limited to, the following:

3.2.1 **Method of Operation.** The method of operation, including the type of recovery program to be employed.

3.2.2 Drilling of Wells. The drilling of any well whether for production of Unitized Substances, for use as an injection well, or for other purposes.

3.2.3 Well Recompletions and Change of Status. The recompletion, abandonment, or change of status of any well, or the use of any well for injection or other purposes.

3.2.4 Acquisitions. The acquisition of equipment and facilities necessary or advisable for Unit Operations, including without limitation the acquisition or construction of roads and other surface facilities, a pipeline system and the acquisition of existing well bores suitable for use as water source, water disposal or miscible gas injection wells.

3.2.5 Unit Operator's Tools and Equipment. The use by Unit Operator of its own tools and equipment in the drilling of a well or in any other operation in which drilling equipment is required.

3.2.6 Expenditures. The making of any single expenditure in excess of Fifty Thousand Dollars ($50,000); however, approval by Working Interest Owners of the drilling, reworking, deepening, or plugging back of any well shall include approval of all necessary expenditures required therefor, and for completing, testing, and equipping the well, including necessary flow lines, separators, and lease tankage.

3.2.7 Appearance Before a Court or Regulatory Agency. The designating of a representative to appear before any court or regulatory agency in matters pertaining to Unit Operations; however, such designation shall not prevent any Working Interest Owner from appearing in person or from designating another representative in its own behalf.

3.2.8 Audit Exceptions. The settlement of unresolved audit exceptions.

3.2.9 Inventories. The taking of periodic inventories as provided by Exhibit D.

3.2.10 Technical Services. The authorizing of charges to the joint account for services by consultants or Unit Operator's technical personnel not covered by the charges provided by Exhibit D.

3.2.11 Assignments to Committees. The appointment of committees to study any problems in connection with Unit Operations.

3.2.12 Removal of Operator. The removal of Unit Operator and the selection of a successor.

3.2.13 Changes and Amendments. The changing of the Unit Area or the amending of this Agreement or the Unit Agreement as provided by Article 11 of the Unit Agreement.

3.2.14 Investment Adjustment. The adjustment and readjustment of investments.

3.2.15 Termination of Unit Agreement. The termination of the Unit Agreement as provided therein.

3.2.16 Border Agreements. The approval of border agreements necessary or required by any governmental agency having jurisdiction.

3.2.17 Enlargements. The enlargement of the Unit Area as provided by Section 3.9 of the Unit Agreement.

ARTICLE 4

MANNER OF EXERCISING SUPERVISION

4.1 Designation of Representatives. Each Working Interest Owner shall inform Unit Operator in writing of the names and addresses of the representative and alternate who are authorized to represent and bind such Working Interest Owner with respect to Unit Operations. The representative or alternate may be changed from time to time by written notice to Unit Operator.

4.2 Meetings. All meetings of Working Interest Owners shall be called by Unit Operator upon its own motion or at the request of one or more Working Interest Owners having a total Unit Participation of not less than five percent (5%) calculated on the phase participation in effect at the time. No meeting shall be called on less than fourteen (14) days' advance written notice, with agenda for the meeting attached. Should any Working Interest Owner advise Unit Operator of a proposed change to the agenda, Unit Operator shall make a good faith effort to notify all of the Working Interest Owners of such proposed change prior to the meeting. Working Interest Owners who attend the meeting may amend items included in the agenda and may act upon an amended item or other items presented at the meeting. The Unit Operator's representative shall be chairman of each meeting. In the event of an emergency requiring a vote by the Operating Committee or Working Interest Owners, Unit Operator may call a meeting by telephone, telex or other means, and, upon verbal approval of seventy-five percent (75%) of the voting interest, such meeting shall be held as soon as possible. When the time for such meeting is established, Unit Operator shall notify all Working Interest Owners by appropriate means, to be confirmed in writing.

4.3 Voting Procedure. Working Interest Owners shall determine all matters coming before them as follows:

4.3.1 Voting Interest. Each Working Interest Owner shall have a voting interest equal to its Unit Participation in the phase in effect at the time the vote is taken.

4.3.2 Vote Required. Unless otherwise provided herein or in the Unit Agreement, Working Interest Owners shall determine all matters by the affirmative vote of two (2) or more Working Interest Owners having a combined voting interest of at least seventy percent (70%).

4.3.3 **Vote at Meeting by Nonattending Working Interest Owner.** Any Working Interest Owner who is not represented at a meeting may vote on any agenda item by letter, fax or telegram addressed to the representative of Unit Operator if its vote is received prior to the vote at the meeting.

4.3.4 **Poll Votes.** Working Interest Owners may vote by letter, fax or telegram on any matter submitted in writing to all Working Interest Owners. If a meeting is not requested, as provided in Section 4.2, within seven (7) days after a written proposal is sent to Working Interest Owners, the vote taken by letter, fax or telegram shall control. Unit Operator shall give prompt notice of the results of such voting to each Working Interest Owner.

ARTICLE 5

INDIVIDUAL RIGHTS OF WORKING INTEREST OWNERS

5.1 **Reservation of Rights.** Working Interest Owners retain all their rights, except as otherwise provided in this Agreement or the Unit Agreement.

5.2 **Specific Rights.** Each Working Interest Owner shall have, among others, the following specific rights:

5.2.1 **Access to Unit Area.** Access to the Unit Area at all reasonable times to inspect Unit Operations, all wells, and the records and data pertaining thereto.

5.2.2 **Reports.** The right to receive from Unit Operator, upon written request, copies of material reports to any governmental agency, reports of crude oil runs and stocks, inventory reports, and all other information pertaining to Unit Operations. The cost of gathering and furnishing information not ordinarily furnished by Unit Operator to all Working Interest Owners shall be charged to the Working Interest Owner that requests the information.

5.2.3 Audits. The right to audit the accounts of Unit Operator pertaining to Unit Operations according to the provisions of Exhibit D.

5.2.4 Reversionary Interest. When a Tract ownership changes due to the payout (or multiple) of a well within the unit, the balance remaining to recover will be calculated on an allocated Tract basis after the effective date of the unit. Payout will be deemed to occur at 7:00 A.M. on the first day following the day that the payout balance becomes zero.

ARTICLE 6

UNIT OPERATOR

6.1 Unit Operator. Conoco Inc. is designated as the initial Unit Operator.

6.2 Resignation or Removal. The provisions covering the resignation or removal of Unit Operator and the selection of a successor are set forth in Article 4 of the Unit Agreement.

ARTICLE 7

AUTHORITY AND DUTIES OF UNIT OPERATOR

7.1 Exclusive Right to Operate Unit. Subject to the provisions of this Agreement and to instructions from Working Interest Owners, Unit Operator shall have the exclusive right and be obligated to conduct Unit Operations, including, but not limited to, the right to execute contracts and agreements with third parties as are usual and customary for conducting Unit Operations.

7.2 Workmanlike Conduct. Unit Operator shall conduct Unit Operations in a good and workmanlike manner as would a prudent operator under the same or similar circumstances. Unit Operator shall freely consult with Working Interest Owners and keep them informed of all matters which Unit Operator, in the exercise of its best judgment, considers important. Unit

Operator shall not be liable to Working Interest Owners for damages, unless such damages result from its gross negligence or willful misconduct.

7.3 Liens and Encumbrances. Unit Operator shall endeavor to keep the lands and leases in the Unit Area and Unit Equipment free from all liens and encumbrances occasioned by Unit Operations, except those provided for in Article 11.

7.4 Employees. The number of employees used by Unit Operator in conducting Unit Operations, their selection, hours of labor, and compensation shall be determined by Unit Operator. Such employees shall be the employees of Unit Operator.

7.5 Records. Unit Operator shall keep correct books, accounts, and records of Unit Operations.

7.6 Reports to Working Interest Owners. Unit Operator shall furnish Working Interest Owners periodic reports of Unit Operations.

7.7 Reports to Governmental Authorities. Unit Operator shall make all reports to governmental authorities that it has the duty to make as Unit Operator.

7.8 Engineering and Geological Information. Unit Operator shall furnish to a Working Interest Owner, upon written request, a copy of all logs and other engineering and geological data pertaining to wells drilled for Unit Operations.

7.9 Expenditures. Unit Operator is authorized to make single expenditures not in excess of Fifty Thousand Dollars ($50,000) without prior approval of Working Interest Owners. In the event of an emergency, Unit Operator may immediately make or incur such expenditures as in its opinion are required to deal with the emergency. Unit Operator shall report to Working Interest Owners, as promptly as possible, the nature of the emergency and the action taken.

7.10 Wells Drilled by Unit Operator. All wells drilled by Unit Operator shall be at the rates prevailing in the area.

7.11 Use of Unit Surface. Unit operator is hereby granted the non-exclusive right to use the unit surface, including roads, rights-of-way, easements, and surface leases and facilities, where necessary to conduct unit operations. Each Working Interest Owner, when requested, shall deliver to Unit Operator document(s) evidencing Unit Operator's rights to so use the Unit Surface.

ARTICLE 8

TAXES

8.1 Property Taxes. Beginning with the first calendar year after the Effective Date hereof, Unit Operator shall make and file all necessary property tax renditions and returns with the proper taxing authorities with respect to all property of each Working Interest Owner used or held by Unit Operator for Unit Operations. Unit Operator shall settle assessments arising therefrom. All such property taxes shall be paid by Unit Operator and charged to the joint account; however, if the interest of a Working Interest Owner is subject to a separately assessed overriding royalty interest, production payment, or other interest in excess of a one-eighth (1/8) royalty, such Working Interest Owner shall be given credit for the reduction in taxes paid resulting therefrom.

8.2 Other Taxes. Each Working Interest Owner shall pay or cause to be paid all production, severance, gathering, and other taxes imposed upon or with respect to the production or handling of its share of Unitized Substances.

8.3 Income Tax Election. Notwithstanding any provisions herein that the rights and liabilities hereunder are several and not joint or collective, or that this Agreement and operations hereunder shall not constitute a partnership, if for Federal income tax purposes this Agreement and the operations hereunder are regarded as a partnership, then each Person hereby affected elects to be excluded from the application of all of the provisions of Subchapter K, Chapter 1, Subtitle A, of the Internal Revenue Code of 1986, as permitted and authorized by Section 761 of the Code and the regulations promulgated thereunder. Unit Operator is authorized and directed to execute on behalf of each Person hereby affected such evidence of this election as may be required by the Secretary of the Treasury of the United States or the Federal Internal Revenue Service, including specifically, but not by way of limitation, all of the returns, statements, and the data required by Federal Regulations 1.761-1(a). Should there be any requirement that each Person hereby affected give further evidence of this election, each such Person shall execute such documents and furnish such other evidence as may be required by the Federal Internal Revenue Service or as may be necessary to evidence this election. No such Person shall give any notices or take any other action inconsistent with the election made hereby. If any present or future income tax laws of the state or states in which the Unit Area is located or any future income tax law of the United States contain provisions similar to those in Subchapter K, Chapter 1, Subtitle A, of the Internal Revenue Code of 1986, under which an election similar to that provided by Section 761 of the Code is permitted, each Person hereby affected shall make such election as may be permitted or required by such laws. In making the foregoing election, each such Person states that the income derived by such Person from Unit Operations can be adequately determined without the computation of partnership taxable income.

8.4 Transfer of Interests. In the event of a transfer by one Working Interest Owner to another under the provisions of this Agreement of any Working Interest or of any other interest in any well or in the materials and equipment in any well, the taxes above mentioned assessed against the transferred interest for the taxable period in which such transfer occurs shall be apportioned among said Working Interest Owners so that each shall bear the percentage of such taxes which is proportionate to that portion of the taxable period during which it owned an interest.

ARTICLE 9

INSURANCE

9.1 Insurance. Unit Operator, with respect to Unit Operations, shall:

(a) comply with the Workmen's Compensation Laws of the state.

(b) comply with Employer's Liability and other insurance requirements of the laws of the state.

(c) comply with the provisions of Exhibit G of this Agreement.

ARTICLE 10

ADJUSTMENT OF INVESTMENTS

10.1 Property Taken Over. Upon the Effective Date, Working Interest Owners shall deliver to Unit Operator the following:

10.1.1 Wells. All wells shown on Exhibit E which satisfy the requirements of Section 10.7.

10.1.2 Equipment. The casing and tubing in each such well, the wellhead connections thereon, and all other lease and operating equipment that is used in the operation of such wells which Working Interest Owners determine is necessary or desirable for conducting Unit Operations.

10.1.3 Records. A copy of all production and well records for such wells.

10.2 Inventory and Evaluation. Working Interest Owners shall at Unit Expense inventory and evaluate the wells and equipment taken over. The inventory of equipment shall be limited to those items considered controllable as recommended in the most current Material Classification Manual in Bulletin No. 6 dated May, 1971, published by the Petroleum Accountant Society of North America except, upon determination of Working Interest Owners, items such as sucker rods considered noncontrollable may be included in the inventory in order to insure a more equitable adjustment of investment. The method of evaluating wells and equipment shall be determined by Working Interest Owners.

10.3 Investment Adjustment. Upon approval by Working Interest Owners of the inventory and evaluation, each Working Interest Owner shall be credited with the value of its interest in all wells and equipment taken over under Section 10.1, and shall be charged with an amount equal to that obtained by multiplying the total value of all wells and equipment taken over under Section 10.1 by such Working Interest Owner's Unit Participation. If the charge against any Working Interest Owner is greater than the amount credited to such Working Interest Owner, the resulting net charge shall be an item of Unit Expense chargeable against such Working Interest Owner. If the credit to any Working Interest Owner is greater than the amount charged against such Working Interest Owner, the resulting net credit shall be paid to such Working Interest Owner by Unit Operator out of funds received by it in settlement of the net charges described above.

10.4 General Facilities. The acquisition of warehouse stocks, facility systems, and buildings necessary for Unit Operations shall be by negotiation by the owners thereof and Unit Operator, subject to the approval of Working Interest Owners.

10.5 Ownership of Property and Facilities. Each Working Interest Owner, individually, shall by virtue hereof own an undivided interest, equal to its Unit Participation in all wells, equipment, and facilities taken over or otherwise acquired by Unit Operator pursuant to this Agreement.

10.6 Non-Unit Equipment. Each Working Interest Owner shall solely be liable for all its equipment within the Unit Area which is not deemed necessary for Unit Operations and shall solely be responsible for the care, maintenance and removal of such equipment as required by contract, law or regulation.

10.7 Useable Well. All wells delivered to the Unit Operator shall be (a) in good physical condition, (b) completed in some portion of the Unitized Formation, (c) physically separated from formations not a part of the Unitized Formation as of the Effective Date, and (d) in compliance with North Dakota rules and regulations dealing with protection of potable water resources (North Dakota Administrative Code 43-02-03-20). Unit Operator shall make all determinations required under this Section 10.7.

ARTICLE 11

UNIT EXPENSE

11.1 **Basis of Charge to Working Interest Owners.** Unit Operator initially shall pay all Unit Expense. Each Working Interest Owner shall reimburse Unit Operator for its share of Unit Expense. Each Working Interest Owner's share shall be the same as its Unit Participation for the phase in effect at the time the expense is incurred. All charges, credits, and accounting for Unit Expense shall be in accordance with Exhibit D.

11.2 **Budgets.** Before or as soon as practical after the Effective Date, Unit Operator shall prepare a budget of estimated Unit Expense for the remainder of the calendar year, and thereafter shall prepare an annual operations and capital budget for submission to the Working Interest Owners by December 1. Budgets shall be estimates only, and shall be adjusted or corrected by the Unit Operator whenever an adjustment or correction is proper. A copy of each budget and adjusted budget shall be furnished promptly to each Working Interest Owner.

11.3 **Advance Billings.** Unit Operator shall have the right to require Working Interest Owners to advance their respective shares of estimated Unit Expense as provided by Exhibit D.

11.4 **Commingling of Funds.** Funds received by Unit Operator under this Agreement need not be segregated or maintained by it as a separate fund, but may be commingled with its own funds.

11.5 **Unpaid Unit Expense.** If any Working Interest Owner fails or is unable to pay its share of Unit Expense within sixty (60) days after rendition of a statement therefor by Unit Operator, the non-defaulting Working Interest Owners shall, upon request by Unit Operator, pay the unpaid amount as if it were Unit Expense in the proportion that the Unit Participation of each such Working Interest Owner bears to the Unit Participation of all such Working Interest Owners for the Phase in effect at the time of payment failure. Each Working Interest Owner so paying its share of the unpaid amount shall, to obtain reimbursement thereof, be subrogated to the security rights described in Section 11.6 of this Agreement.

11.6 Security Rights. In addition to any other security rights and remedies provided for by the laws of the State of North Dakota with respect to services rendered or materials and equipment furnished under this Agreement, Unit Operator, on behalf of the Unit, shall have a first and prior lien upon each Working Interest, including the Unitized Substances and Unit Equipment credited thereto, in order to secure payment of the Unit Expense charged against such Working Interest, together with interest thereon at the rate set forth in Exhibit D or the maximum rate allowed by law, whichever is less. If any Working Interest Owner does not pay its share of Unit Expense when due, Unit Operator on behalf of the Unit shall have the right to collect from the purchaser the proceeds from the sale of such Working Interest Owner's share of Unitized Substances until the amount owed, plus interest at the rate herein provided, has been paid. Each purchaser shall be entitled to rely on Unit Operator's statement concerning the amount owed and the interest payable thereon. If any Working Interest Owner pays its proportionate share of a defaulting party's Unit Expense, Unit Operator shall make monthly statements to that Working Interest Owner as to the collection of principal and interest from the purchaser. Exercise of any of the rights of Unit Operator granted or recognized above shall not be deemed an election of remedies or otherwise affect the rights of Unit Operator to bring suit and obtain judgment and foreclosure. The Working Interest Owners specifically authorize Unit Operator to file of record in the State of North Dakota a memorandum of agreement referencing this Unit Operating Agreement and the lien and security rights herein granted.

11.7 Subsequently Created Interests. Any overriding royalty, production payment, net proceeds interest, carried interest or any other interest carved out of a Working Interest and created after the Effective Date of this Agreement shall be subject to this Agreement. If a Working Interest Owner does not pay its share of Unit Expense and the proceeds from the sale of Unitized Substances under Section 11.6 are insufficient for that purpose, the security rights provided for therein may be applied against the carved-out interests with which such Working Interest is burdened. In such event, the owner of such carved-out interest shall be subrogated to the security rights granted by Section 11.6. Should any Working Interest Owner elect to withdraw from the unit and this Unit Operating Agreement as provided in Section 16, its assignment and transfer to the Working Interest Owners desiring to accept such transfer shall be free and clear from, and not in any way burdened by, any such subsequently created carved-out interest.

11.8 Pre-Unitization Expense. Prior to Effective Date, Unit Operator will have incurred certain costs and expenses (herein referred to as "Pre-unitization Expense") for and on behalf of the Working Interest Owners in anticipation of the Unit Agreement and this Agreement becoming effective. All Pre-unitization Expense shall have been previously approved by two or more Working Interest Owners representing at least Seventy Percent (70%) of the Phase I Unit Participation. Each Working Interest Owner shall reimburse Unit Operator for its share of such actual Pre-unitization Expense, determined on the basis of its Phase I Unit Participation. For the purposes of this Agreement, all such Pre-unitization Expense shall be considered an item of Unit Expense.

ARTICLE 12

NONUNITIZED FORMATIONS

12.1 Right to Operate. Any Working Interest Owner that now has or hereafter acquires the right to drill for and produce oil, gas, or other minerals, from a formation underlying the Unit Area other than the Unitized Formation, shall have the right to do so notwithstanding this Agreement or the Unit Agreement. In exercising the right, however, such Working Interest Owner shall exercise care to prevent unreasonable interference with Unit Operations. No Working Interest Owner other than Unit Operator shall produce Unitized Substances. If any Working Interest Owner drills any well into or through the Unitized Formation, the Unitized Formation shall be protected in a manner satisfactory to Working Interest Owners so that the production of Unitized Substances will not be affected adversely.

ARTICLE 13

LIABILITY, CLAIMS, AND SUITS

13.1 Individual Liability. The duties, obligations, and liabilities of Working Interest Owners shall be several and not joint or collective; and nothing herein shall ever be construed as creating a partnership of any kind, joint venture, association, or trust among Working Interest Owners.

13.2 Settlements. Unit Operator may settle any single damage claim or suit involving Unit Operations if the expenditure does not exceed Fifty Thousand Dollars ($50,000) and if the payment is in complete settlement of such claim or suit. If the amount required for settlement exceeds the above amount, Working Interest Owners shall determine the further handling of the claim or suit. All costs and expense of handling, settling, or otherwise discharging such claim or suit shall be an item of Unit Expense, subject to such limitation as is set forth in Exhibit D. If a claim is made against any Working Interest Owner or if any Working Interest Owner is sued on account of any matter arising from Unit Operations over which such Working Interest Owner individually has no control because of the rights given Working Interest Owners and Unit Operator by this Agreement and the Unit Agreement, the Working Interest Owner shall immediately notify Unit Operator, and the claim or suit shall be treated as any other claim or suit involving Unit Operations.

13.3 **Notice of Loss.** Unit Operator shall report to Working Interest Owners as soon as practicable after each occurrence, damage or loss to Unit Equipment, and each accident, occurrence, claim, or suit involving third party bodily injury or property damage not covered by insurance carried for the benefit of Working Interest Owners.

ARTICLE 14

NONDISCRIMINATION

14.1 **Nondiscrimination.** During the performance of work under this Agreement, Unit Operator agrees to comply with all the provisions of Exhibit "F" of this Agreement.

ARTICLE 15

NOTICES

15.1 **Notices.** All notices required hereunder shall be in writing and shall be deemed to have been properly served when sent by mail, data fax or telegram to the address of the representative of each Working Interest Owner as furnished to Unit Operator in accordance with Article 4.

ARTICLE 16

WITHDRAWAL OF WORKING INTEREST OWNER

16.1 **Withdrawal.** A Working Interest Owner may withdraw from this Agreement by transferring, without warranty of title either express or implied, to the Working Interest Owners who do not desire to withdraw, all its Oil and Gas Rights, exclusive of Royalty Interests, together with its interest in all Unit Equipment and in all wells used in Unit Operations, provided that such transfer shall not relieve such Working Interest Owner from any obligation or liability incurred prior to the first day of the month following receipt by Unit Operator of such transfer. The delivery of the transfer shall be made to Unit Operator for the transferees. The transferred interest shall be owned by the transferees in proportion to their respective Unit Participations. The transferees, in proportion to the respective interests so acquired, shall pay the transferor for its interest in Unit Equipment, the salvage value thereof less its share of the estimated cost of salvaging same and of plugging and abandoning all wells then being used or held for Unit Operations, as determined by Working Interest Owners. In the event such withdrawing owner's interest in the aforesaid salvage value is less than such owner's share of such estimated costs, the withdrawing owner, as a condition precedent to withdrawal, shall pay the Unit Operator, for the benefit of Working Interest Owners succeeding to its interest, a sum equal to the deficiency. Within ninety (90) days after receiving delivery of the transfer, Unit Operator shall render a final statement to the withdrawing owner for its share of Unit Expense, including any deficiency in salvage value, as determined by agreement between the withdrawing owner and the Unit Operator, incurred as of the first day of the month following the date of receipt of the transfer. Provided all Unit Expense, including any deficiency hereunder, due from the withdrawing owner has been paid in full within thirty (30) days after the rendering of such final statement by the Unit Operator, the transfer shall be effective the first day of the month following its receipt by Unit Operator and, as of such effective date, withdrawing owner shall be relieved from all further obligations and liabilities hereunder and under the Unit Agreement, and the rights of the withdrawing Working Interest Owner hereunder and under the Unit Agreement shall cease insofar as they existed by virtue of the interest transferred.

16.2 Limitation on Withdrawal. Notwithstanding anything set forth in Section 16.1, Working Interest Owners may refuse to permit the withdrawal of a Working Interest Owner if its Working Interest is burdened by any royalties, overriding royalties, production payments, net proceeds interest, carried interest, or any other interest created out of the Working Interest in excess of one-eighth (1/8) lessor's royalty, unless the other Working Interest Owners willing to accept the assignment agree to accept the Working Interest subject to such burdens.

ARTICLE 17

ABANDONMENT OF WELLS

17.1 Rights of Former Owners. If Working Interest Owners determine to permanently abandon any well within the Unit Area prior to termination of the Unit Agreement, Unit Operator shall give written notice thereof to the Working Interest Owners of the Tract on which the well is located, and they shall have the option for a period of thirty (30) days after the sending of such notice to notify Unit Operator in writing of their election to take over and own the well. Within ten (10) days after the Working Interest Owners of the Tract have notified Unit Operator of their election to take over the well, they shall pay Unit Operator, for credit to the joint account, the amount determined by Working Interest Owners to be the net salvage value of the casing and equipment, through the wellhead, in and on the well. The Working Interest Owners of the Tract, by taking over the well, agree to seal off the Unitized Formation, and upon abandonment to plug the well in compliance with applicable laws and regulations.

17.2 Plugging. If the Working Interest Owners of a Tract do not elect to take over a well located within the Unit Area that is proposed for abandonment, Unit Operator shall plug and abandon the well in compliance with applicable laws and regulations.

ARTICLE 18

EFFECTIVE DATE AND TERM

18.1 Effective Date. This Agreement shall become effective when the Unit Agreement becomes effective.

18.2 Term. This Agreement shall continue in effect so long as the Unit Agreement remains in effect, and thereafter until (a) all unit wells have been plugged and abandoned or turned over to Working Interest Owners in accordance with Article 19; (b) all Unit Equipment and real property acquired for the joint account have been disposed of by Unit Operator in accordance with instructions of Working Interest Owners; and (c) there has been a final accounting.

ARTICLE 19

ABANDONMENT OF OPERATIONS

19.1 Termination. Upon termination of the Unit Agreement, the following will occur:

19.1.1 Oil and Gas Rights. Oil and Gas Rights in and to each separate Tract shall no longer be affected by this Agreement, and thereafter the parties shall be governed by the terms and provisions of the leases, contracts, and other instruments affecting the separate Tracts.

19.1.2 Right to Operate. Working Interest Owners of any Tract that desire to take over and continue to operate wells located thereon may do so by paying Unit Operator, for credit to the joint account, the net salvage value, as determined by Working Interest Owners, of the casing and equipment, through the wellhead, in and on the wells taken over and by agreeing upon abandonment to plug each well in compliance with applicable laws and regulations.

19.1.3 Salvaging Wells. Unit Operator shall salvage as much of the casing and equipment in or on wells not taken over by Working Interest Owners of separate Tracts as can economically and reasonably be salvaged, and shall cause the wells to be plugged and abandoned in compliance with applicable laws and regulations.

19.1.4 Cost of Abandonment. The cost of abandonment of Unit Operations shall be Unit Expense.

19.1.5 Distribution of Assets. Working Interest Owners shall share in the distribution of Unit Equipment, or the proceeds thereof, in proportion to their Unit Participations.

ARTICLE 20

APPROVAL

20.1 Original, Counterpart, or Other Instrument. A Working Interest Owner may approve this Agreement by signing the original, a counterpart thereof, or other instrument approving this Agreement. The signing of any such instrument shall have the same effect as if all Persons had signed the same instrument.

ARTICLE 21

SUCCESSORS AND ASSIGNS

21.1 Successors and Assigns. This Agreement shall extend to, be binding upon, and inure to the benefit of the Persons hereto and their respective heirs, devisees, legal representatives, successors, and assigns, and shall constitute a covenant running with the lands, leases, and interests covered hereby.

IN WITNESS WHEREOF, this Agreement is approved on the dates opposite the respective signatures.

CONOCO INC.

By: Roger B. Brown

Roger B. Brown
Attorney-In-Fact

Date of Execution: April 15, 1994

Exhibit "A" and "B" of this Unit Operating Agreement
are Exhibits "A" and "B" of the Unit Agreement
and will be incorporated by reference.

Exhibit C to Unit Operating Agreement
dated April 15, 1994

DICKINSON LODGEPOLE UNIT
STARK COUNTY, NORTH DAKOTA

WORKING INTEREST OWNER	TRACT	PARTICIPATION PERCENTAGE OF TRACT IN UNIT		PERCENTAGE OF WORKING INTEREST IN THE TRACT	PARTICIPATION % OF TRACT IN UNIT MULTIPLIED BY % WORKING INTEREST IN TRACT		WORKING INTEREST OWNER UNIT PARTICIPATION %	
		PHASE I	PHASE II		PHASE I	PHASE II	PHASE I	PHASE II
Andrea Singer Pollack Trust	2	33.16362%	31.78581%	50.00000%	16.58181%	15.89291%	16.58181%	15.89291%
					16.58181%	15.89291%		
ARS Limited Partnership	5	0.84655%	1.64933%	96.36607%	0.81579%	1.58939%	0.81579%	1.58939%
					0.81579%	1.58939%		
Conoco Inc.	1	50.12991%	50.35218%	100.00000%	50.12991%	50.35218%	75.13624%	74.88075%
	2	33.16362%	31.78581%	50.00000%	16.58181%	15.89291%		
	3	12.36359%	11.64830%	44.45695%	5.49648%	5.17848%		
	4	2.23917%	2.11507%	100.00000%	2.23917%	2.11507%		
	5	0.84655%	1.64933%	3.63393%	0.03076%	0.05994%		
	6	0.01840%	0.03584%	50.00000%	0.00920%	0.01792%		
	7	0.32677%	0.63664%	25.00000%	0.08169%	0.15916%		
	8	0.41141%	0.80156%	16.19752%	0.06664%	0.12983%		
	9	0.50058%	0.97527%	100.00000%	0.50058%	0.97527%		
					75.13624%	74.88075%		
Hunt Oil Company	8	0.41141%	0.80156%	0.83333%	0.00343%	0.00668%	0.00343%	0.00668%
					0.00343%	0.00668%		

04/21/94

Exhibit C to Unit Operating Agreement
dated April 15, 1994

DICKINSON LODGEPOLE UNIT
STARK COUNTY, NORTH DAKOTA

WORKING INTEREST OWNER	TRACT	PARTICIPATION PERCENTAGE OF TRACT IN UNIT PHASE I	PARTICIPATION PERCENTAGE OF TRACT IN UNIT PHASE II	PERCENTAGE OF WORKING INTEREST IN THE TRACT	PARTICIPATION % OF TRACT IN UNIT MULTIPLIED BY % WORKING INTEREST IN TRACT PHASE I	PARTICIPATION % OF TRACT IN UNIT MULTIPLIED BY % WORKING INTEREST IN TRACT PHASE II	WORKING INTEREST OWNER UNIT PARTICIPATION % PHASE I	WORKING INTEREST OWNER UNIT PARTICIPATION % PHASE II
Hunt Petroleum Corporation	3	12.36359%	11.64830%	8.40336%	1.03896%	0.97885%	1.03896%	0.97885%
					1.03896%	0.97885%		
Huntington Resources Inc.	3	12.36359%	11.64830%	4.72689%	0.58441%	0.55060%	0.58528%	0.55230%
	6	0.01840%	0.03584%	4.72689%	0.00087%	0.00169%		
					0.58528%	0.55230%		
Louis W. Hill, Jr.	3	12.36359%	11.64830%	4.13910%	0.51174%	0.48213%	0.54513%	0.54719%
	8	0.41141%	0.80156%	8.11625%	0.03339%	0.06506%		
					0.54513%	0.54719%		
Louisiana – Hunt Petroleum	6	0.01840%	0.03584%	8.40336%	0.00155%	0.00301%	0.00155%	0.00301%
					0.00155%	0.00301%		
Mid – Continent Energy [B.P.O.]	3	12.36359%	11.64830%	0.00000%	0.00000%	0.00000%	0.00087%	0.00169%
	6	0.01840%	0.03584%	4.72689%	0.00087%	0.00169%		
					0.00087%	0.00169%		

Exhibit C to Unit Operating Agreement
dated April 15, 1994

DICKINSON LODGEPOLE UNIT
STARK COUNTY, NORTH DAKOTA

WORKING INTEREST OWNER	TRACT	PARTICIPATION PERCENTAGE OF TRACT IN UNIT		PERCENTAGE OF WORKING INTEREST IN THE TRACT	PARTICIPATION % OF TRACT IN UNIT MULTIPLIED BY % WORKING INTEREST IN TRACT		WORKING INTEREST OWNER UNIT PARTICIPATION %	
		PHASE I	PHASE II		PHASE I	PHASE II	PHASE I	PHASE II
Mobil Exploration & Producing	7	0.32677%	0.63664%	50.00000%	0.16339%	0.31832%	0.16339%	0.31832%
					0.16339%	0.31832%		
North American Royalties, Inc.	8	0.41141%	0.80156%	9.01957%	0.03711%	0.07230%	0.03711%	0.07230%
					0.03711%	0.07230%		
Petro-Hunt Corporation	8	0.41141%	0.80156%	0.20833%	0.00086%	0.00167%	0.00086%	0.00167%
					0.00086%	0.00167%		
Phillips Petroleum Company	3	12.36359%	11.64830%	4.38126%	0.54168%	0.51034%	0.88050%	1.17048%
	7	0.32677%	0.63664%	25.00000%	0.08169%	0.15916%		
	8	0.41141%	0.80156%	62.50000%	0.25713%	0.50098%		
					0.88050%	1.17048%		
Placid Oil Company	3	12.36359%	11.64830%	32.14286%	3.97401%	3.74410%	3.97993%	3.75562%
	6	0.01840%	0.03584%	32.14286%	0.00591%	0.01152%		
					3.97993%	3.75562%		

Exhibit C to Unit Operating Agreement
dated April 15, 1994

DICKINSON LODGEPOLE UNIT
STARK COUNTY, NORTH DAKOTA

WORKING INTEREST OWNER	TRACT	PARTICIPATION PERCENTAGE OF TRACT IN UNIT		PERCENTAGE OF WORKING INTEREST IN THE TRACT	PARTICIPATION % OF TRACT IN UNIT MULTIPLIED BY % WORKING INTEREST IN TRACT		WORKING INTEREST OWNER UNIT PARTICIPATION %	
		PHASE I	PHASE II		PHASE I	PHASE II	PHASE I	PHASE II
Ruth Ray Hunt	8	0.41141%	0.80156%	1.25000%	0.00514%	0.01002%	0.00514%	0.01002%
					0.00514%	0.01002%		
The Wiser Oil Company	3	12.36359%	11.64830%	1.74958%	0.21631%	0.20380%	0.22317%	0.21716%
	8	0.41141%	0.80156%	1.66667%	0.00686%	0.01336%		
					0.22317%	0.21716%		
Unit Four Partnership	8	0.41141%	0.80156%	0.20833%	0.00086%	0.00167%	0.00086%	0.00167%
					0.00086%	0.00167%		
						TOTAL:	100.00000%	100.00000%

CASE No. 5933

Robert O. Wefald

Attorney And Counselor At Law

2800 North Washington Street
Post Office Box One
Bismarck, North Dakota 58502-0001

Phone 701-258-8945
Fax 701-255-7212

April 1, 1994

Wes Norton, Director
Oil & Gas Division
N.D. Industrial Commission
600 East Boulevard
Bismarck ND 58505-0840

Dear Wes:

This letter will confirm the several telephone conversations we have had concerning the fact that I represent the Andrea Singer Pollack Revocable Trust and the interest it owns in a proposed Dickinson Lodgepole Unit for which I understand a unitization plan is going to be presented to the Industrial Commission. My client sent me a copy of John Morrison's letter to you dated March 22, 1994, wherein he is representing Placid Oil Company. Our position is essentially identical to his. That is, my client does not oppose the unitization of this field; rather, my client's only concern relates to what we understand is Conoco's proposal with respect to the boundaries of the unit. I gather from John Morrison's letter to you that Lawrence Bender represents Conoco.

I would very much appreciate it if, when any unitization request is filed by Conoco for this particular unit, you would see to it that Conoco provides notice to us so I can represent my client's interest at each stage of the proceedings.

I look forward to working with you, members of the staff of the Oil and Gas Division of the Industrial Commission and counsel for Placid Oil Company and Conoco. Please call me if you have any questions or comments.

Sincerely,

Bob

Robert O. Wefald

mw

c: Kevin Preston
John Morrison
Lawrence Bender

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CURTIS L. WIKE*
CHARLES S. MILLER, JR.*
CRAIG C. SMITH**
SCOTT K. PORSBORG*++
DEENELLE L. RUUD*

ALSO LICENSED IN:
*MINNESOTA
**MONTANA
+IOWA
++SOUTH DAKOTA

March 22, 1994

Mr. Wes Norton, Director
Oil & Gas Division
ND INDUSTRIAL COMMISSION
600 East Boulevard
Bismarck, ND 58505-0840

In re Conoco Unitization Proposal
Dickinson-Lodgepole Field
Our File No. 22227

Dear Wes:

Please be advised that we represent Placid Oil Company with respect to Conoco's proposal to unitize the Dickinson-Lodgepole Field. At this time, Placid intends to oppose Conoco's request, thus making the hearing a contested case proceeding with respect to § 28-32-12.1 of the North Dakota Century Code. Placid is not opposed to the unitization of the field but only to the boundaries of the unit area proposed by Conoco.

As you know, the customary practice in North Dakota is for the operator of a proposed unit area to meet privately with the Commission staff in advance of the hearing to review such matters as the unit outline and the equity formula. Because unitization hearings are frequently uncontested, this practice is appropriate and helpful to both the Commission staff and the applicant. However, when it is anticipated that a matter will be contested, § 28-32-12.1 appears to prohibit such meetings.

If you have any questions concerning this matter, please let me know.

Very truly yours,

JOHN W. MORRISON

bz
cc: Lawrence Bender
Jimmy Campbell

STATE OF NORTH DAKOTA | IN DISTRICT COURT

COUNTY OF STARK | SOUTHWEST JUDICIAL DISTRICT

Andrea Singer Pollack Revocable Trust, Andrea Singer Pollack, Trustee,

Appellant,

vs.

The Industrial Commission of the State of North Dakota, Conoco, Inc., and all other persons having an interest in the Dickinson-Lodgepole Unit,

Appellees.

Civil No. 94C-283

APPELLANT'S SUPPLEMENTAL RECORD

An Appeal to the District Court of Stark County
From the Decision of the North Dakota Industrial Commission
Pursuant to NDCC 38-08-14 in Regard to the Unitization of
the Dickinson Lodgepole Unit in Stark County, North Dakota

CHARLES CARVELL
Assistant Attorney General
Attorney for The Industrial Commission
For the State of North Dakota
900 East Boulevard Avenue
Bismarck ND 58505-0041
(701) 328-3604

LAWRENCE BENDER
Attorney for Conoco, Inc.
P. O. Box 400
Bismarck ND 58502-0400
(701) 223-2890

ROBERT O. WEFALD
Attorney for Andrea Singer Pollack Revocable Trust
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(701) 258-8945

APPELLANT'S SUPPLEMENTAL RECORD
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DEFINITIONS

Isopach Maps: A map that shows the thickness of a bed, formation, sill, or other tabular body throughout a geographic area by means of isopachs (ie. lines of equal value) at regular intervals. (From American Geological Institute (AGI), Glossary of Geology, 1987).

Structure Map: A map that portrays the subsurface configuration by means of contour lines. This type of map shows the relationship of the surface to a datum, generally sea level. (From AGI, 1987).

Synthetic Seismogram: An artificial seismic reflection record, manufactured from velocity-log (ie. sonic log) data by convolving the reflectivity function with a waveform that includes the effects of filtering by the earth and the recording system. It is then compared with an actual seismogram to aid in identifying events or in predicting how stratigraphic and thickness variations might affect a seismic record. (From API, 1987).

2-D Seismic: A seismic survey that only measures in one plane (usually vertical). The data is collected along a line at the ground surface and results in a planar two dimensional data set oriented vertically. The data is usually displayed in a fashion similiar to a cross section of the earth. Because there is no variation in the direction perpendicular to the line of measurement, no determination of the spatial relationships of features can be made. (After R.E. Sheriff, 1984, Encyclopedic Dictionary of Exploration Geophysics, Society of Exploration Geophysicists).

3-D Seismic: A survey involving the collection of seismic data over an area with an objective of determining spatial relations in three dimensions. The data obtained constitute a volume which can be displayed in different ways. The fundamental objective of this method is increased resolution in both vertical and horizontal directions. (From Sheriff, 1984, and A.R. Brown, 1993; Interpretation of 3-Dimensional Data, American Association of Petroleum Geologists, Memoir 42.)

Fryburg: A rock formation within the Williston Basin, North Dakota of Mississippian age (320 to 345 million years old) and consisting of interbedded limestone and dolomite. This formation produces in the Dickinson Field area and is approximately 1000 feet above the lodgepole reservoir. check to see if it has ever produced.

Lodgepole Mound: This is the productive interval within the Lodgepole Dickinson Field. It is a Mississippian in age, but older than the Fryburg that overlies it. Regionally the Lodgepole is a tight margin limestone 250 to 275 feet in thickness. Locally at Dickinson a bioherm consisting of bryozoans and crinods developed. Through Lodgepole time the bioherm continued to grow above the sea floor. The resultant mound or "reef" is approximately 400 feet in thickness. Porosity developed after burial of the Lodgepole and this is the reservoir for the oil found in this field.

Sp? "crinoids"

DEFINITIONS

Unitization: The process by which smaller properties with various individual ownerships are combined into one larger property. Unitization, therefore, makes it possible to implement a secondary recovery program in the most efficient manner to increase the amount of oil production. After unitization, each individual owner shares in every barrel of oil produced from the entire project throughout its remaining life. The property formed by this pooling of ownerships and sharing of production is called a "unit". This is not necessarily true of Phase I for all units

Volumetric Calculation of OOIP: An estimation of original oil in place based on a reservoir's areal extent and thickness (pay isopach map) which incorporates estimated rock and fluid properties such as porosity, oil saturation, and formation volume factor.

Original Oil in Place (OOIP): The estimated number of stock tank barrels of crude oil in known reservoirs prior to any production. Known reservoirs include (1) those that are currently productive; (2) those to which proved reserves have been credited but from which there has been no production; and (3) those that have been depleted.

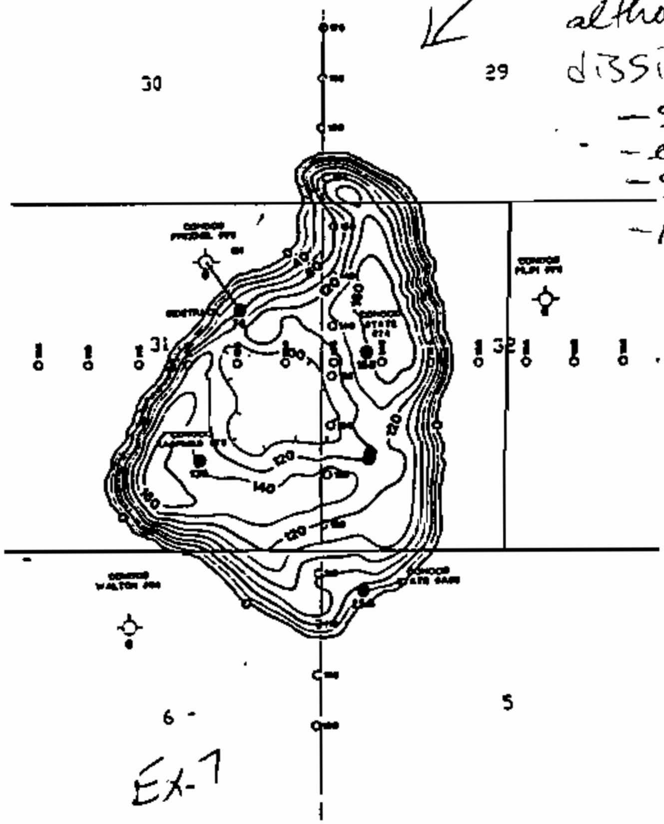
Material Balance Calculation of OOIP: An estimation of original oil in place in a reservoir based on the amount of reservoir pressure decrease for a given volume of production.

Oil Water Contact: The line of demarcation between the water zone and the oil zone in a petroleum reservoir. "line" may be inaccurate due to a transitional zone

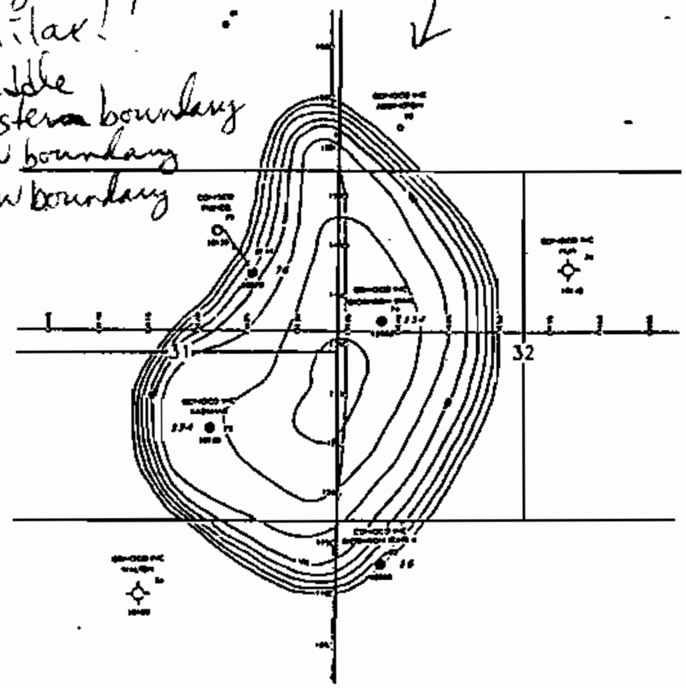
Reservoir Model: A computer representation of an oil or gas field which applies the concepts and techniques of mathematical modeling to the analysis of the behavior of petroleum reservoir systems. This model or simulation is used to predict the future performance of oil and gas wells and fields.

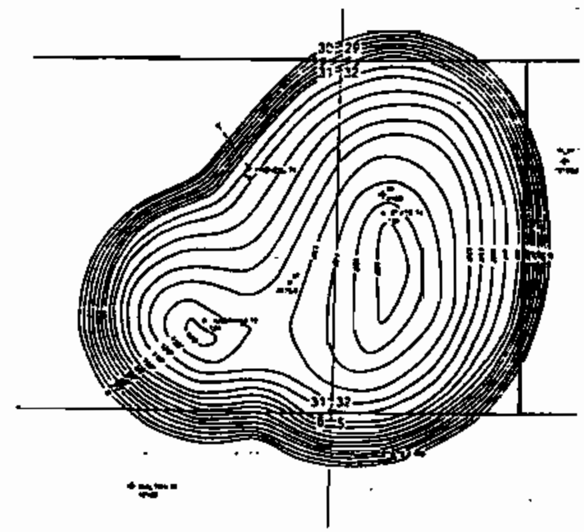
LODGEPOLE NET PAY ISOPACH MAPS

both maps were based
on the same seismic lines
although maps are very
dissimilar!
— saddle
— ~~eastern~~ boundary
— SW boundary
— NW boundary



Ex-7





ASPRT MAP

(C.R.____)

PLACID MAP

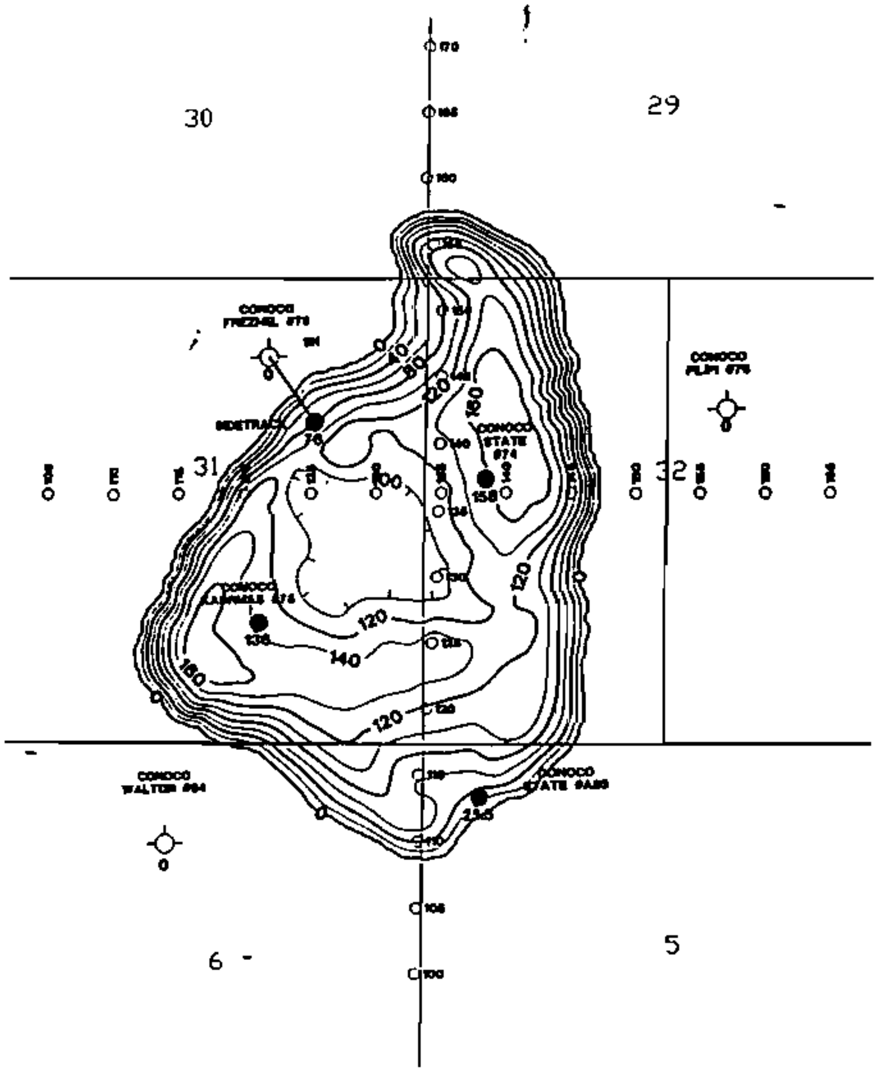
(C.R.____)

CONOCO MAP

(C.R.____)

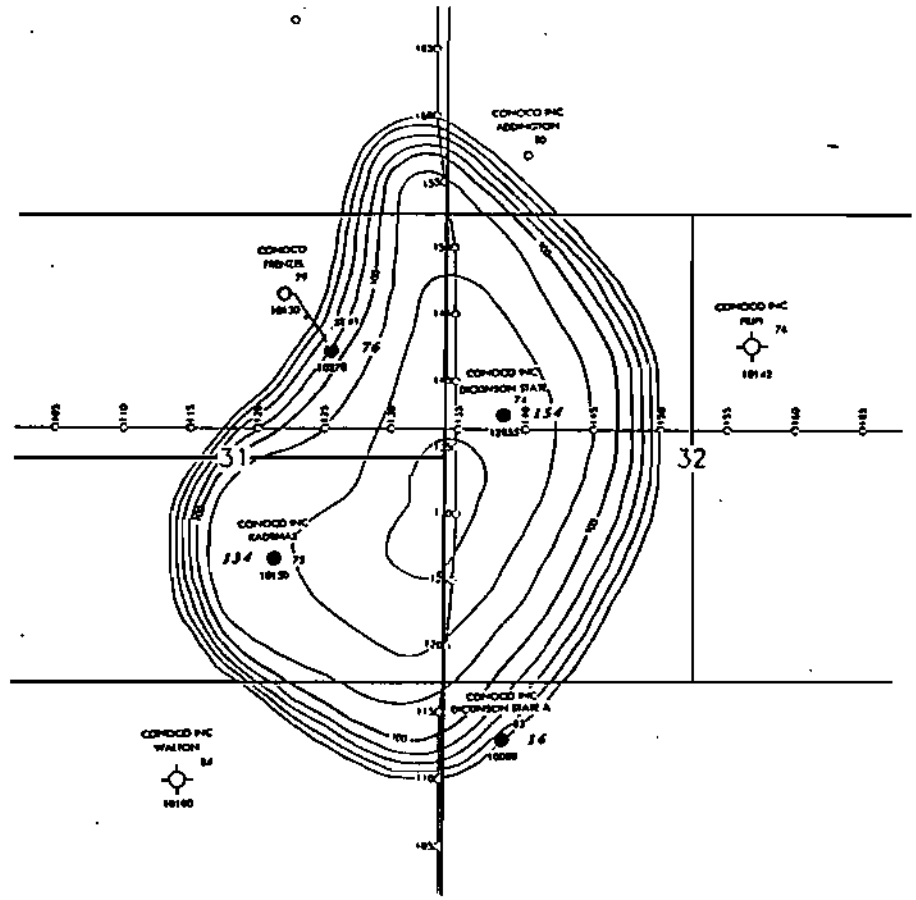
Map doesn't
honor the "saddle"!

LODGEPOLE NET PAY ISOPACH MAPS



ASPRT MAP

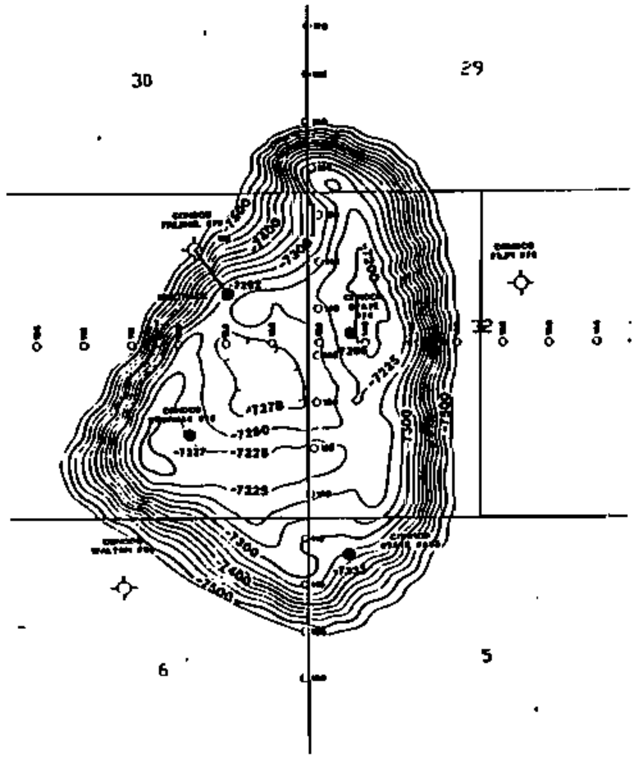
(C.R.___)



PLACID MAP

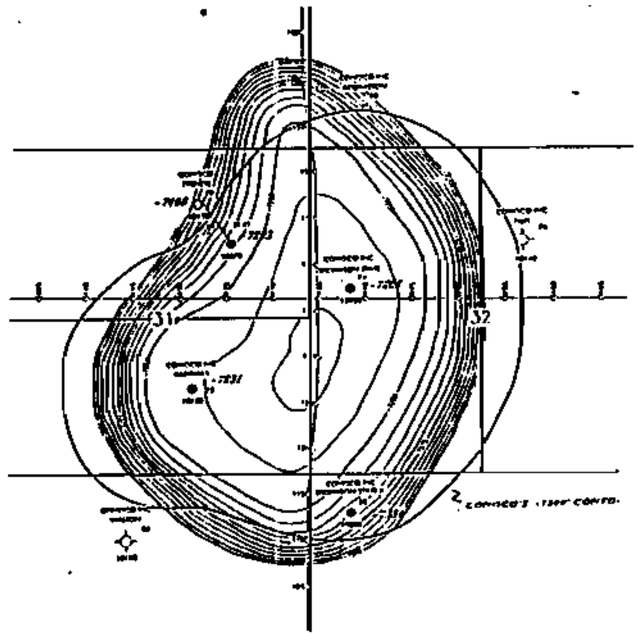
(C.R.___)

LODGEPOLE STRUCTURE MAPS



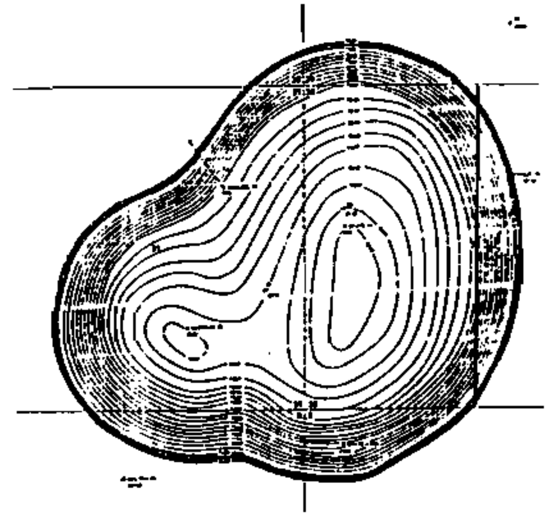
ASPRT MAP

(C.R.___)



PLACID MAP

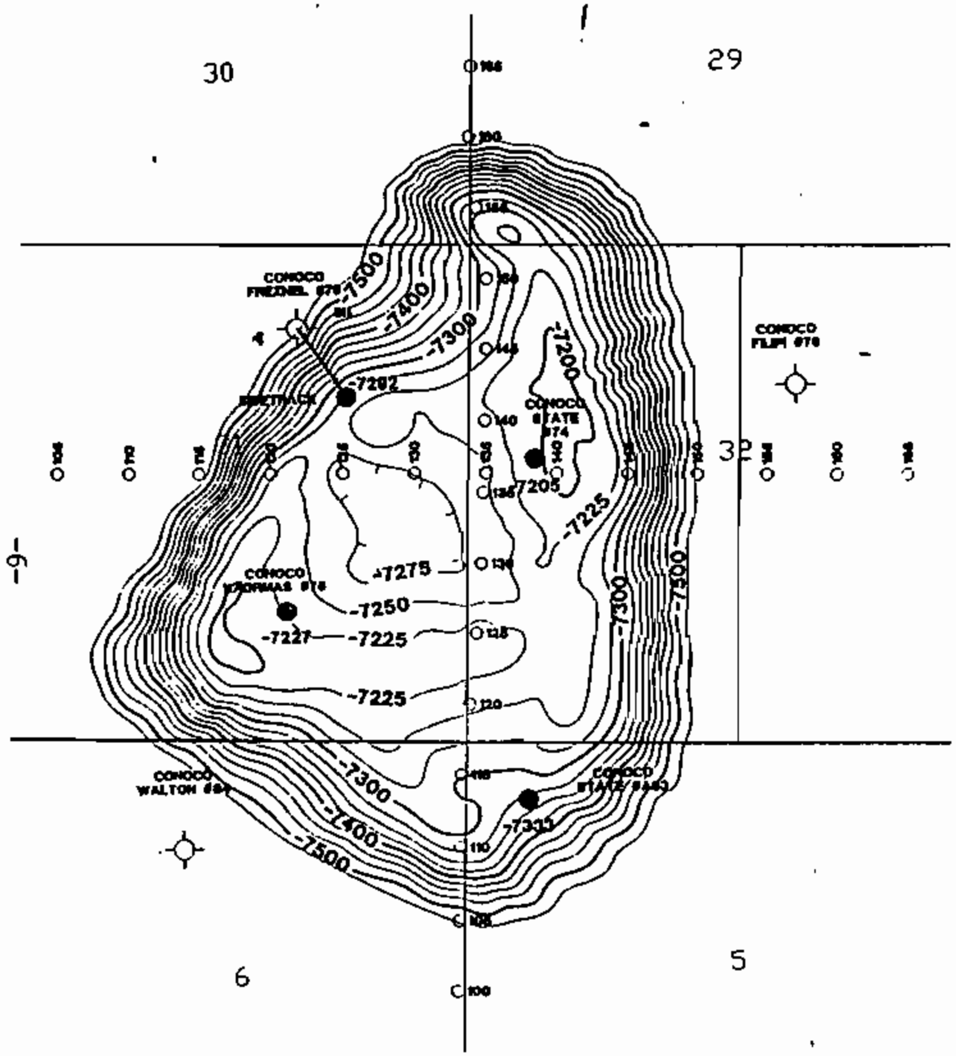
(C.R.___)



CONOCO MAP

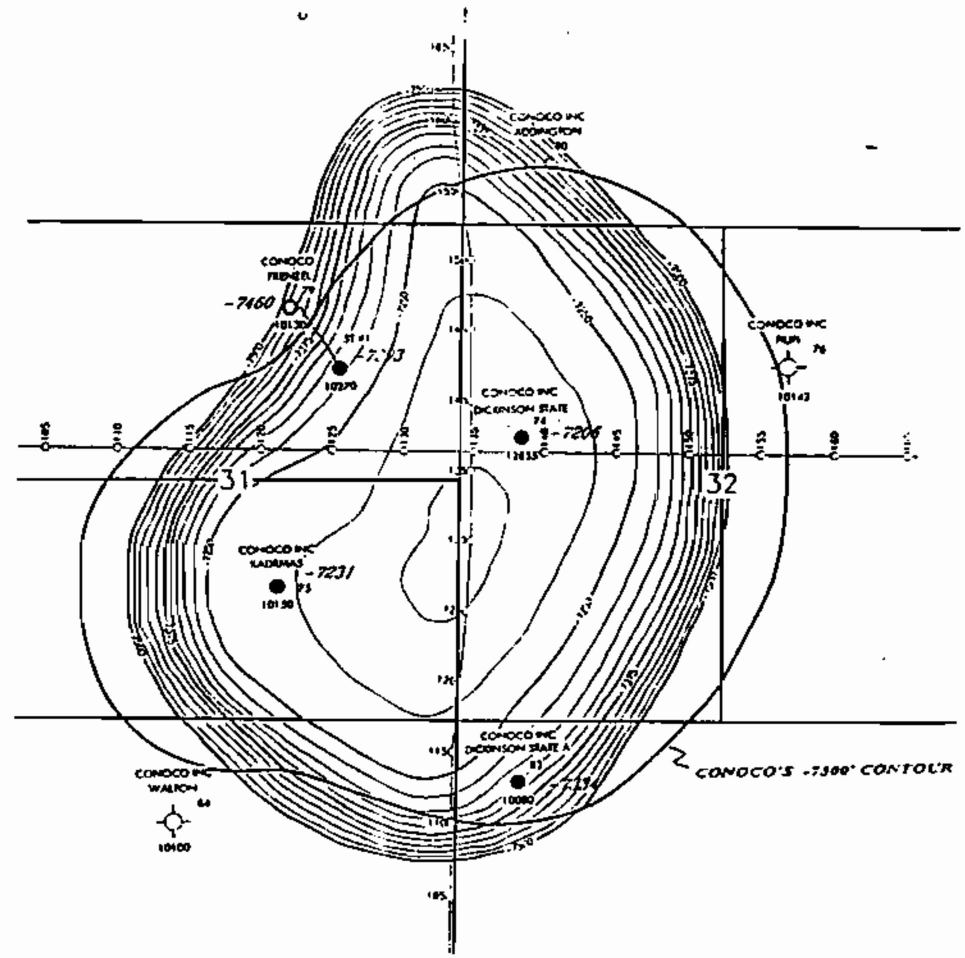
(C.R.___)

LODGEPOLE STRUCTURE MAPS



ASPRT MAP

(C.R.____)



PLACID MAP

(C.R.____)

STATE OF NORTH DAKOTA — IN DISTRICT COURT

COUNTY OF STARK — SOUTHWEST JUDICIAL DISTRICT

Andrea Singer Pollack Revocable Trust, Andrea Singer Pollack, Trustee,

Appellant,

vs.

The Industrial Commission of the State of North Dakota, Conoco, Inc., and all other persons having an interest in the Dickinson-Lodgepole Unit,

Appellees.

Civil No. 94C-283

AFFIDAVIT OF THOMAS L. DAVIS

The record of this case (DLP) was closed on 6-8-94. This affidavit can not be entered into the record.

STATE OF COLORADO)
) ss
COUNTY OF JEFFERSON)

Thomas L. Davis, being first duly sworn, states:

1. I am, and have been since August of 1988, a full professor in the Department of Geophysics at the Colorado School of Mines. My entire career has been spent working in the field of geophysics. Attached hereto and made a part hereof is my resume listing my complete experience. I received my Ph.D. from the Colorado School of Mines in 1974 in the field of geophysical engineering. An area of concentration in my career has been the use and interpretation of seismic data in the exploration for oil and in defining oil field boundaries. I have worked extensively as a professor of geophysics, an author, a public speaker, and a consultant in the use and interpretation of all types of seismic data. I have been recognized as an expert in the field of geophysics and in the interpretation of seismic data.

2. In my experience in geophysics, I have become very familiar with the extensive use of both 2-D and 3-D seismic data in the exploration for oil resources and in the definition of field boundaries. I know of my own knowledge that the oil industry in America and worldwide spends substantial millions of dollars each year in obtaining and analyzing both 2-D and 3-D seismic data. 3-D seismic data is very useful in exploring for new oil fields and reservoirs. 3-D seismic data is particularly useful in defining the limits of a particular geologic formation which might have a high probability of containing oil reserves. Necessarily in interpreting 2-D or 3-D seismic data, the person doing the interpretation needs to have a knowledge of the geology of the area from which the data has been taken. A combination of the knowledge of the geology of a particular area and an analysis of the seismic data can lead to an interpretation of the geology of the particular area with a high degree of probability that a potential oil bearing reservoir has been located and its parameters defined. 3-D seismic is particularly useful in defining the boundaries of a particular formation. It is common in the oil exploration industry for 3-D seismic to be used to define the limits of a particular oil bearing formation. In fact, the 3-D seismic is so good in many situations that companies can literally know precisely what area to lease so that the productive formation and only the immediate area of the productive formation needs to be covered by leases.

he doesn't say what "type" of reservoirs 3-D works best in. Has it been used in "mound" type reservoirs?

3. Although I have never directly done consulting work for Conoco, Inc., I have done extensive consulting work involving the

use and interpretation of both 2-D and 3-D seismic data throughout the world. I am familiar with the geology of the Williston Basin in North Dakota, Montana and Canada, and I know that both 2-D and 3-D seismic data have been used successfully in the Williston Basin. I know of my own knowledge that the geology of the Williston Basin lends itself particularly well to the use of 3-D seismic data and information to define the limits of productive formations.

— has it been successful in the Lp Mound? Not yet!! Ask: Duncan True, armstrong Columbus

4. It is my opinion and my experience that 3-D seismic is a very useful tool in the Williston Basin for defining the boundaries of a potentially productive formation.

Thomas L. Davis

Subscribed and sworn to before me this 12th day of October, 1994.

Sara J Summers, Notary Public

My commission expires: My Commission Expires March 31 1998

RESUME

THOMAS L. DAVIS

Department of Geophysics
Colorado School of Mines
Golden, Colorado 80401
Telephone: 303/273-3938

Education:

BE	University of Saskatchewan, 1969, Geol. Eng., GP option
MS	University of Calgary, 1971, Geology/Geophysics
PhD	Colorado School of Mines, 1974, Geophysical Engineering

Work Experience:

Aug.1988-present, Professor, Department of Geophysics,Colorado School of Mines
Aug. 1986-Aug. 1988, Professor and Assistant Head, Department of Geophysics, Colorado School of Mines
Aug. 1983-Aug. 1986, Associate Professor and Assistant Head, Department of Geophysics, Colorado School of Mines
Aug. 1982-Aug. 1983, Associate Professor of Geophysics,Colorado School of Mines
Jan. 1980-April 1982, Assistant Professor of Geophysics, Colorado School of Mines
Sept. 1979-Dec. 1979, Associate Professor of Geology and Geophysics, University of Calgary
July 1977-July 1979, Assistant Professor of Geology, University of Calgary
Sept. 1974-July 1977, Assistant Professor of Geophysics, Colorado School of Mines
Summer 1973, Geophysicist, Amoco Canada Pet. Co. of Calgary, Alberta
May 1971-Aug. 1972, Geophysicist, Amoco Canada Pet. Co.,Calgary, Alberta
Summer 1969, 1970, Geophysicist, Chevron Standard Pet.Co.,Calgary, Alberta
Summer 1968, Geophysicist, Amoco Canada Pet. Co. of Calgary, Alberta

Affiliations:

President, TLD Geophysical Consulting Ltd.
President, Geophysics Fund Inc.
Director, Legacy Energy Corporation
Registered Professional Geophysicist and Engineer (Alberta)

Awards:

CSEG Best Paper Award 1971, cited in 1981
Canada National Research Council Fellowship 1973-74

Publications:

Davis, T.L., 1972, Velocity variations around Keg River reefs: CSEG Jour., v. 8, no. 1, p. 1-13.

Davis, T.L., 1972, Velocity variations around Leduc reefs Alberta: Geophysics, v. 37, p. 584-604.

Publications (continued):

Davis, T.L., 1973, Geophysical study of Alberta's Keg River reefs: Oil and Gas Jour., v. 71, no. 43, p. 46-50.

Hollister, J.C., and Davis, T.L., 1974, Geophysical prospecting for petroleum: Short course manual.

Davis, T.L., 1975, Influence of lateral compression on seismic velocity in the Cretaceous foreland of southern Alberta: Geophysics, v. 41, p. 349 (abstract).

Davis, T.L., 1975, Structural interpretation of seismic data: in New Trends in Seismic Interpretation Symposium sponsored by the Denver Geophysical Society.

Davis, T.L., Shuck, E.L., Money, N.R., 1976, Seismic investigation of the Golden fault zone: abstract in Geophysics, v. 42, no. 1.

Davis, T.L., and Weimer, R.J., 1976, Seismic evidence for late growth faulting in the Denver Basin: in R.C.Epis and R.J. Weimer, editors, Professional Contributions of the Colorado School of Mines, Studies in Colorado Field Geology: Special Pub #8, p. 280-300.

Davis, T.L., 1977, Structural interpretation of seismic data: Am. Assoc. of Pet.Geologists Structural Geology School note manual, 47 p.

Hollister, J.C., and Davis, T.L., 1977, Seismic prospecting for petroleum: in L.W. Leroy, D.O. Leroy and J.W. Raese, editors, Subsurface Geology, Colo. School of Mines Publication p. 425-437.

Davis, T.L., and Young, T.K., 1977, Seismic investigation of the Colorado Front Range zone of flank deformation immediately north of Golden, Colorado: in H. Veal, editor, Exploration Frontiers of Central and Southern Rockies, Rocky Mountain Association of Geologists Guidebook, p. 77-88.

Weimer, R.J., and Davis, T.L., 1977, Stratigraphic and seismic evidence for late Cretaceous growth faulting: in C.E. Payton, editor, Seismic Stratigraphy, Applications to Hydrocarbon Exploration, American Association of Petroleum Geologists, Mem. 26, p. 277-300.

Davis, T.L., 1979, Seismic-stratigraphic facies models: in Roger G. Walker, editor, Facies Models, Geological Assoc. of Canada Publication, Toronto, p. 201-211.

Davis, T.L., 1979, Seismic-stratigraphic analysis, Cretaceous of Rocky Mountain region: Oil and Gas Journal, November.

Davis, T.L., and Stoughton, D., 1979, Interpretation of seismic data from the northern San Luis Valley, south-central Colorado: in Robert E. Riecker, editor, Rio Grande Rift-Tectonics and Magmatism, American Geophysical Union, p. 185-194.

Davis, T.L., 1980, Application of reflection seismology to carbonate porosity and direct hydrocarbon detection: Canadian Society of Exploration Geophysicists Journal, v. 16, no. 1, p. 19-25.

Weimer, R.J., Emme, J.J., Farmer, C.L., Anna, L.O., Davis, T.L., and Kidney, R.L., 1982, Tectonic influence on sedimentation, Early Cretaceous, east flank Powder River basin, Wyoming and South Dakota: CSM Quarterly, v. 77, no. 4.

Davis, T.L., 1984, Seismic facies models: in Roger G. Walker, editor, Facies Models, 2nd edition, Geoscience Canada Reprint Series 1, p. 311-317.

Publications (continued):

Davis, T.L., 1985, Seismic evidence of tectonic influence on development of Cretaceous listric normal faults, Boulder-Wattenberg-Greeley area, Denver Basin: Mountain Geologist, v. 22, no. 2, p. 47-54.

Davis, T.L., and Lawton, D.C., 1985, Field testing of explosive surface seismic sources in the Canadian thrust belt: Geophysics, v. 50, no. 1, p. 56-62.

Zalan, P.V., Nelson, E.P., Warme, J.E. and Davis, T.L., 1985, Piau basin (Brazil); rifting and wrenching in an equatorial Atlantic transform basin: in Kevin T. Biddle and Nicholas Christie-Block, editors, Strike-Slip Deformation, Basin Formation, and Sedimentations, Society of Economic Paleontologists and Mineralogists Special Publication, No. 37, p. 177-192.

Davis, T.L., 1987, Seismic Facies Analysis: The Leading Edge, v. 6, no. 7, p. 18-23.

Martin, M.A. and Davis, T.L., 1987, Shear wave birefringence: A new tool for evaluating fractured reservoirs: The Leading Edge, v. 6, no. 10, p. 22-28.

Davis, T.L., 1987, Three-component seismic reservoir characterization study of Silo field, Denver basin, Wyoming: Society of Exploration Geophysicists Abstracts of Fifty-seventh Annual International Meeting, New Orleans, LA, Paper W2.5.

Davis, T.L. and Jackson, G.M., 1988, Seismic-stratigraphic study of algal mound reservoirs, Patterson and Nancy fields, San Juan County, Paradox basin, Utah: Geophysics, v. 53, no. 7, p. 875-880.

Davis, T.L., 1988, Seismic attribute studies, Mississippian Frobisher-Alida oil fields, Northeast Williston basin: Am. Assoc. of Petroleum Geol. Bull., v. 72, no. 7, p. 868.

Weimer, R.J., Rebne, C.A., and Davis, T.L., 1988, Geologic and seismic models, Muddy Sandstone, Lower Cretaceous, Bell Creek -- Rocky Point area, Powder River Basin, Montana and Wyoming: Wyoming Geological Association Guidebook, p. 161-177.

Davis, T.L., and Jackson,G.M., 1989, On seismic stratigraphy of algal mound reservoirs - a discussion: Geophysics v. 54, no. 3, p. 406-407.

Davis, T.L. and Lewis, C., 1990, Reservoir characterization by 3-D, 3-C seismic imaging, Silo field, Wyoming: The Leading Edge, November, p. 22-25.

Davis, T.L., 1990, The Road Ahead: The Leading Edge, February.

Lewis, C.L., Davis, T.L., and Vuillermoz, C., 1991, Three-dimensional multicomponent imaging of reservoir heterogeneity, Silo field, Wyoming: Geophysics, v. 56, no. 12, p. 2048-2056.

Lewis, C.L., Davis, T.L., and Vuillermoz, C., 1992, Three-dimensional multicomponent imaging of reservoir heterogeneity, Silo Field, Wyoming: in R.E. Sheriff, ed, Reservoirs Geophysics, SEG Special Publication #7, p.362-370.

Davis, T.L., 1992, SPG/SEG 1990 Carbonate Exploration Symposium, The Leading Edge, vol. 11, no. 1, p. 38-41.

Davis T.L. and Benson, R.D., 1992, Characterizing fractured reservoirs: World Oil, March.

Kramer, D. and Davis, T.L., 1992, Multicomponent VSPs for reservoir characterization, South Casper Creek field, Wyoming: The Leading Edge, September, p. 31-35.

Publications (continued):

Davis, T.L., 1992, 3-D seismic optimizes horizontal drilling: The American Oil and Gas Reporter, v.35, no.11, p. 30-36.

Davis, T.L. and Benson, R.D., 1992, Fractured reservoir characterization using multicomponent seismic surveys in J.W. Schmoker, E.B. Coalson and C.A. Brown, eds., Geological Studies Relevant to Horizontal Drilling: Examples from Western North America: Rocky Mountain Assoc. of Geologists Guidebook, p. 89-94.

Kendall, R.R., and Davis. T.L., 1993, Noise analysis using a multicomponent surface seismic test spread: The Leading Edge, October, p. 1002-1006.

Davis, T.L., Shuck, E.L., and Benson, R.D., 1994, Coalbed methane multicomponent 3-D reservoir characterization study, Cedar Hill Field, San Juan Basin, New Mexico: in R.R. Ray, editor, High Definition Seismic, Rocky Mountain Association of Geologists Guidebook.

Presentations:

Invited speaker at:

Society of Exploration Geophysicists section talks -- Calgary 1971; 1978, 1981, 1990, Casper 1972, 1987; Denver 1972, 1975, 1980, 1990, 1993, Amarillo 1989, Midland 1990, Houston 1991

American Association of Petroleum Geologists 1975 Special Session on Seismic Stratigraphy, Dallas, TX.

Rocky Mountain Association of Geologists Seismic Stratigraphy Symposium, March 30, 31, 1982.

Denver Geophysical Society Seismic Stratigraphy Symposium, September 28, 1983.

Montana Tech, Seismic Stratigraphy Course, April 5, 6, 1983.

Caracas, Venezuela, Second Geophysical Congress, November 18-22, 1984.

Maracaibo, Venezuela, First International Symposium on Reservoir Characterization, March 11-13, 1990.

SEPM National Convention, Golden, Colorado, August 11, 1985. Convened special sessions on seismic-stratigraphy.

Australian SEG meeting, October 30, 1985, Adelaide.

Canadian Society of Petroleum Geologists, Reef Symposium, January 27, 1987.

South African Geophysical Association meeting -- Capetown, September 24, 1987.

Geological Society of America Symposium on Rocky Mountain Tectonics, May 2, 1987, Boulder, organizer and presenter.

SEG/SPG Symposium on Petroleum Exploration in Carbonates Chengdu , China, August 24-29, 1990, organizer, SEG delegation leader.

Presentations (continued):

Geophysical Society of Tulsa Spring Symposium on Integrated Exploration, 1991.

Rocky Mountain Association of Geologists - Niobrara Symposium, May 6, 7, 1991;
- Sequence Stratigraphy Symposium, March, 1992.

Wyoming Geological Association Luncheon Speaker, Casper, Wyoming April 19, 1991.

Society of Petroleum Engineers Section meeting, June 16, 1992, Adelaide, Australia.

Society of Exploration Geophysicists, 62nd Annual International Meeting and Exposition, October, 1992.

Australia SEG meeting, June 8, 1993.

Caracas Venezuela, Second International Symposium on Reservoir Characterization, February 16-18, 1994

Short courses presented:

AAPG

Structural Geology Schools -- Vail, Colorado, July 1977, September 1977, July 1978; Jackson Hole, Wyoming, July 1979; Palm Springs, California, May 1980, May 1981; Jackson Hole, Wyoming, September 20-24, 1982, August 29-September 2, 1983.
Southwest Section, Forth Worth, Texas, February 21, 1993-3-D seismic course.

SEG

Carbonate seismology, November 16-17, 1982, Houston; March 2-1, 1984, Tulsa; December 1-2, 1984, Atlanta; May 12-13, 1986, Calgary; May 11-12, 1987, Calgary; October 1-2, 1987, Midland; April 9-10, 1988, Oklahoma City; September 22-23, 1988, Dallas; April 27-28, 1989, San Antonio; August 21-23, 1990, Chengdu, China; April 14, 1991, Dallas; May 4, 5, 1992, Calgary; March 17, 18, 1994, Midland.

Fractured reservoirs, March 14, 1987, Dallas; June 18, 1987, Calgary; March 20, 1988, Houston; October 30, 1988, Anaheim; May 8-9, 1989 Calgary; June 8, 1989, Calgary; February 8-9, 1990, Bakersfield and Los Angeles; April 11, 1990, Dallas; June 2, 1989, San Francisco; November 15, 1990, Calgary; May 8, 1992, Calgary, May 3-4, 1993, Calgary.

CSM Stratigraphic concepts course, Golden, Colorado:

August 21-26, 1978; May 16-20, June 6-10, July 11-15, August 22-26 and October 3-4, 1983; June 7-8, July 12-13, August 30-31, October 1-2, 1984; March 4-8, May 4-8, May 23-24, July 11-12, August 22-23, October 10, 1985; May 16, July 18, August 8, 1986; June 1, 1987; June 10, 1988; August 18, 1989; August 6-10, 1990, July 20-24, 1992, July 19-23, 1993.

H.K. Van Poollen and Associates

Geophysical prospecting for petroleum - Adelaide, Australia, August 1974, June 1976; Santa Cruz, Bolivia, October 1974; Denver, Colorado, March 1975, February 1976, March 1977, February 1978, September 1979, January 1980, January 18-22, 1982; Calgary, Alberta, April 1978; Benghazi, Libya, March 3-7, March 31-April 4, 1980.

Professional Training Resources, Inc., Tulsa, OK.

Seismic-Stratigraphy and Reservoir Definition, April 4-8, 1988, July 29-August 4, 1989, October 28-November 1, 1991.

LetService Party Ltd-Seismic reservoir delineation and characterization, Melbourne, Australia, June 26-30, 1990, June 15-19, 1992 and June 7-11, 1993, Adelaide, Australia.

Short courses presented (continued):

Industry Seismic Interpretation short courses:

Amoco, Denver, February, 1979; February 25-29, April 14-18, 1980; January 5-9, February 16-20, May 4-8, 1981;
February 22-26, 1986.
Amoco, Houston, September 29-October 3, 1980; February 2-6, September 21-25, 1981; February 8-12, September 13-17, 1982; September 1-17, 1983.
Tenneco, Houston, October 13-17, 1980; August 6, November 16-20, 1981; March 10, August 19, November 19, 1982; March 10, October 6, November 8-12, 1983; March 1, April 2-6, November 5-9, 1984; April 15-19, October 14-18, 1985; April 14-18, 1986; May 4-8, 1987; June 20-24, 1988, July 16-20, 1990.
Mobil, Denver, April 6-10, 1981.
Marathon Research Center, Littleton, Colorado, September 17, October 1 and 8, 1981.
USGS Oil and Gas Branch, Denver, October 1-2, 1981.
Soekor - South African Southern Oil Exploration Corporation, Johannesburg, South Africa, August 5-13, 1982.
Canadian Superior, Calgary, November 22-26, December 6-10, 1982; December 12-16, 1983; January 28, February 1, September 30-October 2, 1985.
Public Petroleum Company of Greece, April 11-15, 1983.
Petro Canada Ltd., April 30-May 4, September 10-14,1984; September 16-20, December 16-20, 1985; October 27-31, 1986; October 23-27, 1988.
Lagoven/CEPET, Caracas, Venezuela, November 25-30, 1985;
November 24-28, 1986; November 16-20, 1987, November 23-27, 1987.
Western Mining, Perth, Australia, July 7-11, 1986.
Unocal, Brea, California, September 8-12, 1986; April 5-6, 1990.
Texaco, Denver, December 15-19, 1986; New Orleans, June 3-7, 1991.
ENAP, Punta Arenas, Chile, July 6-10, 1987; January 2-3, 1989.
South African Geophysical Association, Johannesburg, South Africa, September 7-11, 1987.
Japan National Oil Company, Tokyo, Japan, December 14-18, 1987.
Petroleum Authority of Thailand, Bangkok, July 11-22, 1988.
Dome Petroleum, Calgary, January 11-15, 1988.
Petroleum Authority of Jordan, Amman, Jordan, April 1-6, 1989.
Overseas Petroleum Investment Corp., Kuala Lumpur, Malaysia, November 13-17, 1989.
Industry open enrollment:
Vail, Colorado, April 19-23, 1982; April 30-May 4, 1983.
Golden, Colorado, March 5-9, 1984; April 29-May 4, 1985; March 24-28, 1986.
Australian Mineral Foundation, Adelaide, Australia, Geology and geophysics of cratonic basins (co-lecturers Drs. R.J. Weimer and Cooper B. Land), November 7-12, 1983; October 28-November 2, 1985.
Melbourne, Australia, June 26-30, 1990; Adelaide, June 15-19, 1992.
Pacific Coast Section, SEG, Seismic Stratigraphy, Pasadena, Bakersfield, CA., February 10-11, 1988.
Gold fields of South Africa, Johannesburg, August 29-September 9, 1988.
Geophysical Society of Tulsa and Tulsa Geological Society, Carbonate facies and their seismic expression, Tulsa, October 29-30, 1990.
Ecopetrol, Bucaramanga, Colombia, June 5-14, 1990.
Petronas Carigali, Kuala Lumpur, Malaysia, March 16-20, 1992.
Canadian International Development Agency / Petro Canada, Petro Vietnam, Vietnamese Petroleum Institute and the Philippine National Oil Company, Seismic Interpretation, November 15-19, 1993, Hanoi, Vietnam.

University Courses

Colorado School of Mines:

GP352	Introduction to seismic prospecting, Spring 1976, 30 students; Spring 1977, 60 students; Spring 1980, 29 students; Fall 1980, 48 students; Spring 1981, 35 students.
GP452	Methods in seismic prospecting, 1975, 42 students; 1976, 47 students; 1977, 30 students.
GP551	Seminars in Seismic Exploration, 1975, 12 students; 1976, 20 students; 1977, 25 students; Fall 1981, 15 students; Fall 1982, 5 students; Fall 1983, 5 students.
GP671	Advanced seismic interpretation, 1976, 22 students; 1977, 23 students.
GP382	Six week summer seismic field camp, 1975, 47 students; 1984, 100 students; 1985, 100 students.
GP384	Seismic field interpretation and processing, 1975, 20 students; 1976, 20 students; 1977, 20 students; 1978, 20 students.
GP553	Seismic data processing, 1976, 23 students; 1977, 25 students.
GP671	Vibroseis data acquisition, 1976, 15 students.
GP661 & GP662	Graduate Seminars, 1975, approximately 20 students per class; 1976, approximately 20 students per class; 1977, approximately 20 students per class; 1981, approximately 20 students per class.
GPGN558	Seismic interpretation, Spring 1980, 18 students; Spring 1981, 36 students; Spring 1982, 32 students; Spring 1983, 25 students; Spring 1984, 35 students; Spring 1985, 41 students; Spring 1986, 35 students; Spring 1987, 21 students; Spring 1988, 23 students, Spring 1989, 14 students; Spring 1990, 12 students; Spring 1991, 15 students; Spring 1992, 5 students, Spring 1993, 15 students
GPGN/ GEOL503	Integrated exploration, Spring 1980, 23 students; Fall 1980, 13 students; Fall 1981, 20 students; Fall 1982, 15 students; Fall 1983, 30 students; Fall 1984, 40 students; Fall 1985, 18 students; Fall 1986, 14 students; Fall 1987, 14 students; Fall 1988, 4 students; Fall 1989, 15 students; Fall 1990, 21 students; Fall 1991, 7 students; Fall 1992, 24 students, Fall 1993, 10 students
GPGN/ GEOL504 & PE510C	Seminar topics in integrated exploration, Spring 1987,4 students; Spring 1988, 30 students; Spring 1989, 16 students; Spring 1990, 8 students; Spring 1991, 15 students, Spring 1993, 24 students

University of Calgary:

GE271	Geology for engineers, 130, 110, 160 students, 3 semesters 1977-78.
GP551	Advanced petroleum geophysics, Fall 1978, Fall 1979, 25 students per class.
GP471	Petroleum geophysics, 47 students Fall 1977; 90 students, Spring 1978.
GP357	Introduction to geophysics, Spring 1979 and Fall 1979, 25 students per class.
GP481	First geophysics field school, May 1979, 16 students.
GP459	Geophysics field schools, April 28-May 16, 1980, 23 students, 1981, 30 students.

University Committees:

Scholarly Publications' Committee of CSM (1975-77).
Curriculum Committee Faculty of Science, University of Calgary (1977-79).
CSM Student Affairs Committee (1982).
Advisory Committee on Continuing Education (1984, 1985).
Curriculum Committee (1986-1988).
Graduate Advisory Committee, Department of Geophysics (1983-present).
Graduate Council (1983-present).

Professional Societies:

Society of Exploration Geophysicists (SEG)
Canadian Society of Exploration Geophysicists (CSEG)
American Association of Petroleum Geologists (AAPG)
Sigma XI (Research Society of North America)
Association of Professional Engineers, Geologists and Geophysicists of Alberta (APEGGA)
Rocky Mountain Association of Geologists (RMAG)
European Association of Exploration Geophysicists (EAEG)
Denver Geophysical Society (DGS)
Canadian Society of Petroleum Geologists (CSPG)
South African Geophysical Association (SAGA)
Geological Society of Malaysia (GSM)

Professional Society Activities:

AAPG Geophysics Committee, 1984-present
AAPG committee on education, 1984-87 -- geophysics representative.
Associate Editor, CSEG Journal, 1978-1987.
Vice President, Denver Geophysical Society, 1987.
President, Denver Geophysical Society, 1988.
Second Vice President, Society of Exploration Geophysicists, 1989-90.
Geophysical Advisor to Western Interior Cretaceous Project.
SEG Academic Liaison Committee, 1989-present.
SEG International Affairs Committee, 1989-present.

Research Projects:

Seismic field studies in Colorado, Geophysics Fund, Golden,Colorado, 1975-80, $250,000.
Seismic stratigraphy:
- Tenneco Oil Company, Houston, 1982-1989, Williston basin, $85,000.
- Canada National Research Council, Calgary, 1977-79, $11,000.
- Dome Petroleum, Calgary, 1981, $10,000
- USGS, Denver, Newcastle project, 1981, $80,000.
- Mountain Petroleum, Denver, 1981, Niobrara project, $3,000.
- Anshutz Petroleum, Denver, 1981, Williston basin,$5,000.
- Sefel Geophysical, Denver, 1982, San Juan basin, $5,000.
- Unocal, Brea, California, 1987, Silo field, Wyoming, $5,000.
- ARCO, 1987, $2,500.
- Gulf Canada Resources, Calgary, 1988, $8,500.
- Amoco, 1988, $6,000.
- Unocal, 1989, $6,000.
- Union Texas, 1989, $16,500.
- Reservoir Characterization:
  - Conoco, 1990, 91, 92, $30,000.

Halliburton 1991-92, $10,000.
3D/3C seismic near surface site characterization-DOE, 1994-95, $105,000.00.
Interdisciplinary study of reservoir compartments, DOE, 1993-96, $750,000.00.

Industry Consortia:

Front Range flank, 1984-87, $100,000.
Reservoir Characterization Project
Phase I, Silo field, 1985-87, $225,000
Phase II, Silo field, 1987-89, $550,000
Phase III, South Casper Creek and Cedar Hill field, 1989-91, $1 million
Phase IV, Cedar Hill and South Casper Creek fields, 1991-92, $1 million
Phase V, Joffre and Sorrento fields, 1992-present 1.5 million

Theses completed under direction of Thomas L. Davis:

Marshall, David B., 1975, Geophysical interpretation of development of development of Tertiary structure in the Gulf of Panama basin: MS T-1792, Colorado School of Mines.

Shuck, Edward L., 1976, A seismic survey of the Ralston area, Jefferson County, Colorado: MS T-1835, Colorado School of Mines.

Omari, S.N., 1976, Integrated geophysical study of the central Algerian Sahara: MS T-1823, Colorado School of Mines.

Rodriquez N.O., 1976, Computer assisted interpretation of seismic refraction data: MS T-1860, Colorado School of Mines.

Beggs, G., 1977, Interpretation of seismic reflection data from the Hartzel and Sulfur Mountain quadrangles, Park County, Colorado: MS T-1880, Colorado School of Mines.

Money, Nancy R., 1977, A seismic investigation of the north Golden area, Jefferson County, Colorado: MS T-1849, Colorado School of Mines.

Olson, W.R., 1977, Seismic investigation of the Round Butte area, north-central Colorado: MS T-1853, Colorado School of Mines.

Stoughton, D.H., 1977, Interpretation of seismic reflection data from the San Luis Valley, south-central Colorado: MS T-1960, Colorado School of Mines.

Young, T.K., 1977, A seismic investigation of North and South Table Mountains near Golden, Jefferson County, Colorado, MS T-1947, Colorado School of Mines.

Brown, D., 1978, A seismic study of the Canon city - Pueblo area, Fremont and Pueblo Counties, Colorado: MS T-2109, Colorado School of Mines.

Buchanan, P.C., 1978, Seismic stratigraphy of the Terry and Hygiene members of the Pierre Shale, Weld County, Colorado: MS T-2110, Colorado School of Mines.

Nelson, K.J., 1978, A seismic investigation of the Golden Quadrangle area, Jefferson County, Colorado: MS T-2110, Colorado School of Mines.

Miller, J.J., 1979, A velocity smoothing program package - an aid to reflection seismic interpretation and data enhancement processing techniques: MS T-2127, Colorado School of Mines.

Theses completed under direction of Thomas L. Davis (continued):

Story, Chip. 1979, Seismic modeling and interpretation of the hogback thrust system in the Wyoming overthrust belt, Lincoln County, Wyoming: MS T-2158, Colorado School of Mines.

Tieman, H., 1979, Seismic modeling study: MS thesis, University of Calgary.

Claussen, J.P., 1982, Direct detection of Niobrara gas using seismic techniques: Yuma County, Colorado: MS T-2599, Colorado School of Mines.

Kidney, R.L., 1982, Seismic reflection study of depositional patterns of Newcastle formation, Newcastle Wyoming area, Eastern Powder River basin: MS T-2516, Colorado School of Mines.

Wallis, C.M., 1982, Seismic detection of porosity, Red River Formation, Williston basin, Sheridan County, Montana: MS T-2542, Colorado School of Mines.

Milligan, S.E., 1983, A seismic study of the Lower Cretaceous Muddy Sandstone, Southeast Big Horn basin, Wyoming: MS T-2742, Colorado School of Mines.

Watkins, G.L., 1983, Seismic-stratigraphic analysis of Ireton and Nisku depositional environments, northwest of Edmonton, Alberta: MS T-2579, Colorado School of Mines.

Salti, B.M., 1983, Regional velocity study of the Middle Cretaceous stratigraphic interval, Northern Denver, Basin, Colorado: MS T-2748, Colorado School of Mines.

Haberman, S.A., 1983, An integrated geophysical case study of the Cretaceous Codell Sandstone in the vicinity of the Hambert field, Weld County, Colorado: MS T-2772, Colorado School of Mines.

Plybon, S.C., 1983, Masters field seismic study, Denver, basin, Weld County, Colorado: MS T-2781, Colorado School of Mines.

Northrup, D.R., 1984, An evaluation of seismic reflection methods as applied to uranium exploration: MS T-2865, Colorado School of Mines.

Hayden, V.L., 1984, Seismic detection of fractured zones within the Bakken Shale, Antelope field, Williston basin, North Dakota: MS T-2796, Colorado School of Mines.

Benson, R.D., 1984, Seismic investigation of the Permian Pennsylvanian Minnelusa Formation, Prong Creek Field, Crook County, Wyoming: MS T-2863, Colorado School of Mines.

Weitzel, C.M., 1984, Seismic modeling and interpretation of Elk Basin field, Park County, Wyoming and Carbon County, Montana: MS T-2961, Colorado School of Mines.

Jackson, G.M., 1984, Seismic stratigraphic study and analysis of a test line, Patterson field area, San Juan County, Paradox basin, Utah: MS T-2992, Colorado School of Mines.

Williams, M.C., 1985, Geophysical investigation of sandstones in the Upper Cretaceous Frontier Formation, Southwestern Powder River basin, Wyoming: MS T-2888, Colorado School of Mines.

Phillips, D.H., 1985, A geophysical investigation of the Southeastern San Juan Mountains, Colorado: MS T-3077, Colorado School of Mines.

Dwyer, R.A., 1985, Seismic reflection investigation of the new Madrid rift zone near Caruthersville, Missouri: MS T-3159, Colorado School of Mines.

Rebne, C., 1986, A seismic study of the Muddy Formation, Bell Creek Field, Montana: MS T-3158, Colorado School of Mines.

Squires, S.G., 1986, Seismic study of Permian salt dissolution features, Northeastern Colorado: MS T-3203, Colorado School of Mines.

Domoracki, W.J., 1986, Integrated geophysical survey of the Golden thrust north of Golden, Colorado: MS T-3052, Colorado School of Mines.

Reeve, D.M., 1986, Seismic detection of Mississippian Frobisher-Alida facies, Wiley and Mouse River Park fields, Bottineau and Renville Counties, Williston basin, North Dakota: MS T-3255, Colorado School of Mines.

Krueger, P.G., 1986, Seismic-stratigraphic study of the Red Fork sandstone in Kay County, Oklahoma: MS T-3252, Colorado School of Mines.

Bergeon, T.C., 1986, Seismic character study Ismay Cycle, Paradox Formation, Paradox basin Southwest Colorado: MS T-3218, Colorado School of Mines.

Durrenberger, S.A., 1986, An integrated geophysical investigation and comparison of compressional and shear wave seismic reflection data from the San Juan Volcanic area, Southwestern Colorado: MS T-3226, Colorado School of Mines.

Gable, D.M., 1986, Delineating Pierre formation fracture reservoir using compressional and horizontal shear wave seismic data near Florence, Freemont County, Colorado: MS T-3087, Colorado School of Mines.

Martin, M.A., 1987, Three-component seismic investigation of a fractured reservoir,Silo field, Wyoming: PhD T-3339, Colorado School of Mines.

Harwell, J.W., 1987, Offset-amplitude seismic analysis, Bonny Gas field Yuma,Colorado: MS T-3399, Colorado School of Mines.

Mueller, T.L., 1987, A seismic-stratigraphic analysis of Starkey and Winters gas reservoirs using amplitude-offset studies from the Crossroads field, Sacramento Valley, California: MS T-3370, Colorado School of Mines.

Covarrubias, O., 1988, An integrated geological and geophysical study of the structural boundary between the San Luis basin and the San Juan sag, South-Central Colorado: MS T-3330, Colorado School of Mines.

Marhoefer, J.,1988, Seismic prestack analysis of a Mission Canyon Reservoir, Wiley field, Bottineau County, North Dakota: MS T-3575, Colorado School of Mines.

Lu, Ming-Tar, 1988, Offset amplitude analysis of compressional seismic data, Silo field, Wyoming: PhD T-3405, Colorado School of Mines.

Gurch, M.L., 1989, Four component rotation of 3-D shear wave data, Silo field, Wyoming: MS T-3716, Colorado School of Mines.

Lewis, C. 1989, Three-dimensional multicomponent imaging of reservoir heterogeneity, Silo field, Wyoming: PhD T-3700, Colorado School of Mines.

Schipperijn, A.P., 1989, One-dimensional modeling and rotation analysis of azimuthally anisotropic, four component shear wave data, Silo field, Wyoming: MS T-3745, Colorado School of Mines.

Persyn, S.M., 1989, Seismic detection of Dakota-D valley-fill sandstones using shear and compressional wave seismic data, Busy Bee field, Adams County, Colorado: MS T-3732,

Colorado School of Mines.

<u>Theses completed under direction of Thomas L. Davis</u> (continued):

Emmer, D.P., 1989, Converted P-S wave analysis of a fractured reservoir, Silo field, Wyoming: MS T-3638, Colorado School of Mines.

Kirkpatrick, J.R., 1989, Influence of tectonics and sea level change on sedimentation of the Jurassic Springhill and Todifera Formations, Central Tierra del Fuego, Chile -- An integrated study: PhD T-3603, Colorado School of Mines.

Van Meter, J.R., 1990, Psuedo-sonic log derivation, Central Kansas Uplift, Kansas: MS T-3768, Colorado School of Mines.

Grose, C.T., 1990, Structural and seismic interpretation of Laramide structure in Roxborough Park, Perry Park area, Front Range, Colorado: MS T-3671, Colorado School of Mines.

Luzietti, E.A., 1990, An investigation of seismic wavelet instability associated with near-surface geologic variations in the Powder River Basin: MS T-3884, Colorado School of Mines.

Young, M.T., 1990, A seismic and geologic study of the Morrow formation of Mount Pearl, Sorrento and Bledsoe Ranch fields, Cheyenne County, Colorado: MS T-3908, Colorado School of Mines.

Englemark, F.L., 1990, Seismic facies analysis of Jurassic sand dunes, South-eastern San Juan Basin, New Mexico: MS T-2811, Colorado School of Mines.

Kramer, Darrell L., 1991, Multicomponent vertical seismic profiles for reservoir characterization South Casper Creek field, Natrona County, Wyoming: PhD T-3939, Colorado School of Mines.

Harris, Wayne R., 1991, Patterns and controls for dissolution of the Prairie Formation, Bottineau, McHenry, Renville and Ward Counties, North Dakota: MS T-4066, Colorado School of Mines.

Faquira, Mohammad I., 1991, An integrated study of porosity distribution in the Upper Tensleep Formation, Natrona County, Wyoming: MS T-4085, Colorado School of Mines.

Johnson, Robert D., 1991, The control of structure and stratigraphy on differential compaction of the Fruitland Formation coal bearing intervals, Cedar Hill Field, San Juan County, New Mexico: MS T-4095, Colorado School of Mines.

Vieytes, Hugo, 1991, Velocity anisotropy in the near surface from 3D-3C refraction data, South Casper Creek field, Wyoming: MS T-4088, Colorado School of Mines.

Molinero, Gary T., 1992, Application of multicomponent VSP's to reservoir characterization at Cedar Hill coal bed methane field, San Juan County, New Mexico. MS T-4242, Colorado School of Mines.

Gilmore, Larry, 1992, Modeling and interpretation of a 3-D seismic survey, South Casper Creek field, Natrona County, Wyoming. MS T-4137, Colorado School of Mines.

Ketyungyoenwong, Boonsom, 1992, Seismic interpretation of 3-D converted wave data, Silo field, Wyoming. MS T-4087, Colorado School of Mines.

Kendall, Robert R., 1992, Analysis of a multicomponent seismic test spread: South Casper Creek field, Natrona County, Wyoming. MS T-4188, Colorado School of Mines.

Peinado, Adrian, 1992, Porosity estimation from inversion of compressional seismic data, South Casper Creek Field, Natroma County, Wyoming. MS T-4341, Colorado School of Mines.

Hu, Shin-Tai, 1993, Seismic imaging of complex subsurface structure, Western flank of Denver basin, PhD T-3284, Colorado School of Mines.

Theses completed under direction of Thomas L. Davis (continued):

Shuck, E.L., 1993, Multicomponent, trhee-dimensional seismic characterization of a fractured coalbed methane reserovir, Cedar Hill Field, San Juan County, New Mexico. PhD T-4170, Colorado School of Mines.

Ramos, Antonio C.B., 1993, Three-dimensional AVO analysis and anisotropic modeling applied to fracture characterization in coalbed methane reservoirs, Cedar Hill Field, San Juan basin, New Mexico, PhD T-4481, Colorado School of Mines.

Consulting Experience:

Van Poollen & Associates, Denver:
Seismic interpretation of data from Australia (1974), Libya(1975),Algeria(1976), North Slope of Alaska (1978), Beaufort Sea (1978), Offshore Louisiana (1982).

Evergreen Geophysical Associates, Evergreen, Colorado:
Seismic interpretation of data from Gulf of Alaska (1975-76); Wyoming Washikie Basin (1976); Western Canada (1977-78); Offshore Brazil (1978); Offshore Spain (1979); Offshore California (1981); China (1980), Offshore Brazil (1981).

Ted Manning, Edmonton, Alberta:
Seismic interpretation of Sherman Flats area of northwestern Alberta (1977), Frazer Valley, British Columbia (1984).

Geophysics Fund Inc., Golden, Colorado:
Seismic field work, processing and interpretation in Pueblo, Golden, Carr, Glenwood Springs, Pagosa Springs, Holyoke, and Julesburg areas, Colorado (1975-80).

D'Appolonia Consulting Engineers, Brussels, Belgium:
Seismic investigation of Gioa Tauro site of Italian steel company, 5th steel works, Calabria, Italy (1977); Iranian nuclear power plant siting, Isfahan, Saveh, (1978); Savannah River, Georgia, nuclear power plant siting (1979).

William E. Hughes, Santa Fe, New Mexico:
Seismic interpretation of the Gramps field area, Archuleta County, Colorado (1977-1988).

Group Seven Inc.:
Seismic review of Milford-Roosevelt Hot Springs (1980).

Arabian Gulf Exploration Company, Libya:
Sirtie basin, seismic interpretation, Libya (1980).

Exploration Data Consultants (Edcon), Denver:
Seismic review offshore China, Indonesia, South Africa (January 1981, October 1983).

Professional Geophysics Inc. (PGI), Denver:
Seismic interpretation offshore California, Point Arenas basin (March/April 1981).

Prairie Eagle Exploration Company, Denver:
Vibrator source experimentation (1981).

Wilderness Energy, Calgary:
Canon City Prospect area, Colorado (1982).

Consulting Experience (continued):

Bow Valley Exploration Co., Denver:
Western Kansas, Greeley County prospect (1982).

South African Southern Oil Exploration Co., Soekor:
Offshore South Africa, regional seismic study (1982,1985).

Century Geophysical, Calgary:
Vertical Seismic Survey - (VSP) (1982).

St. Michael Exploration Co., Denver:
D.J. basin prospect review (1982).

Resource Service Int., Denver:
Williston basin, Bowman County, North Dakota, seismic review (1982).

Seis-Port Exploration, Denver:
Piceance basin, Colorado, regional speculative survey planning (1982), Paradox basin seismic review (1985).

Public Petroleum Company of Greece, Athens:
Agean, Ionian seismic interpretation reviews (1983).

Golden and Land Oil Company, Bismark, North Dakota:
Bighorn basin, Montana, North Elk basin prospect review (1983).

Elmore-Lockhart, Denver:
Interpretation of regional speculative seismic survey, Weld County, Denver basin, Colorado (1983).

Texas Instruments, Dallas:
Strategic corporate planning (1983).

Chinese Petroleum Corporation, Taipei, Taiwan:
Interpretation of 2-D and 3-D surveys, Taiwan Straits (1984).

Amoco Production company, Denver:
Expert witness, lawsuit, Amoco vs Douglas Energy, et al (1984-85)

RPI, Texas, California:
Seismic interpretation of Yegua trend, East Texas (1985); Cook Inlet, Alaska (1985).

Simmons Group of Companies, Calgary:
Geophysical study of Togo, Africa (1985).

Chaparral Resources, Inc., Denver:
Expert witness, Chaparral vs Monsanto lawsuit (1985).

Broken Hill Proprietaries Ltd (BHP), Melbourne, Australia:
Seismic review of Jabaru, Challis area, Northwest (1985).

BP Canada Ltd., Calgary, Alberta:
Seismic review of Red Earth area, Alberta (1986, 1987).

Western Mining Corporation, Perth, Australia:
Seismic review of Barrow Island area, Northwest shelf, Australia (1986).

Consulting Experience (continued):

INTEVEP, Caracas, Venezuela:
Seismic-stratigraphy study of fractured Cretaceous reservoirs, western Lake Maracaibo region, Venezuela (1986).

ENAP, National Oil company of Chile, Punta Arenas, Chile:
Seismic interpretation, Magallenas basin, Chile (1987, 1989, 1991).

Dome Petroleum Company Ltd., Calgary:
Carbonate seismology (1988).

Gold Fields of South Africa Ltd., Johannesburg, South Africa: Witwatersrand basin and Bushveld complex South Africa (1987, 1988).

Anglo-American Corp., Klerksdorp, South Africa:
Seismic interpretation, Witwatersrand basin, South Africa (1987).

Gencor, Springs, South Africa:
Seismic interpretation, Witwatersrand basin (1987).

Johannesburg Consolidated Investment Co.:
Seismic interpretation Witwatersrand basin (1987).

Petroleum Authority of Thailand:
Seismic interpretation, Gulf of Thailand, onshore basins, Thailand, (1988).

Gold Fields of South Africa, Ltd. -- Johannesburg, Africa:
Seismic interpretation review, Witwatersrand basin, Bushveld Complex, South Africa and Tsumeb and other areas, South West Africa (1988).

United Nations and Ministry of Geology, People's Republic of China:
Seismic stratigraphy of carbonate basins in Southern China (1988).

OPIC, Overseas Petroleum Investment Corp., Kuala Lumpur, Malaysia:
Seismic interpretation, offshore Sarawak (1989).

ECOPETROL (National Oil Company of Colombia):
Seismic stratigraphy, Colombian basins, (1990).

McAdam, Roux and Associates:
Expert witness in MRA/AMPOL lawsuit (1990).

First Seismic:
On Board of Directors (July 1990-June 1991).

USEPA, United States Environmental Protection Agency:
Seismic interpretation reviews (1990, 1991).

Midale Petroleums Ltd., Midale, Saskatchewan:
Joint venture exploration in Southeast Saskatchewan portion of Williston basin (1991-present).

Petronas Carigali, Kuala Lumpur, Malaysia:
Seismic interpretation of carbonate reservoirs from Luconia Province offshore Sarawak (1992).

Consulting Experience (continued):

SANTOS, Adelaide, South Australia:
Reservoir characterization, Cooper basin (1992).

Union Pacific Resources Company:
Expert witness in UPRC vs City and County of Denver lawsuit involving Denver International Airport (1992-1993)

US Steel:
Seismic interpretation of the Pittsburgh coal seam, Pennsylvania (1993).

Woodward Clyde
Geismar, Louisiana waste injection site seismic study (1993).

Canadian International Development Agency/Petro Canada
Taught first ever course on seismic interpretation in Hanoi, Vietnam (1993).

ENAP, National Oil Company of Chile (1994)
Seismic interpretation of Atacama area, Northern Chile.

INDUSTRIAL COMMISSION OF NORTH DAKOTA

Edward T. Schafer	Heidi Heitkamp	Sarah Vogel
Governor	Attorney General	Commissioner of Agriculture

I, Karlene Fine, Executive Director and Secretary to the Industrial Commission of North Dakota, do hereby certify that this is a copy of the transcript of the Commission's discussion on Case 5933 held on June 16, 1994, at their meeting in the State Capitol, Bismarck, North Dakota.

STATE OF NORTH DAKOTA SEAL INDUSTRIAL COMMISSION

Karlene Fine
Executive Director and Secretary to the Commission
October 3, 1994

Karlene K. Fine, Executive Director and Secretary
600 East Boulevard Avenue - State Capitol - Bismarck, North Dakota 58505
Phone: (701) 224-3722 FAX: (701) 224-2820

Excerpt from a Meeting of the Industrial Commission of North Dakota
Held on June 16, 1994

Present: Governor Edward T. Schafer, Chairman
Attorney General Heidi Heitkamp
Commissioner of Agriculture Sarah Vogel
Bob Harms, Governor's Office
Wes Norton, Oil and Gas Division
Bruce Hicks, Oil and Gas Division
Charles Carvell, Attorney General's Office
Members of the Press

Wes Norton: This was a case that was a proposal by Conoco to unitize the Dickinson-Lodgepole which is the good well out in the Dickinson area. Good wells now. Basically, what they are doing is because the reservoir pressure has been dropping so fast, they are restricting production from the entire reservoir to 300 barrels per day. As soon as they start injection, they will raise the production to between 2,000 and 3,000 barrels a day. Two operating interests opposed the unit because they felt they were not getting their fair share. One was the Singer Trust which is AVIVA the operating company represented by Bob Wefald and the other was Placid which is Hunt people represented by John Morrison. Phillips is in agreement on the unit although they felt they were not getting their fair share but they are agreeing to it. And basically what we have here are three interpretations plus Conoco's. And interestingly enough, Hunt's interpretation is in the direction of their acreage.

Attorney General Heitkamp: Which one is Conoco's.

Wes Norton: Conoco is, I will pull that right now.

Commissioner Vogel: Oh, how odd.

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Governor Schafer: Yea, how those sheets change.

Wes Norton: Conoco really is a compromise of the three when you really look at it. The Singer Trust's big interest is in the south half of Section 31 so you can see that they feel there is more reservoir there. And of course Phillips and Conoco are over here and...

Attorney General Heitkamp: Those two come out further.

Governor Schafer: They might take it all the way to...

Wes Norton: It is interesting enough the Hunt exhibit agrees on that side more with Conoco than it does the Hunt interest or the AVIVA interests. AVIVA agrees with Conoco on this area and with the saddle in the middle in the south and then Phillips, of course, feels it goes out to the east like so. And this is Conoco's. The Placid...

Attorney General Heitkamp: I think you should just lay them all over each other and then where ever the outer boundaries are...

Commissioner Vogel: That's how they decide wetlands.

<u>Wes Norton</u>: What we have done in recommending approval is we feel that they have an order that they can defend in court and I will let Charles decide that but we... anyway AVIVA and Placid primarily had their interpretation based on seismic data. They used the same shot lines, the identical seismic data and they came up with two different maps, completely different as far as where the reservoir is and where the thick reservoir is. So, there is a credibility problem. We are not saying which one is right and which one's wrong. Conoco in their geologic interpretation used a marker on the Fryburg which is a pay above and the Bakken for thickening and thinning. In other words, they said where this mound is, the deposition is still the same so if you have 200 foot of mound, your Fryburg marker is going to be 200 foot higher. And the reason they used the geologic interpretation using the Fryburg marker is they had two more data points that the other ones did not use. This and there is another well in the center. The Conoco people ran a material balance which is an engineering equation using pressure, declines and so forth for the amount of production. It is a complicated engineering formula. And they came out using the material balance of 18.25 as a reservoir volume – million barrels of oil in place. AVIVA agreed with that and so did Placid. The AVIVA volume used in their geologic interpretation is 16 million barrels of oil in place. Which is an error of about 12% from the material balance. Conoco's is a little over 19 million which is 6% in error from the material balance which is in the limits of what you would consider in error. In the findings we say that they complied with the law. We went into the seismic interpretation and the material balance volumes. We thought an important factor was that the seismic did not coincide using identical data. We said that seismic is an exploration

tool, we agree with Conoco on that and does not determine reservoir quality. And those are the high points and we are recommending approval. The other thing is...

Commissioner Vogel: Of which...

Wes Norton: Approval of the Conoco proposed unit. The other thing is, it's in the findings, we have in excess of 70% ratification which complies with the statute. The ratification of the royalty owners already is Phase I 86% and Phase II 86%. So 86% of the royalty interests have ratified the unit including royalty owners under the AVIVA interests and also the Placid interests.

Commissioner Vogel: I will move approval that Order No. 6861 issued in Case No. 5933 be approved this 16th day of June, 1994.

Attorney General Heitkamp: Second.

Governor Schafer: It has been moved and approved. Any further discussion?

Attorney General Heitkamp: Ed, do you have any insights on this having sat through the hearing?

Governor Schafer: Well, my question - yea, it is amazing with the same data, how they shape these things. One point in time, they were arguing about whether 3D data was better than 2D data and all that kind of stuff but somebody had mentioned or suggested a neutral third party review the data and draw the – whatever happened to that approach.

Wes Norton: Placid or AVIVA recommended that. Then you are bringing someone in to put the unit together that is not, they are not familiar with the information and you start all over again. If they do not come up with the picture that Placid wants or that AVIVA wants or that Conoco wants, those people aren't going to agree with that and you are in the same dilemma number one. And number two is I don't know who they would get as a third party to do it that would not have a conflict with one of the companies.

Governor Schafer: They were kind of talking about an arbitrator, though weren't they. I mean then agreeing upon the answer.

Wes Norton: But you've got a unit here put together that 86% of the royalty owners have ratified. This is what happened in Little Knife when. They have got these people signed saying this is what you have and this is what your neighbor has and so forth and you come back to them with a different percentage and they have less, say, they are not going to ratify it and you're going to have a percentage ratification problem. It is one of those things where you got a thick reservoir you only got four data points, the company that knows the most about the reservoir and drilled the wells made the proposal and they stated they have an obligation to protect their lessees and lessors if they got farm outs and so forth. The engineering committee and of course, Bob Wefald made the issue that its a 800 pound gorilla because of their interests that is calling the shots. But by the same token, there are other working interests that agree with Conoco's interpretation including working interest owners in the Placid leases. They agreed, at an initial engineering committee meeting the parameters they would use, average porosity, etc... Then went forward with that and they used common software or state of the art software for doing things like this whereas on cross examination Placid and AVIVA stated they did not use software in the contouring, they used interpretation which meant they would draw it themselves.

Governor Schafer: And this is not my... You asked for an observation from being there. I thought Conoco's presentations were real professional and real clear and to me, not knowing much about it, it is very logical. The other two seem to be a little more "seat of the pants" or "shoot from the hip", or whatever you want to call it.

Wes Norton: I think the order will be appealed regardless

Governor Schafer: Pardon.

Wes Norton: I think the order will be appealed regardless of what kind of an order...

Attorney General Heitkamp: But you're

Commissioner Vogel: You think this one is more defensible in a court of law.

Wes Norton: I think it is, you can ask Charles.

Governor Schafer: From an outside observer...

Attorney General Heitkamp: Right, and actually that observation is very valuable because if you felt watching this that the credible evidence really was on the side of Conoco, that is an important observation.

Governor Schafer: Well, it seemed to be certainly even in the cross examination. How did maps get changed from this particular time to this particular time. They really did not have a super good answer other than, it is better for us.

Commissioner Vogel: Do we need a motion.

Governor Schafer: We already have a motion on the table. Is there any further discussion. All those in favor signify by saying aye...

Commissioner Vogel, Attorney General Heitkamp and Governor Schafer: Aye.

Governor Schafer: Opposed? The motion carries.

INDUSTRIAL COMMISSION OF NORTH DAKOTA

Edward T. Schafer
Governor

Heidi Heitkamp
Attorney General

Sarah Vogel
Commissioner of Agriculture

I, Karlene Fine, Executive Director and Secretary to the Industrial Commission of North Dakota, do hereby certify that this is a copy of the transcript of the Commission's discussion on Case 5933 held on August 3, 1994, at their meeting in the State Capitol, Bismarck, North Dakota.

Karlene Fine
Executive Director and Secretary to the Commission
October 3, 1994

Karlene K. Fine, Executive Director and Secretary
600 East Boulevard Avenue - State Capitol - Bismarck, North Dakota 58505
Phone: (701) 224-3722 FAX: (701) 224-2820

Excerpt from a Meeting of the Industrial Commission of North Dakota
Held on August 3, 1994

Present: Governor Edward T. Schafer, Chairman
Attorney General Heidi Heitkamp
Commissioner of Agriculture Sarah Vogel
Wes Norton, Oil and Gas Division
Charles Carvell, Attorney General's Office
Members of the Press

Wes Norton: If you remember at the last meeting, we had two requests for reconsideration of the unit approval order of the Dickinson Lodgepole and Bob Wefald came with additional information etc... and the Commission asked us to look over the information etc... We have prepared, Charles and Bruce Hicks did most of the work on it, have prepared an order denying the request for rehearing. They can go directly to court then if we errored in the decision. We did not see any additional new evidence and we feel we have complied with the law and made the right decision. Charles you may want to add...

Charles Carvell: I don't have anything to add.

Governor Schafer: I thought it was interesting it was in the newspaper who...

Wes Norton: Yea, they are trying to try it in the newspaper but there was .... If the person that was given the expert testimony on seismic data is an accountant, she is the bookkeeper for the Andrea Singer Trust.

Attorney General Heitkamp: I will move approval of Order No. 6893 issued in Case 5933 denying the petition for rehearing.

<u>Commissioner Vogel</u>: And I will second.

<u>Governor Schafer:</u> It has been moved and seconded to approve the order denying the rehearing. Is there any further discussion. All those in favor signify by saying aye.

<u>Attorney General Heitkamp, Commissioner Vogel and Governor Schafer</u>: Aye.

<u>Governor Schafer</u>: Opposed? Motion carries.

Waterflood Feasibility Study

and

Unitization Parameters

LITTLE MISSOURI MINNELUSA FIELD

This study was not introduced into the record!
S. F

Crook County, Wyoming

VOLUME 1

TEXT AND MAPS

JANUARY 1989

TABLE OF CONTENTS

VOLUME I

VOLUME II

INTRODUCTION

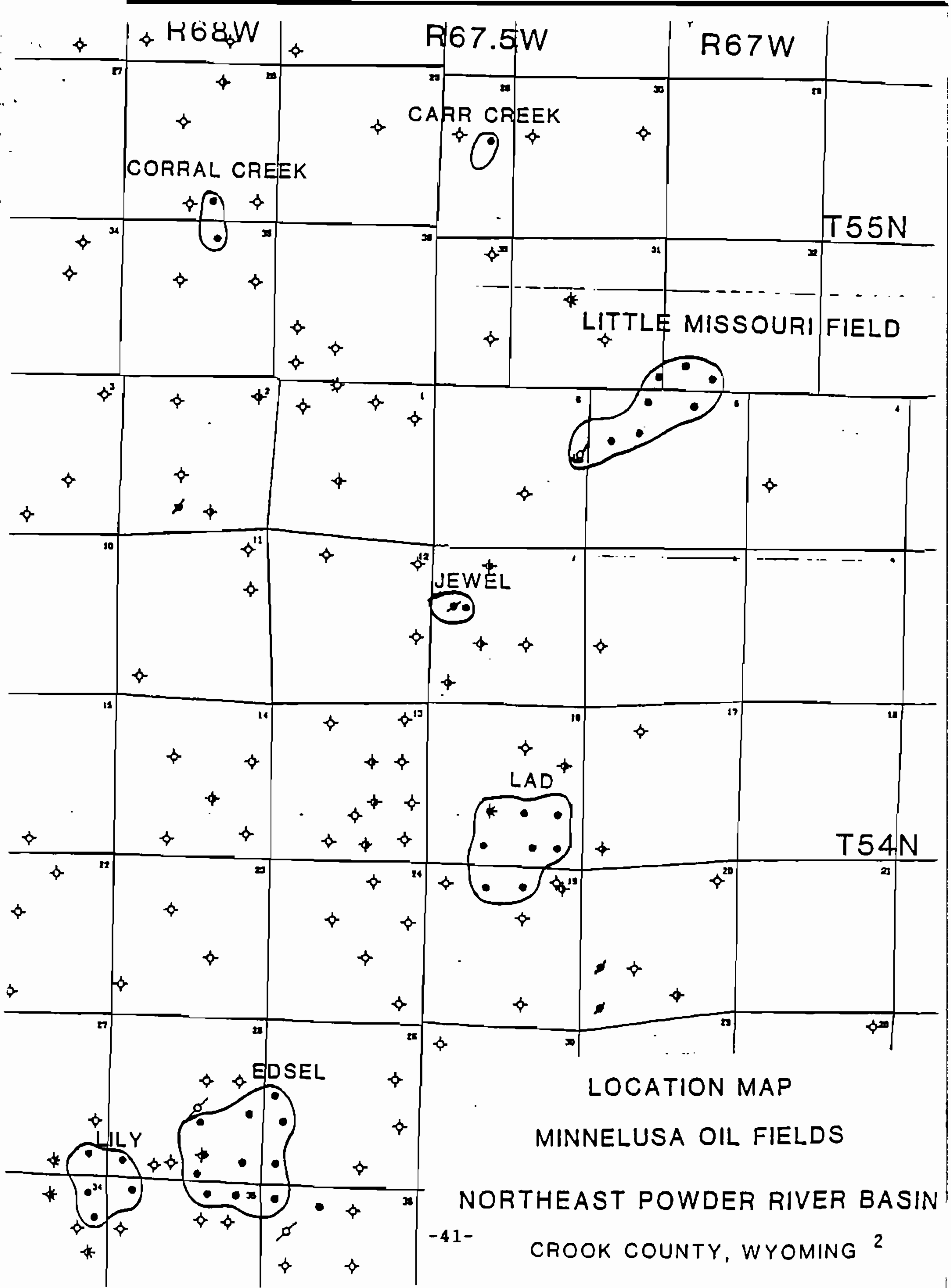
An engineering study has been made to investigate the economic feasibility of initiating supplemental recovery operations in the Little Missouri (Minnelusa) Field, Crook County, Wyoming. This report was prepared by McAdams, Roux & Associates, Inc. (MRA) to present the results of this study.

The Little Missouri Field is located on the east side of the Powder River Basin, some 40 miles northeast of Gillette, Wyoming (see enclosed Location Map). Production was established from the Minnelusa Upper "B" Sandstone in October, 1986 at a depth of 5600 feet. A total of eight wells have been drilled on 40-acre spacing, all of which encountered the Upper "B" Sandstone reservoir. The formation averages 25.1 feet of net pay, has an average porosity of 15.1 percent and an average water saturation of 16.9 percent. The original bottomhole pressure was 2163 psi and the reservoir temperature is 137° F.

As the field was developed, bottomhole pressure measurements revealed that the reservoir pressure was declining rapidly, indicative of a highly undersaturated reservoir. As a result of the low bubble point pressure, reservoir energy for primary recovery is derived from the expansion of the reservoir rock and fluids since there is no evidence of water encroachment. As expected, oil production has declined rapidly and primary recovery will be a small fraction of the total oil-in-place, thus necessitating the implementation of a supplemental recovery injection program to maximize the ultimate oil recovery from this reservoir.

not similar to LP rock Dickman LP's limestone w/~~plants~~ bryozoans + crinoids

The field had an estimated 4.684 million barrels of original oil-in-place and is expected to produce 326,048 barrels (7.0%) by primary. The total recovery is increased to 1,373,027 barrels (29.3%) and 1,832,880 barrels (39.1%) by the implementation of a straight waterflood and a polymer enhanced waterflood, respectively.



LOCATION MAP

MINNELUSA OIL FIELDS

NORTHEAST POWDER RIVER BASIN

CROOK COUNTY, WYOMING 2

CONCLUSIONS

1. Original oil-in-place (OOIP) is estimated to be 4.684 million stock tank barrels of oil (STBO) from volumetric calculations and confirmed by above-the-bubble point material balance calculations.

2. Cumulative oil production as of 10/1/88 is 158,367 STBO, or 3.4% of the OOIP.

3. Ultimate primary recovery is estimated to be 326,048 STBO, (7.0% of the OOIP) as determined by extrapolation of each individual well's primary production performance.

4. Straight waterflooding of this reservoir is estimated to recover an additional 1,046,979 STBO (over primary) for a total recovery of 1,373,027 gross STBO (29.3% of the OOIP).

5. Due to a high permeability variation, supplemental recovery from straight waterflooding would be reduced because of early water breakthrough and poor volumetric sweep efficiency.

6. A polymer-enhanced waterflood with the attendant mobility ratio and permeability control, is estimated to recover an additional 459,853 STBO over straight waterflooding, or 1,506,832 STBO in addition to the estimated primary recovery of 326,048 STBO. This results in a total recovery from primary plus polymer waterflooding of 1,832,880 STBO or 39.1% of the OOIP.

7. An economic analysis based on a 100% working interest and a 76.5% net revenue interest as of 5/1/89 yields the following results:

	Primary Only	Straight Waterflood*	Polymer Augmented Waterflood*
Net Cash Operating Income, M$	457.0	6,946.8	9,234.3
Investment, M$	-0-	356.0	548.0
Undiscounted Profit, M$	457.0	6,590.8	8,686.3
Discounted Profit, M$			
10%	385.7	5,297.1	6,408.6
15%	356.9	4,775.3	5,554.9
20%	331.6	4,319.3	4,839.8

* Includes Remaining Primary

The above comparison is based on escalation of oil prices and operating expenses at 6 percent/year and is before federal income taxes.

8. The estimated cost to install a waterflood plant and injection lines, develop an injection water supply from the Fox Hills, convert two wells to injection, purchase and equip an existing Minnelusa well for salt water disposal and to provide for a salt water disposal plant and tank battery consolidation is $460,000. Investment costs for polymer injection equipment total $35,000 and polymer chemical costs are expected to total $450,427 over a 40 - month polymer injection period. Following response to injection, additional funds in the amount of $53,000 will be required for the installation of high volume artificial lift and additional water handling facilities.

9. Unitization of the Little Missouri Field is both necessary and desirable for supplemental recovery operations.

10. Tract 1 is a communitized lease in which Federal lands cover 74.25 percent. Based on this tract's share of the proposed unitization parameters, it appears likely that this will be a Federal Unit.

RECOMMENDATIONS

1. Unitize the leases in the Little Missouri Field for the purpose of conducting a polymer augmented waterflood.

2. Negotiate a unitization formula utilizing the parameters outlined in the Feasibility Study.

3. Tertiary exemption should be requested from the Wyoming Oil and Gas Conservation Commission and filed with the Wyoming Tax Commission in order to receive the severance tax reduction of 2% as per Wyoming statutes (Article 3, Section 39-6-302).

4. Install an injection plant (capable of 2000 BWPD at 1800 psi), associated polymer equipment and centralized production facilities. The centralized battery should be constructed using available equipment from the individual tank batteries.

5. Convert MRA Winegar 1-6 and MRA Fowler 1-5 to water injection.

6. Develop an injection water source from the Fox Hills. The Fox Hills is absent under the proposed unit area, but is present and adequately developed within two to three miles (to the west and southwest) of the proposed site for the injection plant.

7. When required, purchase the MRA State Clayton 2-4, (NW/4 SW/4 Section 4, T54N-R67W) located about one mile southeast of the Little Missouri Field, for use as a salt water disposal well in the Minnelusa Lower "B" and Minnelusa "D" Sands.

POLYMER AUGMENTED WATERFLOOD IMPLEMENTATION PLAN

Straight waterflooding of the Minnelusa in the Powder River Basin has been a very successful supplementary recovery technique. Polymer technology was first used in the Minnelusa in 1972 and experience has shown that this application has resulted in improved flood efficiency because less water is both injected and produced to recover a barrel of oil. In addition, the improvement in mobility ratio and permeability control results in an increase in ultimate oil recovery over straight waterflooding.

Some 40 Minnelusa fields have been polymer flooded. Initially, the technique involved injection of an anionic polymer; however, the process rapidly advanced to include the initial injection of a cationic polymer followed by an anionic polymer either mixed or alternated with an aluminum citrate cross linker to provide in-situ gelling. Of the 40 polymer floods, 33 have used the cationic-anionic approach and 30 of the 33 have included in-situ gelling.

The initial cationic polymer that is injected has good adsorption/retention properties and moves into the high permeability layers where it provides an anchor for the anionic polymer and the aluminum citrate cross linker, thereby providing both near well-bore permeability reduction and in-depth permeability unification which results in an improved vertical sweep efficiency. The process is completed with the injection of a different anionic polymer for mobility control, thereby improving the areal sweep efficiency. This process is recommended for the Little Missouri Field. The key elements of the overall proposal are discussed below.

Injection Rate

The recommended field injection rate is 1250 BWPD. This rate was determined based on field size and the estimated receptivity of Fowler 1-5 and Winegar 1-6, the proposed injection wells. Injectivity for each well was estimated using Muskat's equation for injectivity at fillup in a radial flow system. Input data for these calculations included:

1. Pressure differential - 4000 psi (maximum surface pressure = 1750 psi based on a limiting bottomhole pressure of 0.75 psi/ft.)

2. End-point relative permeabilities = (K_{rw} = 0.25 and K_{ro} = 1.0)

3. Fluid viscosities - (Water = 0.6 cp and Oil = 19.6 cp)

4. Injector to producer - 1320'

5. Water bank radius - 100'

The results are summarized below for straight water injection and for a polymer solution with a resistance factor of 10 and 20. The results are expressed in both BWPD/millidarcy-foot and in BWPD for each of the proposed water injection wells.

	Estimated Injectivity BWPD/Md.Ft.	Estimated Injectivity, BWPD Fowler 1-5 Kh = 6000	Winegar 1-6 Kh = 4000
Water Injection	0.45	2700	1800
Polymer Injection			
R = 10	0.16	960	640
R = 20	0.10	600	400

The Kh value for Winegar 1-6 is based on core data from this well. Since Fowler 1-5 was not cored, its Kh product was based on data presented in the Petrophysical and Log Analysis sections - 32 feet of net pay and an average permeability of 190 millidarcies (taken from porosity vs permeability plot for a porosity value of 17 percent). It is suspected that this value for Fowler 1-5 is low, as current production indicates this well has the highest productivity index of any producing well in the field.

In summary, these data indicate that each of the proposed injectors will have the required receptivity to polymerized water to take its share of the proposed field injection rate of 1250 barrels per day. The planned injection rates for Fowler 1-5 and Winegar 1-6 are 950 and 300 barrels per day, respectively.

Injection Plant

The injection plant will be designed for a maximum output of 2000 BWPD at 1800 psi. Polymer chemicals will be handled through a dry solids feed system consisting of a feed bin, mix tank, charge pump and controls for injecting aluminum citrate. The polymerized water will not be injected through any chokes, thereby avoiding a reduction in viscosity by shearing of the polymer. The source water will be filtered prior to entering the fresh water tank. Source and produced water will not be mixed and produced water will be disposed of separately. A Water Quality Control Station (WQCS) will be installed at Winegar 1-6 (The lowest volume and most remote injector from the plant) to monitor the water thereby identifying any water quality problems.

Source Water

The source water of choice for Minnelusa polymer floods is the Fox Hills. Although not present at Little Missouri, the Fox Hills produces 1200 BWPD at a depth of about 380 feet in the Lad Field some three miles to the southwest. It is believed that a sufficient Fox Hills water source can be developed at a depth of about 500 feet some 2 1/2 miles to the west and southwest of the injection plant. The cost estimate provides $38,000 to drill and complete two Fox Hills water source wells. If two wells are needed, their combined production would be shipped to the injection plant through a common gathering line at an estimated cost of $46,000.

Salt Water Disposal

During the period of polymer injection, produced water cannot be used for injection purposes, thus requiring a separate salt water disposal system. When a disposal well is required, the MRA State Clayton 2-4 should be purchased. This well, located one mile southeast, is cased through the Minnelusa and 100 percent water was recovered on selective swab tests of the Minnelusa Lower "B" and Minnelusa "D" Sands. Both of these sands could be used for disposal.

Polymer Augmented Plan

The recommended technique for the Little Missouri Field is the injection of a cationic polymer followed by a mix of an anionic polymer and aluminum citrate, the latter of which will provide in-situ gelling. This mix is then followed by another anionic polymer. An example of this three-stage design is enclosed. The overall injection plan is described as follows:

1. Install a WQCS at the wellhead of Winegar 1-6 to monitor water quality.

2. Initiate injection with straight water at 1250 BWPD for 20-30 days. The individual well rates are 950 BWPD (Fowler 1-5) and 300 BWPD (Winegar 1-6).

3. Run tracer and temperature surveys on each injector to determine if injected water is being confined to the completion interval.

4. Run a step rate test on each injector to determine fracture pressure. The maximum injection pressure will be 200 psi below the fracture pressure.

5. While still injecting straight water, start polymer feed system and run a 24-hour checkout test for oxygen, total and dissolved iron and suspended solids.

6. Reduce the field injection rate to 750 BWPD (Fowler 1-5 - 560 BWPD; Winegar 1-6 - 190 BWPD) and start the polymer augmented process with the Stage 1 injection of 24,321 pounds of cationic polymer in 115,640 BW (2% of reservoir pore volume), a concentration of 600 mg/l. This cationic polymer will adhere to the reservoir rock and provide an anchor for the Stage 2 anionic polymer. Stage 1 is injected at a reduced injection rate of 750 BWPD to insure its placement into the most permeable sections of the reservoir. During this 154-day injection period, if pre-mature response is noted, the injection rate would be further reduced while maintaining the same daily cationic treatment in pounds of polymer until the total of 24,321 pounds had been injected.

7. Increase the injection rate to the planned 1250 BWPD. Start Stage 2 injection by injecting anionic polymer at a rate of 100 pounds per day (225 mg/l). This high molecular weight polymer will attach to the previously injected cationic polymer to provide the needed permeability reduction. This stage of injection may also include the concurrent addition of aluminum citrate to provide in-situ gelling; however, the need for the aluminum citrate will depend on the injection performance (Hall Slope) during the first 60 - 70 days of Stage 2. During Stage 2, a total of 59,282 pounds of anionic polymer will be injected over 601 days. The aluminum citrate requirements could total 65,869 pounds, depending on the injection well response. The total Stage 2 injection equals 751,660 barrels or 13% of the reservoir pore volume.

8. Stage 3 will consist of the injection of 60,802 pounds of a low molecular weight anionic polymer in 578,200 BW (10% pore volume) at a concentration of 300 mg/l. At the field injection rate of 1250 BWPD, this injection period will require 463 days. This polymer is designed to provide mobility control throughout the horizontal and vertical section.

9. The expected period of polymer injection is 40 months, followed by straight water injection. From the previous discussion, it is evident that the reservoir's response will control the overall process and that the program must be closely monitored to determine if a modification is required. Routine injection and production performance data that will be collected and continuously reviewed are daily injection rates and pressures, oil and water production, polymer concentrations, produced water analyses and pumping fluid level shots. Performance graphs will include oil and water production vs time, water-oil ratio vs time, cumulative injection vs cumulative oil production, cumulative injection volume vs cumulative pressure (Hall Plot) and injectivity index vs time. Water quality and the condition of process components will be monitored by the WQCS installed at the most remote low volume injection well.

Alkaline Polymer Flooding

This process is believed to have the potential to increase oil recovery in the Minnelusa by reducing the oil-water interfacial tension, thereby lowering the residual oil saturation by an additional 10 percent in the swept zone. Terra is currently testing this technique in the Minnelusa in the West Kiel Field.

The Little Missouri crude was tested to see if the alkaline polymer process would increase oil recovery. As seen on the enclosed data sheet and graph, Tiorco's tests indicate that the desired 100-fold decrease in interfacial tension could be achieved with the addition of either a 0.2 weight percent of potassium hydroxide or by a 0.4 weight percent of 50:50 potassium hydroxide and sodium bicarbonate.

A possible 10 percent additional reduction in the residual oil saturation in the swept zone would appear to be an attractive target for additional oil recovery; however, given the possibility of alkaline agent breakthrough in the producers with the attendant scaling problem, the alkaline injection design must be significantly reduced to insure that this breakthrough does not occur. As a consequence of this smaller alkaline injection program, the potential for additional recovery is less than 3 percent of the reservoir pore volume. At Little Missouri, this target volume would be under 175,000 barrels of additional oil. The alkaline polymer process is not recommended for the Little Missouri Field.

TIORCO INC.
THE IMPROVED OIL RECOVERY COMPANY

TABLE 2

MCADAMS, ROUX & ASSOCIATES
LITTLE MISSOURI FIELD
CROOK COUNTY, WYOMING

CHEMICAL FLOOD DESIGN
BASIS: Injection Rate = 1250 BWIPD
Reservoir Volume = 4939 acre-ft.
Pore Volume = 5,782,000 BBLS

STAGE	ONE	TWO		THREE
CUMULATIVE INJ. % PV	2.0	13.0		10.0
BBLS	115,640	751,660		578,200
DAYS	154	601		463
CHEMICAL PRODUCTS	CAT-AN®260	HI-VIS®350	TIORCO®677	UNI PERM®42
CONCENTRATION - MG/L	600	225	250	300
FEED RATE - LBS/DAY	150	100	110	131
TOTAL POUNDS	24,321	59,282	65,869	60,802
TOTAL COST - $	80,016	168,954	34,252	167,205
AVERAGE COST/DAY - $	520	281	57	361

Total Chemical Cost - $450,427

Chemical Cost per Incremental Barrel of Oil = $0.99
(Based on PAP and WF injection rates of 1250 BWIPD).

Notes:

1. Stage One is based on injection rate of 750 BWIPD.

TIORCO, INC.
CRUDE OIL ALKALINE FLOOD PROSPECT SCREENING
McADAMS-ROUX ASSOCIATES

Field: Little Missouri Field
Sample Description: Fowler #1-5 - Oil Dump Treater
Untreated Minnelusa Crude Oil
Sample Dated: 8-4-88
Taken By: Tom Doll
Reporting Date: 8-17-88

VISCOSITY DATA

Measurements taken using Brookfield Viscometer with UL Adapter

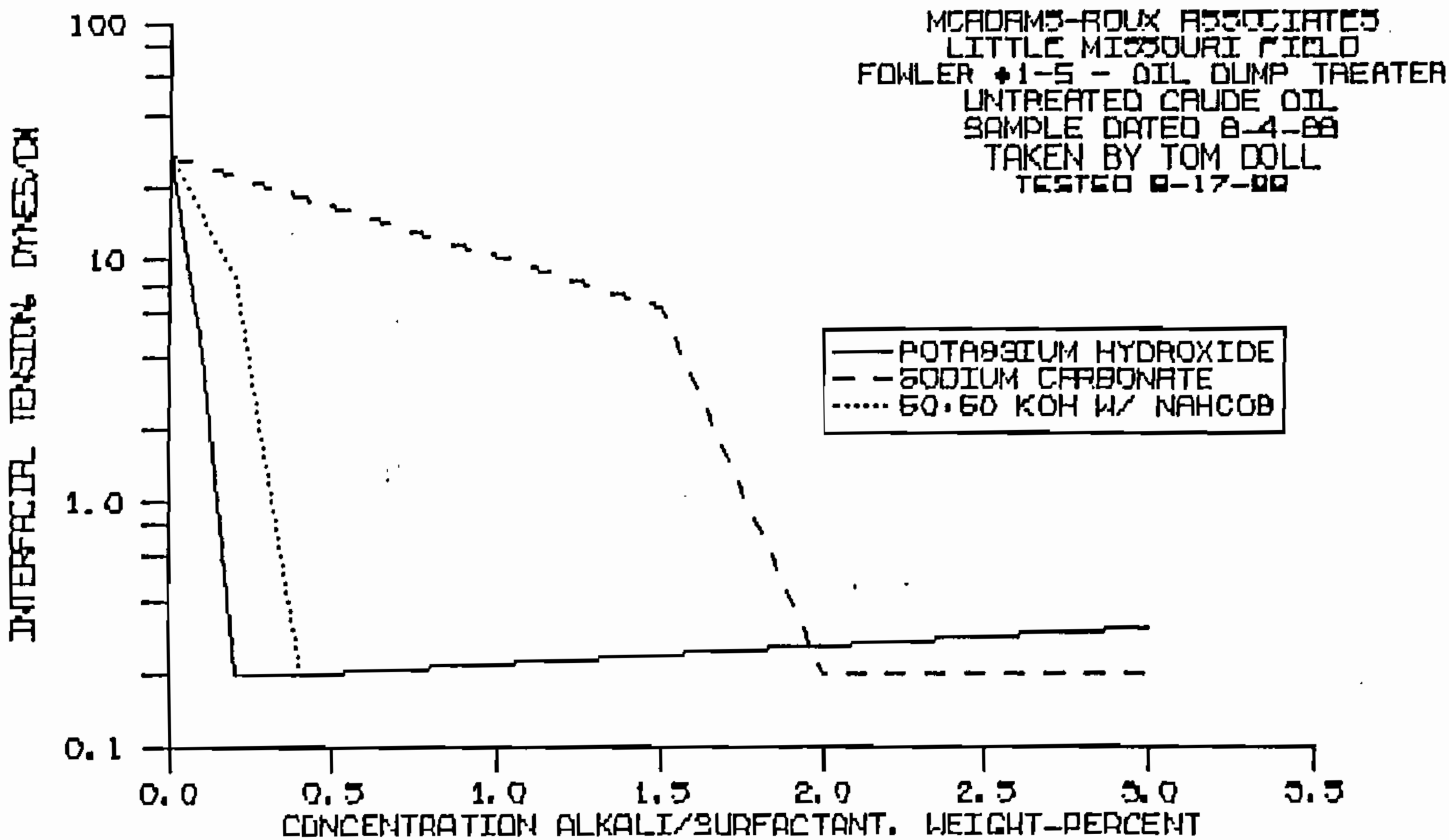
Temperature °C	°F	RPM	FACTOR	READING	VISCOSITY IN CPS
27	80	6	1	90.50	90.50
38	100	6	1	51.15	51.15
49	120	6	1	30.95	30.95
60	140	6	1	20.70	20.70
71	160	6	1	16.40	16.40
82	180	6	1	10.40	10.40
93	200	6	1	7.75	7.75

INTERFACIAL TENSION DATA (Dynes/cm)

Density = 0.921 at 20° C
All IFT's run with Du Nouy Ring at Room Temperature
All aqueous solutions are as active chemical weight percent, in deionized water, since the activities of different products vary

CONCENTRATION ALKALI (WT%)	POTASSIUM HYDROXIDE	SODIUM CARBONATE	50:50 KOH w/ $NaHCO_3$
0	26.9	26.9	26.9
0.1	4.2	-	-
0.2	0.2	-	8.4
0.4	0.2	-	0.2
1.5	-	6.3	-
2.0	-	0.2	-
3.0	0.3	0.2	-

12


MCADAMS-ROUX ASSOCIATES
LITTLE MISSOURI FIELD
FOWLER #1-5 - OIL DUMP TREATER
UNTREATED CRUDE OIL
SAMPLE DATED 8-4-88
TAKEN BY TOM DOLL
TESTED 8-17-88
POTASSIUM HYDROXIDE
SODIUM CARBONATE
50:50 KOH W/ NAHCO3
INTERFACIAL TENSION, DYNES/CM
100
10
1.0
0.1
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
CONCENTRATION ALKALI/SURFACTANT, WEIGHT-PERCENT

DEVELOPMENT & COMPLETION HISTORY

The Little Missouri Field was discovered with the October 20, 1986 completion of the MRA Fowler 1-5 for a 24-hour pumping potential of 575 barrels of oil, and no water through perforations from 5610-5620'. In December 1986, after producing 26,586 barrels of oil, the remainder of the Minnelusa Upper "B" Sand was perforated, resulting in a 33-foot completion interval from 5587-5620'. This discovery well has not been stimulated.

perm must be much lower than Lp which shows interference on 320's.

Since the initial completion, seven additional wells have been drilled on 40-acre spacing. All eight wells encountered the Upper "B" Sandstone reservoir with seven being completed as oil producers. The remaining well (MRA Winegar 1-6) encountered the producing sand downdip and with no oil shows based on core analysis. Subsequent production tests (by swabbing) recovered low volumes of water. The well was temporarily abandoned pending use as a water injection well.

All wells are equipped with 5 1/2 inch casing. The normal completion has been to underbalance perforate with 4 jet shots per foot using a 4-inch casing carrier gun loaded with premium charges. Solubility tests on some 15 core chips taken from five wells indicate solubilities in 15% Fe Hcl acid ranging from 8.3 to 20.1 percent with an average of 12.7 percent. With the exception of the discovery well, stimulation in each well has consisted of a 500-gallon acid wash followed by a larger volume treatment (2500-4200 gallons) using ball sealers at an injection rate that would result in good ball action, thereby maximizing the number of perforations open to production. The completion history on each well is tabulated and included in this section of the report.

In order to reach the desired bottomhole target, the Federal 1-32 had to be directionally drilled due to a topographic problem. A multi-shot survey was essential on this well. In addition, although not required, multi-shot surveys have been recorded on all wells to provide a more precise location of the hole at the Minnelusa level. The bottomhole locations and TVD corrections for all wells are given on the enclosed tabulation. On all maps in this report, the well spot reflects the bottomhole location at the Minnelusa level.

LITTLE MISSOURI FIELD
DRILLING AND COMPLETION SUMMARY

WELL	SPUD DATE	TD	PRODUCTION CASING SIZE	DEPTH	PERFORATED INTERVAL	ACID TREATMENT(S)	INITIAL POTENTIAL TEST DATE	BOPD	BWPD	MCFPD	REMARKS
FOWLER 1-5	09/13/86	5800	5 1/2	5800	5610-5620 5587-5596 * 5596-5610 *	NONE	10/20/86	575	0	0	DST
FOWLER 3-5	11/29/86	5800	5 1/2	5783	5586-5604	500 GAL 2500 GAL	01/29/87	80	46	0	CORE
FEDERAL 1-32	12/22/86	5815	5 1/2	5814	5578-5593	500 GAL 2500 GAL	01/30/87	256	0	0	CORE
FOWLER 4-5	06/08/87	5838	5 1/2	5838	5594-5617	500 GAL 2500 GAL	07/20/87	45	0	0	DST
TERRY 1-31	09/01/87	5775	5 1/2	5775	5541-5602	500 GAL 4200 GAL	10/13/87	25	0	0	CORE
FOWLER 2-32	11/24/87	5790	5 1/2	5780	5546-5572	500 GAL 2500 GAL	01/11/88	50	0	0	CORE
FOWLER 5-5	03/24/88	5880	5 1/2	5884	5652-5670	500 GAL 2000 GAL	05/06/88	9	0	0	CORE
WINEGAR 1-6	7/32/88	5945	5 1/2	5941	5709-5723 5684-5703	500 GAL 3000 GAL	09/29/88 **				CORE, RFT

* PERFORATED IN DECEMBER 1986

** WELL SWABBED 100% WATER. SI.

JAH

LITTLE MISSOURI FIELD
SUBSEA TOPS & BH LOCATIONS

WELL	ELEVATION KB	TOP B SAND POROSITY MD	TVD CORRECTION	TOP B SAND POROSITY TVD	TOP B SAND POROSITY SUBSEA	BH LOCATION AT MINNELUSA (FROM SURFACE LOC.)	BH LOCATION AT MINNELUSA (FROM SECTION LINES)
MRA FOWLER 1-5	3971	5588	-2	5586	-1615	22' N; 141' E	640' FNL; 1902' FEL
MRA FOWLER 3-5	3917	5589	-4	5585	-1668	48' N; 120' E	503' FNL; 1928' FWL
MRA FOWLER 4-5	3930	5595	-3	5592	-1662	13' S; 170' E	1626' FWL; 1529' FNL
MRA FEDERAL 1-32	3917	5579	-38	5541	-1624	389' N; 67' E	734' FSL; 690' FWL
MRA TERRY 1-31	3917	5543	-8	5535	-1618	71' N; 147' E	333' FSL; 189' FEL
MRA FOWLER 2-32	3945	5548	-4	5544	-1599	48' N; 170' E	1605' FWL; 304' FSL
MRA FOWLER 5-5	3945	5653	-4	5649	-1704	95' N; 155' E	1832' FNL; 705' FWL
MRA WINEGAR 1-6	3961	5687	-2	5685	-1724	30' N; 126' E	332' FEL; 2305' FNL

GEOLOGY

Little Missouri Field is located on the eastern flank of the Powder River Basin and produces oil from the Upper "B" Sandstone interval of the Permian Minnelusa Formation. The Minnelusa Formation is unconformably overlain in this area by the Opeche Siltstone member of the Permian Goose Egg Formation, which in turn is overlain by the regional Minnekahta Limestone, also a member of the Goose Egg Formation. These two overlying units together with the major Upper Minnelusa stratigraphic units are defined using the depths where present in the MRA Federal 1-32 (SW SW Sec. 32, T55N-R67W): Minnekahta Limestone (5487), Opeche Siltstone (5521), Minnelusa "A" Dolomite (5566), Minnelusa Upper "B" Sand (5570), Minnelusa Upper "B" Dolomite (5598), Minnelusa Lower "B" Sand (5630), Minnelusa Lower "B" Dolomite (5657). A copy of this log is enclosed. An additional unit, the "A" Sandstone, is present at the MRA Fowler 3-5 location (NE NW Sec. 5, T54N-R67W). This sand is water bearing and is oxidized with no hydrocarbon shows. The "A" Sand is not present in any of the other wells at Little Missouri and it is interpreted to be confined to a very limited area.

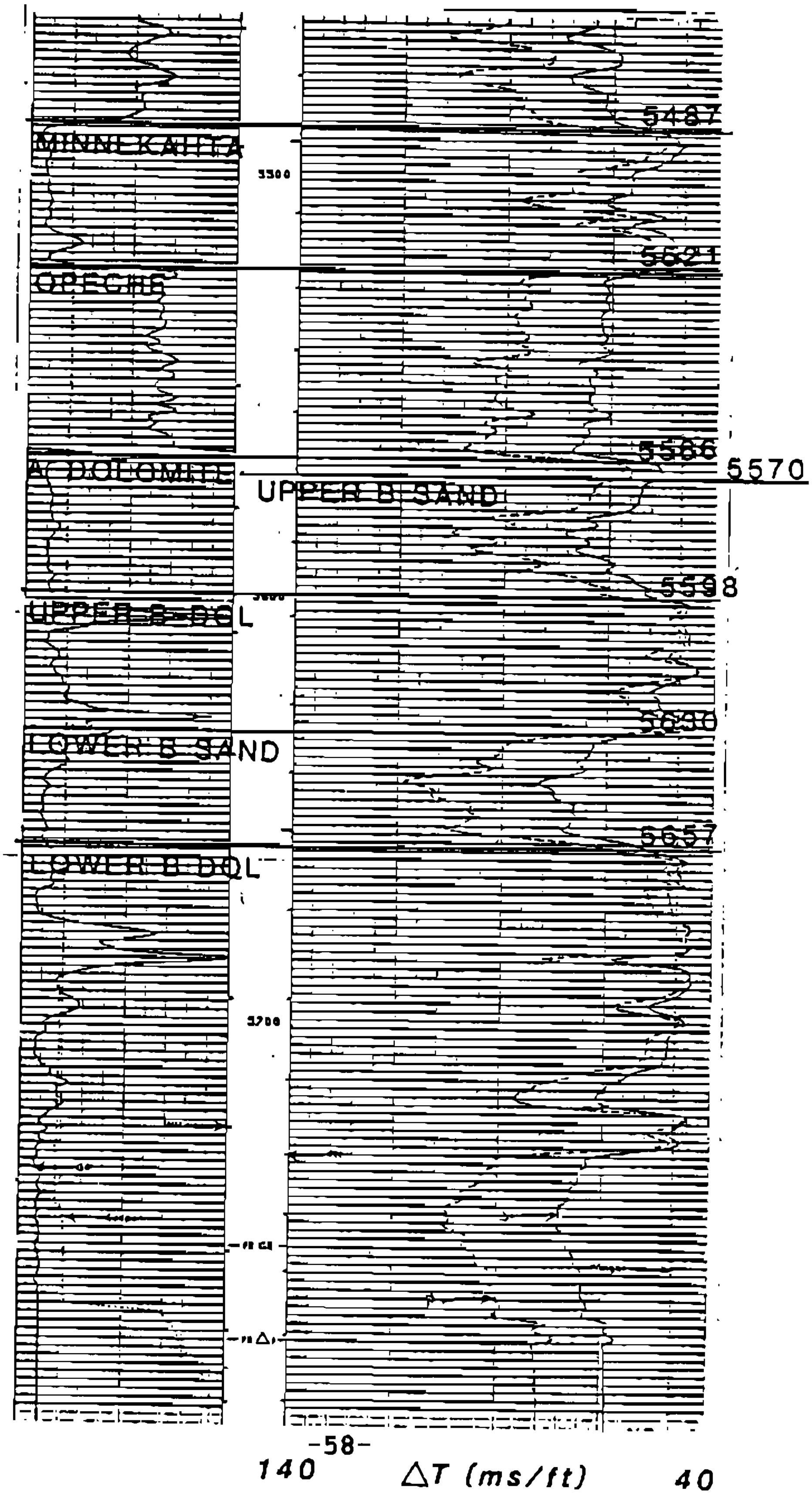
The Upper "B" Sand is the only oil productive unit within the Minnelusa Formation at Little Missouri Field and consists predominantly of eolian sandstone with dolomite and anhydrite cements. The Upper "B" Sand is by definition the second sandstone stratigraphically above the regional Lower "B" Dolomite. The Lower "B" Sand directly overlies the Lower "B" Dolomite, and is separated from the Upper "B" Sand by the Upper "B" Dolomite. All of the above mentioned units are illustrated in the Little Missouri Structural Cross Section that is included with this report.

The trapping mechanism at Little Missouri Field is stratigraphic, and results from the total encasement of the Upper "B" reservoir sand by the impermeable Opeche Siltstone above, and the impermeable Upper "B" Dolomite below. The juxtaposition of the bottom seal (Upper "B" Dolomite) with the Opeche is the result of the depositional history of the stratigraphic sequence. The Lower "B" Sand is of eolian origin and therefore its surface had considerable topographic relief. The Upper "B" Dolomite was deposited on this pre-existing surface, thereby preserving its topography. During the next cycle of eolian deposition, the Upper "B" Sand accumulated and was preferentially preserved in the topographic lows of the underlying surface. The Upper "B" Sand thins and ultimately pinches out as it rises laterally away from this topographic low and up against the thick adjacent Lower "B" Sand. The Upper "B" Dolomite also rises stratigraphically due to its deposition on the increasingly thicker Lower "B" Sand until ultimately it directly juxtaposes the Opeche Siltstone, thereby completely encasing the Upper "B" Sand. This total isolation of the sand is confirmed by the pressure depletion nature of the reservoir.

MRA has acquired extensive high resolution 3-D seismic data over Little Missouri Field (see enclosed map). The Upper "B" Sand reservoir is easily distinguished seismically from the Lower "B" Sand, thereby facilitating the successful development of the field with a notable lack of dry holes. The seismic data also provide the basis for the delineation of the zero reservoir sand contour outline as depicted on the maps included with this report. This outline together with the oil-water contact at -1720 feet (ref. S.L.) define the boundary of the oil accumulation.

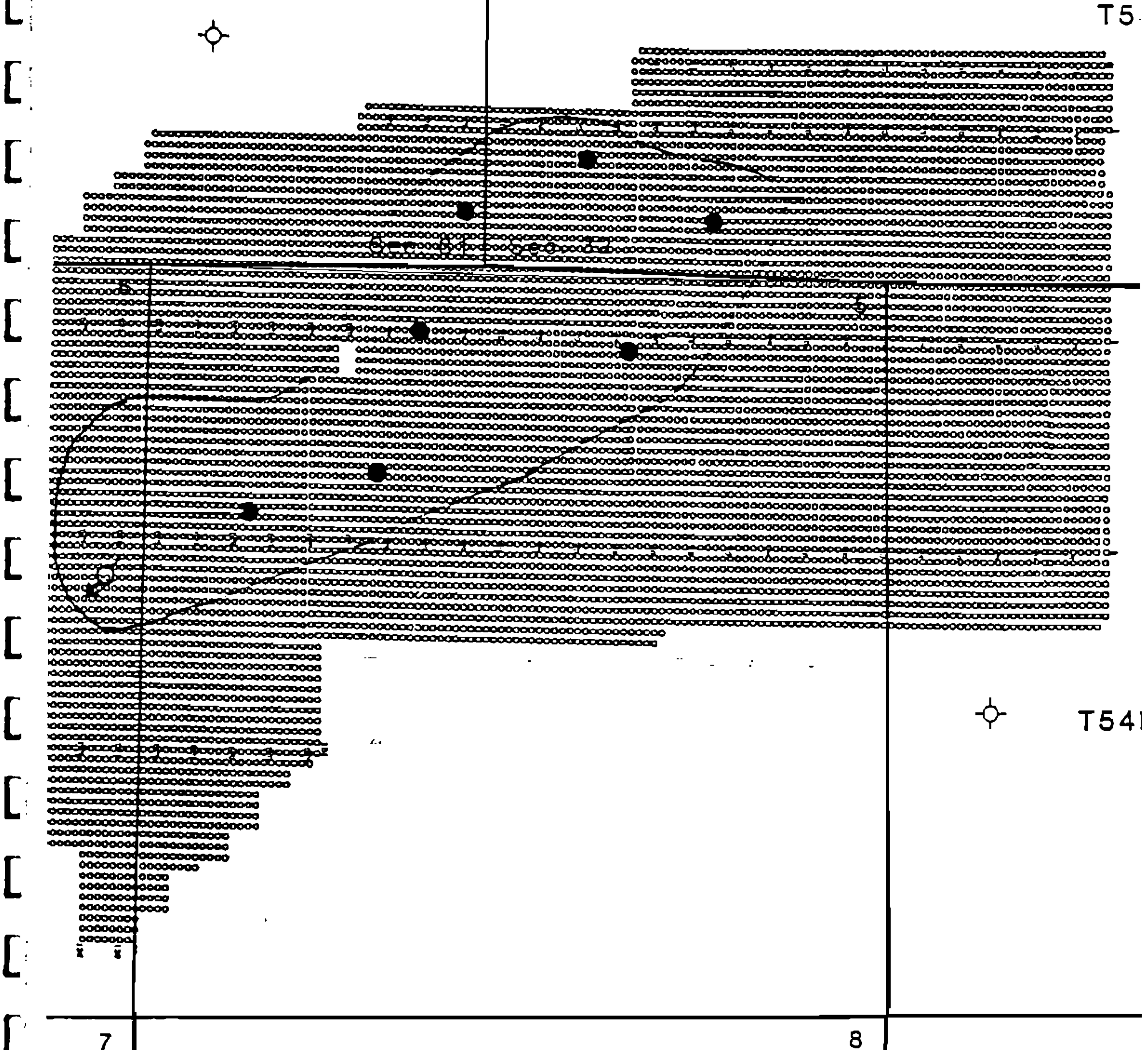
Note the next page. The sonic log shows an extreme variation between travel time of formations above & below the pay.

McADAMS, ROUX & ASSOCIATES, INC.
MRA FEDERAL #1-32
T55N R67W Sec. 32
SW SW
CROOK Co., WYOMING
BHC SONIC/GR LOG



LITTLE MISSOURI FIELD
CROOK Co., WYOMING

3-D SEISMIC COVERAGE



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RESERVOIR FLUIDS

Oil

A subsurface sample was taken on the Fowler 1-5 immediately following completion and prior to the well being placed on artificial lift. A PVT analysis was performed by Core Lab and a copy is included in Appendix A. This analysis reveals that the oil is highly undersaturated, has a low solution GOR and a high viscosity - all factors that are relatively common in Minnelusa reservoirs in this part of the Powder River Basin. The key data from this analysis are:

Initial Pressure, Pi	2162 psi
Bubble Point Pressure, Pb	185 psi
Solution GOR, Ft^3/Barrel	Less than 10
Formation Volume Factor	
Initial Pressure - Boi	1.026
Bubble Point Pressure - Bob	1.036
Viscosity @ BHT, Centipoise	
Initial Pressure - Uoi	25.5
Bubble Point Pressure - Uob	19.6
Compressibility	
2162 psi to 1000 psi	4.88×10^{-6} V/V/psi
1000 psi to 185 psi	5.24×10^{-6} V/V/psi

A crude oil analysis of produced oil samples from Fowler 1-5, Fowler 3-5 and Federal 1-32 are also included in Appendix A. The oil has an average sulfur content of 3.8 percent and an API gravity at 60° of 22°.

Gas

A gas analysis was made during the PVT analysis which indicates the gas contains 42.9 percent nitrogen and 1.7 percent carbon dioxide. No hydrogen sulfide is present although the oil does contain sulfur. At a solution GOR of less than 10 cubic feet per barrel, the gas volumes are insignificant.

Formation Water

The only formation water believed to be indigenous to the Upper "B" Sand has been produced from Fowler 5-5. Two samples have been obtained.

> 8-1-88 - Cl^- = 23,000 mg/l. Using Schlumberger charts, this corrects to a water resistivity at BHT of 0.095 ohm-meters.
>
> 9/30/88 - A complete water analysis conducted by Energy Lab is included in Appendix A. This analysis indicates a water resistivity of 0.17 @ 68°F which corrects to 0.088 at BHT.

A value of 0.09 ohm-meters is used in all log calculations.

Formation water compressibility is estimated to be 3.15 x 10^{-6} V/V/psi using published correlations.

PETROPHYSICAL

Six of the eight wells drilled in the Little Missouri Field were cored. These eight wells have a combined thickness of reservoir quality sand of 186 feet of which 101 feet or 54 percent were cored. Routine core analyses were obtained on these intervals and adjacent intervals of interest. In addition, the following special core analyses were obtained:

1.	Klinkenberg Permeability and Air Permeability	25 samples from 8 wells
2.	Water-Oil Relative Permeability Tests	4 samples from 4 wells
3.	Capillary Pressure Data by Mercury Injection	8 samples from 6 wells
4.	Archie Parameters	4 samples were selected from 4 wells to determine values for a, m (cementation exponent) and n (saturation exponent).
5.	Compatibility Tests	3 samples from 3 wells

The results of these routine and special core analyses are presented in Appendix B.

Porosity vs Permeability

A plot of core porosity vs air permeability is enclosed. This plot indicates that this relationship changes at a porosity value of about 7.5 percent. The permeability corresponding to the field average porosity of 15.1 percent is about 140 millidarcies.

Permeability Variation

A permeability variation plot of all core samples indicates a dual trend in the data. The 20 percent of the samples with the highest permeability are indicated to have a permeability variation of 0.43, while the balance of the samples are shown to have a value of 0.91. The weighted average is about 0.81. The average and median permeability values are 243 and 87 millidarcies, respectively.

Klinkenberg Permeability

The attached graph of air permeability (K_{air}) vs Klinkenberg permeability (K_l) illustrates this relationship based on the laboratory results presented in the Core Laboratories report in Appendix B. The results appear to be typical in that there is little difference between the values of K_{air} and K_l. For this reason, the air permeability values will be used throughout this report.

Water-Oil Relative Permeability

The end-point values for the four water-oil relative permeability tests are summarized below:

WELL	Swi %	Kro @ Swi	Krw @Sor	Sor %
Winegar 1-6	8.8	1.0	0.085	37.4
Fowler 5-5	12.9	1.0	0.307	30.7
Terry 1-31	10.2	1.0	0.190	32.4
Fowler 2-32	11.8	1.0	0.421	35.1
Averages	10.93	1.0	0.251	33.9

The average end-point values for Kro and Krw are used in the calculation of mobility ratio and water injectivity. In the secondary recovery calculations, the residual oil saturation is assumed to be 30 percent based on both the above average of 33.9 percent and the fact that the average oil saturation in the routine core analyses was 28.4 percent.

Capillary Pressure Data

The mercury-air capillary pressure data are summarized on the attached composite plot. The results appear to be typical of a well-developed Minnelusa sandstone. The irreducible minimum saturation is indicated to be about 10 percent.

Archie Parameters

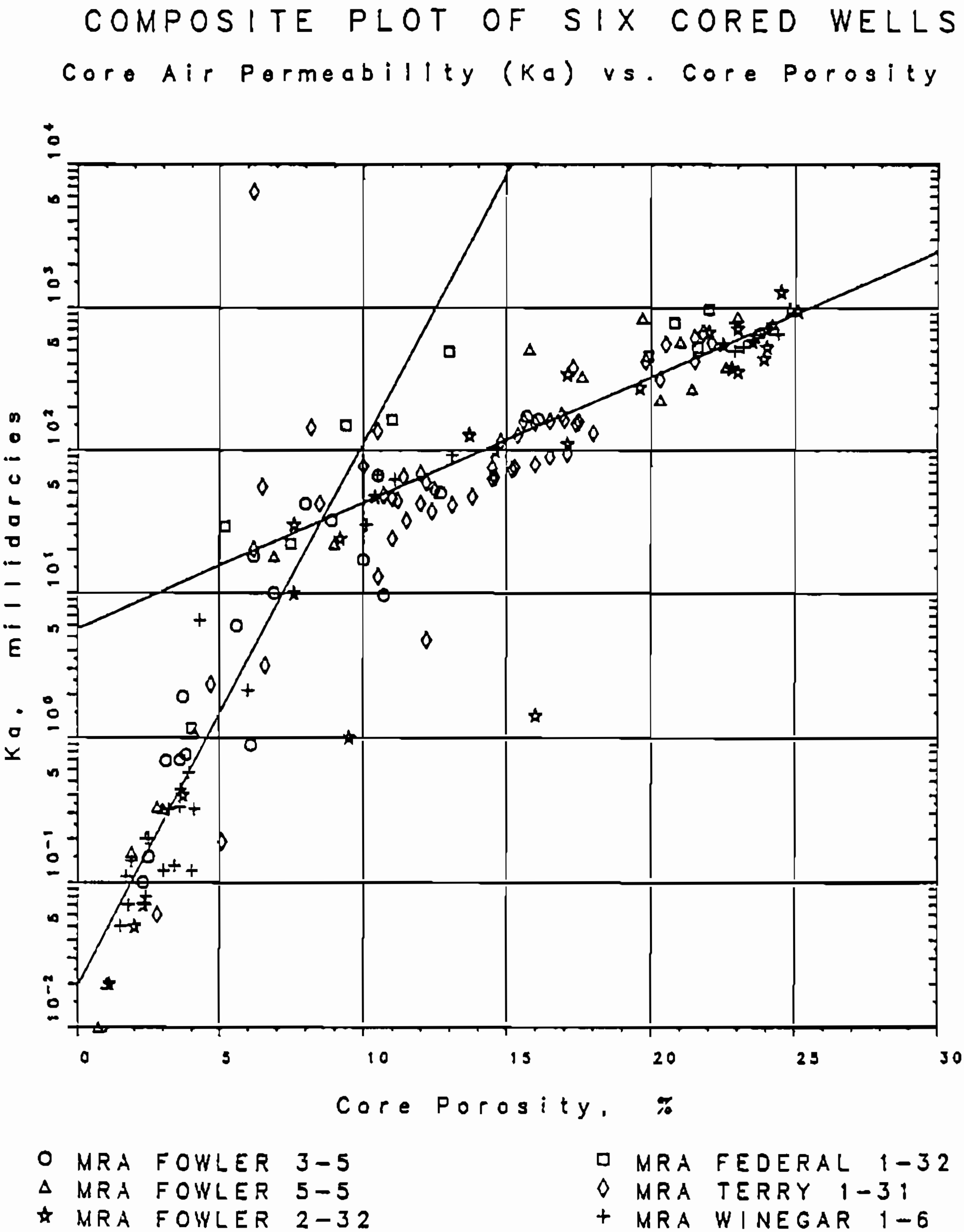
Four samples were selected to determine Archie parameters - a, m and n. The results of the laboratory analysis are summarized below:

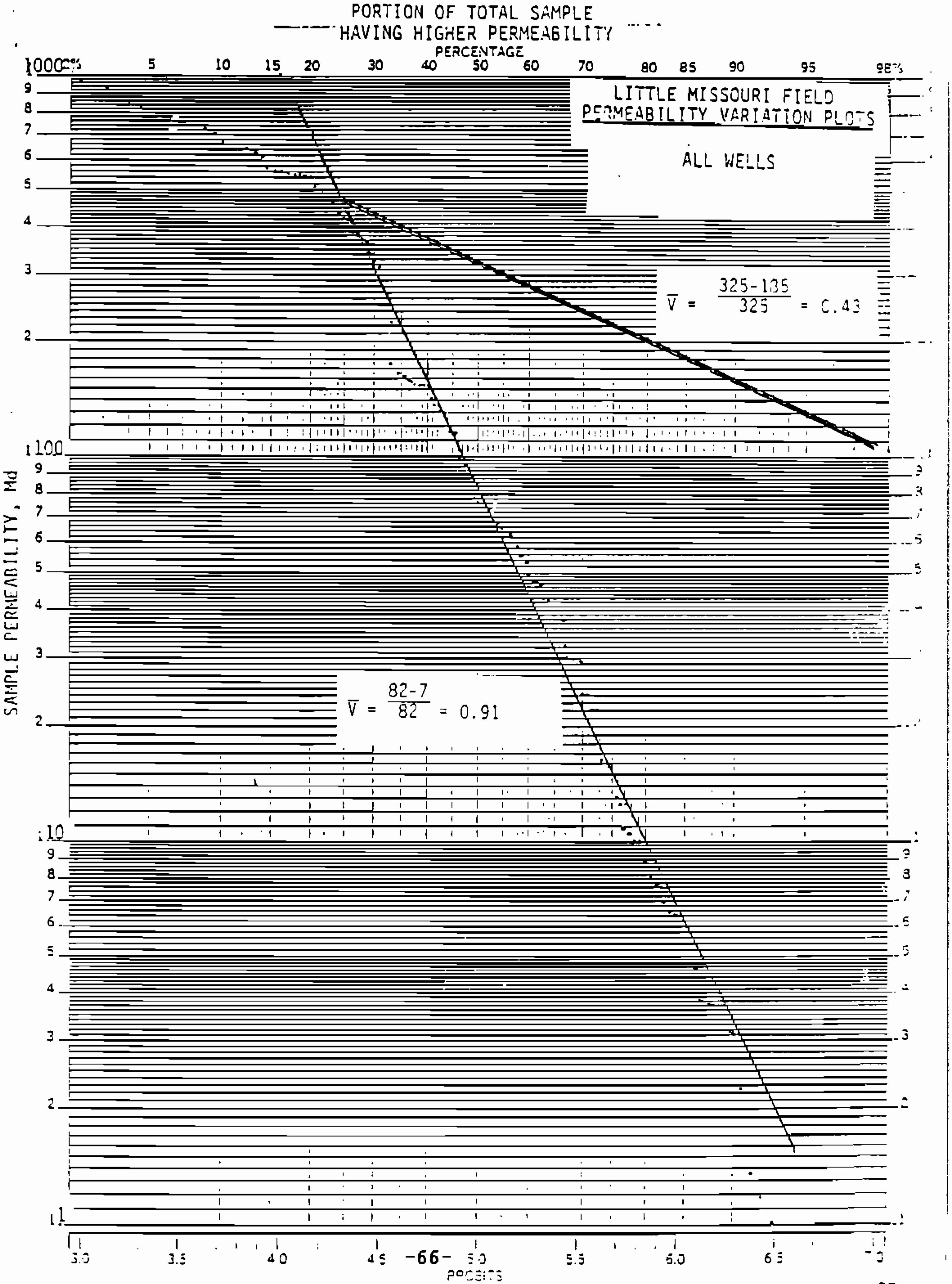
a	1.0
m (cementation exponent)	1.65
n (saturation exponent)	1.30

Compatibility Tests

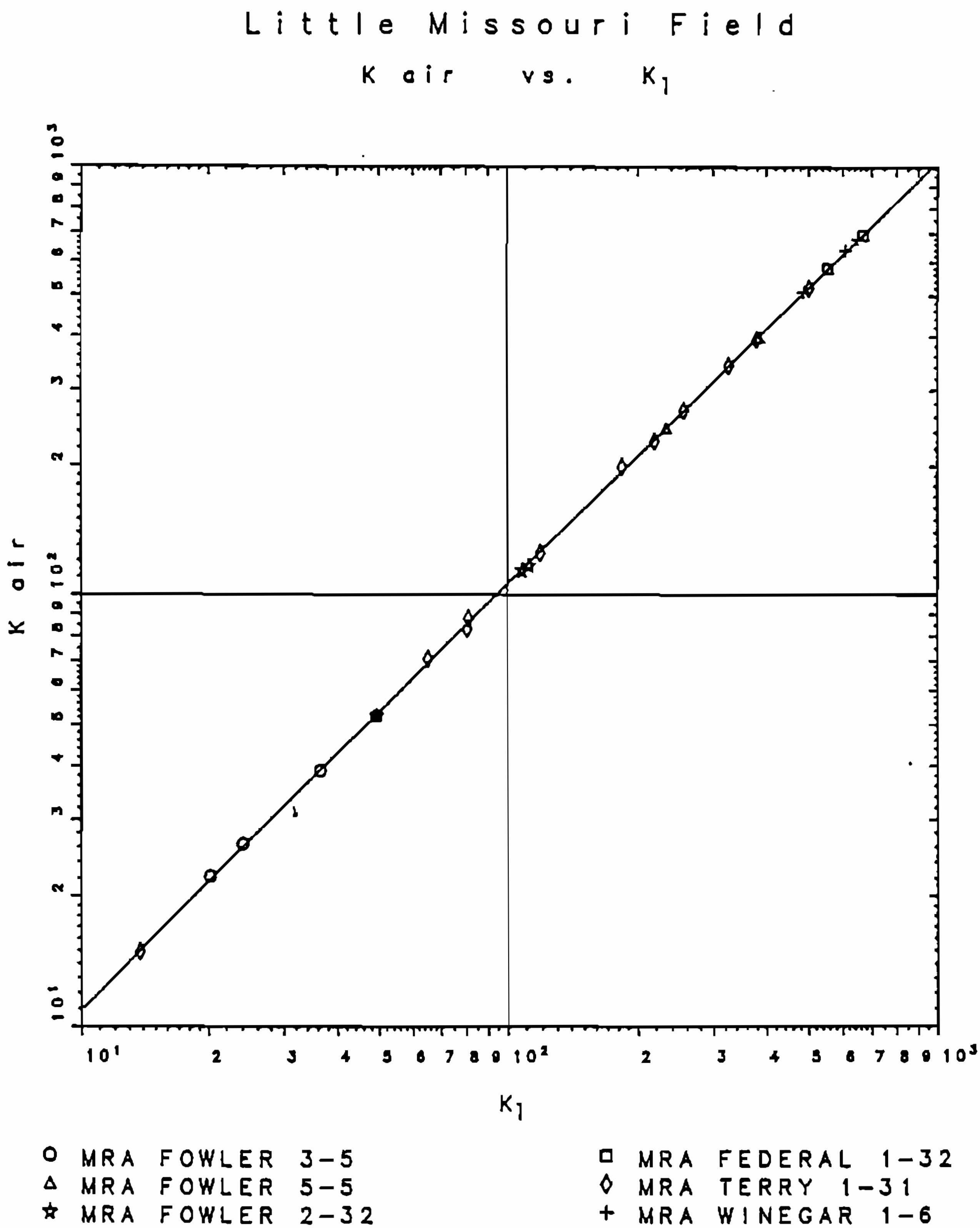
Three samples were selected for throughput testing following their relative permeability analyses. These samples were injected with a simulated brine with a composition similar to the Minnelusa water that was swabbed from the MRA State Clayton 2-4, a nearby temporarily abandoned well that is currently being held as a standby water supply well if an adequate water source cannot be obtained from the Fox Hills. These tests indicate no sensitivity to this simulated brine and there is no evidence of mobile fines in any of the samples.

Little Missouri Field



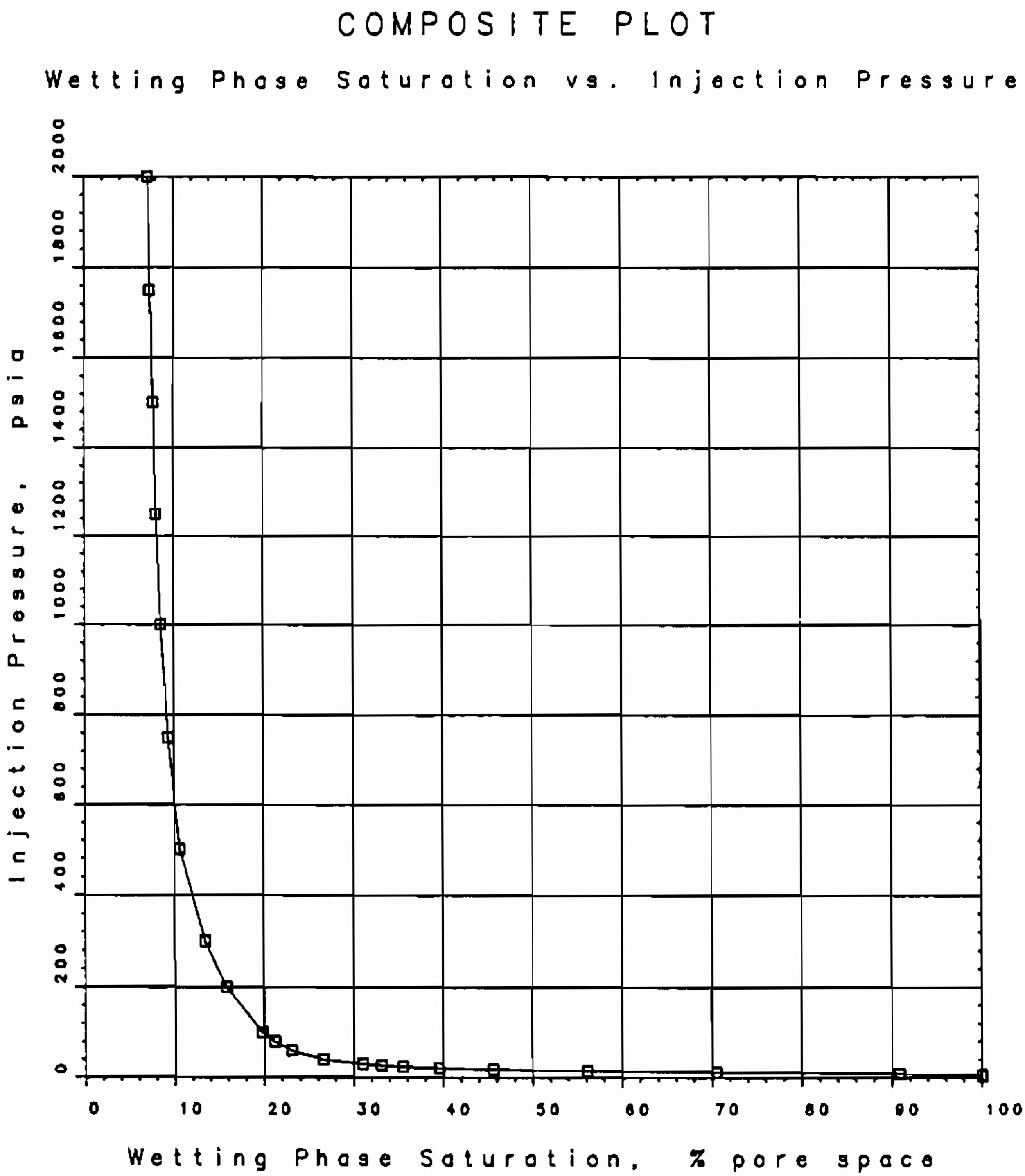


PORTION OF TOTAL SAMPLE
HAVING HIGHER PERMEABILITY
PERCENTAGE
LITTLE MISSOURI FIELD
PERMEABILITY VARIATION PLOTS
ALL WELLS
V̄ = (325-135)/325 = 0.43
V̄ = (82-7)/82 = 0.91
SAMPLE PERMEABILITY, Md



Little Missouri Field
K air vs. K_1
K air
K_1
10^1
10^2
10^3
○ MRA FOWLER 3-5
△ MRA FOWLER 5-5
☆ MRA FOWLER 2-32
□ MRA FEDERAL 1-32
◊ MRA TERRY 1-31
+ MRA WINEGAR 1-6

Little Missouri Field



LOG ANALYSIS

In order to obtain representative values for porosity, water saturation and net pay, all routine core data were first adjusted to log depths, then stored in a master file. This file also contained the log data, (that had been obtained from either a digitized log or directly from a Schlumberger floppy disc) which included resistivity from the ILD, transit time, bulk density and neutron porosity.

Porosity

Core porosity vs log response was investigated by making the following composite plots which are included in this section of the report:

1. Core Porosity VS Transit Time

2. Core Porosity VS Bulk Density

3. Core Porosity VS Neutron Porosity.

The zero porosity intercepts show an average matrix transit time of 53.77 microseconds per foot and an average matrix density of 2.70, both values that appear to be reasonable. Study of these three relationships indicate that the core vs bulk density data spread is significantly less than that seen on the other two plots; therefore, it is concluded that this relationship should best describe the porosity vs log response in the Little Missouri Field. Porosity values will be determined from the following equation:

$$\text{Porosity} = (-56.558 \times \text{Bulk Density}) + 152.646$$

Formation Water Resistivity

Fowler 5-5 is the only well that has produced any water from the Upper "B" Sand. An analysis of this water is included in the discussion of reservoir fluids. A formation water resistivity of 0.09 ohm-meters at bottomhole temperature is used in the log calculations.

Archie Parameters

The values for a, m and n that were obtained from the special core analysis were initially used to calculate water saturation; however, the results are believed to be much too optimistic and do not agree with other data. For example, the calculated average saturation for Winegar 1-6 was 45.9 percent in a zone that showed zero oil saturation in the routine core analysis. Also, the indicated water saturation in the four updip wells ranged from 3.9 to 6.9 percent (average 5.6 percent), a value thought to be too low even for the Minnelusa. In view of these results, the following assumed values are believed to be both more traditional and more representative of the Minnelusa:

$a = 1.0$
$m = 1.8$
$n = 1.6$

Calculations

Based on the above-described assumptions, water saturations were calculated using the Archie equation:

$$Sw = \left(\frac{a}{\phi^m} \frac{Rw}{R_t}\right)^{\frac{1}{n}}$$

where:

Sw = Water saturation, decimal

ϕ = Porosity, decimal

Rw = Water Resistivity

R_t = Formation Resistivity from R_{ILD}

a = - 1.0

m = Cementation Exponent- 1.8

n = Saturation Exponent - 1.6

Cutoff Values for Net Pay Determination

Porosity - 9 percent. This is an average of the commonly used porosity cut-off values of 8 and 10%.

Water Saturation - 50 percent.

Results

Average values for porosity, water saturation and net pay for each well are tabulated below. Detailed log calculations and copies of the logs are included in Appendix C. The average water saturation in the four up-structure wells is 11.4 percent, a value that is supported by composite capillary pressure data (eight samples) which indicate irreducible water saturations in the range of 10 percent.

LITTLE MISSOURI FIELD
SUMMARY OF LOG CALCULATIONS

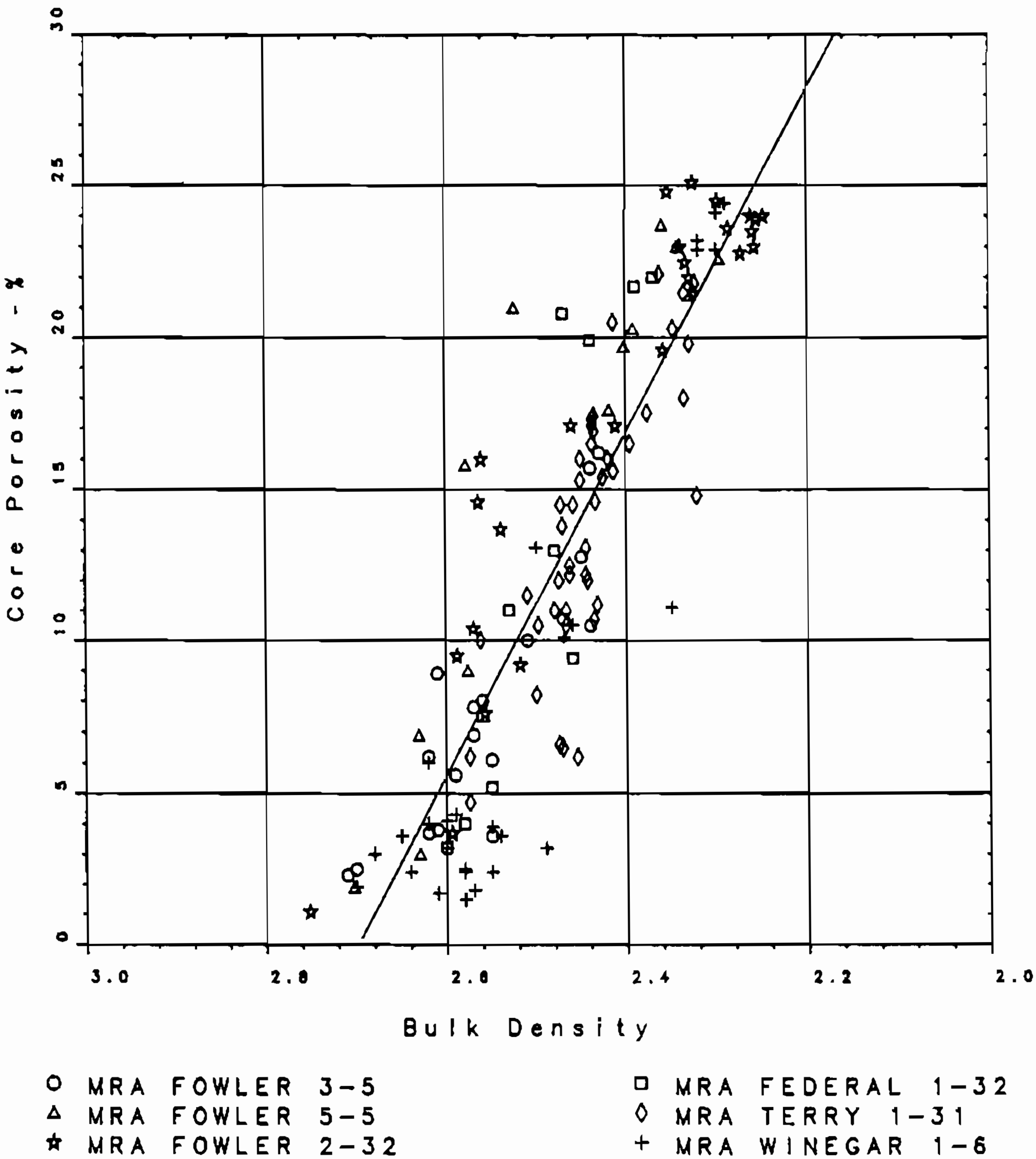
Well	Average Porosity %	Average Water Saturation %	Net Oil Pay Feet
Fowler 1-5	17.0	13.5	32'
Federal 1-32	14.6	8.6	13'
Fowler 3-5	13.7	21.1	6'
Fowler 4-5	14.0	24.7	24'
Terry 1-31	15.8	12.6	57'
Fowler 2-32	19.9	10.9	21'
Fowler 5-5	18.8	32.0	14'
Winegar 1-6*	17.5	66.7	19'

* This well is below the oil-water contact and exhibited no oil shows in the core analysis. Values for net pay are given to show the feet of sand with a porosity greater than 9 percent.

Little Missouri Field

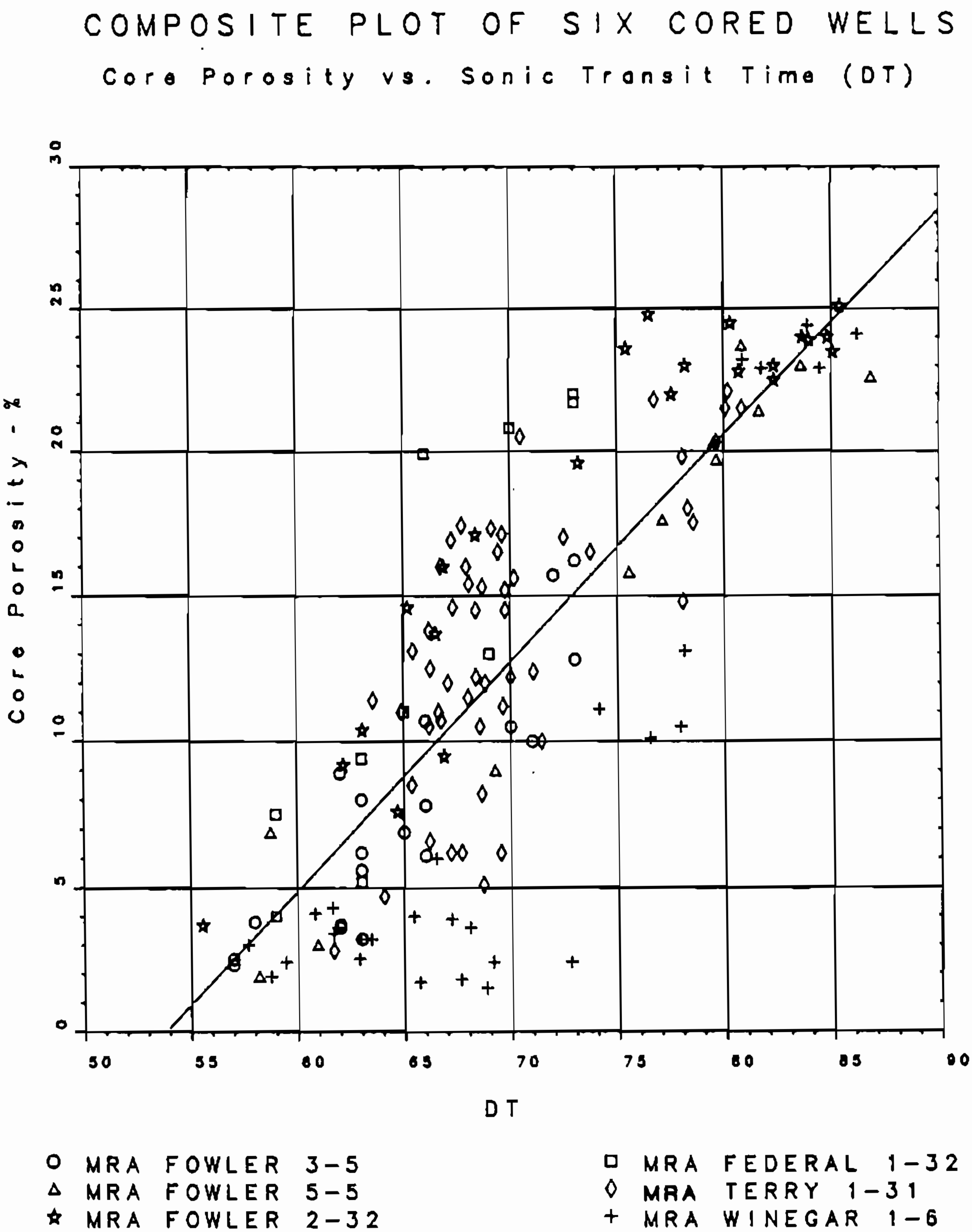
COMPOSITE PLOT OF SIX CORED WELLS

Core Porosity vs. Bulk Density



Core Porosity= −56.558xBulk Density+152.646

Little Missouri Field



Core Porosity=0.787xDT-42.318

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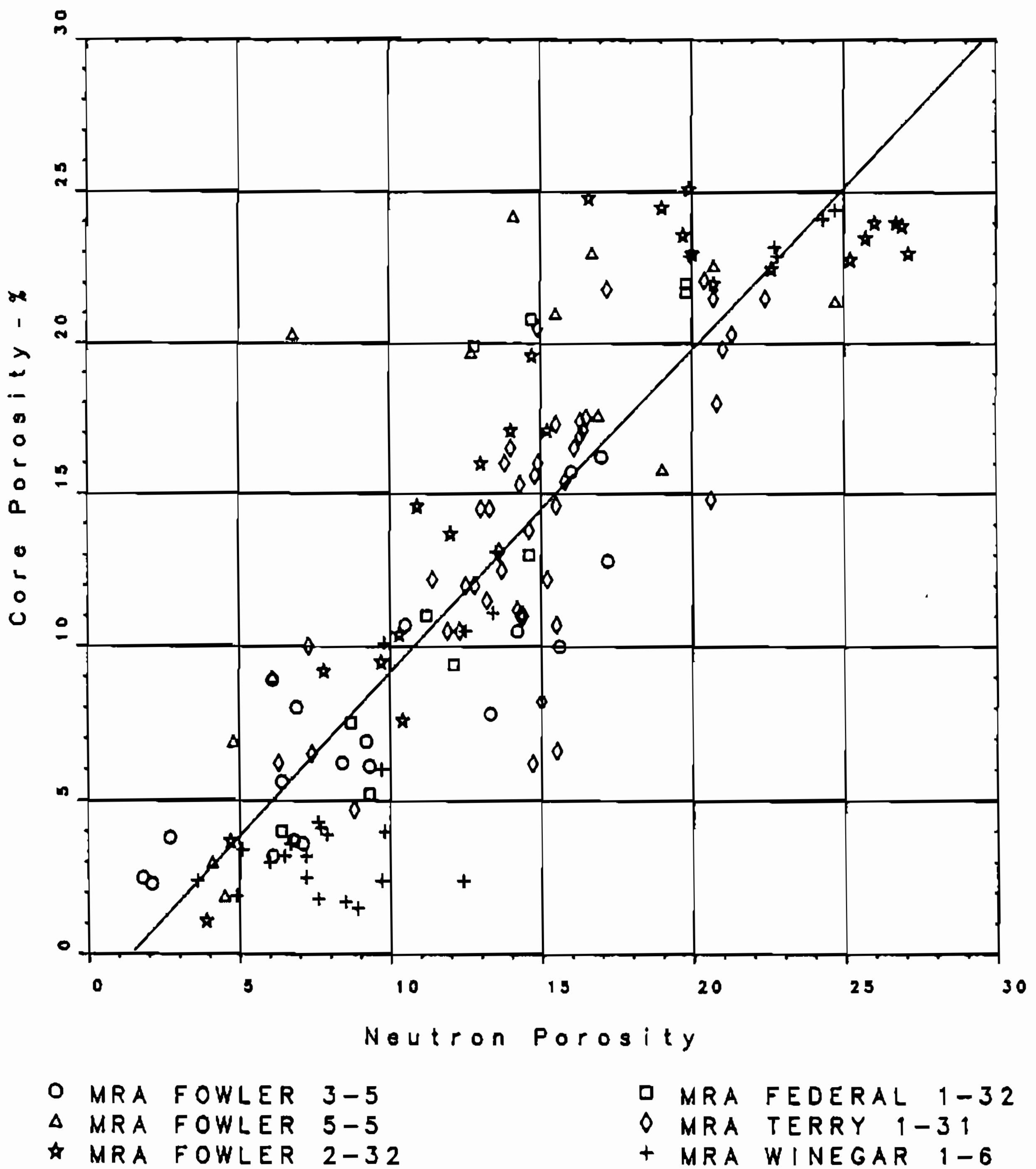
Little Missouri Field

COMPOSITE PLOT OF SIX CORED WELLS

Core Porosity vs. Neutron Porosity



Core Porosity = 1.065xNeutron Porosity−1.478

VOLUMETRICS

A base map of the area was prepared from a Rumph Survey map dated 11/2/87. This Rumph survey data was used to stake all of the wells drilled in the field. This base map was compared to the BLM O & G plat obtained from the BLM in Cheyenne and found to be in very close agreement. From this Rumph survey data, coordinates for the four corners of each tract were calculated and the base map was constructed.

Five maps have been prepared to depict the oil accumulation: (1) A subsea structure map on the top of the Upper "B" Sand porosity, (2) A net oil pay (h) map, (3) A porosity - net oil pay (ϕh) map and (4) A hydrocarbon pore volume ($S_o\phi h$) map. To aid in the construction of the ϕh and $S_o\phi h$ maps, an oil saturation map was also prepared. A computer program was used to determine values for productive acres, acre-feet, porosity-acre-feet and hydrocarbon pore volume, the latter of which was used to determine the value of OOIP. This computer program, which is used in lieu of planimetering, is described below:

To compute the tract and field volumes the map is digitized. The digitized contour values are then gridded to a ten foot grid by ten foot grid using a minimum curvature algorithm developed by I. C. Briggs ("Machine Contouring Using Minimum Curvature", Geophysics, V. 39, no. 1, 1974, pp. 39-48). Each grid is also bounded by the smallest and largest contour values. This is done to prevent the gridding algorithm from extrapolating values above and below the values on the map. The grid then consists of a z value and coordinate information for each ten foot by ten foot area. The volumetrics program uses the grid and the surveyed corners for each tract covering the field. The program overlays each tract onto the grid. The z values for each ten foot by ten foot area which is bounded by the tract is multiplied by the area of the grid cell and then summed. The final sum is the volume for the tract. Individual tract volumes are also summed to give the volume for the field.

The results of this volumetric study are summarized on the following page:

Area, acres	196.9
Acre-Feet	4939.2
Porosity-Acre-Feet, ϕhA	745.3
Oil Saturation-Porosity-Acre-Feet, $S_o \phi hA$	619.5
Hydrocarbon Pore Volume, RVB	4,805,952
Original Oil in Place, STB(Boi = 1.026)	4,684,163
Reservoir Pore Volume, Barrels	5,782,286
Average Net Pay [1]	25.1'
Average Porosity [2]	15.09%
Average Oil Saturation [3]	83.12%

1. Acre Feet/Area
2. Porosity Acre Feet/Acre Feet
3. $S_o\phi hA/\phi hA$

BOTTOMHOLE PRESSURE HISTORY
and
MATERIAL BALANCE CALCULATIONS

The bottomhole pressure history is shown on the enclosed tabulation. The original BHP was 2163 psi at a datum of 1630 feet subsea based on a DST in the discovery well. A subsequent buildup survey was obtained on this well after the production of 26,586 BO that revealed a decline in reservoir pressure to 1403 psi. All other pressure data was obtained as the wells were drilled either from DST data or from a bottomhole pressure buildup survey taken immediately following completion. The bottomhole pressure vs cumulative oil relationship is illustrated on the enclosed graph. This performance supports the conclusion that the reservoir is highly undersaturated and explains why the production performance of subsequent development wells is much poorer than that enjoyed by the discovery well. There is good agreement between the lab-derived bubble point pressure of 185 psi and field performance. From this plot, it appears that approximately 96,000 barrels of oil were produced from the reservoir before the bubble point was reached.

From this pressure vs cumulative oil production history, above the bubble point calculations of OOIP can be made:

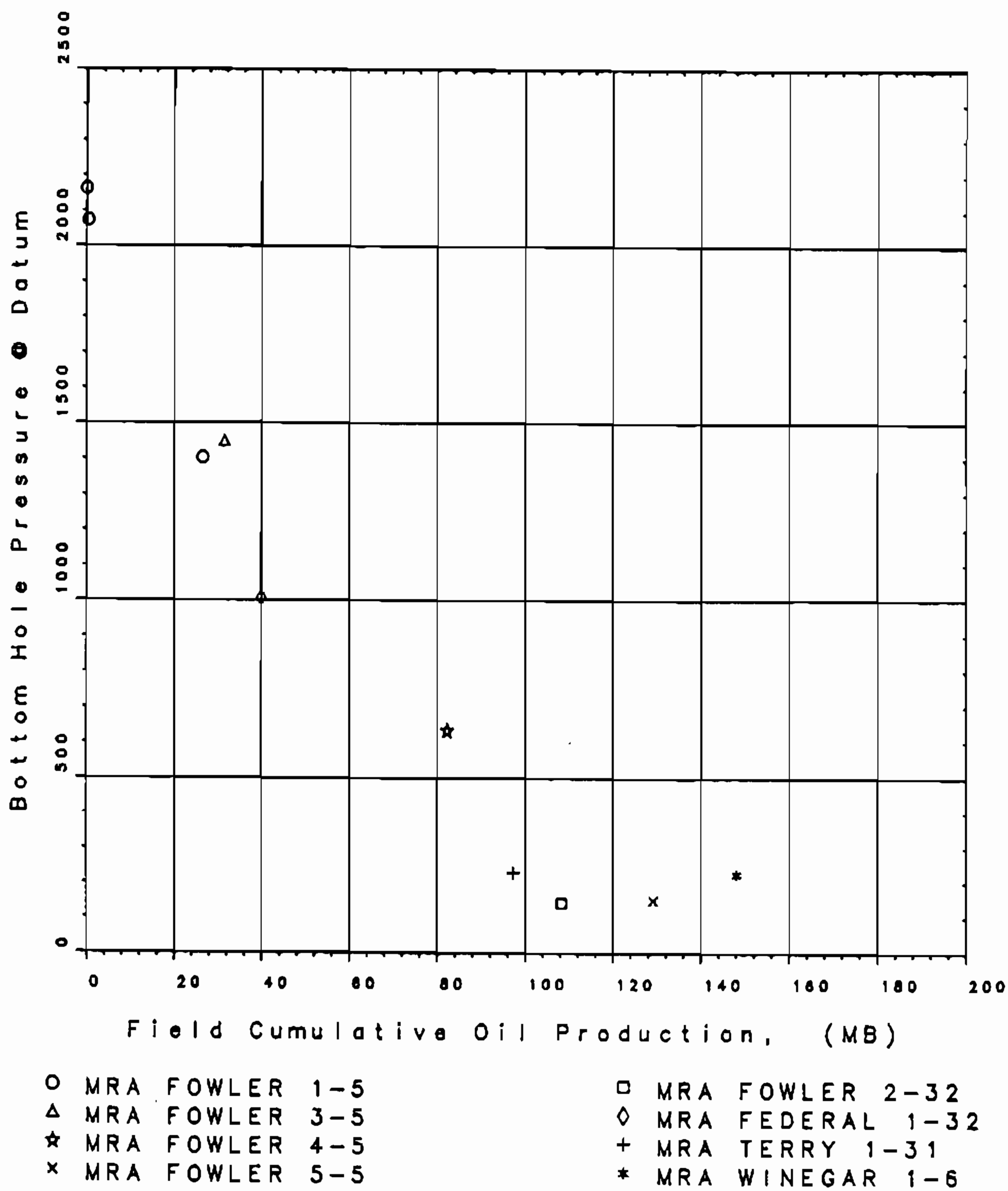
$$N = \frac{Np\ Bo + (Wp - We)}{Boi\ Ce\ (Pi - P)}$$

$$Ce = Co + \frac{Sw}{(1-Sw)} \times Cw + \frac{Cf}{(1-Sw)}$$

N	= OOIP, STB	
Np	= Cumulative Oil Production -	96,000 STB
Wp	= Cumulative Water Production -	0
We	= Cumulative Water Influx -	0
Boi	= Initial Formation Volume Factor -	1.026
Bo	= Current Formation Volume Factor -	1.036
Co	= Oil Compressibility -	5.0×10^{-6}
Cw	= Water Compressibility -	3.15×10^{-6}
Cf	= Rock Compressibility (Ø = 16.8% - Hall) -	3.8×10^{-6}
Ce	=	10.5×10^{-6}
Pi	= Initial Pressure -	2163 psi
P	= Pb -	185 psi

Little Missouri Field

BHP vs. CUMULATIVE PRODUCTION



PRIMARY RECOVERY PERFORMANCE

Seven wells were completed as producers in the Little Missouri Field. Through September 30, 1988, these wells had produced 158,367 STB of oil and 2002 barrels of water. The field production rate at October 1, 1988 was 170 BOPD + 3 BWPD. Oil production statistics for each well are tabulated in this section of the report and the field oil production performance is illustrated graphically in Appendix F.

The field has essentially produced water-free. Almost all of the produced water (1870 barrels) has been from Fowler 3-5. This well was completed in January 1987 pumping 80 BO + 46 BW in 24 hours, declining to 11 BO + 1 BWPD by September 1988. It is believed that this water is not indigenous to the Upper "B" Sand but is channeling downward from the sparsely developed overlying Minnelusa "A" Sand as a result of an acid stimulation. This conclusion is supported by the fact that Fowler 4-5 produces water-free to a deeper subsea depth than Fowler 3-5.

The balance of the water production has been from Fowler 5-5, structurally the lowest producer in the field. This well was completed in May 1988 pumping 9 BOPD with no water from perforations 1703 to 1721 feet subsea. Water production was first observed in June 1988 and on September 30, 1988 this well tested 8 BO + 2 BWPD. Based on this production performance, the lack of any oil saturation in the core analysis of the Winegar 1-6 and the log calculations on both Fowler 5-5 and Winegar 1-6, the oil-water contact has been estimated at -1720 feet (ref.S.L.).

Due to the low saturation pressure and low solution gas-oil ratio, production decline was rapid until the bubble point pressure was reached at a field cumulative oil production of 96,000 barrels, which occurred in September 1987. As seen on the drilling and completion summary, wells completed after the discovery well initially produced at significantly reduced rates because of the decline in reservoir pressure rather than due to the lack of reservoir development. After the pressure reached the bubble point, an exponential decline rate was established.

Primary oil reserves at September 30, 1988 were determined for each well by extrapolating the exponential portion of the decline curve to an economic limit. The details and individual values for each well are outlined in the Unitization Parameter discussion. Based on this analysis, the remaining primary oil reserves at September 30, 1988 are estimated to be 167,681 STB for an ultimate primary oil recovery of 326,048 barrels or 7.0 percent of OOIP.

LITTLE MISSOURI FIELD
OIL PRODUCTION STATISTICS

MONTHLY AND CUMULATIVE PRODUCTION

DATE	MRA FOWLER 1-5		MRA FOWLER 3-5		MRA FEDERAL 1-32		MRA FOWLER 4-5		MRA TERRY 1-31		MRA FOWLER 2-32		MRA FOWLER 5-5		MRA WINEGAR 1-6		FIELD TOTAL	
	MONTHLY	CUM	MONTHLY	CUM	MONTHLY	CUM	MONTHLY	CUM	MONTHLY	CUM	MONTHLY	CUM	MONTHLY	CUM	MONTHLY	CUM	MONTHLY	CUM
10/86	8,825	8,825															8,825	8,825
11/86	14,055	22,880															14,055	22,880
12/86	9,977	32,857															9,977	32,857
01/87	10,497	43,354	456	456	615	615											11,568	44,425
02/87	6,762	50,116	2,097	2,553	4,622	5,237											13,481	57,906
03/87	4,706	54,822	1,530	4,083	3,177	8,414											9,413	67,319
04/87	3,568	58,390	1,094	5,177	2,275	10,689											6,937	74,256
05/87	3,012	61,402	929	6,106	1,820	12,509											5,761	80,017
06/87	2,351	63,753	540	6,646	1,404	13,913											4,295	84,312
07/87	2,038	65,791	583	7,229	1,222	15,135	895	895									4,738	89,050
08/87	1,845	67,636	452	7,681	1,088	16,223	980	1,875									4,365	93,415
09/87	1,698	69,334	371	8,052	1,013	17,236	724	2,599									3,806	97,221
10/87	1,695	71,029	364	8,416	1,024	18,260	625	3,224	679	679							4,387	101,608
11/87	1,591	72,620	317	8,733	930	19,190	559	3,783	807	1,486							4,204	105,812
12/87	1,533	74,153	283	9,016	1,042	20,232	517	4,300	858	2,344							4,233	110,045
01/88	1,652	75,805	343	9,359	1,038	21,270	504	4,804	887	3,231	1,169	1,169					5,593	115,638
02/88	1,492	77,297	328	9,687	969	22,239	444	5,248	845	4,076	1,331	2,500					5,409	121,047
03/88	1,549	78,846	339	10,026	1,009	23,248	453	5,701	883	4,959	1,343	3,843					5,576	126,623
04/88	1,471	80,317	333	10,359	959	24,207	382	6,083	860	5,819	1,263	5,106					5,268	131,891
05/88	1,496	81,813	349	10,708	981	25,188	477	6,560	902	6,721	1,256	6,362	243	243			5,704	137,595
06/88	1,449	83,262	337	11,045	969	26,157	386	6,946	887	7,608	1,178	7,540	115	358			5,321	142,916
07/88	1,441	84,703	334	11,379	945	27,102	398	7,344	893	8,501	1,204	8,744	35	393			5,250	148,166
08/88	1,402	86,105	349	11,728	973	28,075	397	7,741	868	9,369	1,170	9,914	102	495			5,261	153,427
09/88	1,320	87,425	315	12,043	909	28,984	418	8,159	835	10,204	1,074	10,988	69	564			4,940	158,367
10/88																		
11/88																		
12/88																		

SECONDARY RECOVERY PERFORMANCE

The McCartney Engineering Company Secondary Recovery Analysis Model (SRAM) was utilized to forecast secondary recovery. SRAM is a pseudo steady-state, linear flow model utilizing piston-like displacement in each of many non-communicating layers. The model can be used to predict the recovery of slug-type displacement techniques such as chemical (polymer) flood operations as well as conventional waterflood operations. A more detailed description of this model is given in Appendix D.

The input data for this program is summarized on the enclosed data sheet and is described as follows: the reservoir was assumed to have 39 layers of equal thickness based on the assumption that the permeability would vary in accordance with the permeability variation plot in 2.5 percent increments. This resulted in a range of permeability input values from 1000 to 1.4 millidarcies. The layer porosity was allowed to vary uniformly from a high of 24.6 percent to a low of 6 percent, values that were taken from the graph of porosity vs permeability in the Petrophysical discussion. The water saturation was assumed to remain constant at 16.88 percent (field average) in all layers. The resistance factors were taken from Tiorco's core data file and are believed to be representative of the Minnelusa reservoir.

An estimated water viscosity of 0.6 cp, an oil viscosity of 19.6 cp (PVT analysis) and end-point relative permeability values of 1.0 for K_{ro} and 0.25 for K_{rw} (see Petrophysical Section) result in a calculated mobility ratio of 8.2.

The residual oil saturation is assumed to be 30 percent based on both the average end-point relative permeability value of 33.9 percent and the fact that the average oil saturation in the routine core analysis was 28.4 percent.

The assumed values for areal sweep and injection efficiency are 85 percent and 90 percent, respectively.

A production forecast was made for both a straight waterflood and a polymer augmented waterflood at the desired injection rate of 1250 BWPD. The resulting SRAM forecasts are given in Appendix D. The SRAM output data were plotted, then smoothed or averaged to obtain the rate vs time semi-log plot shown in Appendix D. As seen on this plot, the straight waterflood is shown to out perform the polymer augmented flood during the first year. This is because the production response for the polymer augmented case was modified to account for the fact that the initial injection rate during the six month Stage 1 injection period would be limited to 750 BWPD whereas the straight waterflood case was assumed to have a constant injection rate of 1250 BWPD. Since oil response is a function of cumulative injection, this adjustment appears to be reasonable.

TIORCO INC.
THE IMPROVED OIL RECOVERY COMPANY

PROJECT DATA

Project ______
Field Little Missouri Field
County, State Crook County, Wyoming
Legal ______

Operator McAdams, Roux & Associates
Mailing Address 730 17th Street, Suite 530
City & State Denver, Colorado
Telephone 303-573-5275 Zip 80202

FORMATION PROPERTIES

Formation Minnelusa Upper "B"
Type Sandstone
Depth, AVG 5600'
BHT, °F 137°F

Isopach and Structure Map*

Porosity, % 15.09
Permeability, AVG. md See below
Range, md 1.0 to 1293
Variation, Kv See plot
Core Data* 243 md - Arithmetic Average
80 md - Median
140 md - For Average Porosity of 15.09%

RESERVOIR FLUID PROPERTIES

CONNATE WATER
% Pore Volume 16.88
Specific Gravity 1.029
Viscosity @ BHT, cp 0.6 (Estimate)
Relative Permeability, k_{rw} 0.25
Water Analysis*

HYDROCARBON
Oil Gravity, °API 22° @ 60°F
Viscosity @ BHT, cp OIL 25.5* GAS -
Relative Permeability, k_{ro} 1.0 k_{rg} -
Form. Vol. Factor, B_o Initial 1.026 Present 1.026
Residual Oil Saturation, %PV 30

Mobility Ratio 8.2 *At org.press.corr - 19.6

ECONOMIC DATA

Start Date: 5/1/89

Working Interest, % 100.0
Net Interest, % 76.5
Operating Costs, $/Mo. 12,600 Prim;
P. W. Discount Rate, % 15 $30,000/month wf (+ polymer)

Oil Price, $/BBL 10.55
Production Taxes, $/BBL 1.30
Transportation Cost, $/BBL -
Net Oil Price, $/BBL 9.25

RESERVOIR DEVELOPMENT

Total Surface Area, AC 196.9
Well Spacing, AC 40 AC (Staggered)
AVG Net Pay, Ft. 25.10
Volume Oil Zone, AC-FT 4939
Pore Volume, BAF 1171
BBLS 5,782,000

No. of Injection Wells 2 Active ______
Total Injection, BWPD 1250
Injection Efficiency % 90
Areal Sweep, % 85
No. of Producing Wells 6 Active ______
OOIP, STBAF 948 BBLS 4,684,000

RECOVERY FACTORS

PRIMARY RECOVERY
Type of Producing Drive Fluid Expansion
Cum.Actual Recovery, BBLS 190,085
% OOIP 4.06
Primary Producing Rate, BOPD 129
Primary Decline, %/Year 20%
Production Data (By Well)*

SECONDARY RECOVERY	STBAF
OOIP	948
Primary Recovery to 5/1/89	38
Residual Oil	342
Maximum Oil Recovery	568
Waterflood Recovery	332
Chemical Flood Recovery	124

Ultimate Recovery, STBAF 362 % OOIP 38.2

* To Be Attached Prepared By: J.A. Hardwick Date: 1/9/89

UNITIZATION PARAMETERS

Tract descriptions, working interest ownership and unitization parameter tables are presented in Appendix F. Four unitization parameters were prepared.

Remaining Primary Reserves

The remaining primary oil reserves were determined for each well by extrapolating the exponential portion of the decline curve to an economic limit of 307 barrels per month or 10.09 barrels per day. The annual effective decline rate was determined by extrapolation of the monthly production expressed in barrels of oil per producing day. The economic limit was calculated from the following assumptions:

Base Oil Price at 10/17/88	$12.75
Less Gravity Penalty (22^{o} API)	2.56
Oil Price	10.19
Average Monthly Operating Costs	2,100
Net Revenue Interest	76.5%
Taxes	12.34%

The remaining primary reserves for each well are tabulated below and the extrapolations are illustrated on the performance curves for each well (Appendix F). A composite curve of total field production is also included.

WELL	INITIAL PRODUCTION RATE BOPD	INITIAL PRODUCTION RATE BOPM	ANNUAL EFFECTIVE DECLINE %	REMAINING RESERVES OIL BARRELS	REMAINING RESERVES LIFE MONTHS
FOWLER 1-5	42.5	1,293	25.0	41,121	60
FEDERAL 1-32	29.5	897	15.5	42,065	76
FOWLER 3-5	11.0	335	15.0	2,044	6
TERRY 1-31	27.5	836	12.0	49,712	94
FOWLER 2-32	35.5	1,080	28.0	28,233	46
FOWLER 4-5	13.0	395	21.0	4,506	13
FOWLER 5-5	AT ECONOMIC LIMIT			-0-	-0-
TOTALS	159.0	4,836		167,681	

LITTLE MISSOURI FIELD
SECONDARY RECOVERY ECONOMICS
AT 5/1/89

	REMAINING PRIMARY	PRIMARY + STRAIGHT WATERFLOOD	PRIMARY + POLYMER AUGMENTED WATERFLOOD	INCREMENTAL: STRAIGHT WATERFLOOD OVER PRIMARY	INCREMENTAL: POLYMER WATERFLOOD OVER STRAIGHT WATERFLOOD	INCREMENTAL: POLYMER WATERFLOOD OVER PRIMARY
Total Gross Reserves, MB	136.0	1,182.9	1,642.8	1,046.9	459.9	1,506.8
Net Cash Operating Income, M$	457.0	6,946.8	9,234.3	6,489.8	2,287.5	8,777.3
Net Investment, M$	---	356.0	548.0	356.0	192.0	548.0
Undiscounted Net Operating Income or Profit						
M$	457.0	6,590.8	8,686.3	6,133.8	2,095.5	8,229.3
%	---	---	---	1,723 %	1,091 %	1,502 %
iscounted Net Operating ncome or Profit, M$						
10%	385.7	5,297.1	6,408.6	4,911.4	1,111.5	6,022.9
15%	356.9	4,775.3	5,554.9	4,418.4	779.6	5,198.0
20%	331.6	4,319.3	4,839.8	3,987.7	520.5	4,508.2
25%	309.3	3,919.0	4,235.8	3,609.7	316.8	3,926.5
ayout, Years	---	---	---	0.4	2.4	1.0
nnual Rate of Return, %	---	---	---	> 100 %	36.4 %	> 100 %

Useable Wells

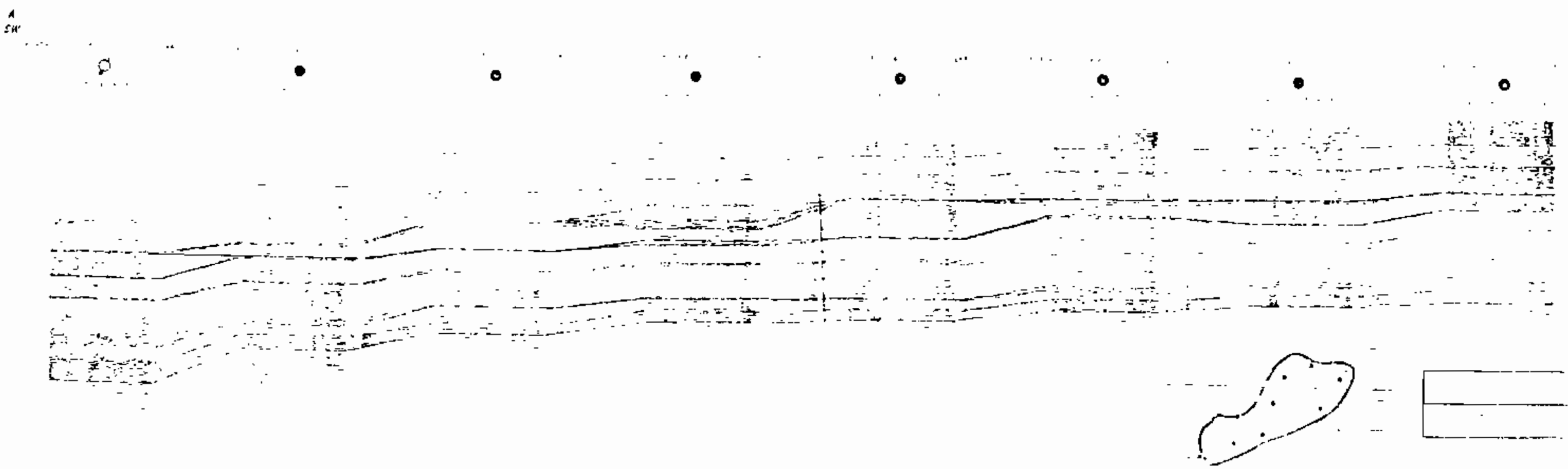
A useable well is defined as any well in the proposed unitized area that has been completed in the unitized formation and is capable of being utilized as either a producer or injector in the proposed secondary recovery operations. There are eight useable wells within the proposed unitized area.

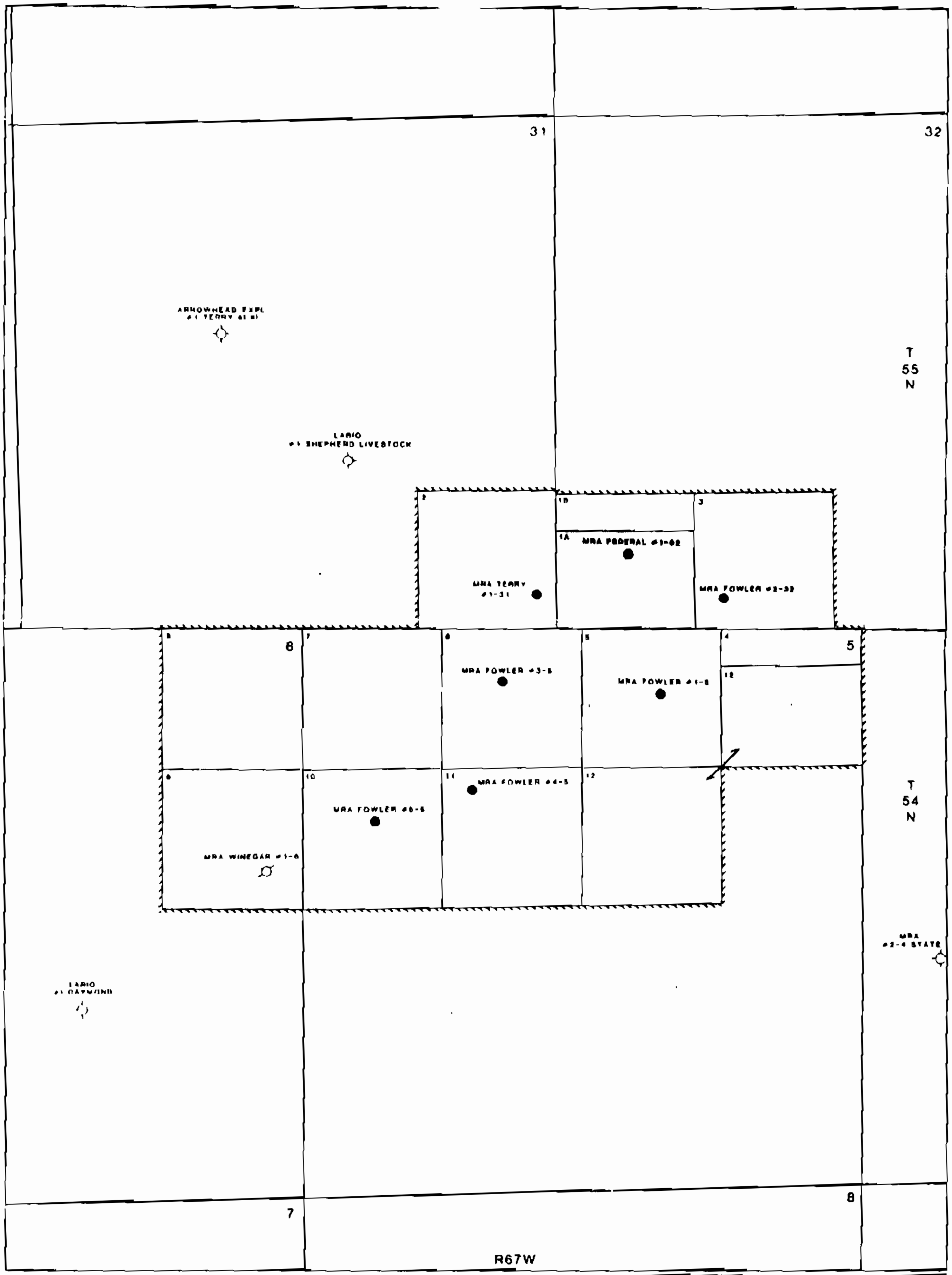
Current Oil Production

The current oil production parameter is defined as the oil production for the three-month period July 1988 through September 1988 as reported to the State of Wyoming on Form 2. Oil production statistics are presented in Appendix F.

Hydrocarbon Pore Volume

The basis for construction of pore volume ($S_o\phi h$) map has previously been discussed in the Petrophysical and Log Analysis sections and the method for determining the hydrocarbon pore volume ($S_o\phi hA$) on a field and tract basis was presented in the discussion of field volumetrics.





LEGEND

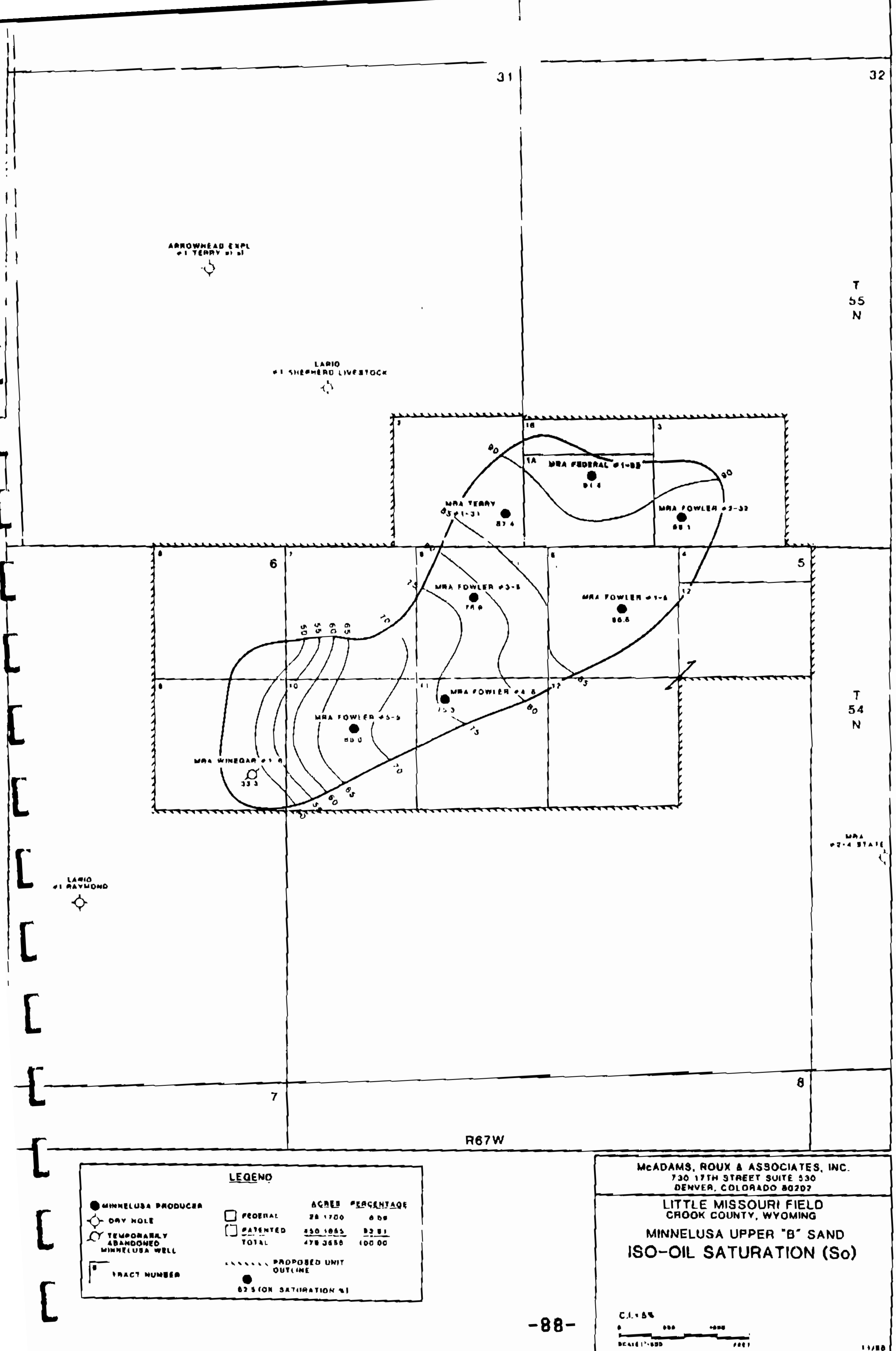
- MINNELUSA PRODUCER
- DRY HOLE
- TEMPORARILY ABANDONED MINNELUSA WELL
- TRACT NUMBER
- PROPOSED UNIT OUTLINE

	ACRES	PERCENTAGE
FEDERAL	29.1700	6.09
PATENTED	450.1865	93.91
TOTAL	479.3565	100.00

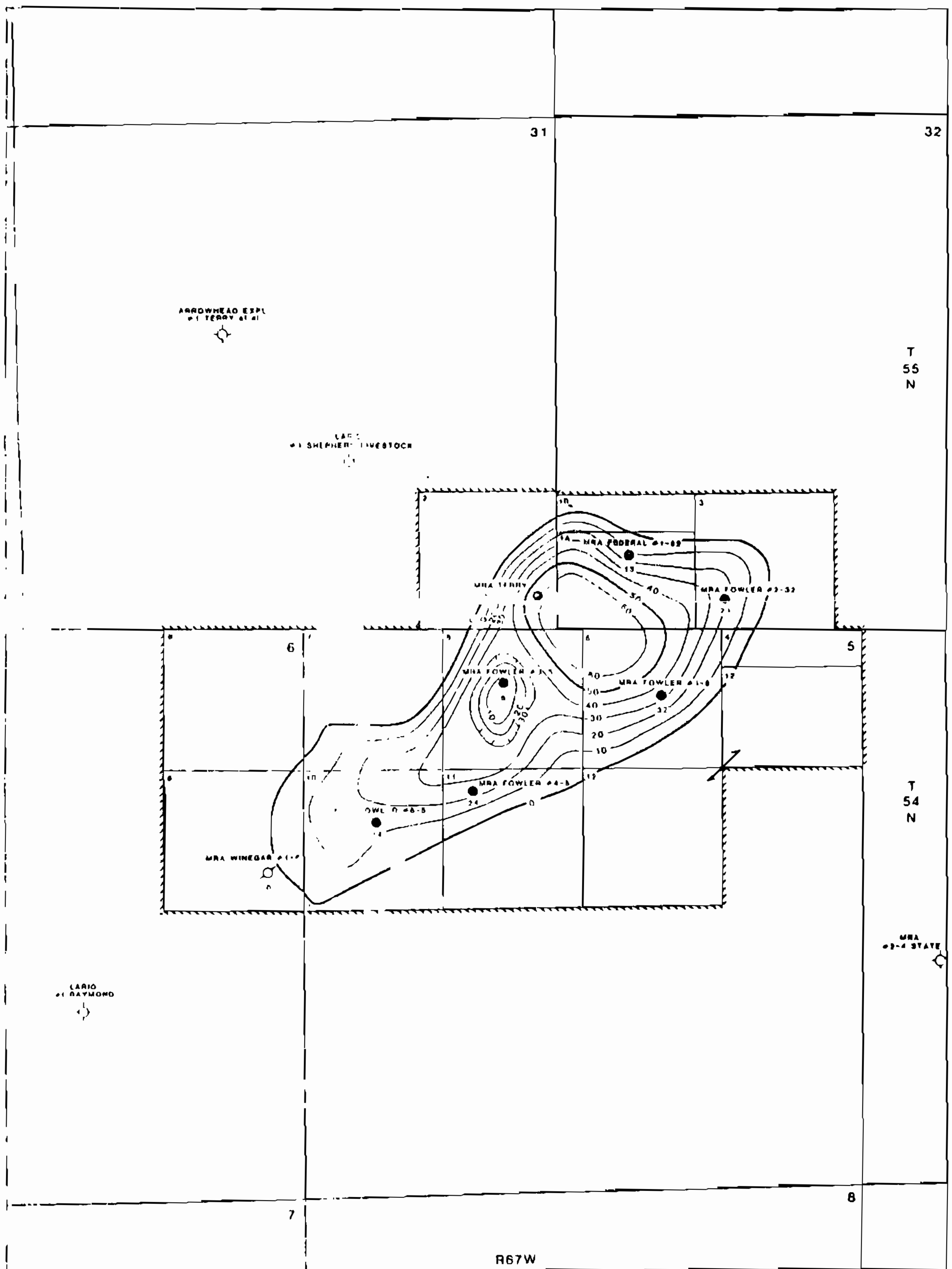
McADAMS, ROUX & ASSOCIATES, INC.
730 17TH STREET SUITE 530
DENVER, COLORADO 80202

LITTLE MISSOURI FIELD
CROOK COUNTY, WYOMING

TRACT MAP



31
32
ARROWHEAD EXPL
LARIO
#1 SHEPHERD LIVESTOCK
T
55
N
MRA FEDERAL #1-32
MRA TERRY
MRA FOWLER #2-32
87.4
6
5
MRA FOWLER #3-5
MRA FOWLER #1-6
MRA FOWLER #4-5
MRA FOWLER #5-5
MRA WINEGAR
33.3
T
54
N
LARIO
#1 RAYMOND
7
8
R67W
LEGEND
MINNELUSA PRODUCER
DRY HOLE
TEMPORARILY ABANDONED MINNELUSA WELL
TRACT NUMBER
ACRES
FEDERAL
PATENTED
TOTAL
PROPOSED UNIT OUTLINE
McADAMS, ROUX & ASSOCIATES, INC.
730 17TH STREET SUITE 530
DENVER, COLORADO 80202
LITTLE MISSOURI FIELD
CROOK COUNTY, WYOMING
MINNELUSA UPPER "B" SAND
ISO-OIL SATURATION (So)



LEGEND

MINNELUSA PRODUCER

DRY HOLE

TEMPORARILY ABANDONED MINNELUSA WELL

TRACT NUMBER

		[illegible]	PERCENTAGE
	FEDERAL	[illegible]	[illegible]
	PATENTED	[illegible]	[illegible]
	TOTAL	[illegible]	[illegible]

PROPOSED UNIT OUTLINE

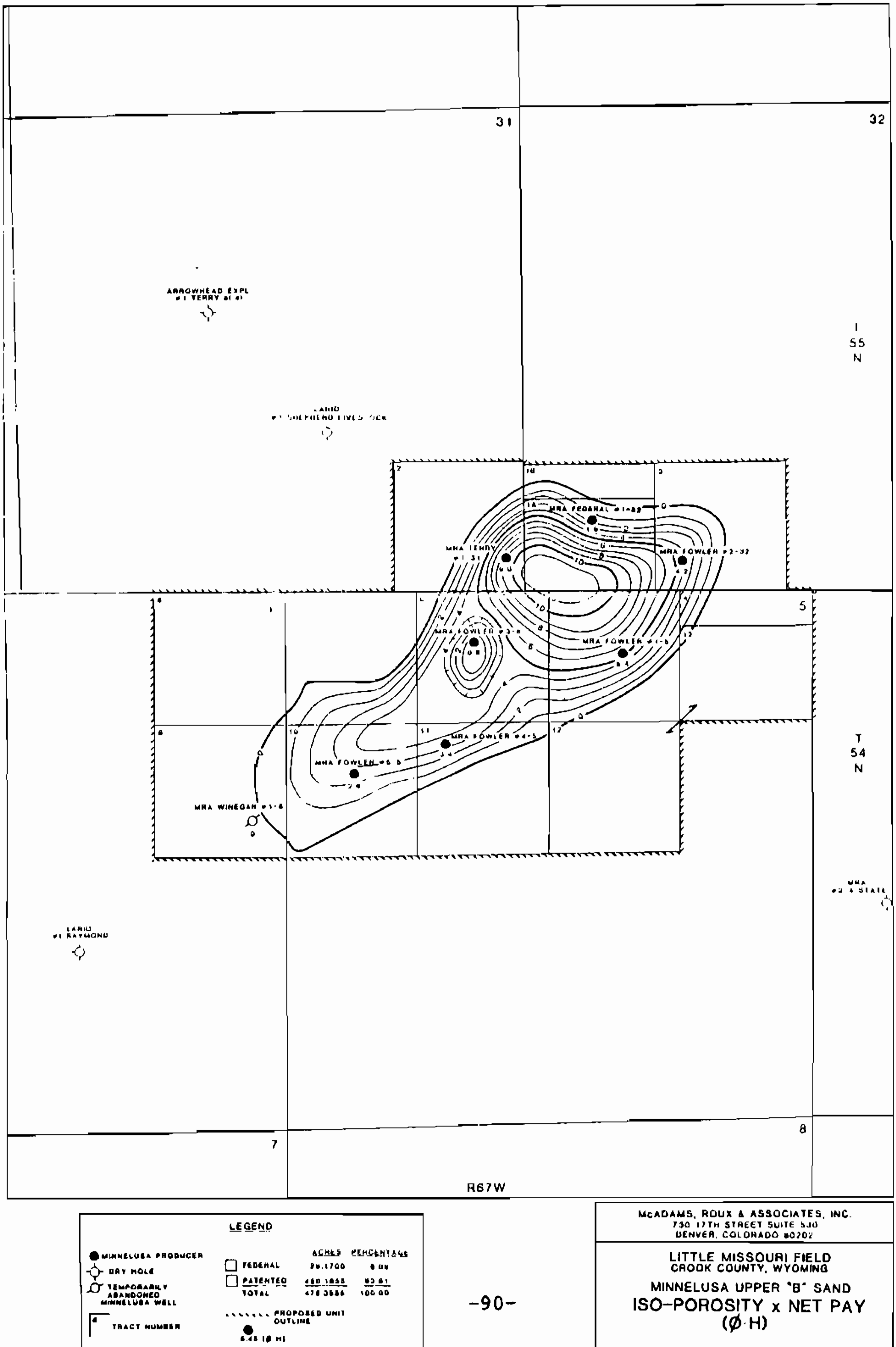
21 (NET PAY)

McADAMS, ROUX & ASSOCIATES, INC
730 17TH STREET SUITE 530
DENVER, COLORADO 80202

LITTLE MISSOURI FIELD
CROOK COUNTY, WYOMING

MINNELUSA UPPER "B" SAND
ISO-NET OIL PAY

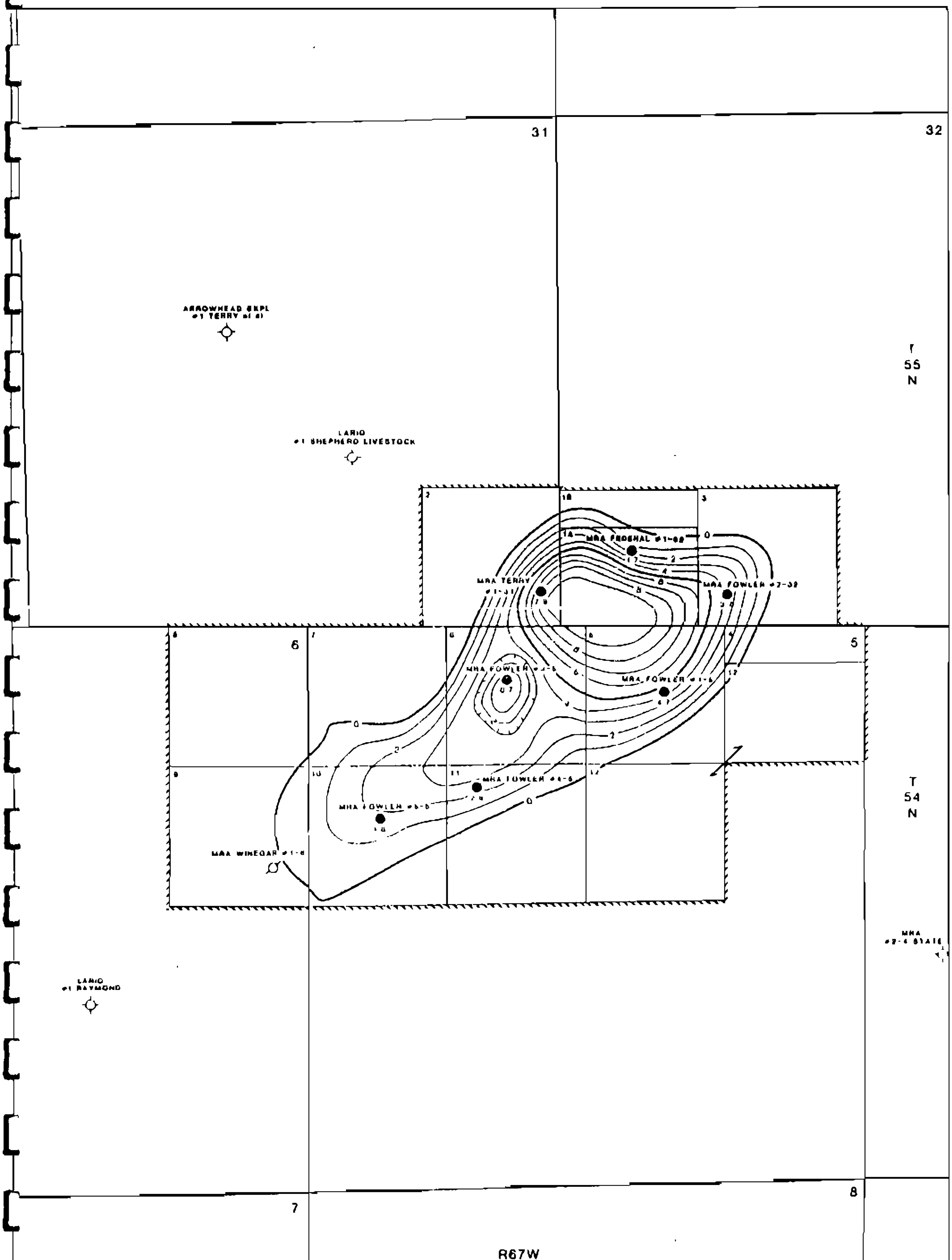
C.I. = 10'



McADAMS, ROUX & ASSOCIATES, INC.
730 17TH STREET SUITE 530
DENVER, COLORADO 80202

LITTLE MISSOURI FIELD
CROOK COUNTY, WYOMING

MINNELUSA UPPER "B" SAND
ISO-POROSITY x NET PAY
($\phi \cdot H$)



LEGEND

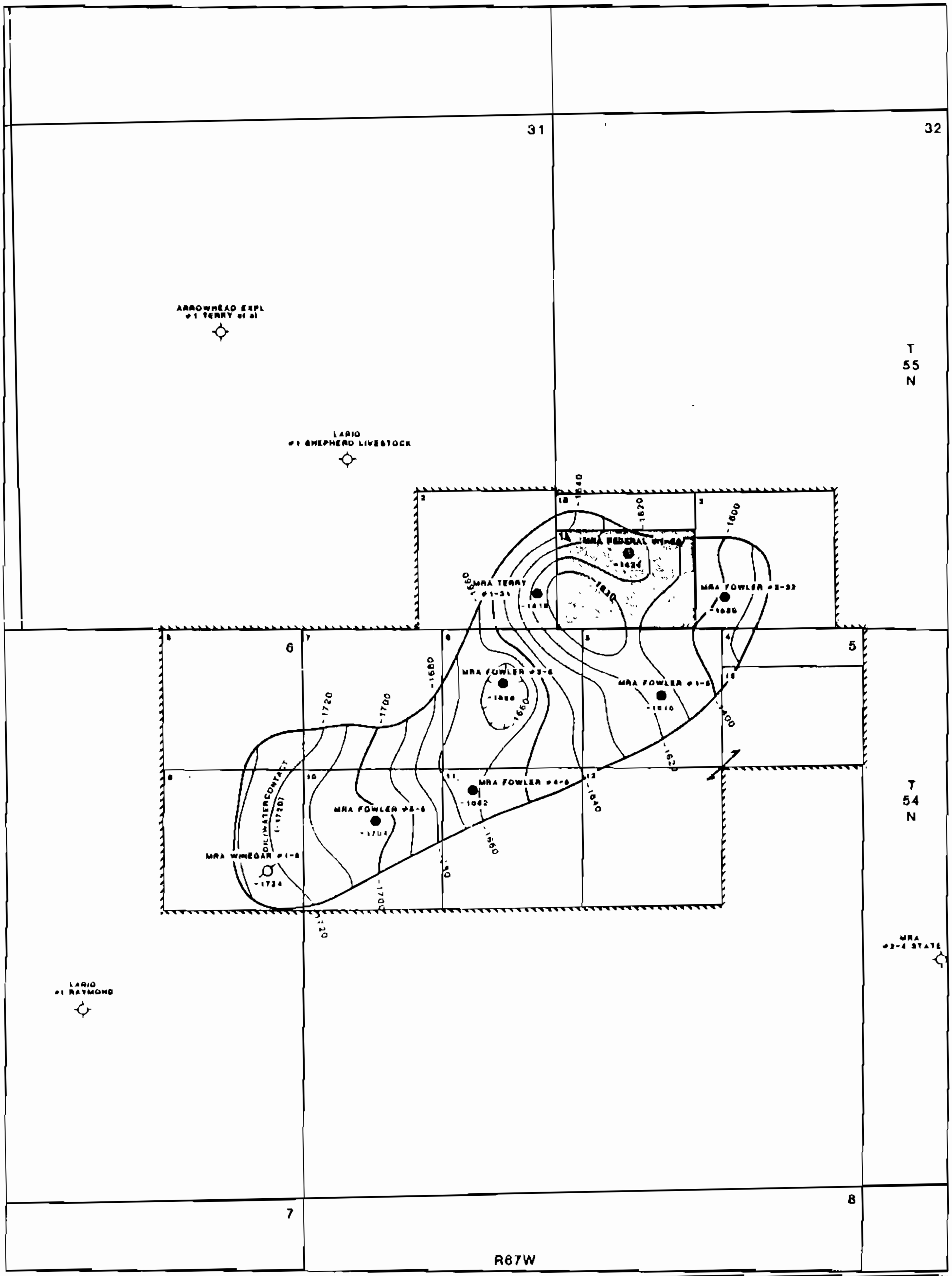
- MINNELUSA PRODUCER
- DRY HOLE
- TEMPORARILY ABANDONED MINNELUSA WELL
- TRACT NUMBER
- PROPOSED UNIT OUTLINE

	ACRES	PERCENTAGE
FEDERAL	[illegible]	[illegible]
PATENTED	[illegible]	[illegible]
TOTAL	[illegible]	100.00

McADAMS, ROUX & ASSOCIATES, INC
730 17TH STREET SUITE 530
DENVER, COLORADO 80202

LITTLE MISSOURI FIELD
CROOK COUNTY, WYOMING

MINNELUSA UPPER "B" SAND
ISO-HYDROCARBON PORE VOLUME



LEGEND

● MINNELUSA PRODUCER

DRY HOLE

TEMPORARILY ABANDONED MINNELUSA WELL

TRACT NUMBER

	ACRES	PERCENTAGE
FEDERAL	99.1760	8.09
PATENTED	460.1588	88.81
TOTAL	478.3548	100.00

PROPOSED UNIT OUTLINE

McADAMS, ROUX & ASSOCIATES, INC.
730 17TH STREET SUITE 630
DENVER, COLORADO 80202

LITTLE MISSOURI FIELD
CROOK COUNTY, WYOMING

MINNELUSA UPPER "B" SAND

STRUCTURE MAP
TOP UPPER "B" SAND

BEFORE THE OIL AND GAS CONSERVATION COMMISSION

OF THE STATE OF WYOMING

IN THE MATTER OF A HEARING BROUGHT ON THE APPLICATION OF AMPOLEX (WYOMING), INC., FOR AN ORDER FROM THE COMMISSION APPROVING UNITIZATION AND UNITIZED OPERATION OF THE MINNELUSA FORMATION IN THE LITTLE MISSOURI UNIT, CROOK COUNTY, WYOMING	)	CAUSE NO. 3 ORDER NO. 1 DOCKET NO. 77-89

Is not part of the record!

APPEARANCES:

NEIL J. SHORT, ATTORNEY REPRESENTING AMPOLEX (WYOMING), INC.

CRAIG NEWMAN, ATTORNEY REPRESENTING MCADAMS, ROUX & ASSOCIATES

Others in attendance were the following:

AMPOLEX (WYOMING), INC. -	Ron Cooper
McADAMS, ROUX & ASSOCIATES -	Wilford Roux
STATE OF WYOMING -	Donald B. Basko, Oil and Gas Supervisor
	Charles W. Farmer, Petroleum Engineer
	Joe Scott, Sp. Ass't Attorney General

REPORT OF THE COMMISSION

This cause came on regularly for hearing before the Wyoming Oil and Gas Conservation Commission at 9:30 A.M. on the 11th day of April 1989, in the office of the State Oil and Gas Supervisor, 777 West First Street, Casper, Wyoming, after due and legal notice was given as required by law and as required by the Rules and Regulations of the Commission to consider Ampolex (Wyoming), Inc.'s application for an order from the Commission approving the unitization and unitized operations of the Minnelusa Formation underlying the proposed Little Missouri Unit, Crook County, Wyoming. Ampolex (Wyoming), Inc., (hereinafter Ampolex) also requests tertiary certification of the unit operations.

The Commission proceeded to hear the sworn statements of the applicant and other interested parties and considered the evidence offered at the hearing. As a result of said hearing, and after review of pertinent files in the office of the State Oil and Gas Supervisor, the Commission makes the following Findings of Fact, Conclusions of Law, and Order:

FINDINGS OF FACT

1. The proposed Little Missouri (Minnelusa) Unit encompasses 479.3555 acres of fee and Federal leases. The proposed waterflood area is to include:

Township 54 North, Range 67 West, 6th P.M.
Section 5: That portion of Tract 37E located North of Lot 5, Tract 38E, Lots 3, 4, 5, 6, SW¼NE¼, S½NW¼

Section 6: Lot 1, SE¼NE¼

Township 55 NOrth, Range 67 West, 6th P.M.
Section 31: Lot 8 and the South 11.04 acres of the NE¼SE¼

Section 32: Lot 2, the South 10.1175 acres of Tract 38B located in the SW¼SW¼, that portion of Tract 38D located in the southern portion of the E½SW¼ and the southern 10-48 acres of Tract 38C

2. The above described lands constitute the entire participating acreage for the unitized operation. Tract participation is as per Article 12 of the Unit Agreement and is based 50% on hydrocarbon pore volume, 25% on remaining primary reserves, 15% on current oil production, and 10% on the number of usable wells.

3. Ampolex (Wyoming), Inc. (Ampolex), has been designated as operator of the proposed Little Missouri (Minnelusa) Unit as per Article 6 of the Unit Agreement which becomes effective the first day of the calendar month next following approval of the unit agreement by the Federal Secretary of Interior or delegate.

4. The effective portion of the Minnelusa Upper "B" Formation lies within the proposed unit boundaries at a drilled depth of approximately 5,540 feet. The dip is to the Southwest. The formation has an average net pay of about 25 feet, porosity of 15 percent, and water saturation of 16.9 percent. The original bottomhole pressure of 2,163 psi declined rapidly indicating an undersaturated reservoir.

5. Eight (8) wells have been drilled in the unit area. Initial unitized operations will involve two converted injectors and six producing wells, providing an efficient sweep to the updip producers. The revenues from the increased oil recovery far exceed the investments required as shown in Findings of Fact 7 and 11 herein.

6. The cumulative recovery as of October 1, 1988 was 158,367 stock tank barrels of oil (STBO) or about 3.4% of the original oil in place (OOIP). Ultimate primary recovery is expected to be about 326,000 STBO or 7% OOIP.

7. Conventional secondary operations may result in the additional recovery of approximately 1,047,000 STBO or an additional 22.3% OOIP. Thus, the ultimate

primary plus secondary recovery would be about 1,373,000 barrels or 29.3% OOIP. Tertiary operations may recover an additional 460,000 STBO.

8. Water will be injected into the Minnelusa "B" at a maximum of 2,000 barrels per day with a maximum injection pressure of 1,800 pounds per square inch (psi). Ampolex received approval of the injection operations under Rule 401 in Docket No. 63-89.

9. Fresh water sources are and will be protected by proper cementing and completion procedures. Further, the Minnelusa Upper "B" was exempt from aquifer classification in Docket No. 63-89.

10. The proposed unit area has been and is being developed in accordance with Rule 302 of the Wyoming Oil and Gas Conservation Commission; i.e., on forty (40) acre well locations. Oil recovery is thus optimized by the proposed secondary and tertiary unitized operations.

11. Approximately $460,000 capital investment will be required to initiate the proposed secondary recovery injection program. The tertiary recovery operations will require about $485,000 more. The project economics for secondary and tertiary operations yield discounted profits of $5,297,100 and $6,408,600 respectively.

12. Ampolex's application for unitized injection operation of the Little Missouri Unit's Minnelusa Upper "B" Formation should be approved to provide for the increased recovery of hydrocarbons and for the protection of correlative rights.

13. Exhibits "B" and "C" of Ampolex's application contain the names and addresses of all included within the unit and adjacent to but not included in the unit. Other items required by W.S. §30-5-110(c) are included in the application.

14. Information contained in Ampolex's exhibits is true and accurate.

15. Working interest owners and royalty interests in the field contemplated unit operation prior to June 1987. In October 1987, they began holding meetings on unitization. There the parties discussed past and future development in the field and formed various committees, such as the engineering committee. Another such meeting was held in November 1987. Subsequently there were weekly partnership meetings lasting through August 1988. In January 1989, there was another meeting at which time the parties agreed on a participation formula. Also, Ampolex was elected unit operator at this meeting. McAdams, Roux, and

Associates (MRA), was the only one to vote against Ampolex being unit operator. There was give and take among all the parties at these meetings. The parties considered various matters, such as interpretation of geology, participation formulas, and who would be unit operator. MRA was notified of these meetings and attended most of them.

16. The U.S. Bureau of Land Management (BLM) has a substantial royalty interest in the field. It has given its preliminary approval to the proposed unitization. However, as is its custom, it will not give its final approval until this Commission has approved unitization. Counting the BLM, 76.05 percent of the royalty interests have approved the proposed unitization. The proposed unitization has also been approved by 97.22 percent of the working interests in the unit.

17. MRA has 22.08 percent of royalty interests in the field. Its only objection to the proposed unitization is that it wants to be the unit operator, and contends it is entitled to be unit operator under a contract with Ampolex. MRA has no objection to the participation formula or anything else about the unitization.

18. Except to the extent we have done so, it is not reasonably practical to make the findings required by Larsen v. Oil and Gas Commission regarding the amount of oil and gas in the pool, the amount under each tract, etc.

CONCLUSIONS OF LAW

1. Due and legal notice of time, place and purpose of this hearing has been given to all persons interested and in all respects as required by law.

2. This Commission has jurisdiction over the matter embraced in the application before the Commission and all parties interested and has jurisdiction to make and promulgate the order hereinafter set forth.

3. A portion of this hearing was conducted in accordance with Rules 513 and 515 of the Wyoming Oil and Gas Conservation Commission and §30-5-105, Wyoming Statutes, 1977, as amended, governing hearings conducted by examiners.

4. This application was submitted under the provisions of §30-5-110, Wyoming Statutes, 1977, as amended, governing unitized operations of oil and gas pools or parts thereof within the State of Wyoming, and fulfills the requirement of that statute.

5. The material allegations of the application are substantially true.

6. The proposed unit operation is feasible, will prevent waste, will protect

should be reduced to seventy-five percent, pursuant to W.S. §30-5-110(f).

ORDER

IT IS THEREFORE HEREBY ORDERED BY THE COMMISSION that unitization of the Minnelusa Upper "B" Formation underlying the Little Missouri Unit area and unitized operations thereunder as proposed in said application, are approved. Lands subject to this order are as follows:

Township 54 North, Range 67 West, 6th P.M.
Section 5: That part of Tract 37E located North of Lot 5, Tract 38E, Lots 3, 4, 5, 6, SW¼NE¼, S½NW¼

Section 6: Lot 1, SE¼NE¼

Township 55 North, Range 67 West, 6th P.M.
Section 31: Lot 8 and the South 11.04 acres of the NE¼SE¼

Section 32: Lot 2, the South 10.1175 acres of Tract 38B located in the SW¼SW¼, that portion of Tract 38D located in the southern portion of the E½SW¼ and the southern 10.48 acres of Tract 38C

IT IS FURTHER ORDERED that the required percentage of royalty interest who have approved the unit for Commission approval, be and hereby is reduced to seventy-five percent.

FURTHER IT IS ORDERED that the Commission or any member thereof, or any of its agents or designees shall have the right at any and all times hereafter to investigate the unitized operations authorized to be carried on by the applicant, and that the applicant shall furnish monthly to the Commission, through the State Oil and Gas Supervisor's office, on Form 2, a report of each injection and production wells' status and rate.

FURTHER IT IS ORDERED that the applicant shall secure approval of the State Oil and Gas Supervisor for any change in the injection wells which the applicant may make in order to carry out the program in the most efficient manner in its waterflood project.

IT IS FURTHER ORDERED that the applicant shall secure permission from the State Oil and Gas Supervisor and the U.S. Bureau of Land Management before drilling, completing, or recompleting any wells in said area as water injection wells. Conversion of existing wells to use as water injection wells shall be submitted on Sundry Notices, and new water injection wells will be submitted for approval on an Application for Permit to drill. The operator shall reference this order on all injection submittals. This order is subject to alterations correlative rights, and can reasonably be expected to increase substantially the ultimate recovery of oil or gas.

7. The value of the estimated additional recovery of oil or gas will exceed the estimated additional costs incident to conducting unit operations.

8. The oil and gas allocated to each separately owned tract within the unit area under the proposed plan of unitization represents, so far as can be practically determined, each such tract's just and equitable share of the oil or gas in the unit area.

9. The proposed unit embraces the whole pool.

10. Article 10 of the Unit Operating Agreement makes a fair and equitable adjustment among the owners within the unit area for their respective investments in wells, tanks, pumps, machinery, materials and equipment which have contributed to unit operations.

11. Article 11 of the Unit Operating Agreement provides for a fair and equitable determination of the cost of unit operations, including capital investment, and establishes a fair and equitable method for allocating such costs to the separately owned tracts and for the payment of such costs by the persons owning such tracts, either directly or out of such person's respective share of unit production.

12. Article 11 of the Unit Operating Agreement prescribes fair, reasonable and equitable terms and conditions as to time and rate of interest for carrying or otherwise financing any person who is unable to promptly meet his financial obligations in connection with the unit.

13. Article 4 of the Unit Operating Agreement provides that each owner shall have a vote in the supervision and conduct of unit operations corresponding to the percentage of costs of unit operations chargeable against the interests of such person.

14. Articles 7 and 8 of the Unit Agreement provide for fair and equitable terms and conditions for removal of the unit operator and for appointment of a successor unit operator.

15. Negotiations for unitization have been conducted for a period of at least nine months prior to the filing of the application, and Ampolex has participated in these negotiations diligently and in good faith. We also conclude that eighty percent of the royalty interest approval (non-cost bearing interests) can not be obtained. The percentage of royalty interest required for approval

or modifications by the Commission if, at a later date, it is found by the Commission that said secondary recovery project is no longer in the interest of conservation or that it does not serve to prevent waste of oil and gas.

FURTHER, this order of the Commission is permanent.

DATED this 25th day of April 1989.

WYOMING OIL AND GAS
CONSERVATION COMMISSION

/S/ Howard M. Schrinar
Mr. Howard M. Schrinar,
Commissioner

/S/ Charles W. Farmer
Mr. Charles W. Farmer - Examiner

/S/ Eddie Moore
Mr. Eddie Moore,
Commissioner

/S/ Géne R. George
Mr. Gene R. George,
Commissioner

BEFORE THE OIL AND GAS CONSERVATION COMMISSION

OF THE STATE OF WYOMING

IN THE MATTER OF A HEARING BROUGHT ON THE APPLICATION OF AMPOLEX (WYOMING), INC., FOR AN ORDER FROM THE COMMISSION APPROVING UNITIZATION AND UNITIZED OPERATION OF THE MINNELUSA FORMATION IN THE LITTLE MISSOURI UNIT, CROOK COUNTY, WYOMING	CAUSE NO. 3 ORDER NO. 1 DOCKET NO. 77-89

APPEARANCES:

NEIL J. SHORT, ATTORNEY REPRESENTING AMPOLEX (WYOMING), INC.

CRAIG NEWMAN, ATTORNEY REPRESENTING MCADAMS, ROUX & ASSOCIATES

Others in attendance were the following:

AMPOLEX (WYOMING), INC. -	Ron Cooper
McADAMS, ROUX & ASSOCIATES -	Wilford Roux
STATE OF WYOMING -	Donald B. Basko, Oil and Gas Supervisor
	Charles W. Farmer, Petroleum Engineer
	Joe Scott, Sp. Ass't Attorney General

REPORT OF THE COMMISSION

This cause came on regularly for hearing before the Wyoming Oil and Gas Conservation Commission at 9:30 A.M. on the 11th day of April 1989, in the office of the State Oil and Gas Supervisor, 777 West First Street, Casper, Wyoming, after due and legal notice was given as required by law and as required by the Rules and Regulations of the Commission to consider Ampolex (Wyoming), Inc.'s application for an order from the Commission approving the unitization and unitized operations of the Minnelusa Formation underlying the proposed Little Missouri Unit, Crook County, Wyoming. Ampolex (Wyoming), Inc., (hereinafter Ampolex) also requests tertiary certification of the unit operations.

The Commission proceeded to hear the sworn statements of the applicant and other interested parties and considered the evidence offered at the hearing. As a result of said hearing, and after review of pertinent files in the office of the State Oil and Gas Supervisor, the Commission makes the following Findings of Fact, Conclusions of Law, and Order:

FINDINGS OF FACT

1. The proposed Little Missouri (Minnelusa) Unit encompasses 479.3555 acres of fee and federal leases. The proposed waterflood area is to include:

Township 54 North, Range 67 West, 6th P.M.
Section 5: That portion of Tract 37E located North of Lot 5, Tract 38E, Lots 3, 4, 5, 6, SW¼NE¼, S½NW¼

Section 6: Lot 1, SE¼NE¼

Township 55 NOrth, Range 67 West, 6th P.M.
Section 31: Lot 8 and the South 11.04 acres of the NE¼SE¼

Section 32: Lot 2, the South 10.1175 acres of Tract 38B located in the SW¼SW¼, that portion of Tract 38D located in the southern portion of the E½SW¼ and the southern 10-48 acres of Tract 38C

2. The above described lands constitute the entire participating acreage for the unitized operation. Tract participation is as per Article 12 of the Unit Agreement and is based 50% on hydrocarbon pore volume, 25% on remaining primary reserves, 15% on current oil production, and 10% on the number of usable wells.

3. Ampolex (Wyoming), Inc. (Ampolex), has been designated as operator of the proposed Little Missouri (Minnelusa) Unit as per Article 6 of the Unit Agreement which becomes effective the first day of the calendar month next following approval of the unit agreement by the Federal Secretary of Interior or delegate.

4. The effective portion of the Minnelusa Upper "B" Formation lies within the proposed unit boundaries at a drilled depth of approximately 5,540 feet. The dip is to the Southwest. The formation has an average net pay of about 25 feet, porosity of 15 percent, and water saturation of 16.9 percent. The original bottomhole pressure of 2,163 psi declined rapidly indicating an undersaturated reservoir.

5. Eight (8) wells have been drilled in the unit area. Initial unitized operations will involve two converted injectors and six producing wells, providing an efficient sweep to the updip producers. The revenues from the increased oil recovery far exceed the investments required as shown in Findings of Fact 7 and 11 herein.

6. The cumulative recovery as of October 1, 1988 was 158,367 stock tank barrels of oil (STBO) or about 3.4% of the original oil in place (OOIP). Ultimate primary recovery is expected to be about 326,000 STBO or 7% OOIP.

7. Conventional secondary operations may result in the additional recovery of approximately 1,047,000 STBO or an additional 22.3% OOIP. Thus, the ultimate

primary plus secondary recovery would be about 1,373,000 barrels or 29.3% OOIP. Tertiary operations may recover an additional 460,000 STBO.

8. Water will be injected into the Minnelusa "B" at a maximum of 2,000 barrels per day with a maximum injection pressure of 1,800 pounds per square inch (psi). Ampolex received approval of the injection operations under Rule 401 in Docket No. 63-89.

9. Fresh water sources are and will be protected by proper cementing and completion procedures. Further, the Minnelusa Upper "B" was exempt from aquifer classification in Docket No. 63-89.

10. The proposed unit area has been and is being developed in accordance with Rule 302 of the Wyoming Oil and Gas Conservation Commission; i.e., on forty (40) acre well locations. Oil recovery is thus optimized by the proposed secondary and tertiary unitized operations.

11. Approximately $460,000 capital investment will be required to initiate the proposed secondary recovery injection program. The tertiary recovery operations will require about $485,000 more. The project economics for secondary and tertiary operations yield discounted profits of $5,297,100 and $6,408,600 respectively.

12. Ampolex's application for unitized injection operation of the Little Missouri Unit's Minnelusa Upper "B" Formation should be approved to provide for the increased recovery of hydrocarbons and for the protection of correlative rights.

13. Exhibits "B" and "C" of Ampolex's application contain the names and addresses of all included within the unit and adjacent to but not included in the unit. Other items required by W.S. §30-5-110(c) are included in the application.

14. Information contained in Ampolex's exhibits is true and accurate.

15. Working interest owners and royalty interests in the field contemplated unit operation prior to June 1987. In October 1987, they began holding meetings on unitization. There the parties discussed past and future development in the field and formed various committees, such as the engineering committee. Another such meeting was held in November 1987. Subsequently there were weekly partnership meetings lasting through August 1988. In January 1989, there was another meeting at which time the parties agreed on a participation formula. Also, Ampolex was elected unit operator at this meeting. McAdams, Roux, and

Associates (MRA), was the only one to vote against Ampolex being unit operator. There was give and take among all the parties at these meetings. The parties considered various matters, such as interpretation of geology, participation formulas, and who would be unit operator. MRA was notified of these meetings and attended most of them.

16. The U.S. Bureau of Land Management (BLM) has a substantial royalty interest in the field. It has given its preliminary approval to the proposed unitization. However, as is its custom, it will not give its final approval until this Commission has approved unitization. Counting the BLM, 76.05 percent of the royalty interests have approved the proposed unitization. The proposed unitization has also been approved by 97.22 percent of the working interests in the unit.

17. MRA has 22.08 percent of royalty interests in the field. Its only objection to the proposed unitization is that it wants to be the unit operator, and contends it is entitled to be unit operator under a contract with Ampolex. MRA has no objection to the participation formula or anything else about the unitization.

18. Except to the extent we have done so, it is not reasonably practical to make the findings required by Larsen v. Oil and Gas Commission regarding the amount of oil and gas in the pool, the amount under each tract, etc.

CONCLUSIONS OF LAW

1. Due and legal notice of time, place and purpose of this hearing has been given to all persons interested and in all respects as required by law.

2. This Commission has jurisdiction over the matter embraced in the application before the Commission and all parties interested and has jurisdiction to make and promulgate the order hereinafter set forth.

3. A portion of this hearing was conducted in accordance with Rules 513 and 515 of the Wyoming Oil and Gas Conservation Commission and §30-5-105, Wyoming Statutes, 1977, as amended, governing hearings conducted by examiners.

4. This application was submitted under the provisions of §30-5-110, Wyoming Statutes, 1977, as amended, governing unitized operations of oil and gas pools or parts thereof within the State of Wyoming, and fulfills the requirement of that statute.

5. The material allegations of the application are substantially true.

6. The proposed unit operation is feasible, will prevent waste, will protect

correlative rights, and can reasonably be expected to increase substantially the ultimate recovery of oil or gas.

7. The value of the estimated additional recovery of oil or gas will exceed the estimated additional costs incident to conducting unit operations.

8. The oil and gas allocated to each separately owned tract within the unit area under the proposed plan of unitization represents, so far as can be practically determined, each such tract's just and equitable share of the oil or gas in the unit area.

9. The proposed unit embraces the whole pool.

10. Article 10 of the Unit Operating Agreement makes a fair and equitable adjustment among the owners within the unit area for their respective investments in wells, tanks, pumps, machinery, materials and equipment which have contributed to unit operations.

11. Article 11 of the Unit Operating Agreement provides for a fair and equitable determination of the cost of unit operations, including capital investment, and establishes a fair and equitable method for allocating such costs to the separately owned tracts and for the payment of such costs by the persons owning such tracts, either directly or out of such person's respective share of unit production.

12. Article 11 of the Unit Operating Agreement prescribes fair, reasonable and equitable terms and conditions as to time and rate of interest for carrying or otherwise financing any person who is unable to promptly meet his financial obligations in connection with the unit.

13. Article 4 of the Unit Operating Agreement provides that each owner shall have a vote in the supervision and conduct of unit operations corresponding to the percentage of costs of unit operations chargeable against the interests of such person.

14. Articles 7 and 8 of the Unit Agreement provide for fair and equitable terms and conditions for removal of the unit operator and for appointment of a successor unit operator.

15. Negotiations for unitization have been conducted for a period of at least nine months prior to the filing of the application, and Ampolex has participated in these negotiations diligently and in good faith. We also conclude that eighty percent of the royalty interest approval (non-cost bearing interests) can not be obtained. The percentage of royalty interest required for approval

should be reduced to seventy-five percent, pursuant to W.S. §30-5-110(f).

ORDER

IT IS THEREFORE HEREBY ORDERED BY THE COMMISSION that unitization of the Minnelusa Upper "B" Formation underlying the Little Missouri Unit area and unitized operations thereunder as proposed in said application, are approved. Lands subject to this order are as follows:

Township 54 North, Range 67 West, 6th P.M.
Section 5: That part of Tract 37E located North of Lot 5, Tract 38E, Lots 3, 4, 5, 6, SW¼NE¼, S½NW¼

Section 6: Lot 1, SE¼NE¼

Township 55 North, Range 67 West, 6th P.M.
Section 31: Lot 8 and the South 11.04 acres of the NE¼SE¼

Section 32: Lot 2, the South 10.1175 acres of Tract 38B located in the SW¼SW¼, that portion of Tract 38D located in the southern portion of the E½SW¼ and the southern 10.48 acres of Tract 38C

IT IS FURTHER ORDERED that the required percentage of royalty interest who have approved the unit for Commission approval, be and hereby is reduced to seventy-five percent.

FURTHER IT IS ORDERED that the Commission or any member thereof, or any of its agents or designees shall have the right at any and all times hereafter to investigate the unitized operations authorized to be carried on by the applicant, and that the applicant shall furnish monthly to the Commission, through the State Oil and Gas Supervisor's office, on Form 2, a report of each injection and production wells' status and rate.

FURTHER IT IS ORDERED that the applicant shall secure approval of the State Oil and Gas Supervisor for any change in the injection wells which the applicant may make in order to carry out the program in the most efficient manner in its waterflood project.

IT IS FURTHER ORDERED that the applicant shall secure permission from the State Oil and Gas Supervisor and the U.S. Bureau of Land Management before drilling, completing, or recompleting any wells in said area as water injection wells. Conversion of existing wells to use as water injection wells shall be submitted on Sundry Notices, and new water injection wells will be submitted for approval on an Application for Permit to drill. The operator shall reference this order on all injection submittals. This order is subject to alterations or modifications by the Commission if, at a later date, it is found by the Commission that said secondary recovery project is no longer in the interest of conservation or that it does not serve to prevent waste of oil and gas.

FURTHER, this order of the Commission is permanent.

DATED this 25th day of April 1989.

WYOMING OIL AND GAS
CONSERVATION COMMISSION

/S/ Howard M. Schrinar
Mr. Howard M. Schrinar,
Commissioner

/S/ Charles W. Farmer
Mr. Charles W. Farmer - Examiner

/S/ Eddie Moore
Mr. Eddie Moore,
Commissioner

/S/ Gene R. George
Mr. Gene R. George,
Commissioner

DICKINSON-LODGEPOLE UNIT

Case Number 5933

Conoco Inc.
Dickinson Lodgepole Unit
Case No. 5933

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Exhibit No. 11	-	Fryburg Structure Map
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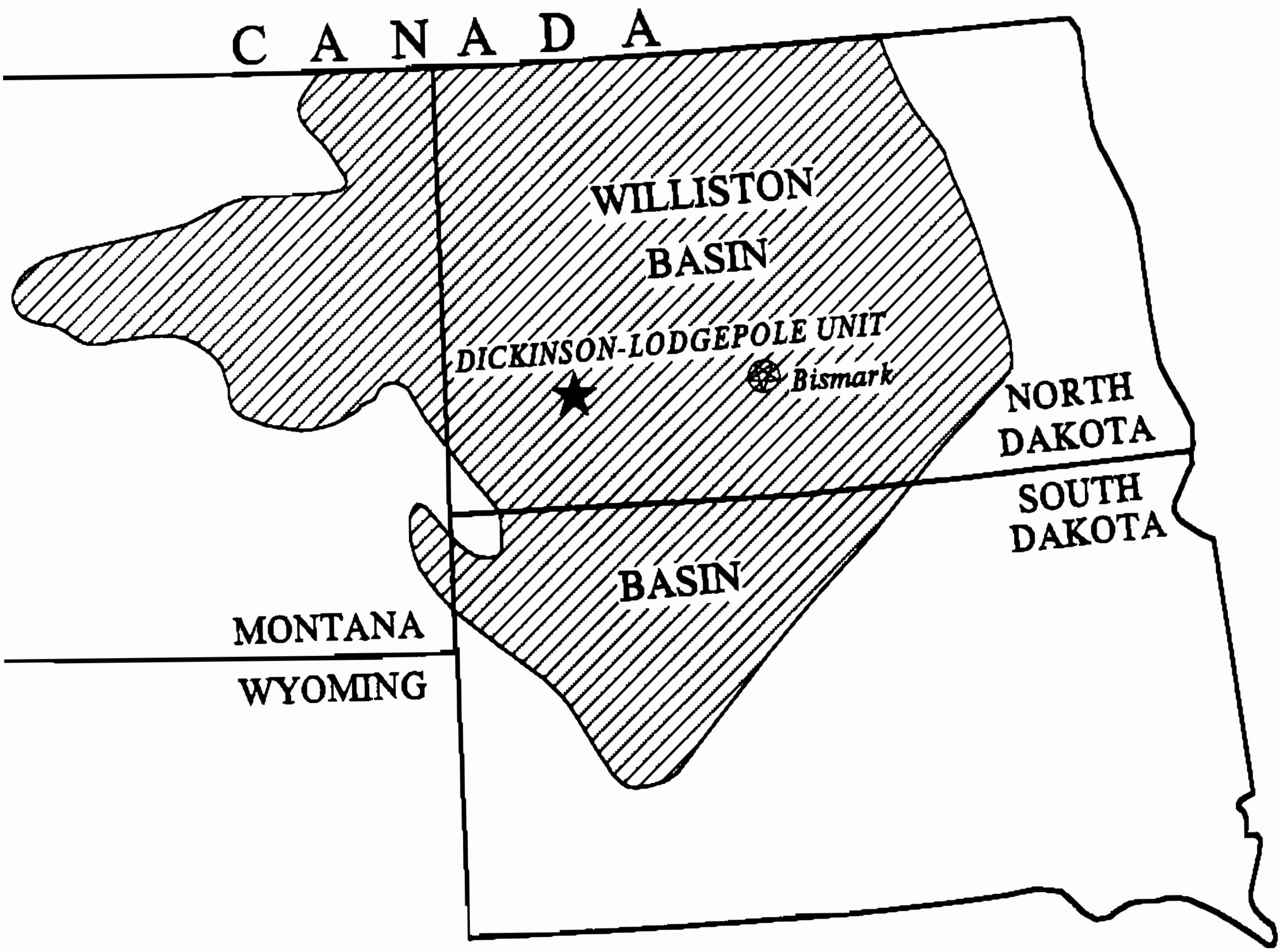
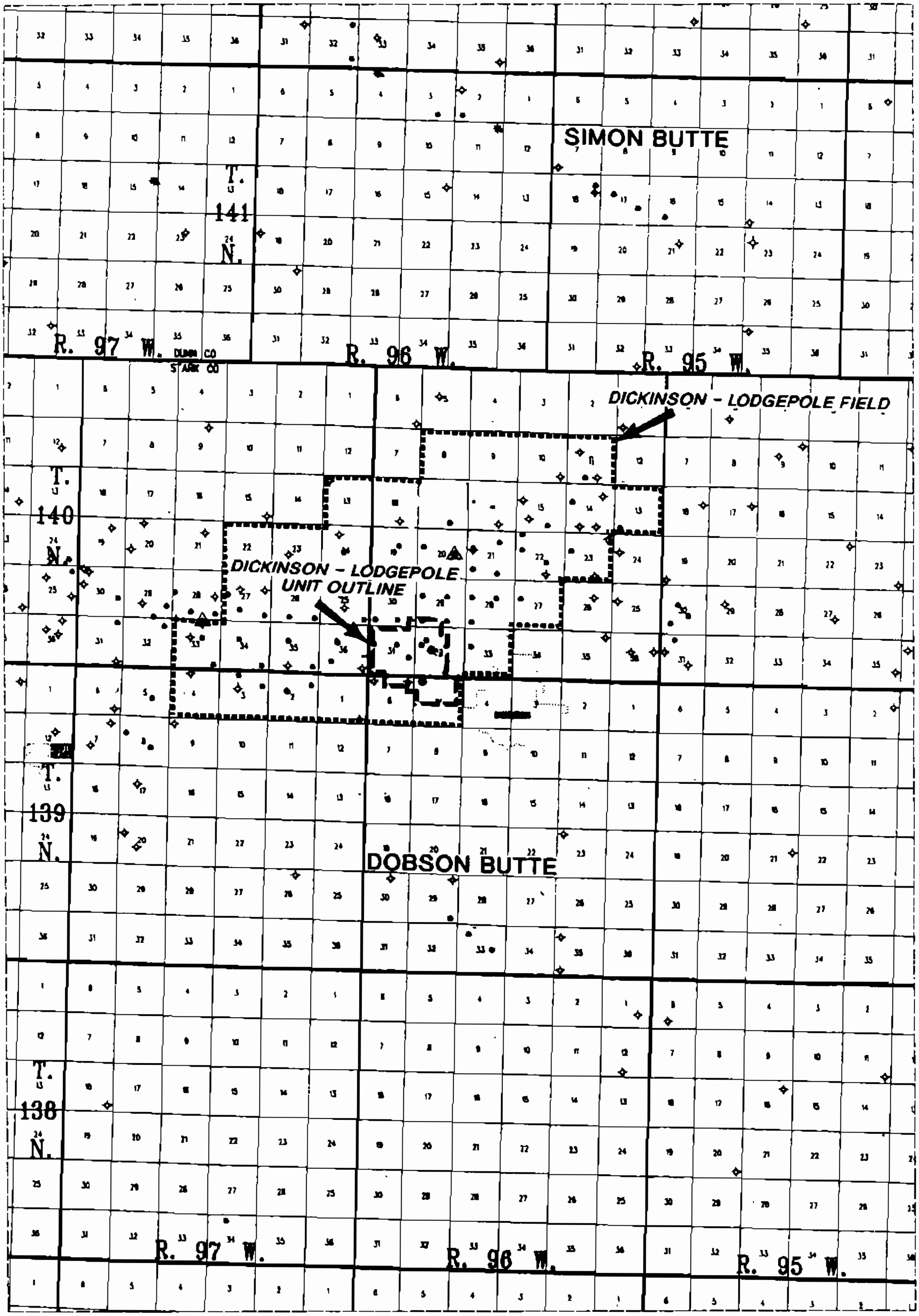
DICKINSON-LODGEPOLE UNIT
Location Map



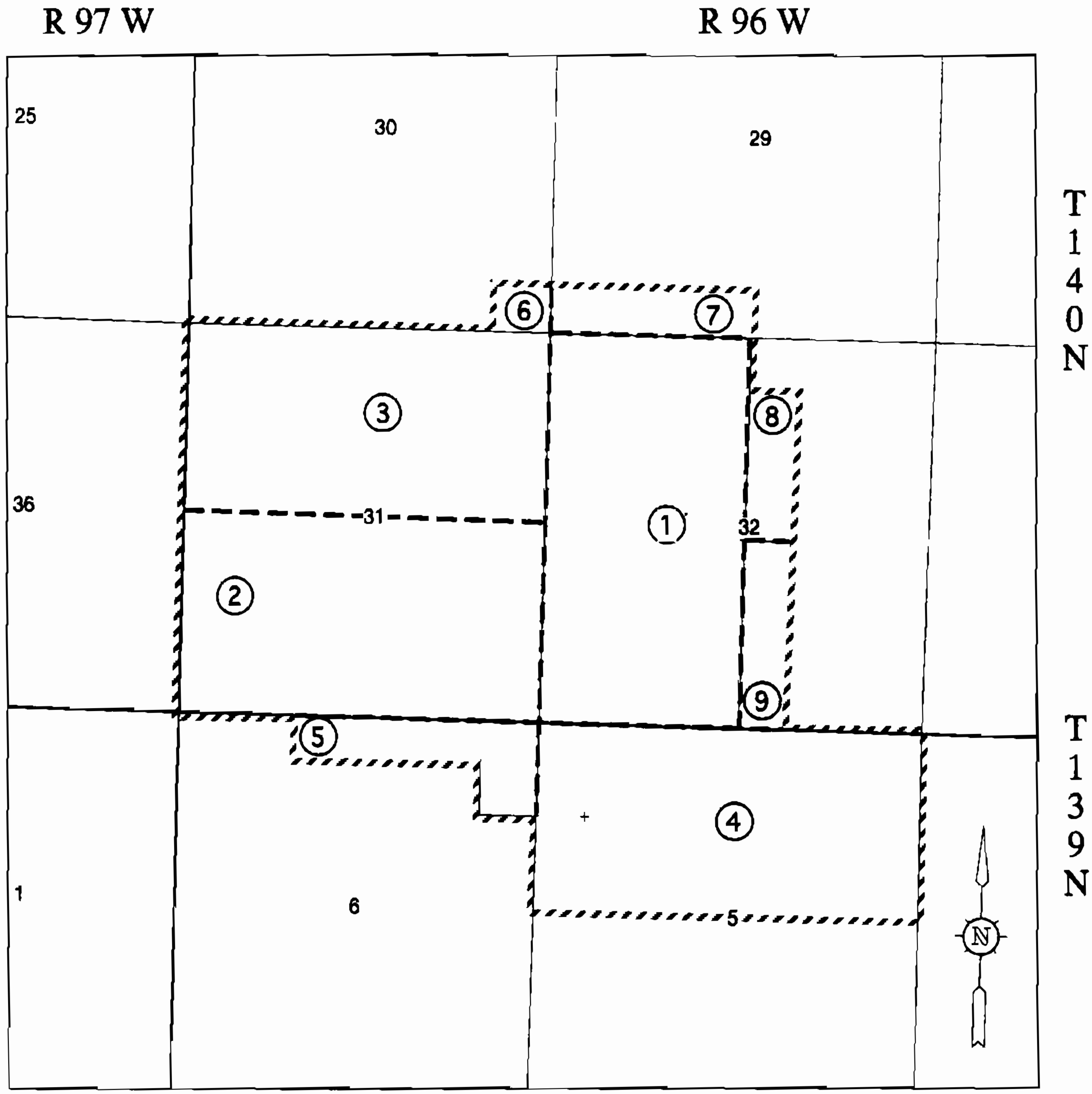
CONOCO INC.
Case No. 5933
Exhibit No. 1



DICKINSON AREA

Stark Co. North Dakota

CONOCO INC.
Case No. 5933
Exhibit No. 2



TRACT	ACRES
1	320.00
2	308.49
3	303.65
4	323.78
5	60.27
6	10.01
7	40.15
8	30.06
9	40.04
TOTAL	1436.45

Unit Boundary

Tract Boundary

1 Tract No.

Scale
1000'

DICKINSON LODGEPOLE UNIT
Stark Co., North Dakota

CONOCO INC.
Case No. 5933
Exhibit No. 3

DICKINSON-LODGEPOLE UNIT DESCRIPTION

Township 140 North, Range 96 West
Section 29: S½S½SW¼
Section 30: SE¼SE¼SE¼
Section 31: Lots 1, 2, 3, 4, E½W½, E½
Section 32: W½, W½W½SE¼, W½SW¼NE¼, SW¼NW¼NE¼

Township 139 North, Range 96 West
Section 5: Lots 1, 2, 3, 4, S½N½
Section 6: N½ of Lot 1, SE¼ of Lot 1, N½ of Lot 2, NE¼ of Lot 3

Stark County, North Dakota

CONOCO INC.
Case No. 5933
Exhibit No. 4

UNIT AGREEMENT

FOR THE DEVELOPMENT AND OPERATION

OF THE

DICKINSON LODGEPOLE UNIT

COUNTY OF STARK

STATE OF NORTH DAKOTA

[Statutory Unit formed pursuant to the North Dakota Century Code, Sections 38-08-09.1 through 38-08-09.16, as amended]

DATED THIS 15TH DAY OF APRIL, 1994

CONOCO INC.
Case No. 5933
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UNIT AGREEMENT

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UNIT AGREEMENT

Dickinson Lodgepole Unit

Stark County, North Dakota

THIS AGREEMENT, entered into as of the 15th day of April, 1994.

WITNESSETH:

WHEREAS, in the interest of the public welfare and to promote conservation and increase the ultimate recovery of Unitized Substances from the Dickinson Field, in Stark County, North Dakota, and to protect the rights of the owners of interests therein, it is deemed necessary and desirable to unitize the Oil and Gas Rights in and to the Unitized Formation in order to conduct Unit Operations as herein provided, pursuant to Sections 38-08-09.1 through 38-08-09.16 of the North Dakota Century Code.

NOW, THEREFORE, it is provided as follows:

ARTICLE 1

DEFINITIONS

As used in this Agreement:

1.1 **Unit Area** is the land identified by Tracts in Exhibit A and shown on Exhibit B, containing 1,436.45 acres, more or less.

1.2 **Unitized Formation** is the common source of supply of hydrocarbons underlying the Unit Area described as the Lodgepole Formation as defined by the North Dakota Industrial Commission, by Order #6607, being that accumulation of oil and gas found in the interval from below the base of the Mission Canyon Formation to above the top of the Bakken Formation.

1.3 **Unitized Substances** are all oil, gas, gaseous substances, sulphur contained in gas, condensate, distillate, and all associated and constituent substances other than Outside Substances within or produced from the Unitized Formation.

1.4 **Working Interest** is an interest in Unitized Substances by virtue of a lease, operating agreement, fee title or otherwise, including a carried interest, the owner of which is primarily obligated to pay, either in cash or out of production or otherwise, a portion of the Unit Expense; however, Oil and Gas Rights that are free of lease or other instrument creating a Working Interest shall be regarded as a Working Interest to the extent of seven-eighths (7/8) thereof and a Royalty Interest to the extent of the remaining one-eighth (1/8) thereof.

1.4a **Carved-out Interests**. Any overriding royalty, production payment, net proceeds interest, carried interest or any other interest carved out of a Working Interest.

1.5 **Royalty Interest** is a right to or interest in any portion of the Unitized Substances or proceeds thereof other than a Working Interest.

1.6 **Royalty Owner** is a Person who owns a Royalty Interest.

1.7 **Working Interest Owner** is a Person who owns a Working Interest.

1.8 **Tract** is the land identified as such and given a tract number in Exhibit A.

1.9 **Unit Operating Agreement** is the agreement having the same Effective Date as this Agreement, entitled "Unit Operating Agreement, Dickinson Lodgepole Unit, Stark County, North Dakota", and with this Agreement constitutes the Plan of Unitization.

1.10 **Unit Operator** is the Working Interest Owner designated by Working Interest Owners under the Unit Operating Agreement to conduct Unit Operations, acting as operator and not as a Working Interest Owner.

1.11 **Tract Participation** is the percentage shown on Exhibit A for allocating Unitized Substances to a Tract.

1.12 **Unit Participation** of a Working Interest Owner is the sum of the percentages obtained by multiplying the Working Interest of such Working Interest Owner in each Tract by the Tract Participation of such Tract.

1.13 **Outside Substances** are substances purchased or otherwise obtained for a consideration by Working Interest Owners and injected into the Unitized Formation.

1.14 **Oil and Gas Rights** are the rights to explore, develop, and operate lands within the Unit Area for the production of Unitized Substances, or to share in the production so obtained or the proceeds thereof.

1.15 **Unit Operations** are all operations conducted pursuant to this Agreement and the Unit Operating Agreement.

1.16 **Unit Equipment** is all personal property, lease and well equipment, plants, and other facilities and equipment taken over or otherwise acquired for the joint account for use in Unit Operations.

1.17 **Unit Expense** is all cost, expense, or indebtedness incurred by Working Interest Owners or Unit Operator pursuant to this Agreement and the Unit Operating Agreement for or on account of Unit Operations.

1.18 **Effective Date** is the time and date this Agreement becomes effective as provided in Article 15.

1.19 **Person** is any individual, corporation, partnership, association, receiver, trustee, curator, executor, administrator, guardian, tutor, fiduciary, or other representative of any kind, any department, agency, or instrumentality of the state, or any governmental subdivision thereof, or any other entity capable of holding an interest in the Unitized Formation.

1.20 **Phase I** means the period of time beginning on March 1, 1994 and continuing until 7:00 a.m. of the first day of the calendar month next following the date on which 4,876,363 barrels of oil have been produced, as determined from the oil production reports submitted by the Operator to the North Dakota State Industrial Commission.

1.21 **Phase II** means the period of time beginning after the end of Phase I and continuing for the remainder of the term of this Agreement.

1.22 **Natural Gas** shall mean methane and that portion of ethane contained in the Natural Gas after conventional mechanical lease separation.

1.23 **Liquified Petroleum Gases, or LPG,** shall mean propane, butane, isobutane, pentane and any ethane contained in any mix of such LPG.

1.24 **Liquid Hydrocarbons** shall mean all liquids contained in any raw or unprocessed stream of clear hydrocarbon liquids (condensate) that exist as a liquid at atmospheric pressure.

1.25 **Blow Down** shall mean that point in time when Outside Substances are no longer injected into the reservoir.

1.26 **Operating Committee** is the Working Interest Owners and the Unit Operator acting through their designated representatives. Where appropriate, reference in this agreement and the Unit Operating Agreement to collective action by the Working Interest Owners to supervise Unit Operations means action by the Operating Committee.

ARTICLE 2

EXHIBITS

2.1 **Exhibits.** The following exhibits, which are attached hereto, are incorporated herein by reference:

2.1.1 **Exhibit A** is a schedule that identifies each Tract in the Unit Area and shows its Tract Participation.

2.1.2 **Exhibit B** is a map or plat that shows the boundary lines of the Unit Area, the Tracts therein, and wells completed in the Unitized Formation.

2.2 **Reference to Exhibits.** When reference is made to an exhibit, it is to the original exhibit or, if revised, to the last revision.

2.3 **Exhibits Considered Correct.** Exhibits A and B shall be considered to be correct until revised as herein provided.

2.4 **Correcting Errors.** The shapes and descriptions of the respective Tracts have been established by using the best information available. If any Tract, because of diverse royalty or working interest ownership on the Effective Date, should have been divided into more than one Tract, or if any mechanical miscalculation or clerical error has been made, Unit Operator shall correct the mistake by revising the exhibits to conform to the facts. The revision shall not include any re-evaluation of engineering or geological interpretations used in determining Tract Participation. Each such revision of an exhibit made prior to thirty (30) days after the Effective Date shall be effective as of the Effective Date. Each such revision thereafter made shall be effective at 7:00 a.m. on the first day of the calendar month next following the filing for record of the revised exhibit or on such other date as may be determined by Working Interest Owners and set forth in the revised exhibit.

2.5 **Filing Revised Exhibits.** If an exhibit is revised, Unit Operator shall execute an appropriate instrument with the revised exhibit attached and file the same with the North Dakota Industrial Commission, and for record in any county or counties in which this Agreement is filed.

ARTICLE 3

CREATION AND EFFECT OF UNIT

3.1 **Oil and Gas Rights Unitized.** All Oil and Gas Rights of Royalty Owners in and to the lands identified in Exhibit A, and all Oil and Gas Rights of Working Interest Owners in and to said lands, are hereby unitized insofar as the respective Oil and Gas Rights pertain to the Unitized Formation, so that Unit Operations may be conducted with respect to the Unitized Formation as if the Unit Area had been included in a single lease executed by all Royalty Owners, as lessors, in favor of all Working Interest Owners, as lessees, and as if the lease contained all of the provisions of this Agreement.

3.2 **Statutory Unitization.** It is the intent of the Working Interest Owners to utilize the statutory unitization provisions of the North Dakota Century Code Sections 38-08-09.1 through 38-08-09.16, as amended, in the formation of this unit. When the Unit Operator receives the approval of the Unit Agreement and Unit Operating Agreement by Working Interest Owners owning a combined Phase I Unit Participation of at least seventy percent (70%) and a combined Phase II Unit Participation of at least seventy percent (70%), an application will be made to the North Dakota Industrial Commission for statutory unitization of the uncommitted interests. Upon approval of the Unit Agreement and the Unit Operating Agreement as a plan of unitization and operating plan and upon approval of statutory unitization by the order of the North Dakota Industrial Commission, all uncommitted lands and all Oil and Gas Rights of Royalty Owners and Working Interest Owners insofar as rights pertain to the Unitized Formation shall be deemed committed to the unit as if approved in writing by all the parties.

3.3 **Personal Property Excepted.** All lease and well equipment, materials, and other facilities heretofore or hereafter placed by any of the Working Interest Owners on the lands covered hereby shall be deemed to be and shall remain personal property belonging to and may be removed by Working Interest Owners. The rights and interests therein as among Working Interest Owners are set forth in the Unit Operating Agreement.

3.4 **Amendment of Leases and Other Agreements.** The provisions of the various leases, agreements, division and transfer orders, or other instruments pertaining to the respective Tracts or the production therefrom are amended to the extent necessary to make them conform to the provisions of this Agreement, but otherwise shall remain in effect.

3.5 **Continuation of Leases and Term Interests.** Except as provided by Section 38-08-09.9 of the North Dakota Century Code, production from any part of the Unitized Formation, except for the purpose of determining payments to Royalty Owners, which is further specifically provided for in this Agreement, or other Unit Operations, as contemplated by this Agreement, shall be considered as production from or operations upon each Tract, and such production or operations shall have the same effect under the terms of each lease or mineral or royalty interest grant as to all lands and formations covered thereby just as if there were production from or operations upon each Tract.

3.6 **Titles Unaffected by Unitization.** Nothing herein shall be construed to result in any transfer of title to Oil and Gas Rights.

3.7 **Injection Rights.** Working Interest Owners are hereby granted the right to inject into the Unitized Formation any substances in whatever amounts Working Interest Owners deem expedient for Unit Operations, together with the right to drill, use, and maintain injection wells in the Unit Area, and to use for injection purposes any nonproducing or abandoned wells or dry holes, and any producing wells completed in the Unitized Formation.

3.8 **Development Obligation.** Nothing herein shall relieve Working Interest Owners from any obligation to reasonably develop the lands and leases committed hereto.

3.9 **Enlargements.** The Unit Area may be enlarged at any time, with the approval of the North Dakota Industrial Commission, to include adjoining portions of the same common source of supply. In such enlargements there shall be no retroactive allocation or adjustment of Unit Expense or of interests in the Unitized Substances produced, or proceeds thereof; however, this limitation shall not prevent an adjustment of investment by reason of the enlargement. In addition, the revised Tract Participations of the respective Tracts included within the Unit Area prior to such enlargement shall remain in the same ratio one to another. Such enlargement shall be effected in the following manner:

(a) The Working Interest Owner or Owners of the Tract or Tracts proposed to be added to the Unit Area shall file an application therefor with Unit Operator requesting such enlargement.

(b) Unit Operator shall circulate a notice of the proposed enlargement to each Working Interest Owner in the Unit Area and in the Tract or Tracts proposed to be added to the Unit Area, setting out the basis for admission, the Tract Participation to be assigned to each Tract in the enlarged Unit Area and other pertinent data, all of which shall be agreed upon by the Working Interest Owners of the Tract or Tracts to be added prior to the circulation of such notice. If Working Interest Owners having in the aggregate at least seventy percent (70%) of the Unit Participation then in effect agree to the inclusion of such Tract or Tracts in the Unit Area on the terms proposed, the Unit Operator shall make application for approval by the North Dakota Industrial Commission in accordance with Section 38-08-09-9 of the North Dakota Century Code.

The enlargement shall become effective on the first day of the month following the approval of the enlargement by the North Dakota Industrial Commission or such other date as may be established by order of the Commission. The effective date of the enlargement shall be set out in the certificate of effectiveness, which shall be filed of record as set forth in Article 15 hereof.

ARTICLE 4

UNIT OPERATIONS

4.1 **Unit Operator.** Conoco Inc. is hereby designated as the initial Unit Operator. Unit Operator shall have the exclusive right to conduct Unit Operations, which shall conform to the provisions of this Agreement and the Unit Operating Agreement. If there is any conflict between such agreements, this Agreement shall govern.

4.2 **Resignation or Removal.** Unit Operator may resign at any time. Unit Operator may be removed at any time by the affirmative vote of Working Interest Owners having fifty-one percent (51%) or more of the voting interest. Such resignation or removal shall not become effective for a period of three (3) months after the resignation or removal, unless a successor Unit Operator has taken over Unit Operations prior to the expiration of such period.

4.3 **Selection of Successor.** Upon the resignation or removal of Unit Operator, a successor Unit Operator shall be selected by Working Interest Owners. If the removed Unit Operator fails to vote or votes only to succeed itself, the successor Unit Operator shall be selected by the affirmative vote of Working Interest Owners having seventy percent (70%) or more of the voting interest remaining after excluding the voting interest of the removed Unit Operator.

4.4 **Method of Operation.** To the end that the quantity of Unitized Substances ultimately recoverable may be increased and waste prevented, Working Interest Owners shall, with diligence and in accordance with good engineering and production practices, engage in a water injection program and/or other future enhanced oil recovery programs designed for improved economic oil recovery.

4.5 **Change of Method of Operation.** Nothing herein shall prevent Working Interest Owners from discontinuing or changing in whole or in part any method of operation which, in their opinion, is no longer in accord with good engineering and production practices.

ARTICLE 5

TRACT PARTICIPATIONS

5.1 **Tract Participations.** The Tract Participation of each Tract is shown in Exhibit A. Beginning at 7:00 a.m. on the Effective Date hereof and continuing during the term hereof, all Unitized Substances shall be allocated on the basis of Tract Participation as shown in Exhibit A, determined under the following formula:

PHASE I - 50% Remaining Primary Recovery as of March 1, 1994.
- 50% Remaining Original Oil in Place as of March 1, 1994.

PHASE II - 100% Original Oil in Place at the Initial Reservoir Pressure of 4536 psia.

5.2 **Relative Tract Participations.** If the Unit Area is changed, the revised Tract Participations of the Tracts in the Unit Area and which were within the Unit Area prior to the change shall remain in the same ratio one to another.

ARTICLE 6

ALLOCATION OF UNITIZED SUBSTANCES

6.1 **Allocation to Tracts.** All Unitized Substances produced and saved shall be allocated to the several Tracts in accordance with the respective Tract Participations effective hereunder during the respective period that the Unitized Substances were produced. The amount of Unitized Substances allocated to each Tract, regardless of whether the amount is more or less than the actual production of Unitized Substances from the well or wells, if any, on such Tract, shall be deemed for all purposes to have been produced from such Tract.

6.2 Distribution Within Tracts. The Unitized Substances allocated to each Tract shall be distributed among, or accounted for to, the Persons entitled to share in the production from such Tract in the same manner, in the same proportions, and upon the same conditions as they would have participated and shared in the production from such Tract, or in the proceeds thereof, had this Agreement not been entered into, and with the same legal effect. If any Oil and Gas Rights in a Tract hereafter become divided and owned in severalty as to different parts of the Tract, the owners of the divided interests, in the absence of an agreement providing for a different division, shall share in the Unitized Substances allocated to the Tract, or in the proceeds thereof, in proportion to the surface acreage of their respective parts of the Tract. Any royalty or other payment which depends upon per well production or pipeline runs from a well or wells on a Tract shall, after the Effective Date, be determined by dividing the Unitized Substances allocated to the Tract by the number of wells on the Tract capable of producing Unitized Substances on the Effective Date; however, if any Tract has no well thereon capable of producing Unitized Substances on the Effective Date, the Tract shall, for the purpose of this determination, be deemed to have one such well thereon.

6.3 Taking Unitized Substances in Kind. The Unitized Substances allocated to each Tract shall be delivered in kind to the respective Persons entitled thereto by virtue of the ownership of Oil and Gas Rights therein or by purchase from such owners. Such Persons shall have the right to construct, maintain, and operate within the Unit Area all necessary facilities for that purpose, provided they are so constructed, maintained, and operated as not to interfere with Unit Operations. Any extra expenditures incurred by Unit Operator by reason of the delivery in kind of any portion of Unitized Substances shall be borne by the owner of such portion. If a Royalty Owner has the right to take in kind a share of Unitized Substances and fails to do so, the Working Interest Owner whose Working Interest is subject to such Royalty Interest shall be entitled to take in kind such share of Unitized Substances.

6.4 **Failure to Take in Kind.** If any Person fails to take in kind or separately dispose of such Person's share of Unitized Substances, Unit Operator shall have the right, but not the obligation, for the time being and subject to revocation at will by the Person owning the share, to purchase or sell to others such share; however, all contracts of sale by Unit Operator of any other Person's share of Unitized Substances shall be only for such reasonable periods of time as are consistent with the minimum needs of the industry under the circumstances, but in no event shall any such contract be for a period in excess of one year. The proceeds of the Unitized Substances so disposed of by Unit Operator shall be paid to the Working Interest Owners of each affected Tract or a Person designated by such Working Interest Owners who shall distribute such proceeds to the Persons entitled thereto.

6.5 **Responsibility for Royalty Settlements.** Any Person receiving in kind or separately disposing of all or part of the Unitized Substances allocated to any Tract shall be responsible for the payment of all royalties, overriding royalties, production payments, and all other payments chargeable against or payable out of such Unitized Substances, and shall indemnify all Persons, including Unit Operator, against any liability for such payment.

6.6 **Rental or Minimum Royalty Settlement.** Rental or minimum royalties due on leases committed hereto shall be paid by Working Interest Owners responsible therefor under existing contracts, laws, and regulations, provided that nothing herein contained shall operate to relieve the lessees of any land from their respective lease obligations for the payment of any rental or minimum royalty in lieu thereof due under their leases.

6.7 **Royalty on Outside Substances.** No payment shall be due or payable to any Royalty Owner, and no production, severance, or other tax will be payable to any taxing authority on Outside Substances injected into the Unitized Formation, and subsequently produced or sold with the Unitized Substances.

If Natural Gas is injected into the Unitized Formation as an Outside Substance, one hundred percent (100%) of the Natural Gas contained in Unitized Substances subsequently produced and sold, or used for other than Unit Operations, shall be deemed an Outside Substance until the total volume of Natural Gas deemed to be an Outside Substance equals the total volume of Natural Gas injected as an Outside Substance. If LPG or Liquid Hydrocarbons are injected into the Unitized Formation as an Outside Substance (either separately or mixed with Natural Gas), one hundred percent (100%) of all Unitized Substances other than Natural Gas subsequently produced, sold, or used for purposes other than Unit Operations, shall be deemed an Outside Substance until the total volume of such production of the LPG or Liquid Hydrocarbons injected as an Outside Substance. If more than one Outside Substance is injected into the Unitized Formation, each Outside Substance will be treated separately under this provision and the recovery percentages stated above will apply cumulatively.

The Unit Operator will account monthly for each Outside Substance injected into and produced from the Unitized Formation. In any accounting month, if the quantity of an Outside Substance injected into the Unitized Formation exceeds the quantity of the like substance produced from the Unitized Formation and deemed to be an Outside Substance, the difference in these quantities will be carried over to succeeding accounting months until the total quantity of the Outside Substance injected into the Unitized Formation has been recovered. If Natural Gas produced from the Unitized Formation is processed in a plant in the vicinity of the unit for the purpose of separating Natural Gas from LPG or Liquid Hydrocarbons, then the amount of Natural Gas, LPG and Liquid Hydrocarbons recovered by such processing and allocated to the unit will be the basis for accounting for Outside Substances under this provision.

6.8 Carved Out Interests. Those leasehold interest owners whose leases are subject to any Carved Out Interests shall bear the burden of payment for said interests in the proportion in which they have contributed said leases to the Unit Area.

ARTICLE 7

PRODUCTION AS OF THE EFFECTIVE DATE

7.1 **Oil or Liquid Hydrocarbons in Lease Tanks.** Unit Operator shall gauge or otherwise determine the amount of merchantable oil or other liquid hydrocarbons produced from the Unitized Formation that are in lease tanks as of 7:00 a.m. on the Effective Date. Oil or other liquid hydrocarbons in oil sale tanks below pipeline connections and in treating vessels and separation equipment shall not be considered merchantable. Any such merchantable oil or other liquid hydrocarbons not promptly removed may be sold by Unit Operator for the account of the Working Interest Owners entitled thereto who shall pay royalty due thereon under the provisions of applicable leases or other contracts. Any oil or liquid hydrocarbons in excess of that attributable to the prior allowable of the wells from which they were produced shall be credited to all Tracts as if they were Unitized Substances.

ARTICLE 8

USE OR LOSS OF UNITIZED SUBSTANCES

8.1 **Use of Unitized Substances.** Working Interest Owners may use or consume Unitized Substances for Unit Operations, including but not limited to the injection thereof into the Unitized Formation.

8.2 **Royalty Payments.** No royalty, overriding royalty, production, or other payments shall be payable on account of Unitized Substances used, lost, or consumed in Unit Operations.

8.3 **Storage of Unitized Substances.** The Working Interest Owners are hereby granted the right to inject Unitized Substances and Outside Substances into the Unitized Formation for storage. Unitized Substances so injected shall be excluded in allocating Unitized Substances to Tracts, and no royalty or other payment shall be payable in respect thereof until they are recovered from the Unitized Formation and sold or used for operations other than operations hereunder.

ARTICLE 9

TITLES

9.1 **Warranty and Indemnity.** Each Person who, by acceptance of produced Unitized Substances or the proceeds thereof, may claim to own a Working Interest or Royalty Interest in and to any Tract or in the Unitized Substances allocated thereto, shall be deemed to have warranted its title to such interest, and, upon receipt of the Unitized Substances or the proceeds thereof to the credit of such interest, shall indemnify and hold harmless all other Persons in interest from any loss due to failure, in whole or in part, of its title to any such interest.

9.2 **Production Where Title is in Dispute.** If the title or right of any Person claiming the right to receive in kind all or any portion of the Unitized Substances allocated to a Tract is in dispute, Unit Operator at the direction of Working Interest Owners shall either:

(a) require that the Person to whom such Unitized Substances are delivered or to whom the proceeds thereof are paid furnish security for the proper accounting therefor to the rightful owner if the title or right of such Person fails in whole or in part, or

(b) withhold and market the portion of Unitized Substances with respect to which title or right is in dispute, and impound the proceeds thereof until such time as the title or right thereto is established by a final judgment of a court of competent jurisdiction or otherwise to the satisfaction of Working Interest Owners, whereupon the proceeds so impounded shall be paid to the Person rightfully entitled thereto.

9.3 **Payment of Taxes to Protect Title.** If any taxes are not paid when due by or for any owner of surface rights to lands within the Unit Area, or severed mineral interests or Royalty Interests in such lands, or lands outside the Unit Area on which Unit Equipment is located, Unit Operator may, with approval of Working Interest Owners, at any time prior to tax sale, or expiration of period of redemption after tax sale, pay the tax and redeem or purchase such rights, interests, or property. Any such payment shall be an item of Unit Expense. Unit Operator shall, if possible, withhold from any proceeds derived from the sale of Unitized Substances otherwise due any delinquent taxpayer an amount sufficient to defray the costs of such payment, such withholding to be credited to Working Interest Owners. Such withholding shall be without prejudice to any other remedy available to Unit Operator or Working Interest Owners.

9.4 **Transfer of Title.** Any conveyance of all or any part of any interest owned by a Person with respect to any Tract shall be subject to this Agreement. No change of title shall be binding upon Unit Operator, or upon any Person other than the Person so transferring, until 7:00 a.m. on the first day of the calendar month next succeeding the date of receipt by Unit Operator of a photocopy or a certified copy of the recorded instrument evidencing such change in ownership.

ARTICLE 10

EASEMENTS OR USE OF SURFACE

10.1 **Grant of Easements.** Working Interest Owners shall have the right to use as much of the surface of the land within the Unit Area as may be reasonably necessary for Unit Operations and the removal of Unitized Substances from the Unit Area.

10.2 **Use of Water.** Working Interest Owners shall have and are hereby granted free use of water from the Unit Area for Unit Operations, except water from any well, lake, pond, or irrigation ditch of a Royalty Owner.

10.3 **Surface Damages.** Working Interest Owners shall pay the owner for damages to growing crops, timber, fences, improvements, and structures on the Unit Area that result from Unit Operations in accordance with the provisions of Chapter 38-11.1 of the North Dakota Century Code.

ARTICLE 11

CHANGES AND AMENDMENTS

11.1 **Changes and Amendments.** Any change of the Unit Area or any amendment to this Agreement or the Unit Operating Agreement shall be in accordance with Section 38-08-09.1 through 38-08-09.16 of the North Dakota Century Code.

ARTICLE 12

RELATIONSHIPS OF PERSONS

12.1 **No Partnership.** All duties, obligations, and liabilities arising hereunder shall be several and not joint or collective. This Agreement shall not be construed to create an association or trust, or to impose a partnership or fiduciary duty, obligation, or liability. Each Person affected hereby shall be individually responsible for its own obligations.

12.2 **No Joint Refining or Marketing.** This Agreement shall not be construed to provide, directly or indirectly, for any joint refining or marketing of Unitized Substances.

12.3 **Royalty Owners Free of Costs.** This Agreement shall not be construed to impose upon any Royalty Owner any obligation to pay Unit Expense unless such Royalty Owner is otherwise so obligated; provided, however, that any interest created out of a Working Interest, shall be subject to the security rights provided by the Unit Operating Agreement. The owner of any such interest shall be subrogated to the security rights available against the Working Interest out of which such interest was created.

ARTICLE 13

BORDER AGREEMENTS

13.1 **Border Agreements.** Unit Operator, subject to the provisions of the Unit Operating Agreement may enter into an agreement or agreements with the working interest owners of adjacent lands with respect to operations and allocation of production, which agreements are designed to increase the ultimate recovery of oil and/or gas from the Unitized Formation, prevent waste, and protect the correlative rights of the parties.

ARTICLE 14

FORCE MAJEURE

14.1 **Force Majeure.** All obligations arising hereunder, except for the payment of money, shall be suspended while compliance is prevented, in whole or in part, by a labor dispute, fire, war, civil disturbance, act of God; by Federal, state, or municipal laws; by any rule, regulations, or order of a governmental agency; by inability to secure materials; or by any other cause or causes, whether similar or dissimilar, beyond reasonable control of the Person. No Person shall be required against his will to adjust or settle any labor dispute. Neither this Agreement nor any lease or other instrument subject hereto shall be terminated by reason of suspension of Unit Operations due to any one or more of the causes set forth in this Article.

ARTICLE 15

EFFECTIVE DATE

15.1 **Effective Date.** This Agreement shall become effective as of the date determined by Working Interest Owners in accordance with the voting provisions of the Unit Operating Agreement. Such determination by Working Interest Owners shall be made in accordance with an order approving this Unit by the North Dakota State Industrial Commission.

15.2 **Ipso Facto Termination.** If this unit is not made effective on or before January 1, 1995, this Agreement shall ipso facto terminate on that date (hereinafter called "termination date") and thereafter be of no further effect, unless prior thereto Working Interest Owners owning a combined Unit Participation of at least seventy percent (70%) have approved this Agreement and Working Interest Owners owning seventy percent (70%) or more of that percent have decided to extend the termination date for a period not to exceed twelve (12) months. If the termination date is so extended and this unit is not made effective on or before the extended termination date, this Agreement shall ipso facto terminate on the extended termination date and thereafter be of no further effect. For the purpose of this Section, Unit Participation shall be as calculated on the basis of Tract Participations for Phase I shown on the original Exhibit A.

15.3 **Certificate of Effectiveness.** Unit Operator shall file with the North Dakota State Industrial Commission and for record in the county or counties in which the land affected is located a certificate stating the Effective Date.

ARTICLE 16

TERM

16.1 **Term.** Except as provided in Section 38-08-09.4(7) of the North Dakota Century Code, this Agreement shall remain in effect so long as Unitized Substances are produced in paying quantities without a cessation of more than ninety (90) days, or so long as other Unit Operations are conducted without a cessation of more than ninety (90) days, unless sooner terminated by Working Interest Owners owning a combined Unit Participation, in effect at the time of voting, of seventy percent (70%) or more whenever such Working Interest Owners determine that Unit Operations are no longer economically feasible.

16.2 **Effect of Termination.** Upon termination of this Agreement, the further development and operation of the Unitized Formation as a unit shall cease. The relationships among owners of Oil and Gas Rights shall thereafter be governed by the terms and provisions of the leases and other instruments, not including this Agreement, affecting the separate Tracts.

16.3 **Salvaging Equipment Upon Termination.** If not otherwise granted by the leases or other instruments affecting the separate Tracts, Working Interest Owners shall have a period of six (6) months after the date of termination of this Agreement within which to salvage and remove Unit Equipment.

16.4 **Certificate of Termination.** Upon termination of this Agreement, Unit Operator shall file with the North Dakota State Industrial Commission and for record in the county or counties in which the land affected is located a certificate that this Agreement has terminated, stating its termination date.

ARTICLE 17

APPROVAL

17.1 **Original, Counterpart, or Other Instrument.** A Working Interest Owner or a Royalty Owner of Oil and Gas Rights may approve this Agreement by signing the original, a counterpart thereof, or other instrument approving this Agreement. The signing of any such instrument shall have the same effect as if all Persons had signed the same instrument and shall constitute approval of the entire Plan of Unitization composed of this Agreement and the Unit Operating Agreement.

17.2 **Commitment of Interests to Unit.** The approval of this Agreement by a Person shall bind that Person and commit all interests owned or controlled by that Person as of the date of such approval, and additional interests thereafter acquired.

ARTICLE 18

DETERMINATIONS BY WORKING INTEREST OWNERS

18.1 **Determinations by Working Interest Owners.** All decisions, determinations, or approvals by Working Interest Owners hereunder shall be made pursuant to the voting procedure of the Unit Operating Agreement unless otherwise provided herein.

ARTICLE 19

SUCCESSORS AND ASSIGNS

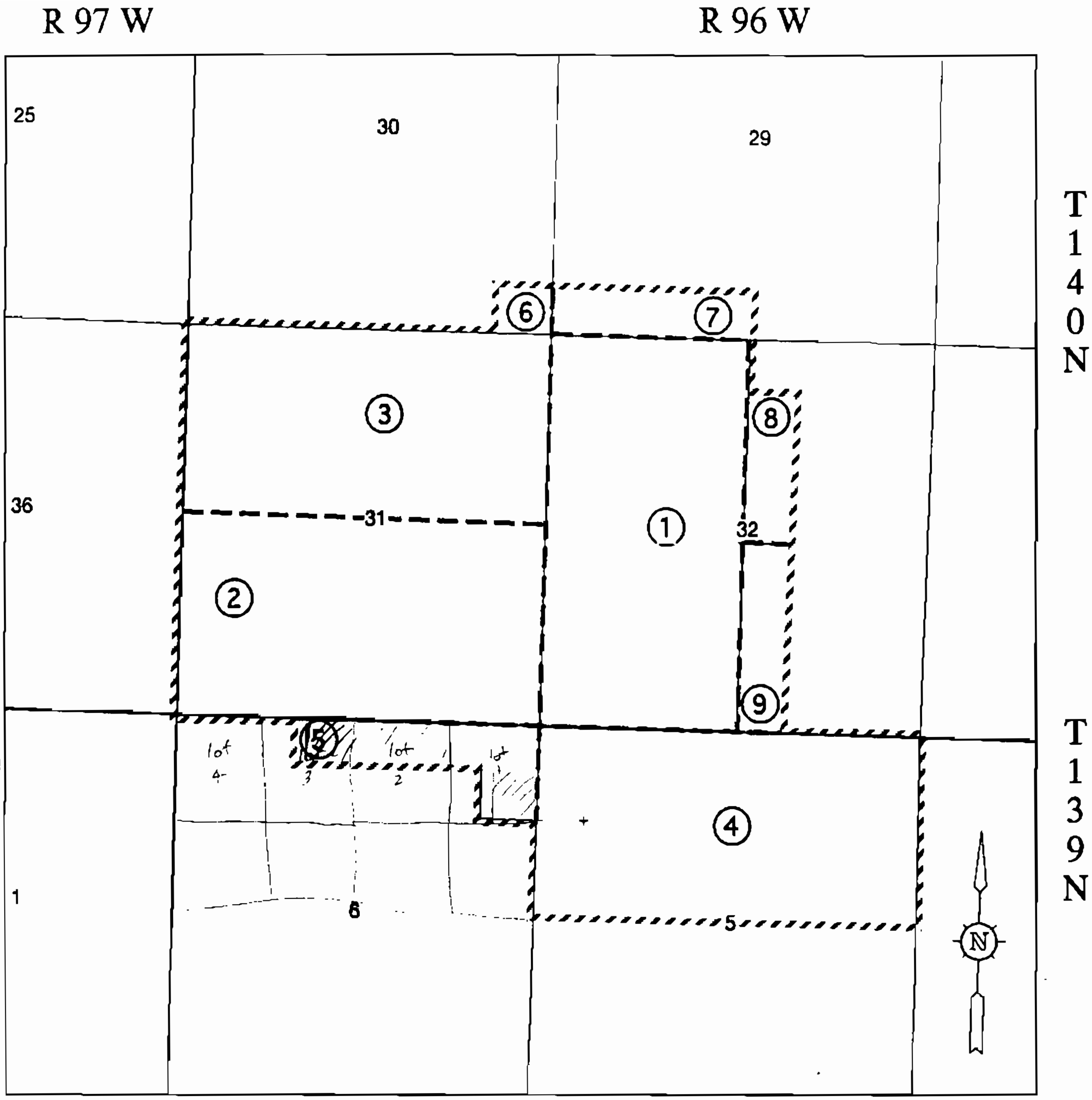
19.1 **Successors and Assigns.** This Agreement shall extend to, be binding upon, and inure to the benefit of the Royalty Owners and Working Interest Owners and their respective heirs, devisees, legal representatives, successors, and assigns, and shall constitute a covenant running with the lands, leases, and interests covered hereby.

IN WITNESS WHEREOF, the Persons hereto have approved this Agreement on the dates opposite their respective signatures.

Date of Execution:
April 15, 1994

CONOCO INC.

By: Roger B. Brown
Roger B. Brown
Division Manager
Attorney-in-Fact



TRACT	ACRES
1	320.00
2	308.49
3	303.65
4	323.78
5	60.27
6	10.01
7	40.15
8	30.06
9	40.04
TOTAL	1436.45

Unit Boundary

Tract Boundary

1 Tract No.

Scale 1000'

DICKINSON LODGEPOLE UNIT

Stark Co., North Dakota

CONOCO INC.
Case No. 5933
Exhibit No. 3

04/21/94

Exhibit A to Unit Agreement
dated April 15, 1994

DICKINSON LODGEPOLE UNIT
STARK COUNTY, NORTH DAKOTA

Tract No.	Description & Acres in Tract	Working Interest Owner & Percentage		Net Acres	Mineral Owner & Percentage		Overriding Royalty Owner & Percentage		PHASE I TRACT PERCENTAGE	PHASE II TRACT PERCENTAGE
1	W½ – Sec. 32 – T140N – R96W	Conoco Inc	100.000%	320.000	J. H. Smart Jr.	3.12500%	Torch Oil & Gas Company	0.46875%	50.12991%	50.35218%
	320.000 acres		100.000%	320.000	Peggy Addington	6.25000%	Louis W. Hill Jr.	0.15381%		
					The Wiser Oil Company	0.97656%	Mobil Exploration & Production	1.87500%		
					Beeman Dockery	1.79688%	Phillips Petroleum	1.84326%		
					The Fasken Foundation	0.15625%		4.34082%		
					Agribank FCB	25.00000%				
					Republic Royalty Company	2.32187%				
					Louis W. Hill Jr.	5.66406%				
					Erma Lowe Trust for Carson Yost, Mary Ralph Lowe Trustee	0.01118%				
					Clark E. Jones	0.31250%				
					Clyde W. Jones	0.78125%				
					Dodge Jones FDN	0.24272%				
					Linda R. Jones a/k/a Linda R. Branting	0.78125%				
					Gerald David Kalanek	12.50000%				
					Darlene McKinley Lane	3.12500%				
					Martha Smart Bennett	3.12500%				
					Julia Jones Matthews	0.05283%				
					Hunter S. Trust	1.56250%				
					J. Hiram Moore, Betty Jane Moore & Michael H. Moore Trust U/I/TR dated 7/1/71	3.35938%				
					Matt-Tex L.P.	0.07500%				
					Pacific West Lease Company	0.78125%				
					Randy Geiselman	0.05625%				
					Baytech Inc.	0.12500%				
					Mary Margarett Pugh	2.34375%				
					Zula Mae Pugh	0.31250%				
					E. E. & Mildred E. Trumbell as Joint Tenants	3.12500%				
					Mary Pearl Lake	3.12500%				
					Leslie J. May	1.56250%				
					Virginia L. Sherron	6.25000%				
					John A. Matthews Jr	0.03750%				
					Fayette K. Stroud MD, Trustee FBO C & F Stroud Trust Fund JT U/D/T dated 12/18/73	0.46875%				
					Andrews Royalty Inc.	0.02313%				
					Erma Lowe Trust for Clayton Yost, Mary Ralph Lowe, Trustee	0.01118%				
					Erma Lowe Trust for Samantha Yost, Mary Ralph Lowe, Trustee	0.01118%				
					Elizabeth H. Welch	3.12500%				
					Conoco Inc	7.42188%				
						100.00000%				

04/21/94

Exhibit A to Unit Agreement dated April 15, 1994

DICKINSON LODGEPOLE UNIT
STARK COUNTY, NORTH DAKOTA

Tract No.	Description & Acres in Tract	Working Interest Owner & Percentage		Net Acres	Mineral Owner & Percentage		Overriding Royalty Owner & Percentage		PHASE I TRACT PERCENTAGE	PHASE II TRACT PERCENTAGE
2	S½ - Sec 31 - T140N - R96W	Andrea Singer Pollack Revocable Trust	50.00000%	154.245	The Wiser Oil Company	25.00000%	Andrea Singer Pollack Revocable Trust	12.50000%	33.16362%	31.78581%
	308.49 acres	Conoco Inc.	50.00000%	154.245	The Fasken Foundation	1.24854%		12.50000%		
			100.00000%	308.490	Republic Royalty Company	18.57500%				
					Erma Lowe Trust for Carson Yost, Mary Ralph Lowe, Trustee	0.09187%				
					Dodge Jones FDN	1.94172%				
					Douglas Kadrmas	12.50000%				
					Arnold E. Kadrmas	12.50000%				
					Linda Kadrmas	12.50000%				
					Julia Jones Matthews	0.12266%				
					Matt-Tex L.L.P	0.60151%				
					Randy Geiselman	0.15000%				
					Baytech Inc	1.00000%				
					Joan Schmidt	12.50000%				
					John A. Matthews Jr	0.29991%				
					Andrews Royalty Inc.	0.18500%				
					Erma Lowe Trust for Clayton Yost, Mary Ralph Lowe, Trustee	0.09187%				
					Erma Lowe Trust for Samantha Yost, Mary Ralph Lowe, Trustee	0.09187%				
						100.00000%				
3	N½ - Sec 31 - T140N - R96W	The Wiser Oil Company	1.74958%	5.313	The Wiser Oil Company	11.79315%			12.36359%	11.64830%
	303.65 acres	Louis W. Hill Jr	4.13910%	12.568	Patricia & William Dowell	1.91818%				
		Hunt Petroleum Company	8.40336%	25.517	Agribank FCB	50.00000%				
		Huntington Resources Inc	4.72689%	14.353	Mary Ann & Edwin A. Feck	1.94818%				
		Placid Oil Company	32.14286%	97.602	John M. Grinde Trust William J. Grinde, Trustee	2.24664%				
		Phillips Petroleum Company	4.38126%	13.304	Lester & Marlene Frenzel	1.94818%				
		Conoco Inc. **	44.45605%	134.994	Rose Frenzel	12.41275%				
			100.00000%	303.650	Irene & Karl Hammann	1.94818%				
					Louis W. Hill, Jr	8.23316%				
					Clyde W. Jones	0.82237%				
					Linda R. Jones, a/k/a Linda R. Branting	0.82237%				
					Paul Karow	0.11933%				
					Diane & Kenneth Mayer	1.91818%				
					Conoco Inc	0.44933%				
						100.00000%				

**BPO

04/21/94

Exhibit A to Unit Agreement dated April 15, 1994

DICKINSON LODGEPOLE UNIT
STARK COUNTY, NORTH DAKOTA

Tract No.	Description & Acres in Tract	Working Interest Owner & Percentage		Net Acres	Mineral Owner & Percentage		Overriding Royalty Owner & Percentage	PHASE I TRACT PERCENTAGE	PHASE II TRACT PERCENTAGE
4	N½ – Sec. 5 – T139N – R96W	Conoco Inc	100.00000%	323.780	State of North Dakota	100.00000%		2.23917%	2.11507%
	323.780 acres		100.00000%	323.780		100.00000%			
5	N½ – Sec 6 – T139N – R96W	Conoco Inc	3.633393%	2.190	Victor B. Walton	25.00000%		0.816555%	1.649333%
	60.270 acres	A R S Limited Partnership	96.366607%	58.080	Robert R. Walton	12.50000%			
			100.00000%	60.270	Dr. William H. Walton, Jr	12.50000%			
					Shirley Jean Larkin	12.50000%			
					Julia Reynolds	6.25000%			
					Elizabeth Bowers	6.25000%			
					Benjamin Deeble	6.25000%			
					James W. Hoffman	3.12500%			
					John A. Hoffman	3.12500%			
					David L. Hoffman	3.12500%			
					William R. Hoffman	3.12500%			
					Victoria Risner	6.25000%			
						100.00000%			
6	SE¼ – Sec 30 – T140N – R96W	Conoco Inc	50.00000%	5.005	Laudie L. Ridl	10.00000%		0.01840%	0.03583%
	10.010 acres	Placid Oil Company	32.11286%	3.218	Irene Ridl Wilson	10.00000%			
		Louisiana – Hunt Petroleum	8.40336%	0.841	Angie Ridl Kadrmas	10.00000%			
		Mid – Continent Energy Investors	4.72689%	0.473	Arthur J. Ridl	10.00000%			
		Huntington Resources Inc	4.72689%	0.473	Blanche Ridl Mack	10.00000%			
			100.00000%	10.010	Agribank FCB	50.00000%			
						100.00000%			

04/21/94

Exhibit A to Unit Agreement dated April 15, 1994

DICKINSON LODGEPOLE UNIT
STARK COUNTY, NORTH DAKOTA

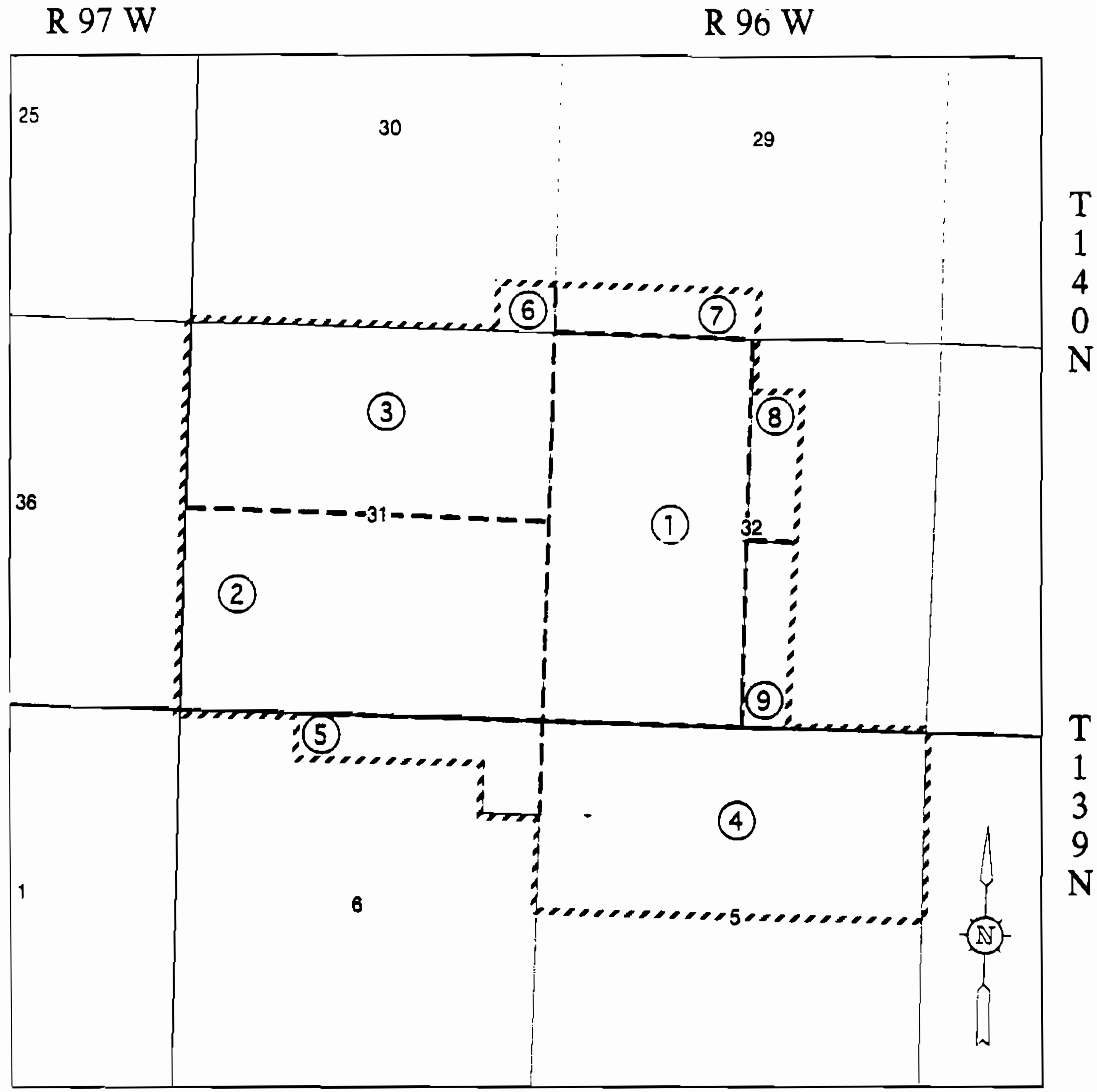
Tract No.	Description & Acres in Tract	Working Interest Owner & Percentage		Net Acres	Mineral Owner & Percentage		Overriding Royalty Owner & Percentage		PHASE I TRACT PERCENTAGE	PHASE II TRACT PERCENTAGE
7	SW¼ – Sec. 29 – T140N – R96W	Phillips Petroleum Company	25.00000%	10.038	E. E. Trumbull	6.25000%			0.32677%	0.63664%
	40.150 acres	Conoco Inc.	25.00000%	10.038	Darlene McKinley Lane	6.25000%				
		Mobil Exploration & Producing NA	50.00000%	20.075	Mary Margaret Pugh	4.68750%				
			100.00000%	40.150	Elizabeth H. Welch	6.25000%				
					Virginia L. Sherron	12.50000%				
					Mary Pearl Lake	6.25000%				
					Beeman Dockery	3.59375%				
					Zula Mae Pugh	0.62500%				
					C & F Stroud Trust – Fund JT UDT, Fayette K. Stroud, M.D., Trustee FBO	0.93750%				
					Clark E. Jones	0.62500%				
					Pacific West Lease Company	1.56250%				
					I. Hiram Moore, Betty Jane Moore and Michael Harrison Moore, Trustees	6.71875%				
					Gerald David Kalanek	8.55556%				
					Vivian Miller	9.72222%				
					Mary Daphne Hibl	9.72222%				
					Hunter S. Tronk	3.12500%				
					Leslie J. May	3.12500%				
					Peggy Addington	12.50000%				
						100.00000%				
8	NE¼ – Sec. 32 – T140N – R96W	Ruth Ray Hunt	1.25000%	0.376	Barbara M. Comeau	1.25000%	R. F. & Mildred Moore **	1.00000%	0.31141%	0.80156%
	30.060 acres	Unit Four Partnership	0.20833%	0.063	Cynthia A. Comeau	1.25000%	TWR, Inc. **	1.00000%		
		Petro-Hunt Corporation	0.20833%	0.063	I. Hiram Moore, Betty Jane Moore and Michael Harrison Moore, Trustees	7.29169%		2.00000%		
		Hunt Oil Company	0.83333%	0.251						
		Phillips Petroleum Company	62.50000%	18.788	Dewitt Landis Jr.	0.52085%	** The above ORRI burdens the Phillips Petroleum WI only			
		North American Royalties Inc	9.01957%	2.711	Charles Landis	0.52085%				
		Louis W. Hill Jr.	8.11625%	2.440	Gerald C. Wiseman	0.26041%				
		Conoco Inc	16.19752%	4.869	Marilyn Kay Ralstin	0.26041%				
		The Wiser Oil Company	1.66667%	0.501	J. R. & Katherine A. Taylor	0.52081%				
			100.00000%	30.060	Viola L. & Virginia Younger	1.04169%				
					Janice S. Haffey	0.52081%				
					Elaine G. Konzelman	0.52081%				
					Johnnie Beth Huskey	1.04169%				
					Conoco Inc	3.75000%				
					Mary H. Ayala	3.75000%				
					Lou Eby Budhill	1.16669%				
					The Wiser Oil Company	6.66669%				
					Stephen Filips	62.50000%				
					Charles Taubman Revocable Trust	0.61406%				
					Henrik Perry Taubman Family Trust	0.01619%				
					Adina Taubman Tr	0.01619%				

Exhibit A to Unit Agreement dated April 15, 1994

DICKINSON LODGEPOLE UNIT
STARK COUNTY, NORTH DAKOTA

Tract No.	Description & Acres in Tract	Working Interest Owner & Percentage		Net Acres	Mineral Owner & Percentage		Overriding Royalty Owner & Percentage	PHASE I TRACT PERCENTAGE	PHASE II TRACT PERCENTAGE
8	NE¼ – Sec. 32 – T140N – R96W				Louis Taubman Trust	0.78575%			
	30.060 acres				L. N. Taubman Revocable Trust	0.05575%			
	(continued)				Bank of Oklahoma, Tulsa, Maurine Taubman Co–Trustee certain Trust dated 12/4/86	0.05575%			
					Herman P. & Sophia Taubman	0.00606%			
					National Bank Tulsa, Trustee, Trust Indenture dated 11/12/69	0.56150%			
					Estate of William David Taubman	0.00725%			
					Barbara Taubman Living Trust	0.01156%			
					Deborah Anne Taubman Trust	0.00725%			
					Hilary Lu Taubman Revocable Trust	0.00725%			
					Andrea Taubman Quijano Revocable Trust	0.00731%			
					Rebecca M. Taubman Revocable Trust	0.00725%			
					Claudia P. Taubman Revocable Trust	0.00725%			
					Robert M. Taubman Revocable Trust	0.55425%			
					Sara K. Taubman Revocable Trust	0.00731%			
					Rosalie Taubman Management Trust	0.17425%			
					Karen P. Shalom Management Trust	0.02906%			
					Jonathan Z. Shalom Management Trust	0.02906%			
					Morris B. Taubman Revocable Trust	0.81238%			
					Anne C. Taubman Trust	0.04119%			
					Janice L. Taubman Revocable Trust	0.00850%			
					Richard J. Taubman Trust	0.04119%			
						100.00000%			
9	SE¼ Sec. 32 – T140N – R96W	Conoco Inc	100.00000%	40.040	State of North Dakota	100.00000%		0.50058%	0.97527%
	40.040 acres		100.00000%	40.040		100.00000%			
							TOTAL:	100.00000%	100.00000%

EXHIBIT "B
to Unit Agreement Dated April 15, 1994



Unit Boundary
Tract Boundary
(1) Tract No.

Scale
1000'

TRACT	ACRES
1	320.00
2	308.49
3	303.65
4	323.78
5	60.27
6	10.01
7	40.15
8	30.06
9	40.04
TOTAL	1436.45

DICKINSON LODGEPOLE UNIT
Stark Co., North Dakota

UNIT OPERATING AGREEMENT

FOR THE DEVELOPMENT AND OPERATION

OF THE

DICKINSON LODGEPOLE UNIT

COUNTY OF STARK

STATE OF NORTH DAKOTA

[Statutory Unit formed pursuant to the North Dakota Century Code, Sections 38-08-09.1 through 38-08-09.16, as amended]

DATED THIS 15TH DAY OF APRIL, 1994

CONOCO INC.

Case No. 5933
Exhibit No. 6

UNIT OPERATING AGREEMENT

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Exhibit "A" and "B" of this Unit Operating Agreement
are Exhibits "A" and "B" of the Unit Agreement
and will be incorporated by reference.

04/21/94

Exhibit C to Unit Operating Agreement
dated April 15, 1994

DICKINSON LODGEPOLE UNIT
STARK COUNTY, NORTH DAKOTA

WORKING INTEREST OWNER	TRACT	PARTICIPATION PERCENTAGE OF TRACT IN UNIT		PERCENTAGE OF WORKING INTEREST IN THE TRACT	PARTICIPATION % OF TRACT IN UNIT MULTIPLIED BY % WORKING INTEREST IN TRACT		WORKING INTEREST OWNER UNIT PARTICIPATION %	
		PHASE I	PHASE II		PHASE I	PHASE II	PHASE I	PHASE II
Andrea Singer Pollack Trust	2	33.16362%	31.78581%	50.00000%	16.58181%	15.89291%	16.58181%	15.89291%
					16.58181%	15.89291%		
ARS Limited Partnership	5	0.84655%	1.64933%	96.36607%	0.81579%	1.58939%	0.81579%	1.58939%
					0.81579%	1.58939%		
Conoco Inc.	1	50.12991%	50.35218%	100.00000%	50.12991%	50.35218%	75.13624%	74.88075%
	2	33.16362%	31.78581%	50.00000%	16.58181%	15.89291%		
	3	12.36359%	11.64830%	44.45695%	5.49648%	5.17848%		
	4	2.23917%	2.11507%	100.00000%	2.23917%	2.11507%		
	5	0.84655%	1.64933%	3.63393%	0.03076%	0.05994%		
	6	0.01840%	0.03584%	50.00000%	0.00920%	0.01792%		
	7	0.32677%	0.63664%	25.00000%	0.08169%	0.15916%		
	8	0.41141%	0.80156%	16.19752%	0.06664%	0.12983%		
	9	0.50058%	0.97527%	100.00000%	0.50058%	0.97527%		
					75.13624%	74.88075%		
Hunt Oil Company	8	0.41141%	0.80156%	0.83333%	0.00343%	0.00668%	0.00343%	0.00668%
					0.00343%	0.00668%		

Exhibit C to Unit Operating Agreement
dated April 15, 1994

DICKINSON LODGEPOLE UNIT
STARK COUNTY, NORTH DAKOTA

WORKING INTEREST OWNER	TRACT	PARTICIPATION PERCENTAGE OF TRACT IN UNIT		PERCENTAGE OF WORKING INTEREST IN THE TRACT	PARTICIPATION % OF TRACT IN UNIT MULTIPLIED BY % WORKING INTEREST IN TRACT		WORKING INTEREST OWNER UNIT PARTICIPATION %	
		PHASE I	PHASE II		PHASE I	PHASE II	PHASE I	PHASE II
Hunt Petroleum Corporation	3	12.36359%	11.64830%	8.40336%	1.03896%	0.97885%	1.03896%	0.97885%
					1.03896%	0.97885%		
Huntington Resources Inc.	3	12.36359%	11.64830%	4.72689%	0.58441%	0.55060%	0.58528%	0.55230%
	6	0.01840%	0.03584%	4.72689%	0.00087%	0.00169%		
					0.58528%	0.55230%		
Louis W. Hill, Jr.	3	12.36359%	11.64830%	4.13910%	0.51174%	0.48213%	0.54513%	0.54719%
	8	0.41141%	0.80156%	8.11625%	0.03339%	0.06506%		
					0.54513%	0.54719%		
Louisiana - Hunt Petroleum	6	0.01840%	0.03584%	8.40336%	0.00155%	0.00301%	0.00155%	0.00301%
					0.00155%	0.00301%		
Mid - Continent Energy [B.P.O.]	3	12.36359%	11.64830%	0.00000%	0.00000%	0.00000%	0.00087%	0.00169%
	6	0.01840%	0.03584%	4.72689%	0.00087%	0.00169%		
					0.00087%	0.00169%		

Exhibit C to Unit Operating Agreement
dated April 15, 1994

DICKINSON LODGEPOLE UNIT
STARK COUNTY, NORTH DAKOTA

WORKING INTEREST OWNER	TRACT	PARTICIPATION PERCENTAGE OF TRACT IN UNIT		PERCENTAGE OF WORKING INTEREST IN THE TRACT	PARTICIPATION % OF TRACT IN UNIT MULTIPLIED BY % WORKING INTEREST IN TRACT		WORKING INTEREST OWNER UNIT PARTICIPATION %	
		PHASE I	PHASE II		PHASE I	PHASE II	PHASE I	PHASE II
Mobil Exploration & Producing	7	0.32677%	0.63664%	50.00000%	0.16339%	0.31832%	0.16339%	0.31832%
					0.16339%	0.31832%		
North American Royalties, Inc.	8	0.41141%	0.80156%	9.01957%	0.03711%	0.07230%	0.03711%	0.07230%
					0.03711%	0.07230%		
Petro-Hunt Corporation	8	0.41141%	0.80156%	0.20833%	0.00086%	0.00167%	0.00086%	0.00167%
					0.00086%	0.00167%		
Phillips Petroleum Company	3	12.36359%	11.64830%	4.38126%	0.54168%	0.51034%	0.88050%	1.17048%
	7	0.32677%	0.63664%	25.00000%	0.08169%	0.15916%		
	8	0.41141%	0.80156%	62.50000%	0.25713%	0.50098%		
					0.88050%	1.17048%		
Placid Oil Company	3	12.36359%	11.64830%	32.14286%	3.97401%	3.74410%	3.97993%	3.75562%
	6	0.01840%	0.03584%	32.14286%	0.00591%	0.01152%		
					3.97993%	3.75562%		

Exhibit C to Unit Operating Agreement
dated April 15, 1994

DICKINSON LODGEPOLE UNIT
STARK COUNTY, NORTH DAKOTA

WORKING INTEREST OWNER	TRACT	PARTICIPATION PERCENTAGE OF TRACT IN UNIT		PERCENTAGE OF WORKING INTEREST IN THE TRACT	PARTICIPATION % OF TRACT IN UNIT MULTIPLIED BY % WORKING INTEREST IN TRACT		WORKING INTEREST OWNER UNIT PARTICIPATION %	
		PHASE I	PHASE II		PHASE I	PHASE II	PHASE I	PHASE II
Ruth Ray Hunt	8	0.41141%	0.80156%	1.25000%	0.00514%	0.01002%	0.00514%	0.01002%
					0.00514%	0.01002%		
The Wiser Oil Company	3	12.36359%	11.64830%	1.74958%	0.21631%	0.20380%	0.22317%	0.21716%
	8	0.41141%	0.80156%	1.66667%	0.00686%	0.01336%		
					0.22317%	0.21716%		
Unit Four Partnership	8	0.41141%	0.80156%	0.20833%	0.00086%	0.00167%	0.00086%	0.00167%
					0.00086%	0.00167%		
						TOTAL:	100.00000%	100.00000%

SECTION **PAGE**

UNIT OPERATING AGREEMENT

Dickinson Lodgepole Unit

Stark County, North Dakota

THIS AGREEMENT is entered into as of the 15th day of April, 1994,

W I T N E S S E T H :

WHEREAS, an agreement entitled "Unit Agreement, Dickinson Lodgepole Unit, Stark County, North Dakota", herein referred to as "Unit Agreement", has been made which, among other things, provides for a separate agreement to provide for Unit Operations as therein defined,

NOW, THEREFORE, it is provided as follows:

ARTICLE 1

CONFIRMATION OF UNIT AGREEMENT

1.1 **Confirmation of Unit Agreement.** The Unit Agreement is hereby confirmed and by reference made a part of this Agreement. The definitions in the Unit Agreement are adopted for all purposes of this Agreement. If there is any conflict between the Unit Agreement and this Agreement, the Unit Agreement shall govern.

ARTICLE 2

EXHIBITS

2.1 **Exhibits.** The following exhibits are incorporated herein by reference or attachment:

2.1.1 **Exhibits A and B** of the Unit Agreement.

2.1.2 **Exhibit C,** attached hereto, is a schedule showing the Working Interest of each Working Interest Owner in each Tract, the portion of each Working Interest

Owner's Unit Participation attributable to each such interest, and the Unit Participation of each Working Interest Owner.

2.1.3 **Exhibit D,** attached hereto, is the Accounting Procedure applicable to Unit Operations. If there is any conflict between this Agreement and Exhibit D, this Agreement shall govern.

2.1.4 **Exhibit E,** attached hereto, contains a list of wells to be taken over by the Unit Operator.

2.1.5 **Exhibit F,** Certificate of Compliance with Federal Contract Requirements.

2.1.6 **Exhibit G,** Insurance Provisions

2.1.7 **Exhibit H,** Gas Balancing Provision, which contains the gas balancing provisions applicable to Unit Operations.

2.2 **Reference to Exhibits.** When reference is made herein to an exhibit, it is to the original exhibit or, if revised, to the last revision.

ARTICLE 3

SUPERVISION OF OPERATIONS BY WORKING INTEREST OWNERS

3.1 **Overall Supervision.** Working Interest Owners shall exercise overall supervision and control of all matters pertaining to Unit Operations. In the exercise of such authority, each Working Interest Owner shall act solely in its own behalf in the capacity of an individual owner and not on behalf of the owners as an entirety.

3.2 **Specific Authority and Duties.** The matters with respect to which Working Interest Owners shall decide and take action shall include, but not be limited to, the following:

3.2.1 **Method of Operation.** The method of operation, including the type of recovery program to be employed.

3.2.2 **Drilling of Wells.** The drilling of any well whether for production of Unitized Substances, for use as an injection well, or for other purposes.

3.2.3 **Well Recompletions and Change of Status.** The recompletion, abandonment, or change of status of any well, or the use of any well for injection or other purposes.

3.2.4 **Acquisitions.** The acquisition of equipment and facilities necessary or advisable for Unit Operations, including without limitation the acquisition or construction of roads and other surface facilities, a pipeline system and the acquisition of existing well bores suitable for use as water source, water disposal or miscible gas injection wells.

3.2.5 **Unit Operator's Tools and Equipment.** The use by Unit Operator of its own tools and equipment in the drilling of a well or in any other operation in which drilling equipment is required.

3.2.6 **Expenditures.** The making of any single expenditure in excess of Fifty Thousand Dollars ($50,000); however, approval by Working Interest Owners of the drilling, reworking, deepening, or plugging back of any well shall include approval of all necessary expenditures required therefor, and for completing, testing, and equipping the well, including necessary flow lines, separators, and lease tankage.

3.2.7 **Appearance Before a Court or Regulatory Agency.** The designating of a representative to appear before any court or regulatory agency in matters pertaining to Unit Operations; however, such designation shall not prevent any Working Interest Owner from appearing in person or from designating another representative in its own behalf.

3.2.8 **Audit Exceptions.** The settlement of unresolved audit exceptions.

3.2.9 Inventories. The taking of periodic inventories as provided by Exhibit D.

3.2.10 Technical Services. The authorizing of charges to the joint account for services by consultants or Unit Operator's technical personnel not covered by the charges provided by Exhibit D.

3.2.11 Assignments to Committees. The appointment of committees to study any problems in connection with Unit Operations.

3.2.12 Removal of Operator. The removal of Unit Operator and the selection of a successor.

3.2.13 Changes and Amendments. The changing of the Unit Area or the amending of this Agreement or the Unit Agreement as provided by Article 11 of the Unit Agreement.

3.2.14 Investment Adjustment. The adjustment and readjustment of investments.

3.2.15 Termination of Unit Agreement. The termination of the Unit Agreement as provided therein.

3.2.16 Border Agreements. The approval of border agreements necessary or required by any governmental agency having jurisdiction.

3.2.17 Enlargements. The enlargement of the Unit Area as provided by Section 3.9 of the Unit Agreement.

ARTICLE 4

MANNER OF EXERCISING SUPERVISION

4.1 Designation of Representatives. Each Working Interest Owner shall inform Unit Operator in writing of the names and addresses of the representative and alternate who are authorized to represent and bind such Working Interest Owner with respect to Unit Operations. The representative or alternate may be changed from time to time by written notice to Unit Operator.

4.2 Meetings. All meetings of Working Interest Owners shall be called by Unit Operator upon its own motion or at the request of one or more Working Interest Owners having a total Unit Participation of not less than five percent (5%) calculated on the phase participation in effect at the time. No meeting shall be called on less than fourteen (14) days' advance written notice, with agenda for the meeting attached. Should any Working Interest Owner advise Unit Operator of a proposed change to the agenda, Unit Operator shall make a good faith effort to notify all of the Working Interest Owners of such proposed change prior to the meeting. Working Interest Owners who attend the meeting may amend items included in the agenda and may act upon an amended item or other items presented at the meeting. The Unit Operator's representative shall be chairman of each meeting. In the event of an emergency requiring a vote by the Operating Committee or Working Interest Owners, Unit Operator may call a meeting by telephone, telex or other means, and, upon verbal approval of seventy-five percent (75%) of the voting interest, such meeting shall be held as soon as possible. When the time for such meeting is established, Unit Operator shall notify all Working Interest Owners by appropriate means, to be confirmed in writing.

4.3 Voting Procedure. Working Interest Owners shall determine all matters coming before them as follows:

4.3.1 Voting Interest. Each Working Interest Owner shall have a voting interest equal to its Unit Participation in the phase in effect at the time the vote is taken.

4.3.2 Vote Required. Unless otherwise provided herein or in the Unit Agreement, Working Interest Owners shall determine all matters by the affirmative vote of two (2) or more Working Interest Owners having a combined voting interest of at least seventy percent (70%).

4.3.3 Vote at Meeting by Nonattending Working Interest Owner. Any Working Interest Owner who is not represented at a meeting may vote on any agenda item by letter, fax or telegram addressed to the representative of Unit Operator if its vote is received prior to the vote at the meeting.

4.3.4 Poll Votes. Working Interest Owners may vote by letter, fax or telegram on any matter submitted in writing to all Working Interest Owners. If a meeting is not requested, as provided in Section 4.2, within seven (7) days after a written proposal is sent to Working Interest Owners, the vote taken by letter, fax or telegram shall control. Unit Operator shall give prompt notice of the results of such voting to each Working Interest Owner.

ARTICLE 5

INDIVIDUAL RIGHTS OF WORKING INTEREST OWNERS

5.1 Reservation of Rights. Working Interest Owners retain all their rights, except as otherwise provided in this Agreement or the Unit Agreement.

5.2 Specific Rights. Each Working Interest Owner shall have, among others, the following specific rights:

5.2.1 Access to Unit Area. Access to the Unit Area at all reasonable times to inspect Unit Operations, all wells, and the records and data pertaining thereto.

5.2.2 Reports. The right to receive from Unit Operator, upon written request, copies of material reports to any governmental agency, reports of crude oil runs and stocks, inventory reports, and all other information pertaining to Unit Operations. The cost of gathering and furnishing information not ordinarily furnished by Unit Operator to all Working Interest Owners shall be charged to the Working Interest Owner that requests the information.

5.2.3 Audits. The right to audit the accounts of Unit Operator pertaining to Unit Operations according to the provisions of Exhibit D.

5.2.4 Reversionary Interest. When a Tract ownership changes due to the payout (or multiple) of a well within the unit, the balance remaining to recover will be calculated on an allocated Tract basis after the effective date of the unit. Payout will be deemed to occur at 7:00 A.M. on the first day following the day that the payout balance becomes zero.

ARTICLE 6

UNIT OPERATOR

6.1 Unit Operator. Conoco Inc. is designated as the initial Unit Operator.

6.2 Resignation or Removal. The provisions covering the resignation or removal of Unit Operator and the selection of a successor are set forth in Article 4 of the Unit Agreement.

ARTICLE 7

AUTHORITY AND DUTIES OF UNIT OPERATOR

7.1 Exclusive Right to Operate Unit. Subject to the provisions of this Agreement and to instructions from Working Interest Owners, Unit Operator shall have the exclusive right and be obligated to conduct Unit Operations, including, but not limited to, the right to execute contracts and agreements with third parties as are usual and customary for conducting Unit Operations.

7.2 Workmanlike Conduct. Unit Operator shall conduct Unit Operations in a good and workmanlike manner as would a prudent operator under the same or similar circumstances. Unit Operator shall freely consult with Working Interest Owners and keep them informed of all matters which Unit Operator, in the exercise of its best judgment, considers important. Unit

Operator shall not be liable to Working Interest Owners for damages, unless such damages result from its gross negligence or willful misconduct.

7.3 **Liens and Encumbrances.** Unit Operator shall endeavor to keep the lands and leases in the Unit Area and Unit Equipment free from all liens and encumbrances occasioned by Unit Operations, except those provided for in Article 11.

7.4 **Employees.** The number of employees used by Unit Operator in conducting Unit Operations, their selection, hours of labor, and compensation shall be determined by Unit Operator. Such employees shall be the employees of Unit Operator.

7.5 **Records.** Unit Operator shall keep correct books, accounts, and records of Unit Operations.

7.6 **Reports to Working Interest Owners.** Unit Operator shall furnish Working Interest Owners periodic reports of Unit Operations.

7.7 **Reports to Governmental Authorities.** Unit Operator shall make all reports to governmental authorities that it has the duty to make as Unit Operator.

7.8 **Engineering and Geological Information.** Unit Operator shall furnish to a Working Interest Owner, upon written request, a copy of all logs and other engineering and geological data pertaining to wells drilled for Unit Operations.

7.9 **Expenditures.** Unit Operator is authorized to make single expenditures not in excess of Fifty Thousand Dollars ($50,000) without prior approval of Working Interest Owners. In the event of an emergency, Unit Operator may immediately make or incur such expenditures as in its opinion are required to deal with the emergency. Unit Operator shall report to Working Interest Owners, as promptly as possible, the nature of the emergency and the action taken.

7.10 **Wells Drilled by Unit Operator.** All wells drilled by Unit Operator shall be at the rates prevailing in the area.

7.11 Use of Unit Surface. Unit operator is hereby granted the non-exclusive right to use the unit surface, including roads, rights-of-way, easements, and surface leases and facilities, where necessary to conduct unit operations. Each Working Interest Owner, when requested, shall deliver to Unit Operator document(s) evidencing Unit Operator's rights to so use the Unit Surface.

ARTICLE 8

TAXES

8.1 Property Taxes. Beginning with the first calendar year after the Effective Date hereof, Unit Operator shall make and file all necessary property tax renditions and returns with the proper taxing authorities with respect to all property of each Working Interest Owner used or held by Unit Operator for Unit Operations. Unit Operator shall settle assessments arising therefrom. All such property taxes shall be paid by Unit Operator and charged to the joint account; however, if the interest of a Working Interest Owner is subject to a separately assessed overriding royalty interest, production payment, or other interest in excess of a one-eighth (1/8) royalty, such Working Interest Owner shall be given credit for the reduction in taxes paid resulting therefrom.

8.2 Other Taxes. Each Working Interest Owner shall pay or cause to be paid all production, severance, gathering, and other taxes imposed upon or with respect to the production or handling of its share of Unitized Substances.

8.3 Income Tax Election. Notwithstanding any provisions herein that the rights and liabilities hereunder are several and not joint or collective, or that this Agreement and operations hereunder shall not constitute a partnership, if for Federal income tax purposes this Agreement and the operations hereunder are regarded as a partnership, then each Person hereby affected elects to be excluded from the application of all of the provisions of Subchapter K, Chapter 1, Subtitle A, of the Internal Revenue Code of 1986, as permitted and authorized by Section 761 of the Code and the regulations promulgated thereunder. Unit Operator is authorized and directed to execute on behalf of each Person hereby affected such evidence of this election as may be required by the Secretary of the Treasury of the United States or the Federal Internal Revenue Service, including specifically, but not by way of limitation, all of the returns, statements, and the data required by Federal Regulations 1.761-1(a). Should there be any requirement that each Person hereby affected give further evidence of this election, each such Person shall execute such documents and furnish such other evidence as may be required by the Federal Internal Revenue Service or as may be necessary to evidence this election. No such Person shall give any notices or take any other action inconsistent with the election made hereby. If any present or future income tax laws of the state or states in which the Unit Area is located or any future income tax law of the United States contain provisions similar to those in Subchapter K, Chapter 1, Subtitle A, of the Internal Revenue Code of 1986, under which an election similar to that provided by Section 761 of the Code is permitted, each Person hereby affected shall make such election as may be permitted or required by such laws. In making the foregoing election, each such Person states that the income derived by such Person from Unit Operations can be adequately determined without the computation of partnership taxable income.

8.4 **Transfer of Interests.** In the event of a transfer by one Working Interest Owner to another under the provisions of this Agreement of any Working Interest or of any other interest in any well or in the materials and equipment in any well, the taxes above mentioned assessed against the transferred interest for the taxable period in which such transfer occurs shall be apportioned among said Working Interest Owners so that each shall bear the percentage of such taxes which is proportionate to that portion of the taxable period during which it owned an interest.

ARTICLE 9

INSURANCE

9.1 **Insurance.** Unit Operator, with respect to Unit Operations, shall:

(a) comply with the Workmen's Compensation Laws of the state.

(b) comply with Employer's Liability and other insurance requirements of the laws of the state.

(c) comply with the provisions of Exhibit G of this Agreement.

ARTICLE 10

ADJUSTMENT OF INVESTMENTS

10.1 **Property Taken Over.** Upon the Effective Date, Working Interest Owners shall deliver to Unit Operator the following:

10.1.1 **Wells.** All wells shown on Exhibit E which satisfy the requirements of Section 10.7.

10.1.2 **Equipment.** The casing and tubing in each such well, the wellhead connections thereon, and all other lease and operating equipment that is used in the operation of such wells which Working Interest Owners determine is necessary or desirable for conducting Unit Operations.

10.1.3 **Records.** A copy of all production and well records for such wells.

10.2 **Inventory and Evaluation.** Working Interest Owners shall at Unit Expense inventory and evaluate the wells and equipment taken over. The inventory of equipment shall be limited to those items considered controllable as recommended in the most current Material Classification Manual in Bulletin No. 6 dated May, 1971, published by the Petroleum Accountant Society of North America except, upon determination of Working Interest Owners, items such as sucker rods considered noncontrollable may be included in the inventory in order to insure a more equitable adjustment of investment. The method of evaluating wells and equipment shall be determined by Working Interest Owners.

10.3 Investment Adjustment. Upon approval by Working Interest Owners of the inventory and evaluation, each Working Interest Owner shall be credited with the value of its interest in all wells and equipment taken over under Section 10.1, and shall be charged with an amount equal to that obtained by multiplying the total value of all wells and equipment taken over under Section 10.1 by such Working Interest Owner's Unit Participation. If the charge against any Working Interest Owner is greater than the amount credited to such Working Interest Owner, the resulting net charge shall be an item of Unit Expense chargeable against such Working Interest Owner. If the credit to any Working Interest Owner is greater than the amount charged against such Working Interest Owner, the resulting net credit shall be paid to such Working Interest Owner by Unit Operator out of funds received by it in settlement of the net charges described above.

10.4 General Facilities. The acquisition of warehouse stocks, facility systems, and buildings necessary for Unit Operations shall be by negotiation by the owners thereof and Unit Operator, subject to the approval of Working Interest Owners.

10.5 Ownership of Property and Facilities. Each Working Interest Owner, individually, shall by virtue hereof own an undivided interest, equal to its Unit Participation in all wells, equipment, and facilities taken over or otherwise acquired by Unit Operator pursuant to this Agreement.

10.6 Non-Unit Equipment. Each Working Interest Owner shall solely be liable for all its equipment within the Unit Area which is not deemed necessary for Unit Operations and shall solely be responsible for the care, maintenance and removal of such equipment as required by contract, law or regulation.

10.7 Useable Well. All wells delivered to the Unit Operator shall be (a) in good physical condition, (b) completed in some portion of the Unitized Formation, (c) physically separated from formations not a part of the Unitized Formation as of the Effective Date, and (d) in compliance with North Dakota rules and regulations dealing with protection of potable water resources (North Dakota Administrative Code 43-02-03-20). Unit Operator shall make all determinations required under this Section 10.7.

ARTICLE 11

UNIT EXPENSE

11.1 **Basis of Charge to Working Interest Owners.** Unit Operator initially shall pay all Unit Expense. Each Working Interest Owner shall reimburse Unit Operator for its share of Unit Expense. Each Working Interest Owner's share shall be the same as its Unit Participation for the phase in effect at the time the expense is incurred. All charges, credits, and accounting for Unit Expense shall be in accordance with Exhibit D.

11.2 **Budgets.** Before or as soon as practical after the Effective Date, Unit Operator shall prepare a budget of estimated Unit Expense for the remainder of the calendar year, and thereafter shall prepare an annual operations and capital budget for submission to the Working Interest Owners by December 1. Budgets shall be estimates only, and shall be adjusted or corrected by the Unit Operator whenever an adjustment or correction is proper. A copy of each budget and adjusted budget shall be furnished promptly to each Working Interest Owner.

11.3 **Advance Billings.** Unit Operator shall have the right to require Working Interest Owners to advance their respective shares of estimated Unit Expense as provided by Exhibit D.

11.4 **Commingling of Funds.** Funds received by Unit Operator under this Agreement need not be segregated or maintained by it as a separate fund, but may be commingled with its own funds.

11.5 **Unpaid Unit Expense.** If any Working Interest Owner fails or is unable to pay its share of Unit Expense within sixty (60) days after rendition of a statement therefor by Unit Operator, the non-defaulting Working Interest Owners shall, upon request by Unit Operator, pay the unpaid amount as if it were Unit Expense in the proportion that the Unit Participation of each such Working Interest Owner bears to the Unit Participation of all such Working Interest Owners for the Phase in effect at the time of payment failure. Each Working Interest Owner so paying its share of the unpaid amount shall, to obtain reimbursement thereof, be subrogated to the security rights described in Section 11.6 of this Agreement.

11.6 Security Rights. In addition to any other security rights and remedies provided for by the laws of the State of North Dakota with respect to services rendered or materials and equipment furnished under this Agreement, Unit Operator, on behalf of the Unit, shall have a first and prior lien upon each Working Interest, including the Unitized Substances and Unit Equipment credited thereto, in order to secure payment of the Unit Expense charged against such Working Interest, together with interest thereon at the rate set forth in Exhibit D or the maximum rate allowed by law, whichever is less. If any Working Interest Owner does not pay its share of Unit Expense when due, Unit Operator on behalf of the Unit shall have the right to collect from the purchaser the proceeds from the sale of such Working Interest Owner's share of Unitized Substances until the amount owed, plus interest at the rate herein provided, has been paid. Each purchaser shall be entitled to rely on Unit Operator's statement concerning the amount owed and the interest payable thereon. If any Working Interest Owner pays its proportionate share of a defaulting party's Unit Expense, Unit Operator shall make monthly statements to that Working Interest Owner as to the collection of principal and interest from the purchaser. Exercise of any of the rights of Unit Operator granted or recognized above shall not be deemed an election of remedies or otherwise affect the rights of Unit Operator to bring suit and obtain judgment and foreclosure. The Working Interest Owners specifically authorize Unit Operator to file of record in the State of North Dakota a memorandum of agreement referencing this Unit Operating Agreement and the lien and security rights herein granted.

11.7 Subsequently Created Interests. Any overriding royalty, production payment, net proceeds interest, carried interest or any other interest carved out of a Working Interest and created after the Effective Date of this Agreement shall be subject to this Agreement. If a Working Interest Owner does not pay its share of Unit Expense and the proceeds from the sale of Unitized Substances under Section 11.6 are insufficient for that purpose, the security rights provided for therein may be applied against the carved-out interests with which such Working Interest is burdened. In such event, the owner of such carved-out interest shall be subrogated to the security rights granted by Section 11.6. Should any Working Interest Owner elect to withdraw from the unit and this Unit Operating Agreement as provided in Section 16, its assignment and transfer to the Working Interest Owners desiring to accept such transfer shall be free and clear from, and not in any way burdened by, any such subsequently created carved-out interest.

11.8 Pre-Unitization Expense. Prior to Effective Date, Unit Operator will have incurred certain costs and expenses (herein referred to as "Pre-unitization Expense") for and on behalf of the Working Interest Owners in anticipation of the Unit Agreement and this Agreement becoming effective. All Pre-unitization Expense shall have been previously approved by two or more Working Interest Owners representing at least Seventy Percent (70%) of the Phase I Unit Participation. Each Working Interest Owner shall reimburse Unit Operator for its share of such actual Pre-unitization Expense, determined on the basis of its Phase I Unit Participation. For the purposes of this Agreement, all such Pre-unitization Expense shall be considered an item of Unit Expense.

ARTICLE 12

NONUNITIZED FORMATIONS

12.1 **Right to Operate.** Any Working Interest Owner that now has or hereafter acquires the right to drill for and produce oil, gas, or other minerals, from a formation underlying the Unit Area other than the Unitized Formation, shall have the right to do so notwithstanding this Agreement or the Unit Agreement. In exercising the right, however, such Working Interest Owner shall exercise care to prevent unreasonable interference with Unit Operations. No Working Interest Owner other than Unit Operator shall produce Unitized Substances. If any Working Interest Owner drills any well into or through the Unitized Formation, the Unitized Formation shall be protected in a manner satisfactory to Working Interest Owners so that the production of Unitized Substances will not be affected adversely.

ARTICLE 13

LIABILITY, CLAIMS, AND SUITS

13.1 **Individual Liability.** The duties, obligations, and liabilities of Working Interest Owners shall be several and not joint or collective; and nothing herein shall ever be construed as creating a partnership of any kind, joint venture, association, or trust among Working Interest Owners.

13.2 **Settlements.** Unit Operator may settle any single damage claim or suit involving Unit Operations if the expenditure does not exceed Fifty Thousand Dollars ($50,000) and if the payment is in complete settlement of such claim or suit. If the amount required for settlement exceeds the above amount, Working Interest Owners shall determine the further handling of the claim or suit. All costs and expense of handling, settling, or otherwise discharging such claim or suit shall be an item of Unit Expense, subject to such limitation as is set forth in Exhibit D. If a claim is made against any Working Interest Owner or if any Working Interest Owner is sued on account of any matter arising from Unit Operations over which such Working Interest Owner individually has no control because of the rights given Working Interest Owners and Unit Operator by this Agreement and the Unit Agreement, the Working Interest Owner shall immediately notify Unit Operator, and the claim or suit shall be treated as any other claim or suit involving Unit Operations.

13.3 Notice of Loss. Unit Operator shall report to Working Interest Owners as soon as practicable after each occurrence, damage or loss to Unit Equipment, and each accident, occurrence, claim, or suit involving third party bodily injury or property damage not covered by insurance carried for the benefit of Working Interest Owners.

ARTICLE 14

NONDISCRIMINATION

14.1 Nondiscrimination. During the performance of work under this Agreement, Unit Operator agrees to comply with all the provisions of Exhibit "F" of this Agreement.

ARTICLE 15

NOTICES

15.1 Notices. All notices required hereunder shall be in writing and shall be deemed to have been properly served when sent by mail, data fax or telegram to the address of the representative of each Working Interest Owner as furnished to Unit Operator in accordance with Article 4.

ARTICLE 16

WITHDRAWAL OF WORKING INTEREST OWNER

16.1 Withdrawal. A Working Interest Owner may withdraw from this Agreement by transferring, without warranty of title either express or implied, to the Working Interest Owners who do not desire to withdraw, all its Oil and Gas Rights, exclusive of Royalty Interests, together with its interest in all Unit Equipment and in all wells used in Unit Operations, provided that such transfer shall not relieve such Working Interest Owner from any obligation or liability incurred prior to the first day of the month following receipt by Unit Operator of such transfer. The delivery of the transfer shall be made to Unit Operator for the transferees. The transferred interest shall be owned by the transferees in proportion to their respective Unit Participations. The transferees, in proportion to the respective interests so acquired, shall pay the transferor for its interest in Unit Equipment, the salvage value thereof less its share of the estimated cost of salvaging same and of plugging and abandoning all wells then being used or held for Unit Operations, as determined by Working Interest Owners. In the event such withdrawing owner's interest in the aforesaid salvage value is less than such owner's share of such estimated costs, the withdrawing owner, as a condition precedent to withdrawal, shall pay the Unit Operator, for the benefit of Working Interest Owners succeeding to its interest, a sum equal to the deficiency. Within ninety (90) days after receiving delivery of the transfer, Unit Operator shall render a final statement to the withdrawing owner for its share of Unit Expense, including any deficiency in salvage value, as determined by agreement between the withdrawing owner and the Unit Operator, incurred as of the first day of the month following the date of receipt of the transfer. Provided all Unit Expense, including any deficiency hereunder, due from the withdrawing owner has been paid in full within thirty (30) days after the rendering of such final statement by the Unit Operator, the transfer shall be effective the first day of the month following its receipt by Unit Operator and, as of such effective date, withdrawing owner shall be relieved from all further obligations and liabilities hereunder and under the Unit Agreement, and the rights of the withdrawing Working Interest Owner hereunder and under the Unit Agreement shall cease insofar as they existed by virtue of the interest transferred.

16.2 Limitation on Withdrawal. Notwithstanding anything set forth in Section 16.1, Working Interest Owners may refuse to permit the withdrawal of a Working Interest Owner if its Working Interest is burdened by any royalties, overriding royalties, production payments, net proceeds interest, carried interest, or any other interest created out of the Working Interest in excess of one-eighth (1/8) lessor's royalty, unless the other Working Interest Owners willing to accept the assignment agree to accept the Working Interest subject to such burdens.

ARTICLE 17

ABANDONMENT OF WELLS

17.1 Rights of Former Owners. If Working Interest Owners determine to permanently abandon any well within the Unit Area prior to termination of the Unit Agreement, Unit Operator shall give written notice thereof to the Working Interest Owners of the Tract on which the well is located, and they shall have the option for a period of thirty (30) days after the sending of such notice to notify Unit Operator in writing of their election to take over and own the well. Within ten (10) days after the Working Interest Owners of the Tract have notified Unit Operator of their election to take over the well, they shall pay Unit Operator, for credit to the joint account, the amount determined by Working Interest Owners to be the net salvage value of the casing and equipment, through the wellhead, in and on the well. The Working Interest Owners of the Tract, by taking over the well, agree to seal off the Unitized Formation, and upon abandonment to plug the well in compliance with applicable laws and regulations.

17.2 Plugging. If the Working Interest Owners of a Tract do not elect to take over a well located within the Unit Area that is proposed for abandonment, Unit Operator shall plug and abandon the well in compliance with applicable laws and regulations.

ARTICLE 18

EFFECTIVE DATE AND TERM

18.1 **Effective Date.** This Agreement shall become effective when the Unit Agreement becomes effective.

18.2 **Term.** This Agreement shall continue in effect so long as the Unit Agreement remains in effect, and thereafter until (a) all unit wells have been plugged and abandoned or turned over to Working Interest Owners in accordance with Article 19; (b) all Unit Equipment and real property acquired for the joint account have been disposed of by Unit Operator in accordance with instructions of Working Interest Owners; and (c) there has been a final accounting.

ARTICLE 19

ABANDONMENT OF OPERATIONS

19.1 **Termination.** Upon termination of the Unit Agreement, the following will occur:

19.1.1 **Oil and Gas Rights.** Oil and Gas Rights in and to each separate Tract shall no longer be affected by this Agreement, and thereafter the parties shall be governed by the terms and provisions of the leases, contracts, and other instruments affecting the separate Tracts.

19.1.2 **Right to Operate.** Working Interest Owners of any Tract that desire to take over and continue to operate wells located thereon may do so by paying Unit Operator, for credit to the joint account, the net salvage value, as determined by Working Interest Owners, of the casing and equipment, through the wellhead, in and on the wells taken over and by agreeing upon abandonment to plug each well in compliance with applicable laws and regulations.

19.1.3 Salvaging Wells. Unit Operator shall salvage as much of the casing and equipment in or on wells not taken over by Working Interest Owners of separate Tracts as can economically and reasonably be salvaged, and shall cause the wells to be plugged and abandoned in compliance with applicable laws and regulations.

19.1.4 Cost of Abandonment. The cost of abandonment of Unit Operations shall be Unit Expense.

19.1.5 Distribution of Assets. Working Interest Owners shall share in the distribution of Unit Equipment, or the proceeds thereof, in proportion to their Unit Participations.

ARTICLE 20

APPROVAL

20.1 Original, Counterpart, or Other Instrument. A Working Interest Owner may approve this Agreement by signing the original, a counterpart thereof, or other instrument approving this Agreement. The signing of any such instrument shall have the same effect as if all Persons had signed the same instrument.

ARTICLE 21

SUCCESSORS AND ASSIGNS

21.1 Successors and Assigns. This Agreement shall extend to, be binding upon, and inure to the benefit of the Persons hereto and their respective heirs, devisees, legal representatives, successors, and assigns, and shall constitute a covenant running with the lands, leases, and interests covered hereby.

IN WITNESS WHEREOF, this Agreement is approved on the dates opposite the respective signatures.

CONOCO INC.

By: Roger B. Brown
Roger B. Brown
Attorney-In-Fact

Date of Execution: April 15, 1994

601, BOX 800 TULSA OK 74101

COPAS

EXHIBIT "D"

Attached to and made a part of Unit Operating Agreement for Dickinson Lodgepole Unit dated April 15, 1994.

ACCOUNTING PROCEDURE
JOINT OPERATIONS

I. GENERAL PROVISIONS

1. Definitions

"Joint Property" shall mean the real and personal property subject to the agreement to which this Accounting Procedure is attached.
"Joint Operations" shall mean all operations necessary or proper for the development, operation, protection and maintenance of the Joint Property.
"Joint Account" shall mean the account showing the charges paid and credits received in the conduct of the Joint Operations and which are to be shared by the Parties.
"Operator" shall mean the party designated to conduct the Joint Operations.
"Non-Operators" shall mean the Parties to this agreement other than the Operator.
"Parties" shall mean Operator and Non-Operators.
"First Level Supervisors" shall mean those employees whose primary function in Joint Operations is the direct supervision of other employees and/or contract labor directly employed on the Joint Property in a field operating capacity.
"Technical Employees" shall mean those employees having special and specific engineering, geological or other professional skills, and whose primary function in Joint Operations is the handling of specific operating conditions and problems for the benefit of the Joint Property.
"Personal Expenses" shall mean travel and other reasonable reimbursable expenses of Operator's employees.
"Material" shall mean personal property, equipment or supplies acquired or held for use on the Joint Property.
"Controllable Material" shall mean Material which at the time is so classified in the Material Classification Manual as most recently recommended by the Council of Petroleum Accountants Societies.

2. Statement and Billings

Operator shall bill Non-Operators on or before the last day of each month for their proportionate share of the Joint Account for the preceding month. Such bills will be accompanied by statements which identify the authority for expenditure, lease or facility, and all charges and credits summarized by appropriate classifications of investment and expense except that items of Controllable Material and unusual charges and credits shall be separately identified and fully described in detail.

3. Advances and Payments by Non-Operators

A. Unless otherwise provided for in the agreement, the Operator may require the Non-Operators to advance their share of estimated cash outlay for the succeeding month's operation within fifteen (15) days after receipt of the billing or by the first day of the month for which the advance is required, whichever is later. Operator shall adjust each monthly billing to reflect advances received from the Non-Operators.

B. Each Non-Operator shall pay its proportion of all bills within fifteen (15) days after receipt. If payment is not made within such time, the unpaid balance shall bear interest monthly at the prime rate in effect at Citibank NA New York, N.Y. on the first day of the month in which delinquency occurs plus 1% or the maximum contract rate permitted by the applicable usury laws in the state in which the Joint Property is located, whichever is the lesser, plus attorney's fees, court costs, and other costs in connection with the collection of unpaid amounts.

4. Adjustments

Payment of any such bills shall not prejudice the right of any Non-Operator to protest or question the correctness thereof; provided, however, all bills and statements rendered to Non-Operators by Operator during any calendar year shall conclusively be presumed to be true and correct after twenty-four (24) months following the end of any such calendar year, unless within the said twenty-four (24) month period a Non-Operator takes written exception thereto and makes claim on Operator for adjustment. No adjustment favorable to Operator shall be made unless it is made within the same prescribed period. The provisions of this paragraph shall not prevent adjustments resulting from a physical inventory of Controllable Material as provided for in Section V.

5. **Audits**

A. A Non-Operator, upon notice in writing to Operator and all other Non-Operators, shall have the right to audit Operator's accounts and records relating to the Joint Account for any calendar year within the twenty-four (24) month period following the end of such calendar year; provided, however, the making of an audit shall not extend the time for the taking of written exception to and the adjustments of accounts as provided for in Paragraph 4 of this Section I. Where there are two or more Non-Operators, the Non-Operators shall make every reasonable effort to conduct a joint audit in a manner which will result in a minimum of inconvenience to the Operator. Operator shall bear no portion of the Non-Operators' audit cost incurred under this paragraph unless agreed to by the Operator. The audits shall not be conducted more than once each year without prior approval of Operator, except upon the resignation or removal of the Operator, and shall be made at the expense of those Non-Operators approving such audit.

B. The Operator shall reply in writing to an audit report within 180 days after receipt of such report.

6. **Approval By Non-Operators**

Where an approval or other agreement of the Parties or Non-Operators is expressly required under other sections of this Accounting Procedure and if the agreement to which this Accounting Procedure is attached contains no contrary provisions in regard thereto, Operator shall notify all Non-Operators of the Operator's proposal, and the agreement or approval of a majority in interest of the Non-Operators shall be controlling on all Non-Operators.

II. DIRECT CHARGES

Operator shall charge the Joint Account with the following items:

1. **Ecological and Environmental**

Costs incurred for the benefit of the Joint Property as a result of governmental or regulatory requirements to satisfy environmental considerations applicable to the Joint Operations. Such costs may include surveys of an ecological or archaeological nature and pollution control procedures as required by applicable laws and regulations.

2. **Rentals and Royalties**

Lease rentals and royalties paid by Operator for the Joint Operations.

3. **Labor**

A. (1) Salaries and wages of Operator's field employees directly employed on the Joint Property in the conduct of Joint Operations.

(2) Salaries of First Level Supervisors in the field.

(3) Salaries and wages of Technical Employees directly employed on the Joint Property if such charges are excluded from the overhead rates.

(4) Salaries and wages of Technical Employees either temporarily or permanently assigned to and directly employed in the operation of the Joint Property if such charges are excluded from the overhead rates.

B. Operator's cost of holiday, vacation, sickness and disability benefits and other customary allowances paid to employees whose salaries and wages are chargeable to the Joint Account under Paragraph 3A of this Section II. Such costs under this Paragraph 3B may be charged on a "when and as paid basis" or by "percentage assessment" on the amount of salaries and wages chargeable to the Joint Account under Paragraph 3A of this Section II. If percentage assessment is used, the rate shall be based on the Operator's cost experience.

C. Expenditures or contributions made pursuant to assessments imposed by governmental authority which are applicable to Operator's costs chargeable to the Joint Account under Paragraphs 3A and 3B of this Section II.

D. Personal Expenses of those employees whose salaries and wages are chargeable to the Joint Account under Paragraph 3A of this Section II.

4. **Employee Benefits**

Operator's current costs of established plans for employees' group life insurance, hospitalization, pension, retirement, stock purchase, thrift, bonus, and other benefit plans of a like nature, applicable to Operator's labor cost chargeable to the Joint Account under Paragraphs 3A and 3B of this Section II shall be Operator's actual cost not to exceed the percent most recently recommended by the Council of Petroleum Accountants Societies.

5. **Material**

Material purchased or furnished by Operator for use on the Joint Property as provided under Section IV. Only such Material shall be purchased for or transferred to the Joint Property as may be required for immediate use and is reasonably practical and consistent with efficient and economical operations. The accumulation of surplus stocks shall be avoided.

6. **Transportation**

Transportation of employees and Material necessary for the Joint Operations but subject to the following limitations:

A. If Material is moved to the Joint Property from the Operator's warehouse or other properties, no charge shall be made to the Joint Account for a distance greater than the distance from the nearest reliable supply store where like material is normally available or railway receiving point nearest the Joint Property unless agreed to by the Parties.

B. If surplus Material is moved to Operator's warehouse or other storage point, no charge shall be made to the Joint Account for a distance greater than the distance to the nearest reliable supply store where like material is normally available, or railway receiving point nearest the Joint Property unless agreed to by the Parties. No charge shall be made to the Joint Account for moving Material to other properties belonging to Operator, unless agreed to by the Parties.

C. In the application of subparagraphs A and B above, the option to equalize or charge actual trucking cost is available when the actual charge is $400 or less excluding accessorial charges. The $400 will be adjusted to the amount most recently recommended by the Council of Petroleum Accountants Societies.

7. **Services**

The cost of contract services, equipment and utilities provided by outside sources, except services excluded by Paragraph 10 of Section II and Paragraph i, ii, and iii, of Section III. The cost of professional consultant services and contract services of technical personnel directly engaged on the Joint Property if such charges are excluded from the overhead rates. The cost of professional consultant services or contract services of technical personnel not directly engaged on the Joint Property shall not be charged to the Joint Account unless previously agreed to by the Parties.

8. **Equipment and Facilities Furnished By Operator**

A. Operator shall charge the Joint Account for use of Operator owned equipment and facilities at rates commensurate with costs of ownership and operation. Such rates shall include costs of maintenance, repairs, other operating expense, insurance, taxes, depreciation, and interest on gross investment less accumulated depreciation not to exceed __eight__ percent (__8__%) per annum. Such rates shall not exceed average commercial rates currently prevailing in the immediate area of the Joint Property.

B. In lieu of charges in paragraph 8A above, Operator may elect to use average commercial rates prevailing in the immediate area of the Joint Property less 20%. For automotive equipment, Operator may elect to use rates published by the Petroleum Motor Transport Association.

9. **Damages and Losses to Joint Property**

All costs or expenses necessary for the repair or replacement of Joint Property made necessary because of damages or losses incurred by fire, flood, storm, theft, accident, or other cause, except those resulting from Operator's gross negligence or willful misconduct. Operator shall furnish Non-Operator written notice of damages or losses incurred as soon as practicable after a report thereof has been received by Operator.

10. **Legal Expense**

Expense of handling, investigating and settling litigation or claims, discharging of liens, payment of judgements and amounts paid for settlement of claims incurred in or resulting from operations under the agreement or necessary to protect or recover the Joint Property, except that no charge for services of Operator's legal staff or fees or expense of outside attorneys shall be made unless previously agreed to by the Parties. All other legal expense is considered to be covered by the overhead provisions of Section III unless otherwise agreed to by the Parties, except as provided in Section I, Paragraph 3.

11. **Taxes**

All taxes of every kind and nature assessed or levied upon or in connection with the Joint Property, the operation thereof, or the production therefrom, and which taxes have been paid by the Operator for the benefit of the Parties. If the ad valorem taxes are based in whole or in part upon separate valuations of each party's working interest, then notwithstanding anything to the contrary herein, charges to the Joint Account shall be made and paid by the Parties hereto in accordance with the tax value generated by each party's working interest.

12. **Insurance**

Net premiums paid for insurance required to be carried for the Joint Operations for the protection of the Parties. In the event Joint Operations are conducted in a state in which Operator may act as self-insurer for Worker's Compensation and/or Employers Liability under the respective state's laws, Operator may, at its election, include the risk under its self-insurance program and in that event, Operator shall include a charge at Operator's cost not to exceed manual rates.

13. **Abandonment and Reclamation**

Costs incurred for abandonment of the Joint Property, including costs required by governmental or other regulatory authority.

14. **Communications**

Cost of acquiring, leasing, installing, operating, repairing and maintaining communication systems, including radio and microwave facilities directly serving the Joint Property. In the event communication facilities/systems serving the Joint Property are Operator owned, charges to the Joint Account shall be made as provided in Paragraph 8 of this Section II.

15. **Other Expenditures**

Any other expenditure not covered or dealt with in the foregoing provisions of this Section II, or in Section III and which is of direct benefit to the Joint Property and is incurred by the Operator in the necessary and proper conduct of the Joint Operations.

III. OVERHEAD

1. **Overhead - Drilling and Producing Operations**

i. As compensation for administrative, supervision, office services and warehousing costs, Operator shall charge drilling and producing operations on either:

(X) Fixed Rate Basis, Paragraph 1A, or
(   ) Percentage Basis, Paragraph 1B

Unless otherwise agreed to by the Parties, such charge shall be in lieu of costs and expenses of all offices and salaries or wages plus applicable burdens and expenses of all personnel, except those directly chargeable under Paragraph 3A, Section II. The cost and expense of services from outside sources in connection with matters of taxation, traffic, accounting or matters before or involving governmental agencies shall be considered as included in the overhead rates provided for in the above selected Paragraph of this Section III unless such cost and expense are agreed to by the Parties as a direct charge to the Joint Account.

ii. The salaries, wages and Personal Expenses of Technical Employees and/or the cost of professional consultant services and contract services of technical personnel directly employed on the Joint Property:

(   ) shall be covered by the overhead rates, or
(X) shall not be covered by the overhead rates.

iii. The salaries, wages and Personal Expenses of Technical Employees and/or costs of professional consultant services and contract services of technical personnel either temporarily or permanently assigned to and directly employed in the operation of the Joint Property:

(   ) shall be covered by the overhead rates, or
(X) shall not be covered by the overhead rates.

A. Overhead - Fixed Rate Basis

(1) Operator shall charge the Joint Account at the following rates per well per month:

Drilling Well Rate $ 7,500
(Prorated for less than a full month)

Producing Well Rate $ 750

(2) Application of Overhead - Fixed Rate Basis shall be as follows:

(a) Drilling Well Rate

(1) Charges for drilling wells shall begin on the date the well is spudded and terminate on the date the drilling rig, completion rig, or other units used in completion of the well is released, whichever is later, except that no charge shall be made during suspension of drilling or completion operations for fifteen (15) or more consecutive calendar days.

(2) Charges for wells undergoing any type of workover or recompletion for a period of five (5) consecutive work days or more shall be made at the drilling well rate. Such charges shall be applied for the period from date workover operations, with rig or other units used in workover, commence through date of rig or other unit release, except that no charge shall be made during suspension of operations for fifteen (15) or more consecutive calendar days.

(b) Producing Well Rates

(1) An active well either produced or injected into for any portion of the month shall be considered as a one-well charge for the entire month.

(2) Each active completion in a multi-completed well in which production is not commingled down hole shall be considered as a one-well charge providing each completion is considered a separate well by the governing regulatory authority.

(3) An inactive gas well shut in because of overproduction or failure of purchaser to take the production shall be considered as a one-well charge providing the gas well is directly connected to a permanent sales outlet.

(4) A one-well charge shall be made for the month in which plugging and abandonment operations are completed on any well. This one-well charge shall be made whether or not the well has produced except when drilling well rate applies.

(5) All other inactive wells (including but not limited to inactive wells covered by unit allowable, lease allowable, transferred allowable, etc.) shall not qualify for an overhead charge.

(3) The well rates shall be adjusted as of the first day of April each year following the effective date of the agreement to which this Accounting Procedure is attached. The adjustment shall be computed by multiplying the rate currently in use by the percentage increase or decrease in the average weekly earnings of Crude Petroleum and Gas Production Workers for the last calendar year compared to the calendar year preceding as shown by the index of average weekly earnings of Crude Petroleum and Gas Production Workers as published by the United States Department of Labor, Bureau of Labor Statistics, or the equivalent Canadian index as published by Statistics Canada, as applicable. The adjusted rates shall be the rates currently in use, plus or minus the computed adjustment.

B. Overhead - Percentage Basis

(1) Operator shall charge the Joint Account at the following rates:

B. If surplus Material is moved to Operator's warehouse or other storage point, no charge shall be made to the Joint Account for a distance greater than the distance to the nearest reliable supply store where like material is normally available, or railway receiving point nearest the Joint Property unless agreed to by the Parties. No charge shall be made to the Joint Account for moving Material to other properties belonging to Operator, unless agreed to by the Parties.

C. In the application of subparagraphs A and B above, the option to equalize or charge actual trucking cost is available when the actual charge is $400 or less excluding accessorial charges. The $400 will be adjusted to the amount most recently recommended by the Council of Petroleum Accountants Societies.

7. **Services**

The cost of contract services, equipment and utilities provided by outside sources, except services excluded by Paragraph 10 of Section II and Paragraph i, ii, and iii, of Section III. The cost of professional consultant services and contract services of technical personnel directly engaged on the Joint Property if such charges are excluded from the overhead rates. The cost of professional consultant services or contract services of technical personnel not directly engaged on the Joint Property shall not be charged to the Joint Account unless previously agreed to by the Parties.

8. **Equipment and Facilities Furnished By Operator**

A. Operator shall charge the Joint Account for use of Operator owned equipment and facilities at rates commensurate with costs of ownership and operation. Such rates shall include costs of maintenance, repairs, other operating expense, insurance, taxes, depreciation, and interest on gross investment less accumulated depreciation not to exceed eight percent (8 %) per annum. Such rates shall not exceed average commercial rates currently prevailing in the immediate area of the Joint Property.

B. In lieu of charges in paragraph 8A above, Operator may elect to use average commercial rates prevailing in the immediate area of the Joint Property less 20%. For automotive equipment, Operator may elect to use rates published by the Petroleum Motor Transport Association.

9. **Damages and Losses to Joint Property**

All costs or expenses necessary for the repair or replacement of Joint Property made necessary because of damages or losses incurred by fire, flood, storm, theft, accident, or other cause, except those resulting from Operator's gross negligence or willful misconduct. Operator shall furnish Non-Operator written notice of damages or losses incurred as soon as practicable after a report thereof has been received by Operator.

10. **Legal Expense**

Expense of handling, investigating and settling litigation or claims, discharging of liens, payment of judgements and amounts paid for settlement of claims incurred in or resulting from operations under the agreement or necessary to protect or recover the Joint Property, except that no charge for services of Operator's legal staff or fees or expense of outside attorneys shall be made unless previously agreed to by the Parties. All other legal expense is considered to be covered by the overhead provisions of Section III unless otherwise agreed to by the Parties, except as provided in Section I, Paragraph 3.

11. **Taxes**

All taxes of every kind and nature assessed or levied upon or in connection with the Joint Property, the operation thereof, or the production therefrom, and which taxes have been paid by the Operator for the benefit of the Parties. If the ad valorem taxes are based in whole or in part upon separate valuations of each party's working interest, then notwithstanding anything to the contrary herein, charges to the Joint Account shall be made and paid by the Parties hereto in accordance with the tax value generated by each party's working interest.

12. **Insurance**

Net premiums paid for insurance required to be carried for the Joint Operations for the protection of the Parties. In the event Joint Operations are conducted in a state in which Operator may act as self-insurer for Worker's Compensation and or Employers Liability under the respective state's laws, Operator may, at its election, include the risk under its self-insurance program and in that event, Operator shall include a charge at Operator's cost not to exceed manual rates.

13. **Abandonment and Reclamation**

Costs incurred for abandonment of the Joint Property, including costs required by governmental or other regulatory authority.

14. **Communications**

Cost of acquiring, leasing, installing, operating, repairing and maintaining communication systems, including radio and microwave facilities directly serving the Joint Property. In the event communication facilities/systems serving the Joint Property are Operator owned, charges to the Joint Account shall be made as provided in Paragraph 8 of this Section II.

15. **Other Expenditures**

Any other expenditure not covered or dealt with in the foregoing provisions of this Section II, or in Section III and which is of direct benefit to the Joint Property and is incurred by the Operator in the necessary and proper conduct of the Joint Operations.

III. OVERHEAD

1. Overhead - Drilling and Producing Operations

i. As compensation for administrative, supervision, office services and warehousing costs Operator shall charge drilling and producing operations on either:

(X) Fixed Rate Basis, Paragraph 1A, or
( ) Percentage Basis, Paragraph 1B

Unless otherwise agreed to by the Parties, such charge shall be in lieu of costs and expenses of all offices and salaries or wages plus applicable burdens and expenses of all personnel, except those directly chargeable under Paragraph 3A, Section II. The cost and expense of services from outside sources in connection with matters of taxation, traffic accounting or matters before or involving governmental agencies shall be considered as included in the overhead rates provided for in the above selected Paragraph of this Section III unless such cost and expense are agreed to by the Parties as a direct charge to the Joint Account.

ii. The salaries, wages and Personal Expenses of Technical Employees and/or the cost of professional consultant services and contract services of technical personnel directly employed on the Joint Property:

( ) shall be covered by the overhead rates, or
(X) shall not be covered by the overhead rates.

iii. The salaries, wages and Personal Expenses of Technical Employees and/or costs of professional consultant services and contract services of technical personnel either temporarily or permanently assigned to and directly employed in the operation of the Joint Property:

( ) shall be covered by the overhead rates, or
(X) shall not be covered by the overhead rates.

A. Overhead - Fixed Rate Basis

(1) Operator shall charge the Joint Account at the following rates per well per month:

Drilling Well Rate $ 7,500
(Prorated for less than a full month)

Producing Well Rate $ 750

(2) Application of Overhead - Fixed Rate Basis shall be as follows:

(a) Drilling Well Rate

(1) Charges for drilling wells shall begin on the date the well is spudded and terminate on the date the drilling rig, completion rig, or other units used in completion of the well is released, whichever is later, except that no charge shall be made during suspension of drilling or completion operations for fifteen (15) or more consecutive calendar days.

(2) Charges for wells undergoing any type of workover or recompletion for a period of five (5) consecutive work days or more shall be made at the drilling well rate. Such charges shall be applied for the period from date workover operations, with rig or other units used in workover, commence through date of rig or other unit release, except that no charge shall be made during suspension of operations for fifteen (15) or more consecutive calendar days.

(b) Producing Well Rates

(1) An active well either produced or injected into for any portion of the month shall be considered as a one-well charge for the entire month.

(2) Each active completion in a multi-completed well in which production is not commingled down hole shall be considered as a one-well charge providing each completion is considered a separate well by the governing regulatory authority.

(3) An inactive gas well shut in because of overproduction or failure of purchaser to take the production shall be considered as a one-well charge providing the gas well is directly connected to a permanent sales outlet.

(4) A one-well charge shall be made for the month in which plugging and abandonment operations are completed on any well. This one-well charge shall be made whether or not the well has produced except when drilling well rate applies.

(5) All other inactive wells (including but not limited to inactive wells covered by unit allowable, lease allowable, transferred allowable, etc.) shall not qualify for an overhead charge.

(3) The well rates shall be adjusted as of the first day of April each year following the effective date of the agreement to which this Accounting Procedure is attached. The adjustment shall be computed by multiplying the rate currently in use by the percentage increase or decrease in the average weekly earnings of Crude Petroleum and Gas Production Workers for the last calendar year compared to the calendar year preceding as shown by the index of average weekly earnings of Crude Petroleum and Gas Production Workers as published by the United States Department of Labor, Bureau of Labor Statistics, or the equivalent Canadian index as published by Statistics Canada, as applicable. The adjusted rates shall be the rates currently in use, plus or minus the computed adjustment.

B. Overhead - Percentage Basis

(1) Operator shall charge the Joint Account at the following rates:

(a) Development

_____________ Percent (_____ %) of the cost of development of the Joint Property exclusive of costs provided under Paragraph 10 of Section II and all salvage credits.

(b) Operating

_____________ Percent (_____ %) of the cost of operating the Joint Property exclusive of costs provided under Paragraphs 2 and 10 of Section II, all salvage credits, the value of injected substances purchased for secondary recovery and all taxes and assessments which are levied, assessed and paid upon the mineral interest in and to the Joint Property.

(2) Application of Overhead - Percentage Basis shall be as follows:

For the purpose of determining charges on a percentage basis under Paragraph 1B of this Section III, development shall include all costs in connection with drilling, redrilling, deepening, or any remedial operations on any or all wells involving the use of drilling rig and crew capable of drilling to the producing interval on the Joint Property; also, preliminary expenditures necessary in preparation for drilling and expenditures incurred in abandoning when the well is not completed as a producer, and original cost of construction or installation of fixed assets, the expansion of fixed assets and any other project clearly discernible as a fixed asset, except Major Construction as defined in Paragraph 2 of this Section III. All other costs shall be considered as operating.

2. **Overhead - Major Construction**

To compensate Operator for overhead costs incurred in the construction and installation of fixed assets, the expansion of fixed assets, and any other project clearly discernible as a fixed asset required for the development and operation of the Joint Property, Operator shall either negotiate a rate prior to the beginning of construction, or shall charge the Joint Account for overhead based on the following rates for any Major Construction project in excess of $ 25,000

A. ____5____ % of first $100,000 or total cost if less, plus

B. ____3____ % of costs in excess of $100,000 but less than $1,000,000, plus

C. ____2____ % of costs in excess of $1,000,000.

Total cost shall mean the gross cost of any one project. For the purpose of this paragraph, the component parts of a single project shall not be treated separately and the cost of drilling and workover wells and artificial lift equipment shall be excluded.

3. **Catastrophe Overhead**

To compensate Operator for overhead costs incurred in the event of expenditures resulting from a single occurrence due to oil spill, blowout, explosion, fire, storm, hurricane, or other catastrophes as agreed to by the Parties, which are necessary to restore the Joint Property to the equivalent condition that existed prior to the event causing the expenditures, Operator shall either negotiate a rate prior to charging the Joint Account or shall charge the Joint Account for overhead based on the following rates:

A. ____5____ % of total costs through $100,000; plus

B. ____3____ % of total costs in excess of $100,000 but less than $1,000,000; plus

C. ____2____ % of total costs in excess of $1,000,000.

Expenditures subject to the overheads above will not be reduced by insurance recoveries, and no other overhead provisions of this Section III shall apply.

4. **Amendment of Rates**

The overhead rates provided for in this Section III may be amended from time to time only by mutual agreement between the Parties hereto if, in practice, the rates are found to be insufficient or excessive.

IV. PRICING OF JOINT ACCOUNT MATERIAL PURCHASES, TRANSFERS AND DISPOSITIONS

Operator is responsible for Joint Account Material and shall make proper and timely charges and credits for all Material movements affecting the Joint Property. Operator shall provide all Material for use on the Joint Property; however, at Operator's option, such Material may be supplied by the Non-Operator. Operator shall make timely disposition of idle and/or surplus Material, such disposal being made either through sale to Operator or Non-Operator, division in kind, or sale to outsiders. Operator may purchase, but shall be under no obligation to purchase, interest of Non-Operators in surplus condition A or B Material. The disposal of surplus Controllable Material not purchased by the Operator shall be agreed to by the Parties.

1. **Purchases**

Material purchased shall be charged at the price paid by Operator after deduction of all discounts received. In case of Material found to be defective or returned to vendor for any other reasons, credit shall be passed to the Joint Account when adjustment has been received by the Operator.

2. **Transfers and Dispositions**

Material furnished to the Joint Property and Material transferred from the Joint Property or disposed of by the Operator, unless otherwise agreed to by the Parties, shall be priced on the following basis exclusive of cash discounts:

A. New Material (Condition A)

(1) Tubular Goods Other than Line Pipe

(a) Tubular goods, sized 2⅜ inches OD and larger, except line pipe, shall be priced at Eastern mill published carload base prices effective as of date of movement plus transportation cost using the 80,000 pound carload weight basis to the railway receiving point nearest the Joint Property for which published rail rates for tubular goods exist. If the 80,000 pound rail rate is not offered, the 70,000 pound or 90,000 pound rail rate may be used. Freight charges for tubing will be calculated from Lorain, Ohio and casing from Youngstown, Ohio.

(b) For grades which are special to one mill only, prices shall be computed at the mill base of that mill plus transportation cost from that mill to the railway receiving point nearest the Joint Property as provided above in Paragraph 2.A.(1)(a). For transportation cost from points other than Eastern mills, the 30,000 pound Oil Field Haulers Association interstate truck rate shall be used.

(c) Special end finish tubular goods shall be priced at the lowest published out-of-stock price, f.o.b. Houston, Texas, plus transportation cost, using Oil Field Haulers Association interstate 30,000 pound truck rate, to the railway receiving point nearest the Joint Property.

(d) Macaroni tubing (size less than 2⅜ inch OD) shall be priced at the lowest published out-of-stock prices f.o.b. the supplier plus transportation costs, using the Oil Field Haulers Association interstate truck rate per weight of tubing transferred, to the railway receiving point nearest the Joint Property.

(2) Line Pipe

(a) Line pipe movements (except size 24 inch OD and larger with walls ¾ inch and over) 30,000 pounds or more shall be priced under provisions of tubular goods pricing in Paragraph A.(1)(a) as provided above. Freight charges shall be calculated from Lorain, Ohio.

(b) Line pipe movements (except size 24 inch OD and larger with walls ¾ inch and over) less than 30,000 pounds shall be priced at Eastern mill published carload base prices effective as of date of shipment, plus 20 percent, plus transportation costs based on freight rates as set forth under provisions of tubular goods pricing in Paragraph A.(1)(a) as provided above. Freight charges shall be calculated from Lorain, Ohio.

(c) Line pipe 24 inch OD and over and ¾ inch wall and larger shall be priced f.o.b. the point of manufacture at current new published prices plus transportation cost to the railway receiving point nearest the Joint Property.

(d) Line pipe, including fabricated line pipe, drive pipe and conduit not listed on published price lists shall be priced at quoted prices plus freight to the railway receiving point nearest the Joint Property or at prices agreed to by the Parties.

(3) Other Material shall be priced at the current new price, in effect at date of movement, as listed by a reliable supply store nearest the Joint Property, or point of manufacture, plus transportation costs, if applicable, to the railway receiving point nearest the Joint Property.

(4) Unused new Material, except tubular goods, moved from the Joint Property shall be priced at the current new price, in effect on date of movement, as listed by a reliable supply store nearest the Joint Property, or point of manufacture, plus transportation costs, if applicable, to the railway receiving point nearest the Joint Property. Unused new tubulars will be priced as provided above in Paragraph 2 A (1) and (2).

B. Good Used Material (Condition B)

Material in sound and serviceable condition and suitable for reuse without reconditioning:

(1) Material moved to the Joint Property

At seventy-five percent (75%) of current new price, as determined by Paragraph A.

(2) Material used on and moved from the Joint Property

(a) At seventy-five percent (75%) of current new price, as determined by Paragraph A, if Material was originally charged to the Joint Account as new Material or

(b) At sixty-five percent (65%) of current new price, as determined by Paragraph A, if Material was originally charged to the Joint Account as used Material.

(3) Material not used on and moved from the Joint Property

At seventy-five percent (75%) of current new price as determined by Paragraph A.

The cost of reconditioning, if any, shall be absorbed by the transferring property.

C. Other Used Material

(1) Condition C

Material which is not in sound and serviceable condition and not suitable for its original function until after reconditioning shall be priced at fifty percent (50%) of current new price as determined by Paragraph A. The cost of reconditioning shall be charged to the receiving property, provided Condition C value plus cost of reconditioning does not exceed Condition B value.

(2) Condition D

Material, excluding junk, no longer suitable for its original purpose, but usable for some other purpose shall be priced on a basis commensurate with its use. Operator may dispose of Condition D Material under procedures normally used by Operator without prior approval of Non-Operators.

(a) Casing, tubing, or drill pipe used as line pipe shall be priced as Grade A and B seamless line pipe of comparable size and weight. Used casing, tubing or drill pipe utilized as line pipe shall be priced at used line pipe prices.

(b) Casing, tubing or drill pipe used as higher pressure service lines than standard line pipe, e.g. power oil lines, shall be priced under normal pricing procedures for casing, tubing, or drill pipe. Upset tubular goods shall be priced on a non upset basis.

(3) Condition E

Junk shall be priced at prevailing prices. Operator may dispose of Condition E Material under procedures normally utilized by Operator without prior approval of Non-Operators.

D. Obsolete Material

Material which is serviceable and usable for its original function but condition and/or value of such Material is not equivalent to that which would justify a price as provided above may be specially priced as agreed to by the Parties. Such price should result in the Joint Account being charged with the value of the service rendered by such Material.

E. Pricing Conditions

(1) Loading or unloading costs may be charged to the Joint Account at the rate of twenty-five cents (25¢) per hundred weight on all tubular goods movements, in lieu of actual loading or unloading costs sustained at the stocking point. The above rate shall be adjusted as of the first day of April each year following January 1, 1985 by the same percentage increase or decrease used to adjust overhead rates in Section III, Paragraph 1.A(3). Each year, the rate calculated shall be rounded to the nearest cent and shall be the rate in effect until the first day of April next year. Such rate shall be published each year by the Council of Petroleum Accountants Societies.

(2) Material involving erection costs shall be charged at applicable percentage of the current knocked-down price of new Material.

3. **Premium Prices**

Whenever Material is not readily obtainable at published or listed prices because of national emergencies, strikes or other unusual causes over which the Operator has no control, the Operator may charge the Joint Account for the required Material at the Operator's actual cost incurred in providing such Material, in making it suitable for use, and in moving it to the Joint Property; provided notice in writing is furnished to Non-Operators of the proposed charge prior to billing Non-Operators for such Material. Each Non-Operator shall have the right, by so electing and notifying Operator within ten days after receiving notice from Operator, to furnish in kind all or part of his share of such Material suitable for use and acceptable to Operator.

4. **Warranty of Material Furnished By Operator**

Operator does not warrant the Material furnished. In case of defective Material, credit shall not be passed to the Joint Account until adjustment has been received by Operator from the manufacturers or their agents.

V. INVENTORIES

The Operator shall maintain detailed records of Controllable Material.

1. **Periodic Inventories, Notice and Representation**

At reasonable intervals, inventories shall be taken by Operator of the Joint Account Controllable Material. Written notice of intention to take inventory shall be given by Operator at least thirty (30) days before any inventory is to begin so that Non-Operators may be represented when any inventory is taken. Failure of Non-Operators to be represented at an inventory shall bind Non-Operators to accept the inventory taken by Operator.

2. **Reconciliation and Adjustment of Inventories**

Adjustments to the Joint Account resulting from the reconciliation of a physical inventory shall be made within six months following the taking of the inventory. Inventory adjustments shall be made by Operator to the Joint Account for overages and shortages, but, Operator shall be held accountable only for shortages due to lack of reasonable diligence.

3. **Special Inventories**

Special inventories may be taken whenever there is any sale, change of interest, or change of Operator in the Joint Property. It shall be the duty of the party selling to notify all other Parties as quickly as possible after the transfer of interest takes place. In such cases, both the seller and the purchaser shall be governed by such inventory. In cases involving a change of Operator, all Parties shall be governed by such inventory.

4. **Expense of Conducting Inventories**

A. The expense of conducting periodic inventories shall not be charged to the Joint Account unless agreed to by the Parties.

B. The expense of conducting special inventories shall be charged to the Parties requesting such inventories, except inventories required due to change of Operator shall be charged to the Joint Account.

EXHIBIT "E"

Attached to and Made a Part of
Unit Operating Agreement dated April 15, 1994

1. Conoco Dickinson State #74
2. Conoco Kadrmas #75
3. Conoco Frenzel #79
4. Conoco State #83

EXHIBIT "F"

Equal Opportunity Certifications and Agreements

Attached to and Made a Part of Unit Operating Agreement dated April 15, 1994

This contract shall be performed by Contractor in compliance with all applicable laws, proclamations, orders, rules and regulations, including, without limitation, the following:

I. **Equal Employment Opportunity**

A. **Equal Opportunity Clause (41 CFR 60-1.4).** (Applicable to all contracts for more than $10,000, individually; or if Contractor has such contracts or subcontracts with the Government in any 12-month period which have an aggregate total value (or can reasonably be expected to have an aggregate total value) exceeding $10,000, the $10,000 or under exemption does not apply, and the contracts are subject to the order and the regulations issued pursuant thereto regardless of whether any single contract exceeds $10,000.)

The equal opportunity clause required by Executive Order 11246 of September 24, 1965, and prescribed in section 60-1.4 of Title 41 of the Code of Federal Regulations is incorporated by reference (as permitted by section 60-1.4(d) of said Regulations) as if set out in full at this point.

B. **Certification of Nonsegregated Facilities (41 CFR 60-1.8).** (Applicable only to contracts which are not exempt from the provisions of the Equal Opportunity Clause set out above.)
Contractor certifies that it does not, and will not, maintain or provide for its employees any segregated facilities at any of its establishments, and that it does not and will not, permit its employees to perform their services at any location, under its control, where segregated facilities are maintained. Contractor agrees that a breach of this certification is a violation of the Equal Opportunity Clause required by Executive Order 11246 of September 24, 1965.

As used in this certification, the term "segregated facilities" means any waiting rooms, work areas, rest rooms and wash rooms, restaurants and other eating areas, time clocks, locker rooms and other storage or dressing areas, parking lots, drinking fountains, recreation or entertainment areas, transportation, and housing facilities provided for employees which are segregated by explicit directive or are in fact segregated on the basis of race, color, religion, or national origin, because of habit, local custom, or otherwise.

Contractor further agrees that (except where it has obtained identical certifications from proposed subcontractors for specific time periods) it will obtain identical certifications from proposed subcontractors prior to the award of subcontracts exceeding $10,000 which are not exempt from the provisions of the Equal Opportunity Clause; that it will retain such certifications in its files; and that it will forward the following notice to such proposed subcontractors (except where the proposed subcontractors have submitted identical certifications for specific time periods):

NOTICE TO PROSPECTIVE SUBCONTRACTORS
OF REQUIREMENT FOR CERTIFICATIONS
OF NONSEGREGATED FACILITIES

A Certificate of Nonsegregated Facilities must be submitted prior to the award of a subcontract exceeding $10,000 which is not exempt from the provisions of the Equal Opportunity Clause. The certification may be submitted either for each subcontract or for all subcontracts during a period (i.e., quarterly, semiannually, or annually).

C. **Affirmative Action Compliance Program (41 CFR 60-1.40).** (Applicable only if Contractor (a) has 50 or more employees and (b) has a contract for $50,000 or more.)
If required under section 60-1.40 of Title 41 of the Code of Federal Regulations, Contractor certifies that it has developed, or agrees to develop, a written affirmative action program for each of its establishments within 120 days from the effectiveness of this contract or the first of the contracts of sale. Contractor shall maintain such program until such time as it is no longer required by law or regulation. Contractor shall maintain a copy of separate programs for each establishment, including evaluations of utilization of minority group personnel and the job classifications tables, at each local office responsible for the personnel matters of such establishment.

D. **Employer Information Report (41 CFR 60-1.7).** (Applicable only if Contractor (a) has 50 or more employees, (b) is not exempt pursuant to 41 CFR 60-1.5 from the requirement for filing Employer Information Report EEO-1, and (c) has a contract or subcontract amounting to $50,000 or more.)

If required under section 60-1.7 of Title 41 of the Code of Federal Regulations to file, Contractor hereby certifies that it has filed, or agrees to file, the Employer Information Report, Standard Form 100 (EEO-1), or such form as may hereinafter be promulgated in its place, in accordance with the applicable instructions and will continue to file such report unless and until Contractor is not required to so file by law or regulation.

II. **Affirmative Action for Disabled Veterans and Veterans of the Vietnam Era**

A. **Affirmative Action Clause (41 CFR 60-250.4).** (Applicable only to contracts for $10,000 or more.)
The affirmative action clause prescribed in section 60-250.4 of Title 41 of the Code of Federal Regulations is incorporated by reference (as permitted by section 60-250.22 of said Regulations) as if set out in full at this point.

B. **Affirmative Action Program (41 CFR 60-250.5).** (Applicable to contracts for $10,000 or more only if Contractor (a) has 50 or more employees and (b) holds a contract of $50,000 or more.)
The affirmative action program prescribed in sections 60-250.5 and 60-250.6 of Title 41 of the Code of Federal Regulations is incorporated by reference (as permitted by section 60-250.22 of said Regulations) as if set out in full at this point.

III. **Affirmative Action for Handicapped Workers**

A. **Affirmative Action Clause (41 CFR 60-741.4).** (Applicable only to contracts for $2,500 or more.)
The affirmative action clause prescribed in section 60-741.4 of Title 41 of the Code of Federal Regulations is incorporated herein by reference (as permitted by section 60-741.22 of said Regulations) as if set out in full at this point.

B. **Affirmative Action Program (41 CFR 60-741.5).** (Applicable to contracts for $2,500 or more only if Contractor (a) has 50 or more employees and (b) holds a contract of $50,000 or more.)
The affirmative action program prescribed in sections 60-741.5 and 60-741.6 of Title 41 of the Code of Federal Regulations is incorporated by reference (as permitted by section 60-741.22 of said Regulations) as if set out in full at this point.

IV. **Minority Business Enterprises (41 CFR 1-1.13, Federal Procurement Regulations)**

A. **Utilization of Minority Business Enterprises (41 CFR 1-1.1310-2(c)).** (Applicable only to contracts which may exceed $10,000 except those, and all subcontracts thereunder, to be performed entirely outside the United States, its possessions, and Puerto Rico, and those for services of a personal nature.)

(1) It is the policy of the Government that minority business enterprises shall have the maximum practicable opportunity to participate in the performance of Government contracts.

(2) Contractor agrees to use its best efforts to carry out this policy in the award of its subcontracts to the fullest extent consistent with the efficient performance of this contract. As used in this contract, the term "minority business enterprise" means a business, at least 50 percent of which is owned by minority group members or, in case of publicly owned businesses, at least 51 percent of the stock of which is owned by minority group members. For the purposes of this definition, minority group members are Negroes, Spanish-speaking American persons, American-Orientals, American-Indians, American-Eskimos, and American Aleuts. Contractor may rely on written representations by subcontractors regarding their status as minority business enterprises in lieu of an independent investigation.

B. **Minority Business Enterprises Subcontracting Program** (41 CFR 1-1.1310-2(b)). (Applicable to all contracts which may exceed $500,000 which contain the clause required by 41 CFR 1-1.1310-2(a) and which offer substantial subcontracting possibilities.)

(1) Contractor agrees to establish and conduct a program which will enable minority business enterprises (as defined in the above clause entitled "Utilization of Minority Business Enterprises") to be considered fairly as subcontractors and suppliers under this contract. In this connection, Contractor shall:

(a) Designate a liaison officer who will administer Contractor's minority business enterprises program.

(b) Provide adequate and timely consideration of the potentialities of known minority business enterprises in all "make-or-buy" decisions.

(c) Assure that known minority business enterprises will have an equitable opportunity to compete for subcontracts, particularly by arranging solicitations, time for the preparation of bids, quantities, specifications, and delivery schedules so as to facilitate the participation of minority business enterprises.

(d) Maintain records showing (i) procedures which have been adopted to comply with the policies set forth in this clause, including the establishment of a source list of minority business enterprises, (ii) awards to minority business enterprises on the source list, and (iii) specific efforts to identify and award contracts to minority business enterprises.

(e) Include the Utilization of Minority Business Enterprises clause in subcontracts which offer substantial minority business enterprises subcontracting opportunities.

(f) Cooperate with the Contracting Officer in any studies and surveys of Contractor's minority business enterprises procedures and practices that the Contracting Officer may from time to time conduct.

(g) Submit periodic reports of subcontracting to known minority business enterprises with respect to the records referred to in subparagraph (d), above, in such form and manner and at such time (not more often than quarterly) as the Contracting Officer may prescribe.

(2) Contractor further agrees to insert, in any subcontract hereunder which may exceed $500,000, provisions which shall conform substantially to the language of this clause, including this paragraph (2), and to notify the Contracting Officer of the names of such subcontractors.

EXHIBIT "G"

Attached to and Made a Part of
Unit Operating Agreement dated April 15, 1994

INSURANCE REQUIREMENTS

1. Operator shall carry insurance as follows for the benefit and protection of the Parties to this Agreement:

   a) Workmen's Compensation Insurance in accordance with laws of governmental bodies having jurisdiction including, if applicable, United States Longshore and Harbor Worker's Compensation Act with Outer Continental Shelf Extension and Employers' Liability Insurance. Employers' Liability Insurance shall provide coverage of $100,000 per accident.

   b) Operator may include the aforesaid risks under its qualified self-insurance program provided Operator complies with applicable laws, and in such event Operator shall charge to the Joint Account, a premium determined by applying manual insurance rates to the payroll.

2. Operator shall not be obligated or authorized to obtain or carry on behalf of the Joint Operating Account any additional insurance covering the Parties or the operations to be conducted hereunder without the consent and agreement of all Parties. Each Party individually may acquire at its own expense such insurance as it deems proper to protect itself against claims, losses or damages arising out of the joint operations provided that such insurance shall include a waiver of subrogation against the other Parties in respect of their interests hereunder. All uninsured losses and all damages to jointly owned property shall be borne by the Parties in proportion to their respective interests.

3. Operator shall promptly notify non-operators in writing of all losses involving damage to a jointly owned property in excess of $100,000.

4. Operator shall require all contractors engaged in operations under this Agreement to comply with the applicable Workmen's Compensation laws and to maintain such other insurance with such limits as Operator deems necessary.

5. In the event less than all Parties participate in an operation conducted under the terms of this Agreement, then the insurance requirement and costs, as well as all losses, liabilities, and expenses incurred as the result of such operation, shall be the burden of the Party or Parties participating therein.

A.A.P.L. FORM 610-E - GAS BALANCING AGREEMENT - 1992

AMERICAN ASSOCIATION OF PETROLEUM LANDMEN APPROVED FORM A.A.P.L. NO. 610-E MAY BE ORDERED DIRECTLY FROM THE PUBLISHER KRAFTBILT® P.O. BOX 800 TULSA, OK 74101

NOTE: Instructions For Use of Gas Balancing Agreement MUST be reviewed before finalizing this document.

EXHIBIT "H"

GAS BALANCING AGREEMENT ("AGREEMENT")
ATTACHED TO AND MADE PART OF THAT CERTAIN
OPERATING AGREEMENT DATED April 15, 1994
BY AND BETWEEN Conoco Inc. , as Operator .
AND ______ **("OPERATING AGREEMENT")**
RELATING TO THE Dickinson Lodgepole Unit **AREA,**
Stark **COUNTY/PARISH, STATE OF** North Dakota

1. DEFINITIONS

The following definitions shall apply to this Agreement:

1.01 "Arm's Length Agreement" shall mean any gas sales agreement with an unaffiliated purchaser or any gas sales agreement with an affiliated purchaser where the sales price and delivery conditions under such agreement are representative of prices and delivery conditions existing under other similar agreements in the area between unaffiliated parties at the same time for natural gas of comparable quality and quantity.

1.02 "Balancing Area" shall mean (select one):

☐ each well subject to the Operating Agreement that produces Gas or is allocated a share of Gas production. If a single well is completed in two or more producing intervals, each producing interval from which the Gas production is not commingled in the wellbore shall be considered a separate well.

☒ all of the acreage and depths subject to the Operating Agreement.

☐ ______

1.03 "Full Share of Current Production" shall mean the Percentage Interest of each Party in the Gas actually produced from the Balancing Area during each month.

1.04 "Gas" shall mean all hydrocarbons produced or producible from the Balancing Area, whether from a well classified as an oil well or gas well by the regulatory agency having jurisdiction in such matters, which are or may be made available for sale or separate disposition by the Parties, excluding oil, condensate and other liquids recovered by field equipment operated for the joint account. "Gas" does not include gas used in joint operations, such as for fuel, recycling or reinjection, or which is vented or lost prior to its sale or delivery from the Balancing Area.

1.05 "Makeup Gas" shall mean any Gas taken by an Underproduced Party from the Balancing Area in excess of its Full Share of Current Production, whether pursuant to Section 3.3 or Section 4.1 hereof.

1.06 "Mcf" shall mean one thousand cubic feet. A cubic foot of Gas shall mean the volume of gas contained in one cubic foot of space at a standard pressure base and at a standard temperature base.

1.07 "MMBtu" shall mean one million British Thermal Units. A British Thermal Unit shall mean the quantity of heat required to raise one pound avoirdupois of pure water from 58.5 degrees Fahrenheit to 59.5 degrees Fahrenheit at a constant pressure of 14.73 pounds per square inch absolute.

1.08 "Operator" shall mean the individual or entity designated under the terms of the Operating Agreement or, in the event this Agreement is not employed in connection with an operating agreement, the individual or entity designated as the operator of the well(s) located in the Balancing Area.

1.09 "Overproduced Party" shall mean any Party having taken a greater quantity of Gas from the Balancing Area than the Percentage Interest of such Party in the cumulative quantity of all Gas produced from the Balancing Area.

1.10 "Overproduction" shall mean the cumulative quantity of Gas taken by a Party in excess of its Percentage Interest in the cumulative quantity of all Gas produced from the Balancing Area.

1.11 "Party" shall mean those individuals or entities subject to this Agreement, and their respective heirs, successors, transferees and assigns.

1.12 "Percentage Interest" shall mean the percentage or decimal interest of each Party in the Gas produced from the Balancing Area pursuant to the Operating Agreement covering the Balancing Area.

1.13 "Royalty" shall mean payments on production of Gas from the Balancing Area to all owners of royalties, overriding royalties, production payments or similar interests.

1.14 "Underproduced Party" shall mean any Party having taken a lesser quantity of Gas from the Balancing Area than the Percentage Interest of such Party in the cumulative quantity of all Gas produced from the Balancing Area.

1.15 "Underproduction" shall mean the deficiency between the cumulative quantity of Gas taken by a Party and its Percentage Interest in the cumulative quantity of all Gas produced from the Balancing Area.

1.16 ☒ (Optional) "Winter Period" shall mean the month(s) of November and December in one calendar year and the month(s) of January and February in the succeeding calendar year.

2. BALANCING AREA

2.1 If this Agreement covers more than one Balancing Area, it shall be applied as if each Balancing Area were covered by separate but identical agreements. All balancing hereunder shall be on the basis of Gas taken from the Balancing Area measured in (Alternative 1) ☒ Mcfs or (Alternative 2) ☐ MMBtus.

2.2 In the event that all or part of the Gas deliverable from a Balancing Area is or becomes subject to one or more maximum lawful prices, any Gas not subject to price controls shall be considered as produced from a single Balancing Area and Gas subject to each maximum lawful price category shall be considered produced from a separate Balancing Area.

3. RIGHT OF PARTIES TO TAKE GAS

3.1 Each Party desiring to take Gas will notify the Operator, or cause the Operator to be notified, of the volumes nominated, the name of the transporting pipeline and the pipeline contract number (if available) and meter station relating to such delivery, sufficiently in advance for the Operator, acting with reasonable diligence, to meet all nomination and other requirements. Operator is authorized to deliver the volumes so nominated and confirmed (if confirmation is required) to the transporting pipeline in accordance with the terms of this Agreement.

3.2 Each Party shall make a reasonable, good faith effort to take its Full Share of Current Production each month, to the extent that such production is required to maintain leases in effect, to protect the producing capacity of a well or reservoir, to preserve correlative rights, or to maintain oil production.

3.3 When a Party fails for any reason to take its Full Share of Current Production (as such Share may be reduced by the right of the other Parties to make up for Underproduction as provided herein), the other Parties shall be entitled to take any Gas which such Party fails to take. To the extent practicable, such Gas shall be made available initially to each Underproduced Party in the proportion that its Percentage Interest in the Balancing Area bears to the total Percentage Interests of all Underproduced Parties desiring to take such Gas. If all such Gas is not taken by the Underproduced Parties, the portion not taken shall then be made available to the other Parties in the proportion that their respective Percentage Interests in the Balancing Area bear to the total Percentage Interests of such Parties.

3.4 All Gas taken by a Party in accordance with the provisions of this Agreement, regardless of whether such Party is underproduced or overproduced, shall be regarded as Gas taken for its own account with title thereto being in such taking Party.

3.5 Notwithstanding the provisions of Section 3.3 hereof, no Overproduced Party shall be entitled in any month to take any Gas in excess of three hundred percent (300%) of its Percentage Interest of the Balancing Area's then-current Maximum Monthly Availability; provided, however, that this limitation shall not apply to the extent that it would preclude production that is required to maintain leases in effect, to protect the producing capacity of a well or reservoir, to preserve correlative rights, or to maintain oil production. "Maximum Monthly Availability" shall mean the maximum average monthly rate of production at which Gas can be delivered from the Balancing Area, as determined by the Operator, considering the maximum efficient well rate for each well within the Balancing Area, the maximum allowable(s) set by the appropriate regulatory agency, mode of operation, production facility capabilities and pipeline pressures.

3.6 In the event that a Party fails to make arrangements to take its Full Share of Current Production required to be produced to maintain leases in effect, to protect the producing capacity of a well or reservoir, to preserve correlative rights, or to maintain oil production, the Operator may sell any part of such Party's Full Share of Current Production that such Party fails to take for the account of such Party and render to such Party, on a current basis, the full proceeds of the sale, less any reasonable marketing, compression, treating, gathering or transportation costs incurred directly in connection with the sale of such Full Share of Current Production. In making the sale contemplated herein, the Operator shall be obligated only to obtain such price and conditions for the sale as are reasonable under the circumstances and shall not be obligated to share any of its markets. Any such sale by Operator under the terms hereof shall be only for such reasonable periods of time as are consistent with the minimum needs of the industry under the particular circumstances, but in no event for a period in excess of one year. Notwithstanding the provisions of Article 3.4 hereof, Gas sold by Operator for a Party under the provisions hereof shall be deemed to be Gas taken for the account of such Party.

4. IN-KIND BALANCING

4.1 Effective the first day of any calender month following at least thirty (30) days prior written notice to the Operator, any Underproduced Party may begin taking, in addition to its Full Share of Current Production and any Makeup Gas taken pursuant to Section 3.3 of this Agreement, a share of current production determined by multiplying fifty percent (50 %) of the Full Shares of Current Production of all Overproduced Parties by a fraction, the numerator of which is the Percentage Interest of such Underproduced Party and the denominator of which is the total of the Percentage Interests of all Underproduced Parties desiring to take Makeup Gas. In no event will an Overproduced Party be required to provide more than one hundred percent (100 %) of its Full Share of Current Production for Makeup Gas. The Operator will promptly notify all Overproduced Parties of the election of an Underproduced Party to begin taking Makeup Gas.

4.2 ☐ **(Optional - Seasonal Limitation on Makeup - Option 1)** Notwithstanding the provisions of Section 4.1, the average monthly amount of Makeup Gas taken by an Underproduced Party during the Winter Period pursuant to Section 4.1 shall not exceed the average monthly amount of Makeup Gas taken by such Underproduced Party during the ______ (____) months immediately preceding the Winter Period.

4.2 ☒ **(Optional - Seasonal Limitation on Makeup - Option 2)** Notwithstanding the provisions of Section 4.1, no Overproduced Party will be required to provide more than fifty percent (50 %) of its Full Share of Current Production for Makeup Gas during the Winter Period.

4.3 ☒ **(Optional)** Notwithstanding any other provision of this Agreement, at such time and for so long as Operator, or (insofar as concerns production by the Operator) any Underproduced Party, determines in good faith that an Overproduced Party has produced all of its share of the ultimately recoverable reserves in the Balancing Area, such Overproduced Party may be required to make available for Makeup Gas, upon the demand of the Operator or any Underproduced Party, up to one hundred percent (100%) of such Overproduced Party's Full Share of Current Production.

5. STATEMENT OF GAS BALANCES

5.1 The Operator will maintain appropriate accounting on a monthly and cumulative basis of the volumes of Gas that each Party is entitled to receive and the volumes of Gas actually taken or sold for each Party's account. Within forty-five (45) days after the month of production, the Operator will furnish a statement for such month showing (1) each Party's Full Share of Current Production, (2) the total volume of Gas actually taken or sold for each Party's account, (3) the difference between the volume taken by each Party and that Party's Full Share of Current Production, (4) the Overproduction or Underproduction of each Party, and (5) other data as recommended by the provisions of the Council of Petroleum Accountants Societies Bulletin No. 24, as amended or supplemented hereafter. Each Party taking Gas will promptly provide to the Operator any data required by the Operator for preparation of the statements required hereunder.

5.2 If any Party fails to provide the data required herein for four (4) consecutive production months, the Operator, or where the Operator has failed to provide data, another Party, may audit the production and Gas sales and transportation volumes of the non-reporting Party to provide the required data. Such audit shall be conducted only after reasonable notice and during normal business hours in the office of the Party whose records are being audited. All costs associated with such audit will be charged to the account of the Party failing to provide the required data.

6. PAYMENTS ON PRODUCTION

6.1 Each Party taking Gas shall pay or cause to be paid all production and severance taxes due on all volumes of Gas actually taken by such Party.

6.2 ☐ (Alternative 1 - Entitlements) Each Party shall pay or cause to be paid all Royalty due with respect to Royalty owners to whom it is accountable as if such Party were taking its Full Share of Current Production, and only its Full Share of Current Production.

6.2.1 ☐ **(Optional - For use only with Section 6.2 - Alternative 1 - Entitlement)** Upon written request of a Party taking less than its Full Share of Current Production in a given month ("Current Underproducer"), any Party taking more than its Full Share of Current Production in such month ("Current Overproducer") will pay to such Current Underproducer an amount each month equal to the Royalty percentage of the proceeds received by the Current Overproducer for that portion of the Current Underproducer's Full Share of Current Production taken by the Current Overproducer; provided, however, that such payment will not exceed the Royalty percentage that is common to all Royalty burdens in the Balancing Area. Payments made pursuant to this Section 6.2.1 will be deemed payments to the Underproduced Party's Royalty owners for purposes of Section 7.5.

6.2 ☒ **(Alternative 2 - Sales)** Each Party shall pay or cause to be paid Royalty due with respect to Royalty owners to whom it is accountable based on the volume of Gas actually taken for its account.

6.3 In the event that any governmental authority requires that Royalty payments be made on any other basis than that provided for in this Section 6, each Party agrees to make such Royalty payments accordingly, commencing on the effective date required by such governmental authority, and the method provided for herein shall be thereby superseded.

7. CASH SETTLEMENTS

7.1 Upon the earlier of the plugging and abandonment of the last producing interval in the Balancing Area, the termination of the Operating Agreement or any pooling or unit agreement covering the Balancing Area, or at any time no Gas is taken from the Balancing Area for a period of twelve (12) consecutive months, any Party may give written notice calling for cash settlement of the Gas production imbalances among the Parties. Such notice shall be given to all Parties in the Balancing Area.

7.2 Within sixty (60) days after the notice calling for cash settlement under Section 7.1, the Operator will distribute to each Party a Final Gas Settlement Statement detailing the quantity of Overproduction owed by each Overproduced Party to each Underproduced Party and identifying the month to which such Overproduction is attributed, pursuant to the methodology set out in Section 7.4.

7.3 ☐ **(Alternative 1 - Direct Party-to-Party Settlement)** Within sixty (60) days after receipt of the Final Gas Settlement Statement, each Overproduced Party will pay to each Underproduced Party entitled to settlement the appropriate cash settlement, accompanied by appropriate accounting detail. At the time of payment, the Overproduced Party will notify the Operator of the Gas imbalance settled by the Overproduced Party's payment.

7.3 ☒ **(Alternative 2 - Settlement Through Operator)** Within sixty (60) days after receipt of the Final Gas Settlement Statement, each Overproduced Party will send its cash settlement, accompanied by appropriate accounting detail, to the Operator. The Operator will distribute the monies so received, along with any settlement owed by the Operator as an Overproduced Party, to each Underproduced Party to whom settlement is due within ninety (90) days after issuance of the Final Gas Settlement Statement. In the event that any Overproduced Party fails to pay any settlement due hereunder, the Operator may turn over responsibility for the collection of such settlement to the Party to whom it is owed, and the Operator will have no further responsibility with regard to such settlement.

7.3.1 ☒ **(Optional - For use only with Section 7.3, Alternative 2 - Settlement Through Operator)** Any Party shall have the right at any time upon thirty (30) days' prior written notice to all other Parties to demand that any settlements due such Party for Overproduction be paid directly to such Party by the Overproduced Party, rather than being paid through the Operator. In the event that an Overproduced Party pays the Operator any sums due to an Underproduced Party at any time after thirty (30) days following the receipt of the notice provided for herein, the Overproduced Party will continue to be liable to such Underproduced Party for any sums so paid, until payment is actually received by the Underproduced Party.

7.4 ☒ **(Alternative 1 - Historical Sales Basis)** The amount of the cash settlement will be based on the proceeds received by the Overproduced Party under an Arm's Length Agreement for the Gas taken from time to time by the Overproduced Party in excess of the Overproduced Party's Full Share of Current Production. Any Makeup Gas taken by the Underproduced Party prior to monetary settlement hereunder will be applied to offset Overproduction chronologically in the order of accrual.

7.4 ☐ **(Alternative 2 - Most Recent Sales Basis)** The amount of the cash settlement will be based on the proceeds received by the Overproduced Party under an Arm's Length Agreement for the volume of Gas that constituted Overproduction by the Overproduced Party from the Balancing Area. For the purpose of implementing the cash settlement provision of the Section 7, an Overproduced Party will not be considered to have produced any of an Underproduced Party's share of Gas until the Overproduced Party has produced cumulatively all of its Percentage Interest share of the Gas ultimately produced from the Balancing Area.

7.5 The values used for calculating the cash settlement under Section 7.4 will include all proceeds received for the sale of the Gas by the Overproduced Party calculated at the Balancing Area, after deducting any production or severance taxes paid and any Royalty actually paid by the Overproduced Party to an Underproduced Party's Royalty owner(s), to the extent said payments amounted to a discharge of said Underproduced Party's Royalty obligation, as well as any reasonable marketing, compression, treating, gathering or transportation costs incurred directly in connection with the sale of the Overproduction.

7.5.1 ☐ **(Optional - For Valuation Under Percentage of Proceeds Contracts)** For Overproduction sold under a gas purchase contract providing for payment based on a percentage of the proceeds obtained by the purchaser upon resale of residue gas and liquid hydrocarbons extracted at a gas processing plant, the values used for calculating cash settlement will include proceeds received by the Overproduced Party for both the liquid hydrocarbons and the residue gas attributable to the Overproduction.

7.5.2 ☒ **(Optional - Valuation for Processed Gas - Option 1)** For Overproduction processed for the account of the Overproduced Party at a gas processing plant for the extraction of liquid hydrocarbons, the full quantity of the Overproduction will be valued for purposes of cash settlement at the prices received by the Overproduced Party for the sale of the residue gas attributable to the Overproduction without regard to proceeds attributable to liquid hydrocarbons which may have been extracted from the Overproduction.

7.5.2 ☐ **(Optional - Valuation for Processed Gas - Option 2)** For Overproduction processed for the account of the Overproduced Party at a gas processing plant for the extraction of liquid hydrocarbons, the values used for calculating cash settlement will include the proceeds received by the Overproduced Party for the sale of the liquid hydrocarbons extracted from the Overproduction, less the actual reasonable costs incurred by the Overproduced Party to process the Overproduction and to transport, fractionate and handle the liquid hydrocarbons extracted therefrom prior to sale.

7.6 To the extent the Overproduced Party did not sell all Overproduction under an Arm's Length Agreement, the cash settlement will be based on the weighted average price received by the Overproduced Party for any gas sold from the

Balancing Area under Arm's Length Agreements during the months to which such Overproduction is attributed. In the event that no sales under Arm's Length Agreements were made during any such month, the cash settlement for such month will be based on the spot sales prices published for the applicable geographic area during such month in a mutually acceptable pricing bulletin.

7.7 Interest compounded at the prime rate in effect at Citibank NA, New York, plus one percent (~~rate of ______ percent (___%)~~ per annum or the maximum lawful rate of interest applicable to the Balancing Area, whichever is less, will accrue for all amounts due under Section 7.1, beginning the first day following the date payment is due pursuant to Section 7.3. Such interest shall be borne by the Operator or any Overproduced Party in the proportion that their respective delays beyond the deadlines set out in Sections 7.2 and 7.3 contributed to the accrual of the interest.

7.8 In lieu of the cash settlement required by Section 7.3, an Overproduced Party may deliver to the Underproduced Party an offer to settle its Overproduction in-kind and at such rates, quantities, times and sources as may be agreed upon by the Underproduced Party. If the Parties are unable to agree upon the manner in which such in-kind settlement gas will be furnished within sixty (60) days after the Overproduced Party's offer to settle in kind, which period may be extended by agreement of said Parties, the Overproduced Party shall make a cash settlement as provided in Section 7.3. The making of an in-kind settlement offer under this Section 7.8 will not delay the accrual of interest on the cash settlement should the Parties fail to reach agreement on an in-kind settlement.

7.9 ☒ **(Optional - For Balancing Areas Subject to Federal Price Regulation)** That portion of any monies collected by an Overproduced Party for Overproduction which is subject to refund by orders of the Federal Energy Regulatory Commission or other governmental authority may be withheld by the Overproduced Party until such prices are fully approved by such governmental authority, unless the Underproduced Party furnishes a corporate undertaking, acceptable to the Overproduced Party, agreeing to hold the Overproduced Party harmless from financial loss due to refund orders by such governmental authority.

7.10 ☒ **(Optional - Interim Cash Balancing)** At any time during the term of this Agreement, any Overproduced Party may, in its sole discretion, make cash settlement(s) with the Underproduced Parties covering all or part of its outstanding Gas imbalance, provided that such settlements must be made with all Underproduced Parties proportionately based on the relative imbalances of the Underproduced Parties, and provided further that such settlements may not be made more often than once every twenty-four (24) months. Such settlements will be calculated in the same manner provided above for final cash settlements. The Overproduced Party will provide Operator a detailed accounting of any such cash settlement within thirty (30) days after the settlement is made.

8. TESTING

Notwithstanding any provision of this Agreement to the contrary, any Party shall have the right, from time to time, to produce and take up to one hundred percent (100%) of a well's entire Gas stream to meet the reasonable deliverability test(s) required by such Party's Gas purchaser, and the right to take any Makeup Gas shall be subordinate to the right of any Party to conduct such tests; provided, however, that such tests shall be conducted in accordance with prudent operating practices only after ten (10) days' prior written notice to the Operator and shall last no longer than seventy-two (72) hours.

9. OPERATING COSTS

Nothing in this Agreement shall change or affect any Party's obligation to pay its proportionate share of all costs and liabilities incurred in operations on or in connection with the Balancing Area, as its share thereof is set forth in the Operating Agreement, irrespective of whether any Party is at any time selling and using Gas or whether such sales or use are in proportion to its Percentage Interest in the Balancing Area.

10. LIQUIDS

The Parties shall share proportionately in and own all liquid hydrocarbons recovered with Gas by field equipment operated for the joint account in accordance with their Percentage Interests in the Balancing Area.

11. AUDIT RIGHTS

Notwithstanding any provision in this Agreement or any other agreement between the Parties hereto, and further notwithstanding any termination or cancellation of this Agreement, for a period of two (2) years from the end of the calendar year in which any information to be furnished under Section 5 or 7 hereof is supplied, any Party shall have the right to audit the records of any other Party regarding quantity, including but not limited to information regarding Btu-content. Any Underproduced Party shall have the right for a period of two (2) years from the end of the calendar year in which any cash settlement is received pursuant to Section 7 to audit the records of any Overproduced Party as to all matters concerning values, including but not limited to information regarding prices and disposition of Gas from the Balancing Area. Any such audit shall be conducted at the expense of the Party or Parties desiring such audit, and shall be conducted, after reasonable notice, during normal business hours in the office of the Party whose records are being audited. Each Party hereto agrees to maintain records as to the volumes and prices of Gas sold each month and the volumes of Gas used in its own operations, along with the Royalty paid on any such Gas used by a Party in its own operations. The audit rights provided for in this Section 11 shall be in addition to those provided for in Section 5.2 of this Agreement.

12. MISCELLANEOUS

12.1 As between the Parties, in the event of any conflict between the provisions of this Agreement and the provisions of any gas sales contract, or in the event of any conflict between the provisions of this Agreement and the provisions of the Operating Agreement, the provisions of this Agreement shall govern.

12.2 Each Party agrees to defend, indemnify and hold harmless all other Parties from and against any and all liability for any claims, which may be asserted by any third party which now or hereafter stands in a contractual relationship with such indemnifying Party and which arise out of the operation of this Agreement or any activities of such indemnifying Party under the provisions of this Agreement, and does further agree to save the other Parties harmless from all judgments or damages sustained and costs incurred in connection therewith.

12.3 Except as otherwise provided in this Agreement, Operator is authorized to administer the provisions of this Agreement, but shall have no liability to the other Parties for losses sustained or liability incurred which arise out of or in connection with the performance of Operator's duties hereunder, except such as may result from Operator's gross negligence or willful misconduct. Operator shall not be liable to any Underproduced Party for the failure of any Overproduced Party (other than Operator) to pay any amounts owed pursuant to the terms hereof.

12.4 This Agreement shall remain in full force and effect for as long as the Operating Agreement shall remain in force and effect as to the Balancing Area, and thereafter until the Gas accounts between the Parties are settled in full, and shall inure to the benefit of and be binding upon the Parties hereto, and their respective heirs, successors, legal representatives and assigns, if any. The Parties hereto agree to give notice of the existence of this Agreement to any successor in interest of any such Party and to provide that any such successor shall be bound by this Agreement, and shall further make any transfer of any interest subject to the Operating Agreement, or any part thereof, also subject to the terms of this Agreement.

12.5 Unless the context clearly indicates otherwise, words used in the singular include the plural, the plural includes the singular, and the neuter gender includes the masculine and the feminine.

12.6 In the event that any "Optional" provision of this Agreement is not adopted by the Parties to this Agreement by a typed, printed or handwritten indication, such provision shall not form a part of this Agreement, and no inference shall be made concerning the intent of the Parties in such event. In the event that any "Alternative" provision of this Agreement is not so adopted by the Parties, Alternative 1 in each such instance shall be deemed to have been adopted by the Parties as a result of any such omission. In those cases where it is indicated that an Optional provision may be used only if a specific Alternative is selected: (i) an election to include said Optional provision shall not be effective unless the Alternative in question is selected; and (ii) the election to include said Optional provision must be expressly indicated hereon, it being understood that the selection of an Alternative either expressly or by default as provided herein shall not, in and of itself, constitute an election to include an associated Optional provision.

12.7 This Agreement shall bind the Parties in accordance with the provisions hereof, and nothing herein shall be construed or interpreted as creating any rights in any person or entity not a signatory hereto, or as being a stipulation in favor of any such person or entity.

12.8 If contemporaneously with this Agreement becoming effective, or thereafter, any Party requests that any other Party execute an appropriate memorandum or notice of this Agreement in order to give third parties notice of record of same and submits same for execution in recordable form, such memorandum or notice shall be duly executed by the Party to which such request is made and delivered promptly thereafter to the Party making the request. Upon receipt, the Party making the request shall cause the memorandum or notice to be duly recorded in the appropriate real property or other records affecting the Balancing Area.

12.9 In the event Internal Revenue Service regulations require a uniform method of computing taxable income by all Parties, each Party agrees to compute and report income to the Internal Revenue Service (select one) ☐ as if such Party were taking its Full Share of Current Production during each relevant tax period in accordance with such regulations, insofar as same relate to entitlement method tax computations; or ☒ based on the quantity of Gas taken for its account in accordance with such regulations, ~~insofar as same relate to sales method tax computations.~~ (the cumulative metho

13. ASSIGNMENT AND RIGHTS UPON ASSIGNMENT

13.1 Subject to the provisions of Sections 13.2 (if elected) and 13.3 hereof, and notwithstanding anything in this Agreement or in the Operating Agreement to the contrary, if any Party assigns (including any sale, exchange or other transfer) any of its working interest in the Balancing Area when such Party is an Underproduced or Overproduced Party, the assignment or other act of transfer shall, insofar as the Parties hereto are concerned, include all interest of the assigning or transferring Party in the Gas, all rights to receive or obligations to provide or take Makeup Gas and all rights to receive or obligations to make any monetary payment which may ultimately be due hereunder, as applicable. Operator and each of the other Parties hereto shall thereafter treat the assignment accordingly, and the assigning or transferring Party shall look solely to its assignee or other transferee for any interest in the Gas or monetary payment that such Party may have or to which it may be entitled, and shall cause its assignee or other transferee to assume its obligations hereunder.

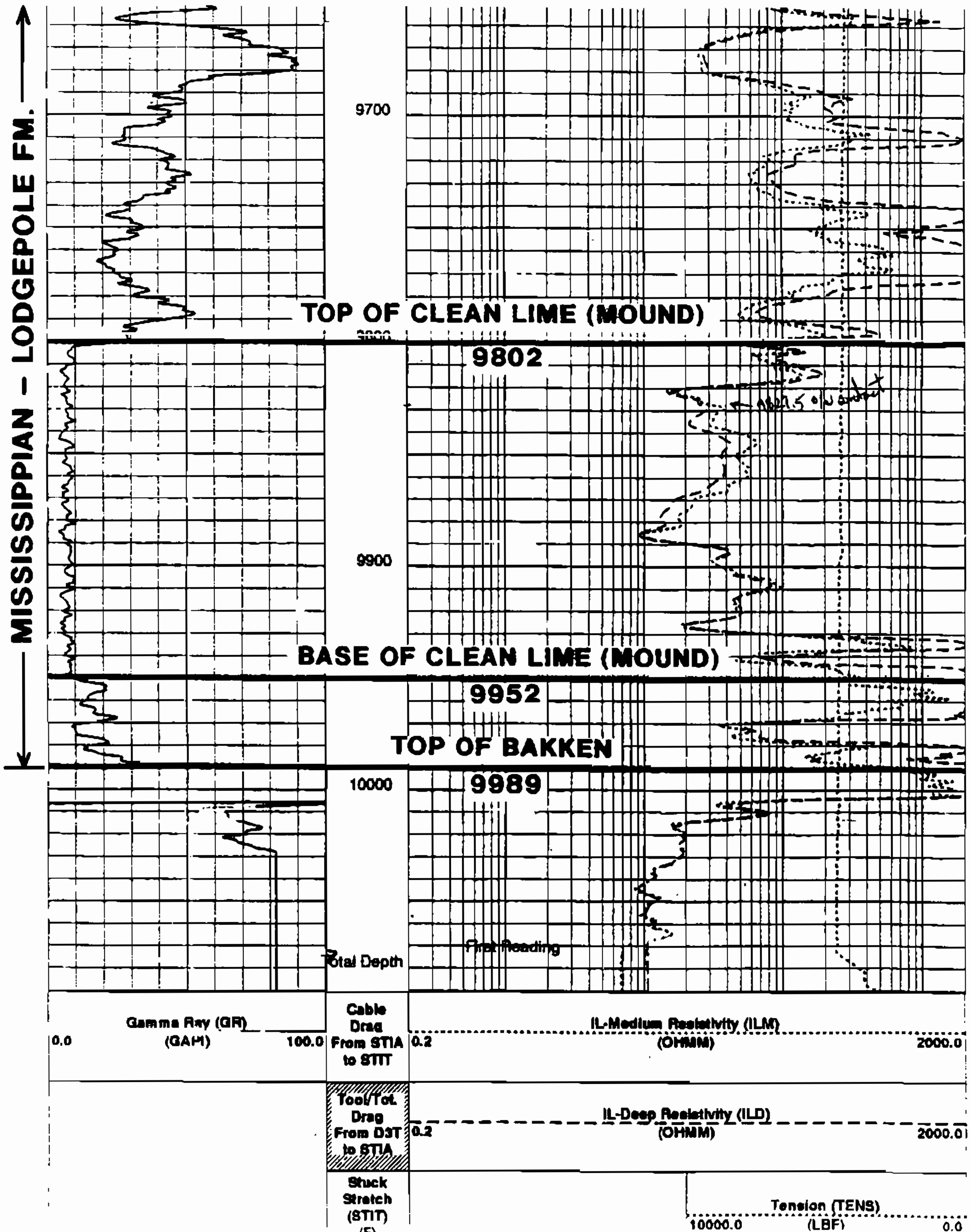
13.2 ☒ (Optional - Cash Settlement Upon Assignment) Notwithstanding anything in this Agreement (including but not limited to the provisions of Section 13.1 hereof) or in the Operating Agreement to the contrary, and subject to the provisions of Section 13.3 hereof, in the event an Overproduced Party intends to sell, assign, exchange or otherwise transfer any of its interest in a Balancing Area, such Overproduced Party shall notify in writing the other working interest owners who are Parties hereto in such Balancing Area of such fact at least thirty (30) days prior to closing the transaction. Thereafter, any Underproduced Party may demand from such Overproduced Party in writing, within thirty (30) days after receipt of the Overproduced Party's notice, a cash settlement of its Underproduction from the Balancing Area. The Operator shall be notified of any such demand and of any cash settlement pursuant to this Section 13, and the Overproduction and Underproduction of each Party shall be adjusted accordingly. Any cash settlement pursuant to this Section 13 shall be paid by the Overproduced Party on or before the earlier to occur (i) of sixty (60) days after receipt of the Underproduced Party's demand or (ii) at the closing of the transaction in which the Overproduced Party sells, assigns, exchanges or otherwise transfers its interest in a Balancing Area on the same basis as otherwise set forth in Sections 7.3 through 7.6 hereof, and shall bear interest at the rate set forth in Section 7.7 hereof, beginning sixty (60) days after the Overproduced Party's sale, assignment, exchange or transfer of its interest in the Balancing Area for any amounts not paid. Provided, however, if any Underproduced Party does not so demand such cash settlement of its Underproduction from the Balancing Area, such Underproduced Party shall look exclusively to the assignee or other successor in interest of the Overproduced Party giving notice hereunder for the satisfaction of such Underproduced Party's Underproduction in accordance with the provisions of Section 13.1 hereof.

13.3 The provisions of this Section 13 shall not be applicable in the event any Party mortgages its interest or disposes of its interest by merger, reorganization, consolidation or sale of substantially all of its assets to a subsidiary or parent company, or to any company in which any parent or subsidiary of such Party owns a majority of the stock of such company.

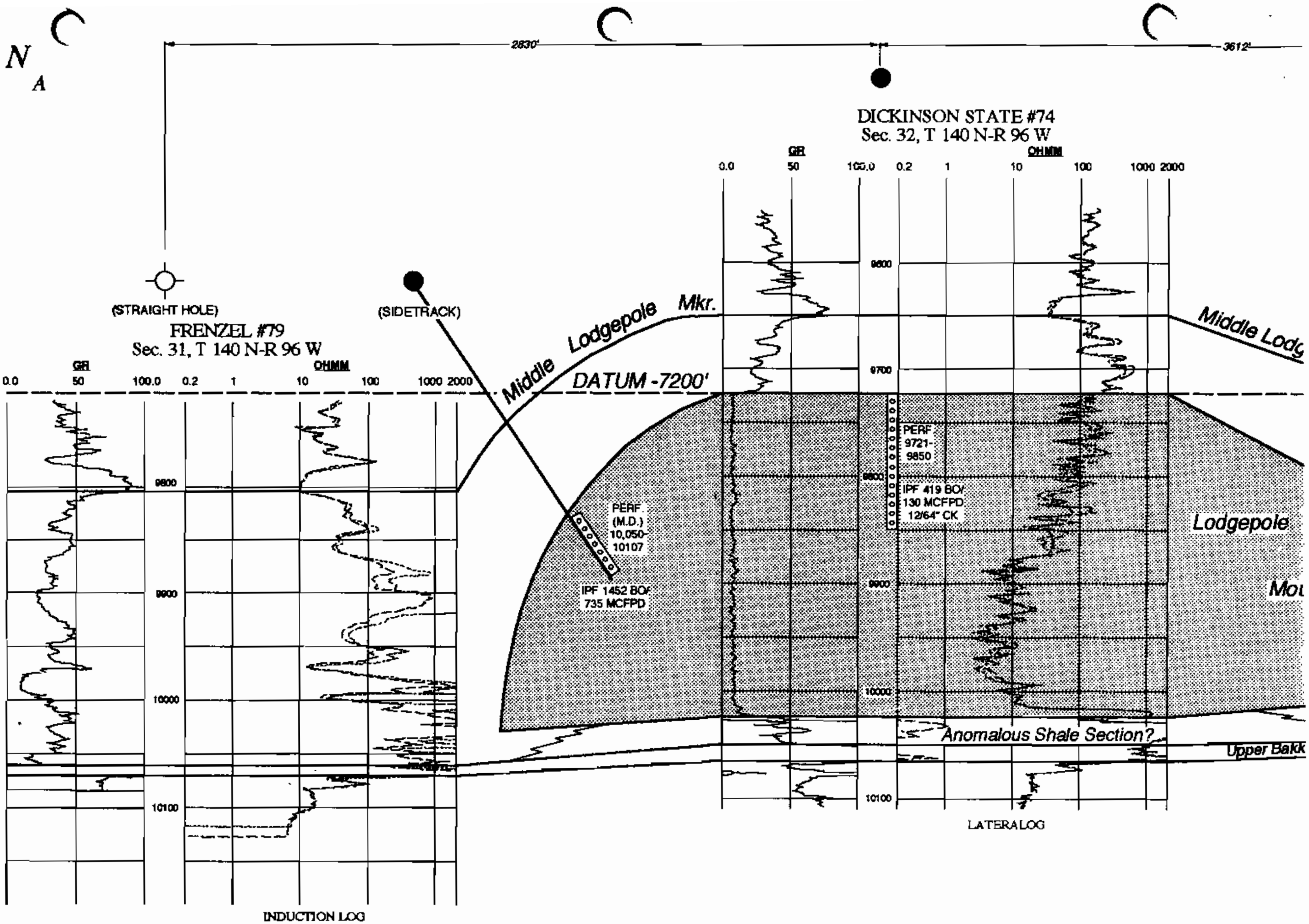
14. OTHER PROVISIONS

State A 83

Sec. 5, T.139 N.– R.96 W



CONOCO INC.
Case No. 5933
Exhibit No. 7



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IPF 419 BO/ 130 MCFPD 12/64" CK
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LATERALOG
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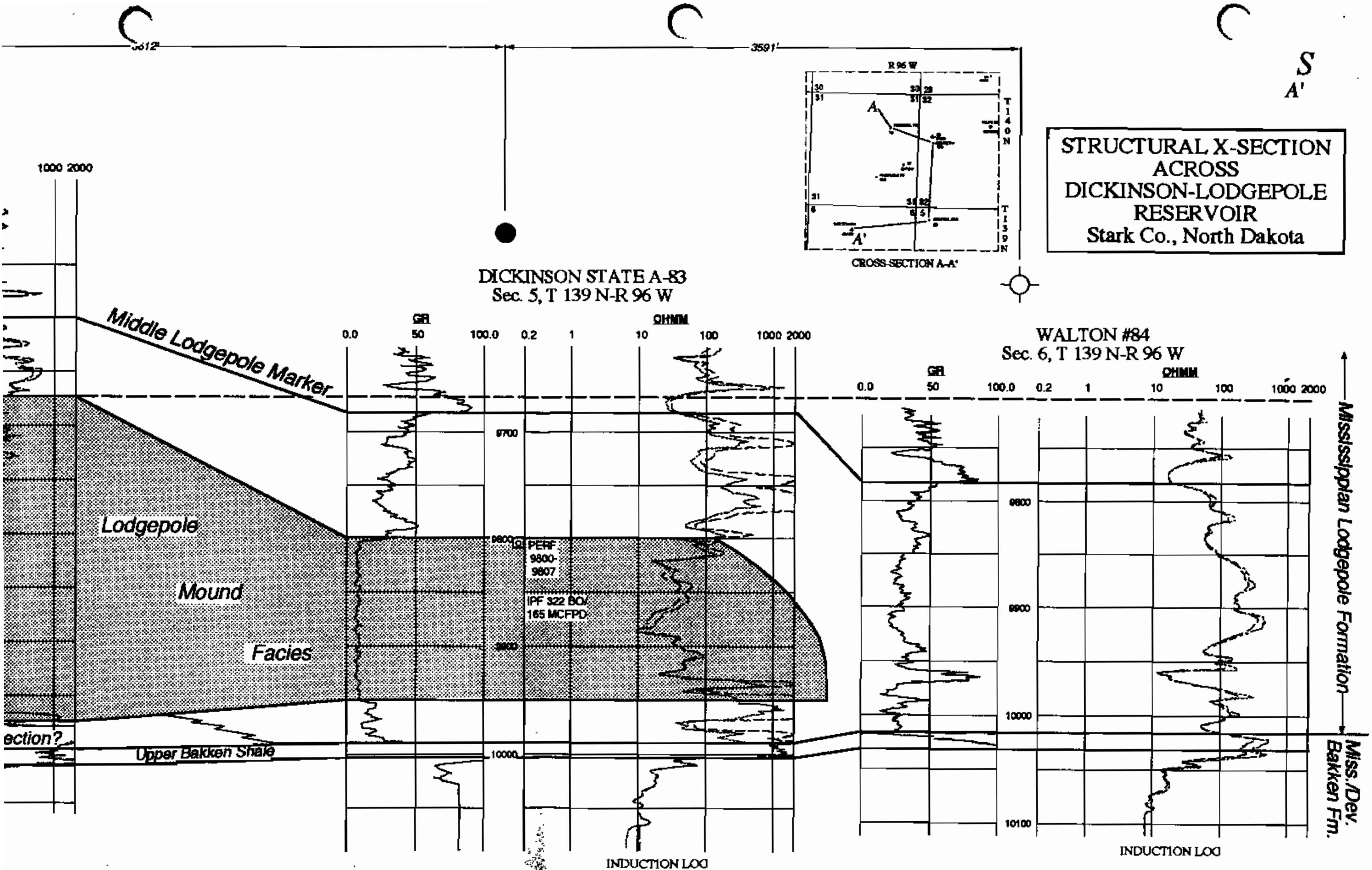
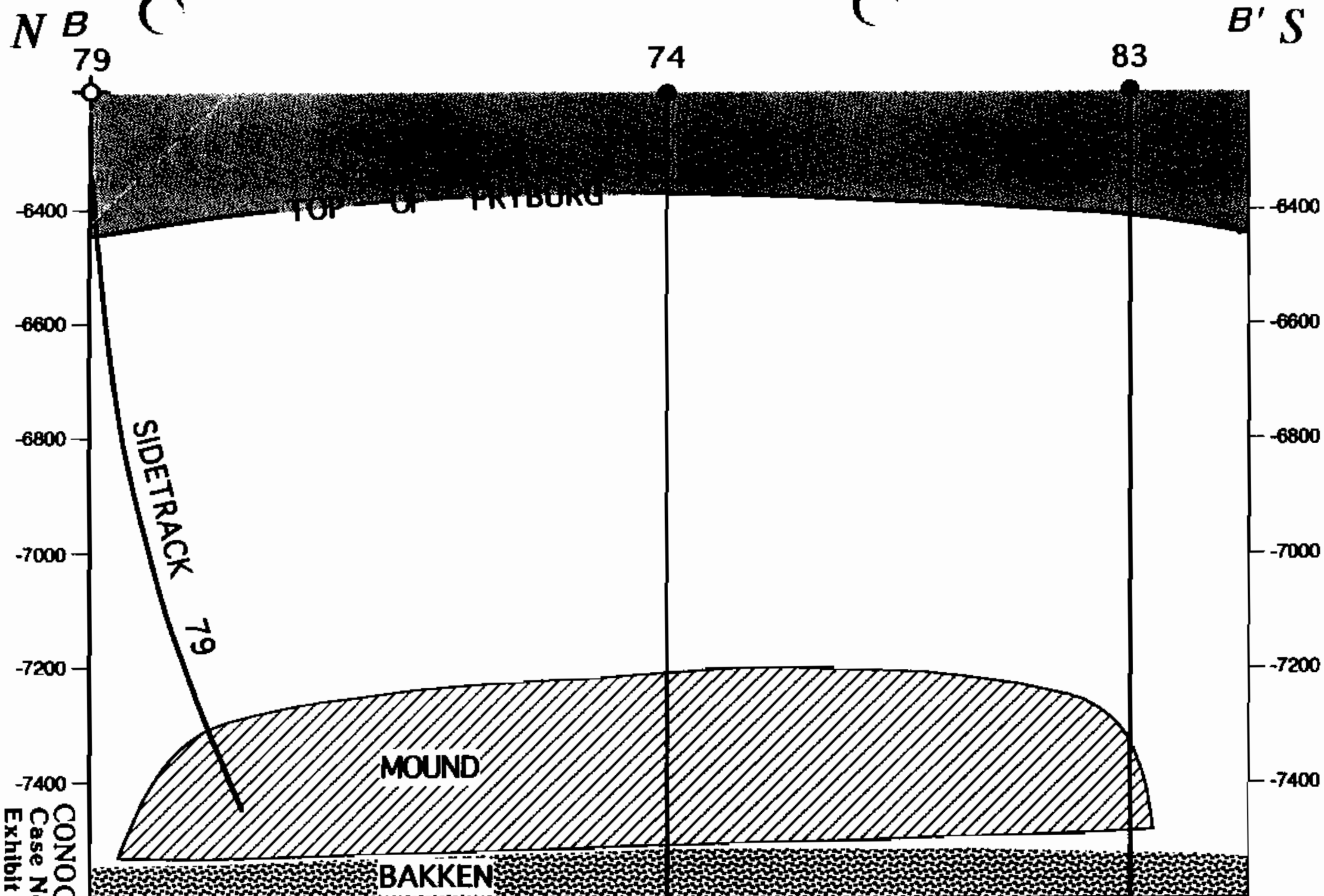
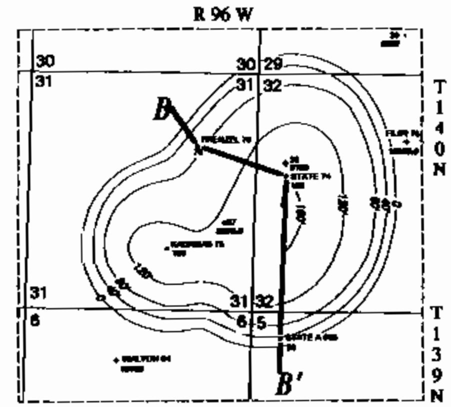


CONOCO INC.
Case No. 5933
Exhibit No. 8



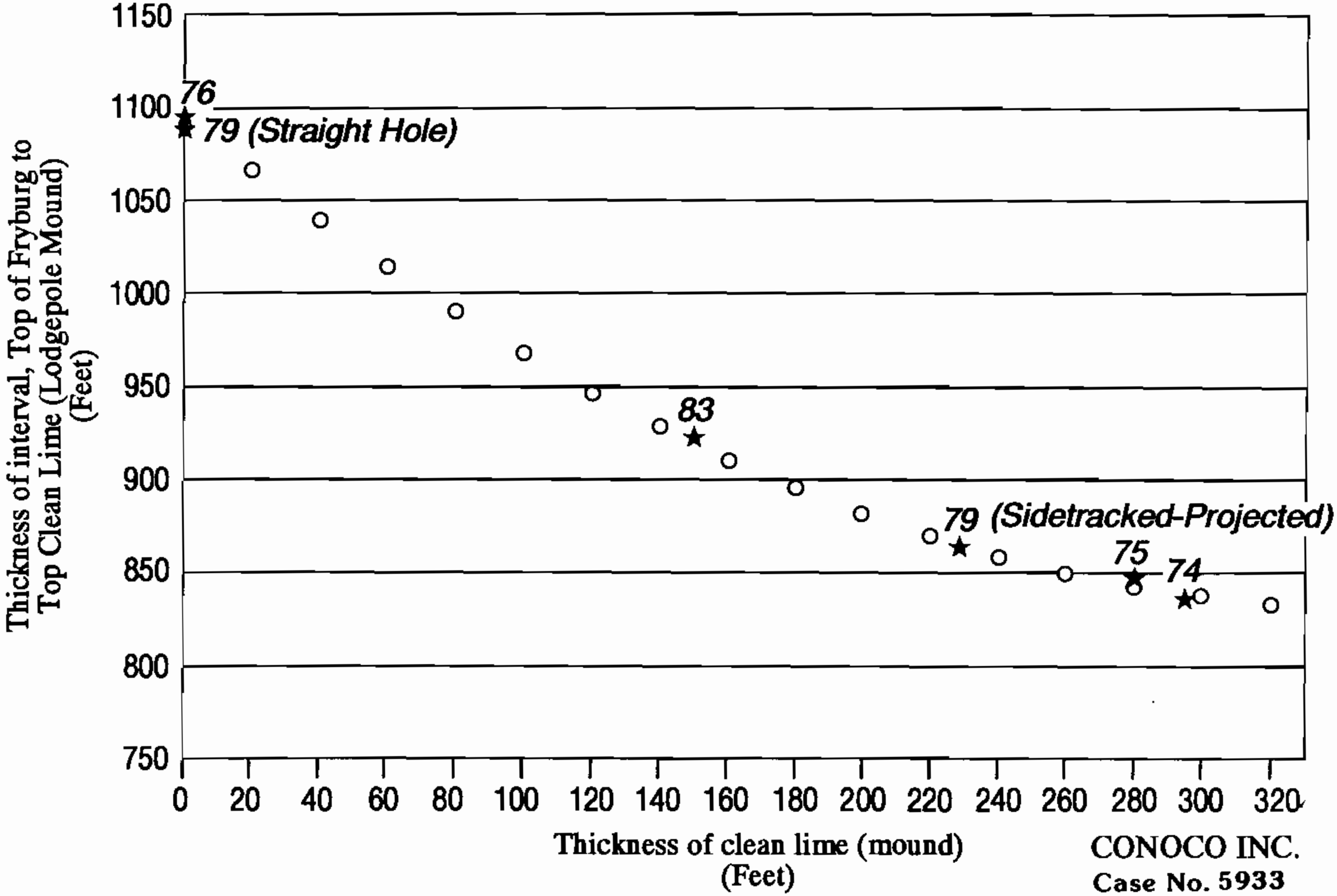


CROSS-SECTION B-B'
ISOPACH OF LODGEPOLE PAY

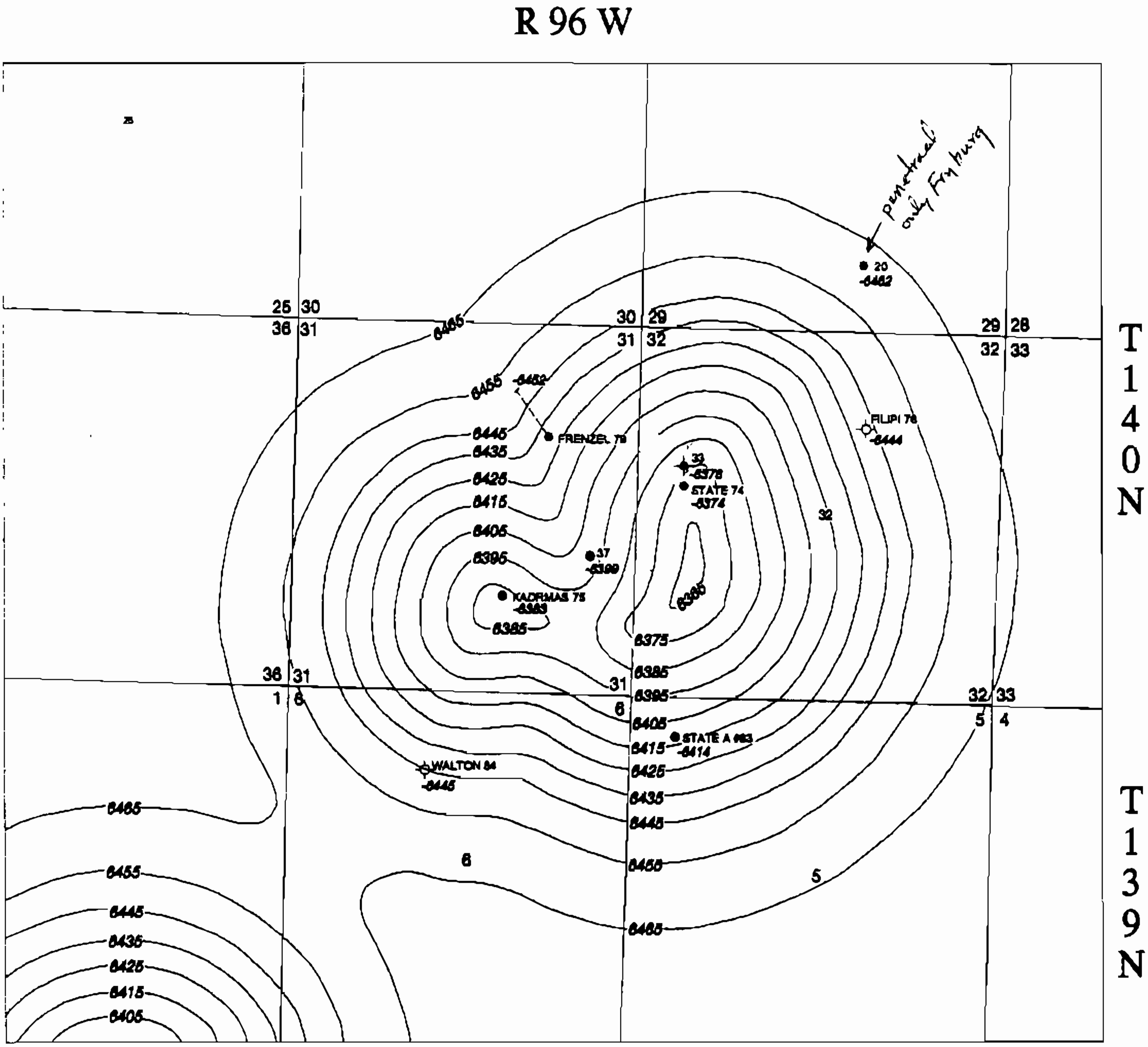
CONOCO INC.
Case No. 5933
Exhibit No. 9

SCHEMATIC X-SECTION THROUGH DICKINSON (LODGEPOLE) RESERVOIR

RELATIONSHIP OF MOUND THICKNESS TO FRYBURG STRUCTURE



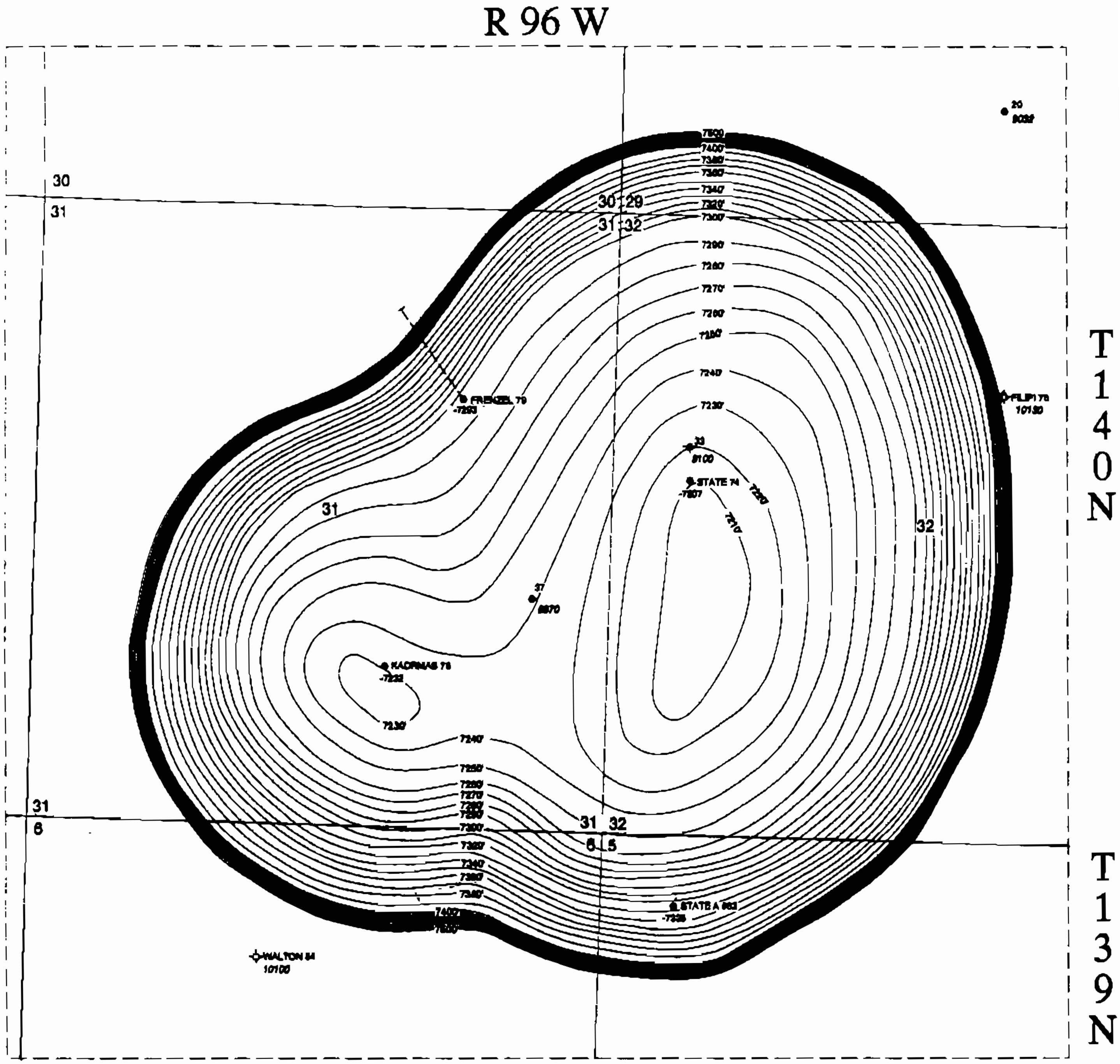
CONOCO INC.
Case No. 5933
Exhibit No. 10



Contour Interval: 10 Feet

SUBSEA TOP OF FRYBURG ZONE
Dickinson Field
Stark Co., North Dakota

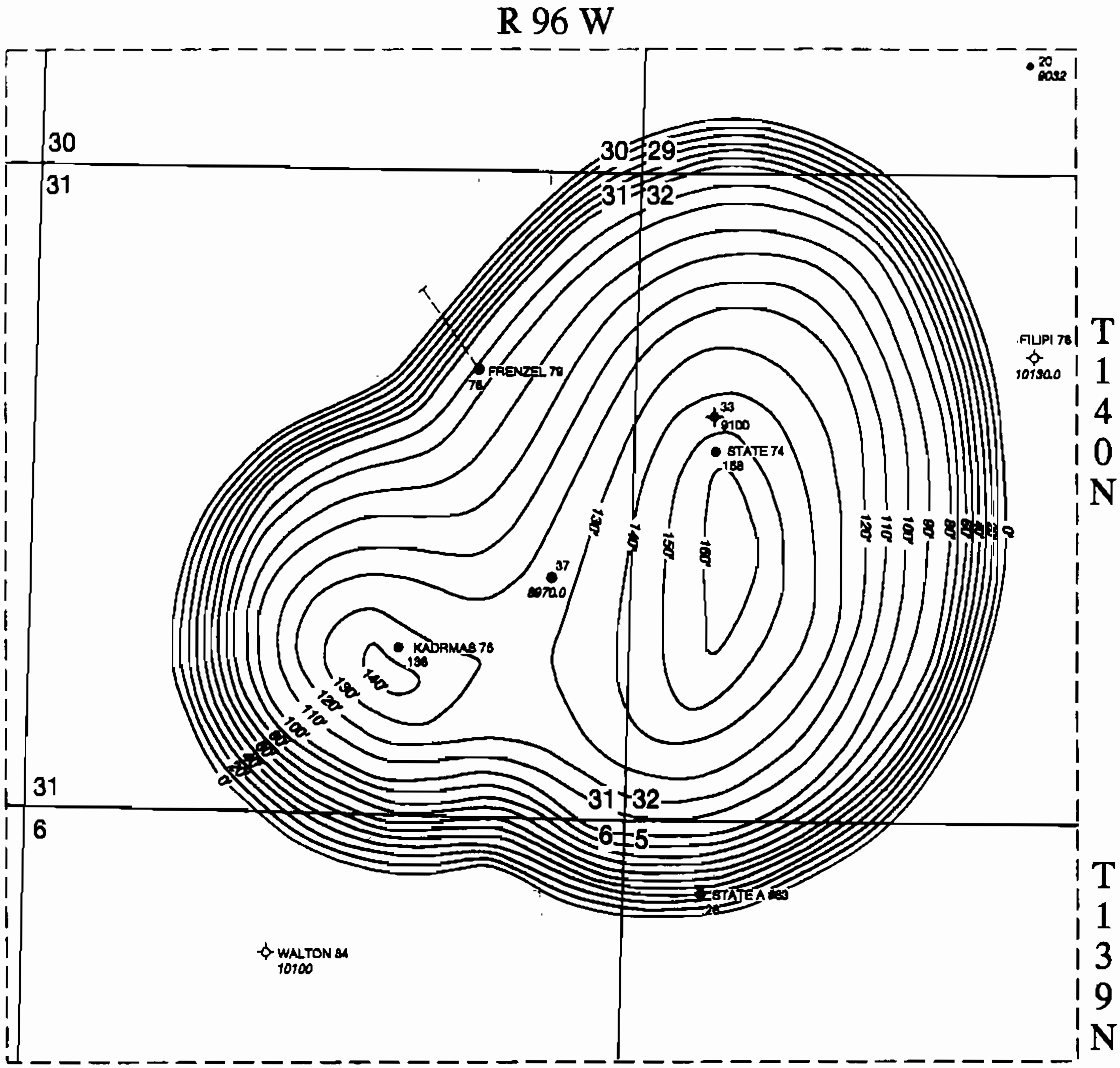
CONOCO INC.
Case No. 5933
Exhibit No. 11



Contour Interval: 10 Feet
Min: -7500' Max: -7210'

SUBSEA TOP OF LODGEPOLE RESERVOIR
Dickinson Field
Stark Co., North Dakota

CONOCO INC.
Case No. 5933
Exhibit No. 12



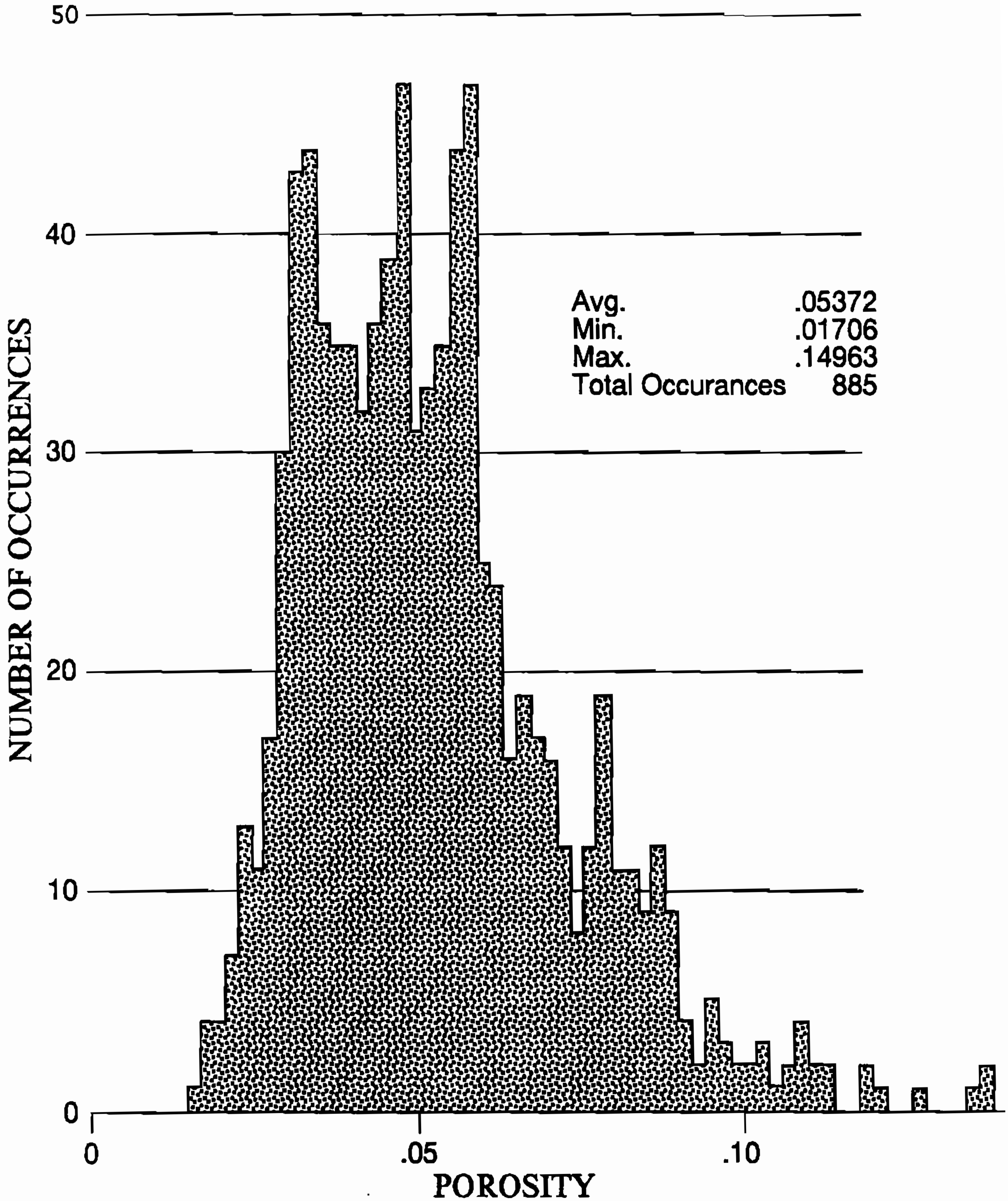
Contour Interval: 10 Feet
Min: 0 Max: 160

ISOPACH OF LODGEPOLE PAY
Dickinson Field
Stark Co., North Dakota

Waterzone deleted from ex # 12.

CONOCO INC.

Case No. 5933
Exhibit No. 13



Porosity readings versus number of occurrences in the Dickinson Lodgepole reservoir. Porosity readings were taken from neutron-density crossplots in all four producing wells.

Considers all reservoir btm o/w contact + top of mound.

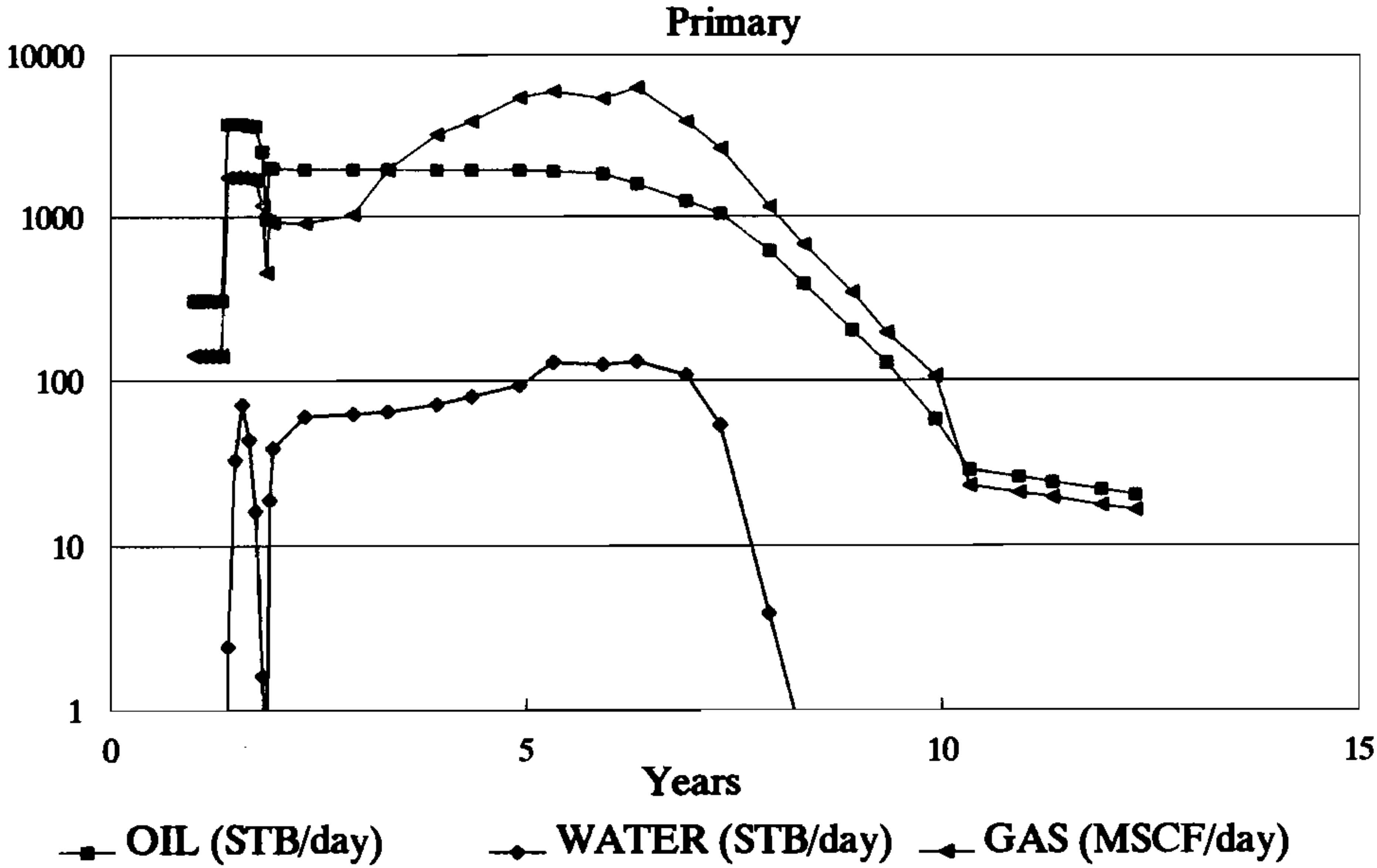
CONOCO INC.
Case No. 5933
Exhibit No. 14

DICKINSON FIELD
LODGEPOLE RESERVOIR
RESERVOIR AND FLUID PROPERTIES

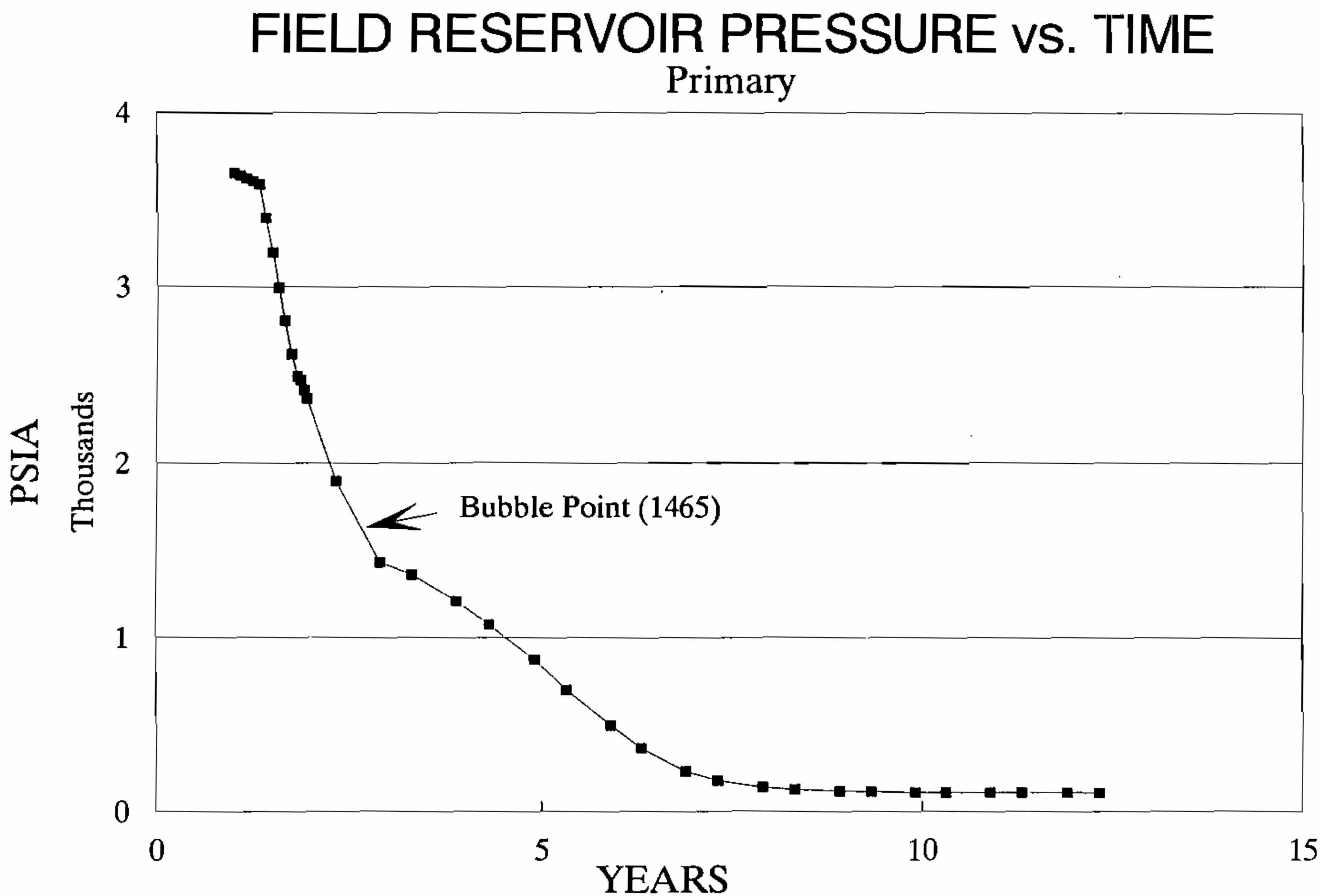
PROPERTY	VALUE	SOURCE
Initial Reservoir Pressure	4,536 psia @ -7,271' subsea	Pressure Test
Reservoir Pressure 4/7/94	3,638 psia @ -7,271' subsea	Pressure Test
Bubble Point Pressure	1,465 psia	PVT Analysis
Oil Formation Volume Factor	1.356 RB/STB @ 4,536 psia 1.420 RB/STB @ 1,465 psia	PVT Analysis
Solution Gas/Oil Ratio	468 SCF/STB (Above Bubble Point)	PVT Analysis
Oil Gravity @ Standard Conditions	43.85 Degrees API	PVT Analysis
Oil Viscosity	0.29 cp	PVT Analysis
Reservoir Temperature	224 Degrees F	Measurement
Average Porosity	5.372 %	Log Analysis
Connate Water Saturation	10.6 %	Core Analysis
Residual Oil Saturation to Water	50.5%	Core Analysis
Permeability	100 to 2,000 md	Pressure Tests
Reservoir Drive Mechanism	Solution Gas	
Reservoir Volume	70,693 Acre-Feet	Mapping
Volumetric Original Oil In Place	19.42 MMBO	
Material Balance Original Oil In Place	18.25 MMBO	

CONOCO INC.
Case No. 5933
Exhibit No. 15

FIELD PRODUCTION RATE vs. TIME

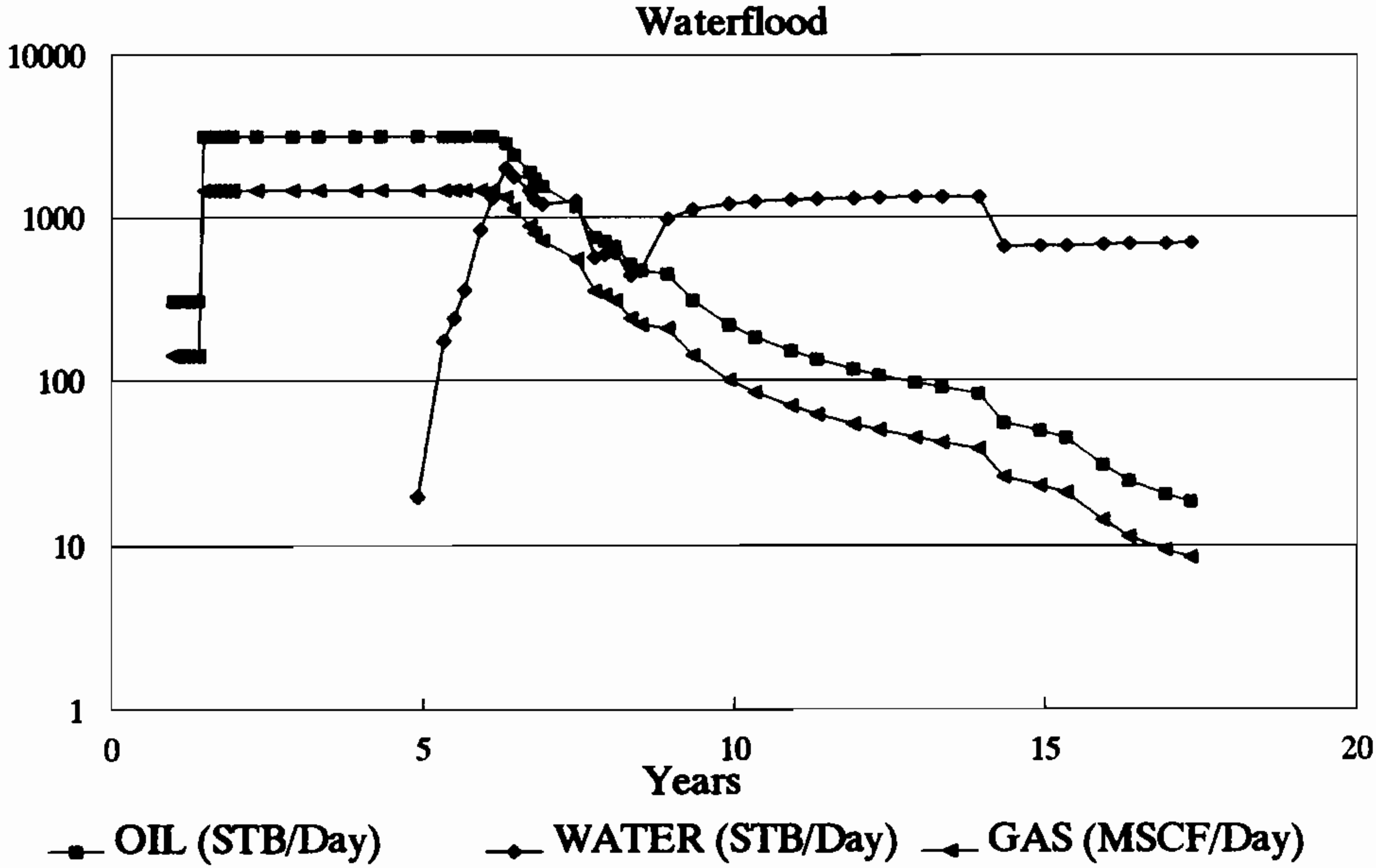


CONOCO INC.
Case No. 5933
Exhibit No. 16

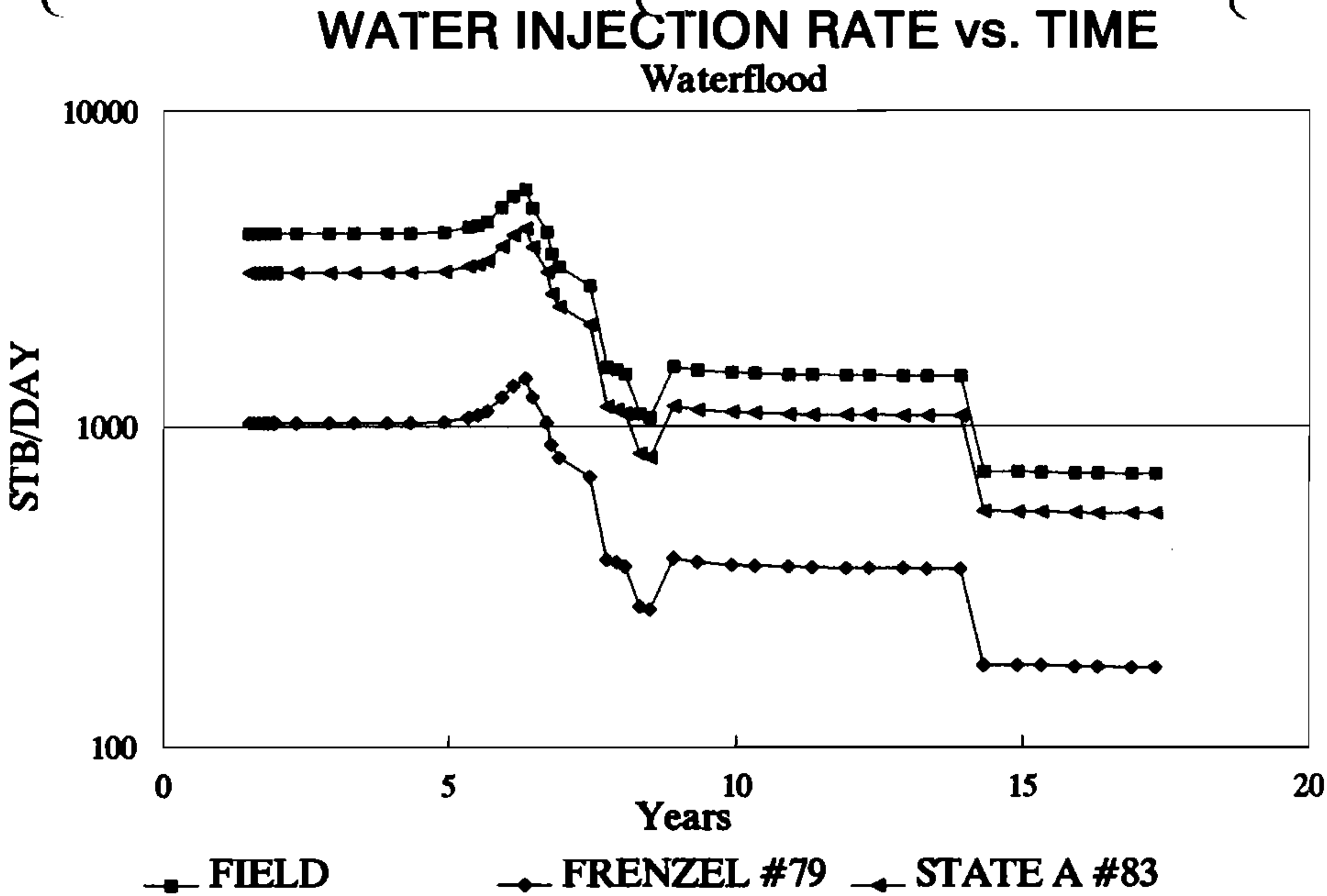


CONOCO INC.
Case No. 5933
Exhibit No. 17

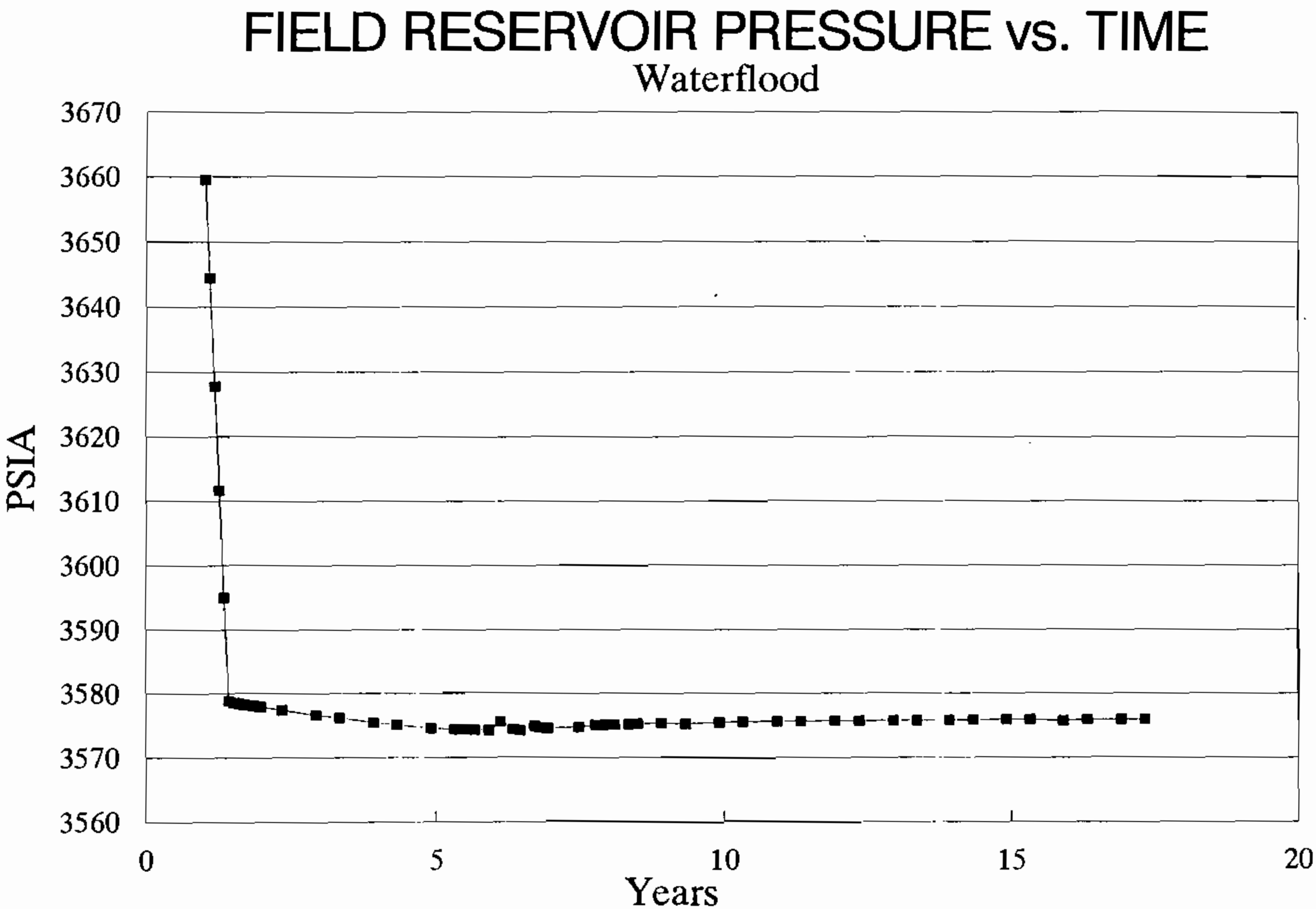
FIELD PRODUCTION RATE vs. TIME



CONOCO INC.
Case No. 5933
Exhibit No. 18

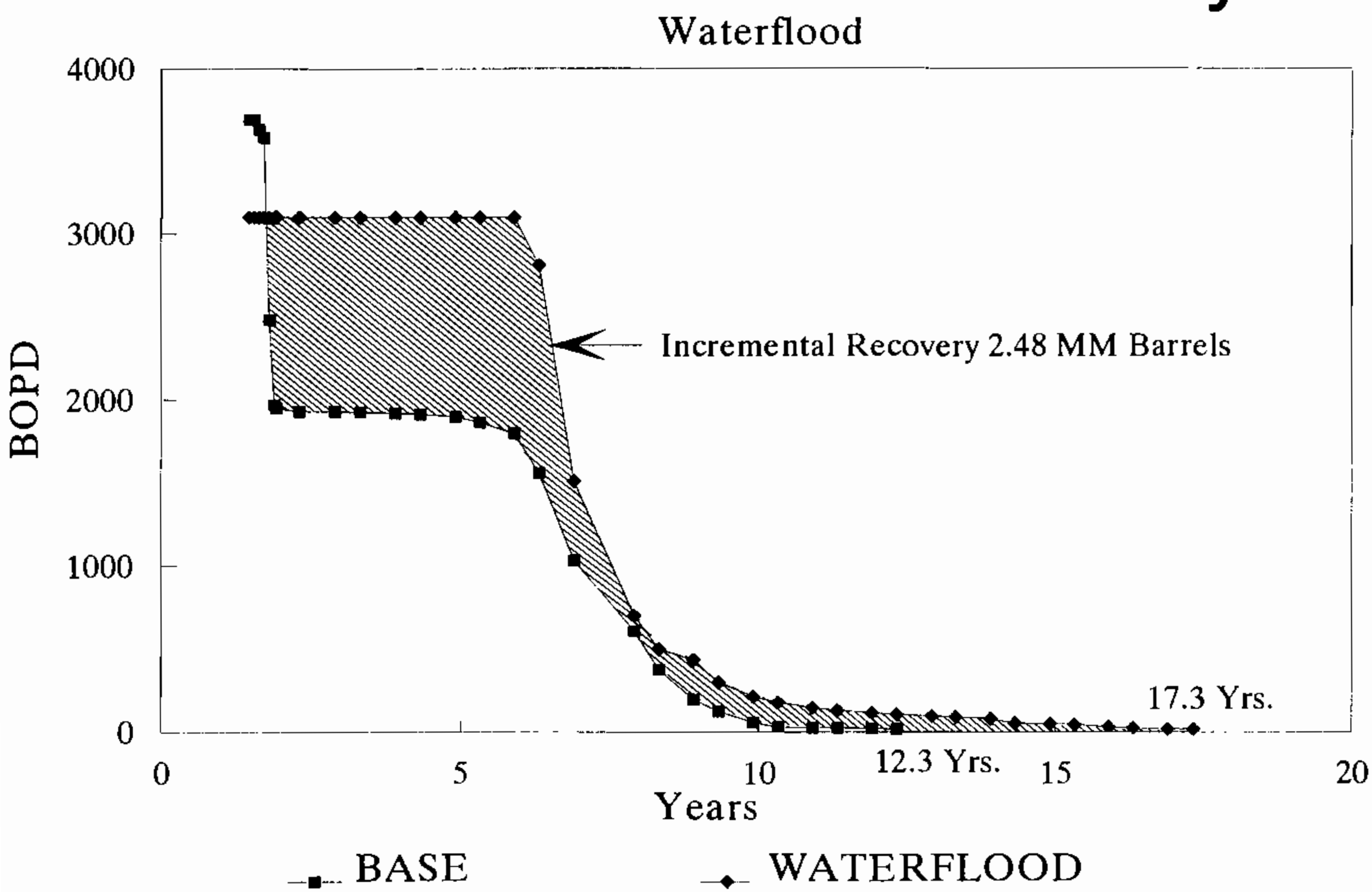


CONOCO INC.
Case No. 5933
Exhibit No. 19



CONOCO INC.
Case No. 5933
Exhibit No. 20

Incremental Recovery



CONOCO INC.
Case No. 5933
Exhibit No. 21

DICKINSON FIELD
LODGEPOLE RESERVOIR
RECOVERY PREDICTIONS

	OIL MMBO	OIL % OF OOIP	GAS BCF
Primary Recovery	5.38	27.7	8.7
Waterflood	7.86	40.5	3.7
Incremental	2.48	12.8	-5.0

CONOCO INC.
Case No. 5933
Exhibit No. 22

DICKINSON FIELD
LODGEPOLE RESERVOIR
ECONOMIC RESULTS

INPUT:

1. Effective date of June 1, 1994
2. Primary recovery investment of $178,000
3. Waterflood Investment of $343,000
4. 100 % working interest and 87.5% net revenue interest
5. Initial oil price of $13.00/bbl WTI, minus $1.20/bbl differential or $11.80/bbl. Escalated at 5%/year
6. Initial gas price of $1.72/MCF escalated per Conoco forecasted contract price
7. Severance tax credit for incremental recovery
8. 37% federal income tax
9. 8% discount factor for net present value calculation

RESULTS:

PRIMARY RECOVERY:	$28 MILLION NET PRESENT VALUE
WATERFLOOD:	$37 MILLION NET PRESENT VALUE
INCREMENTAL:	$9 MILLION NET PRESENT VALUE
INCREMENTAL RATE OF RETURN:	263 % RATE OF RETURN

CONOCO INC.
Case No. 5933
Exhibit No. 23

DICKINSON FIELD
LODGEPOLE RESERVOIR
<u>EQUITY FORMULA</u>

PHASE I :	**50 % REMAINING PRIMARY RESERVES** **50 % REMAINING ORIGINAL OIL IN PLACE**
PHASE II :	**100 % ORIGINAL OIL IN PLACE**

CONOCO INC.
Case No. 5933
Exhibit No. 24

DICKINSON FIELD
LODGEPOLE RESERVOIR
CONCLUSIONS & RECOMMENDATIONS

CONCLUSIONS:

1. The Lodgepole is an undersaturated oil reservoir with a bubble point of 1,465 psia.
2. Through the first year of production, reservoir pressure has declined almost 900 psia. Without some form of pressure maintenance, the reservoir will quickly fall below the bubble point resulting in a significant loss of oil reserves.
3. The reservoir is completely developed at this time.
4. Conoco has determined that the optimum form of pressure maintenance is waterflooding. A waterflood using two injectors and two producers is forecasted to recover an incremental 2.48 million barrels of oil. For an investment of $343,000, the waterflood will return approximately $9 million in incremental net present value to the working interest owners.
5. Failure to initiate a waterflood at this time would result in prolonged curtailment and a significant loss of net present value for the working and royalty interest owners.
6. Unitization will protect the correlative rights of all owners and prevent the drilling of unnecessary wells.

RECOMMENDATIONS:

1. The Lodgepole Reservoir at Dickinson should be unitized immediately for the purpose of initiating a waterflood.
2. The State A No. 83, Section 5-T139N-R96W, and the Frenzel No. 79, Section 31-T140N-R96W, should be converted to downdip injection wells and be recompleted below the oil/water contact. Water should be injected on a reservoir voidage replacement schedule to match fluid injection with oil, gas, and water withdrawals.
3. The State No. 74, Section 32-T140N-R96W, and the Kadrmas No. 75, Section 31-T140N-R96W, should be recompleted in the very top of the producing zone to maximize the distance between the producing perforations and the bottom water injection.

CONOCO INC.
Case No. 5933
Exhibit No. 25

LAW OFFICES OF
FLECK, MATHER & STRUTZ, LTD.
400 EAST BROADWAY, SUITE 600
NORWEST BANK BUILDING
P. O. BOX 2798
BISMARCK, NORTH DAKOTA 58502
TELEPHONE (701) 223-6585
TELECOPIER (701) 222-4853

ERNEST R. FLECK
RUSSELL R. MATHER
WILLIAM A. STRUTZ
WARREN H. ALBRECHT, JR.
GARY R. WOLBERG+
PAUL W. SUMMERS
STEVEN A. STORSLEE*
BRIAN R. BJELLA

JOHN W. MORRISON
DANIEL L. HOVLAND*
ROBERT J. UDLAND*
CURTIS L. WIKE*
CHARLES S. MILLER, JR.*
CRAIG C. SMITH**
SCOTT K. PORSBORG*++
DEENELLE L. RUUD*

ALSO LICENSED IN:
*MINNESOTA
**MONTANA
+IOWA
++SOUTH DAKOTA

March 22, 1994

Mr. Wes Norton, Director
Oil & Gas Division
ND INDUSTRIAL COMMISSION
600 East Boulevard
Bismarck, ND 58505-0840

In re Conoco Unitization Proposal
Dickinson-Lodgepole Field
Our File No. 22227

Dear Wes:

Please be advised that we represent Placid Oil Company with respect to Conoco's proposal to unitize the Dickinson-Lodgepole Field. At this time, Placid intends to oppose Conoco's request, thus making the hearing a contested case proceeding with respect to § 28-32-12.1 of the North Dakota Century Code. Placid is not opposed to the unitization of the field but only to the boundaries of the unit area proposed by Conoco.

As you know, the customary practice in North Dakota is for the operator of a proposed unit area to meet privately with the Commission staff in advance of the hearing to review such matters as the unit outline and the equity formula. Because unitization hearings are frequently uncontested, this practice is appropriate and helpful to both the Commission staff and the applicant. However, when it is anticipated that a matter will be contested, § 28-32-12.1 appears to prohibit such meetings.

If you have any questions concerning this matter, please let me know.

Very truly yours,

JOHN W. MORRISON

bz
cc: Lawrence Bender
Jimmy Campbell

Exhibit 1

DICKINSON LODGEPOLE UNIT

WORKING INTEREST OWNERSHIP PERCENTAGES

INTEREST OWNER	PHASE I INTEREST	PHASE II INTEREST
Conoco Inc.	75.13926%	74.88076%
Andrea Singer Pollack Trust	16.57757%	15.89291%
Placid Oil Company	3.98110%	3.75562%
ARS Limited Partnership	0.81532%	1.58939%
Phillips Petroleum Company	0.79883%	1.01131%
Hunt Petroleum Corporation	1.03926%	0.97885%
Huntington Resources Inc.	0.58546%	0.55230%
Louis W. Hill, Jr.	0.54526%	0.54719%
Mobil Exploration & Production	0.16329%	0.31832%
The Wiser Oil Company	0.22323%	0.21716%
Mid-Continent Energy (B.P.O)	0.08252%	0.16086%
North American Royalties, Inc.	0.03709%	0.07230%
Ray Ruth Hunt	0.00514%	0.01002%
Hunt Oil Company	0.00343%	0.00668%
Louisiana-Hunt Petroleum	0.00154%	0.00301%
Unit Four Partnership	0.00086%	0.00167%
Petro-Hunt Corporation	0.00086%	0.00167%
TOTAL:	100.00000%	100.00000%

EX. C

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA
Date 4/8/94 Case No. #5933
Introduced by Placid Oil Co.
Exhibit #1
Identified by John Morrison

APPROVAL OF UNIT AGREEMENT OF DICKINSON-LODGEPOLE UNIT

STARK COUNTY, NORTH DAKOTA

KNOW ALL MEN BY THESE PRESENTS:

WHEREAS, an instrument entitled "Unit Agreement for the Development and Operation of the Dickinson-Lodgepole Unit, Stark County, North Dakota" ("Unit Agreement"), dated April 15, 1994, provides that any owner of a Royalty Interest in any Tract identified therein may approve such agreement by signing an instrument of approval;

NOW, THEREFORE, the undersigned Royalty Interest Owner(s) hereby expressly join, ratify, approve, adopt and confirm the Unit Agreement as though the undersigned had executed the original instrument.

IN WITNESS WHEREOF, each of the undersigned has executed this instrument on the date set forth below.

Dated: 6-3-94

Arnold E. Kadrmas
P.O. Box 951
Lewiston, ID 83501

STATE OF Idaho)
)ss:
COUNTY OF Nez Perce)

Subscribed and sworn to before me this 3 day of June, 1994.

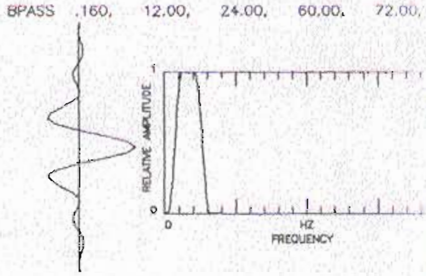
Notary Public
Nez Perce County, ~~North Dakota~~ Idaho
My Commission Expires: 7-21-97

LODGEPOLE REEF

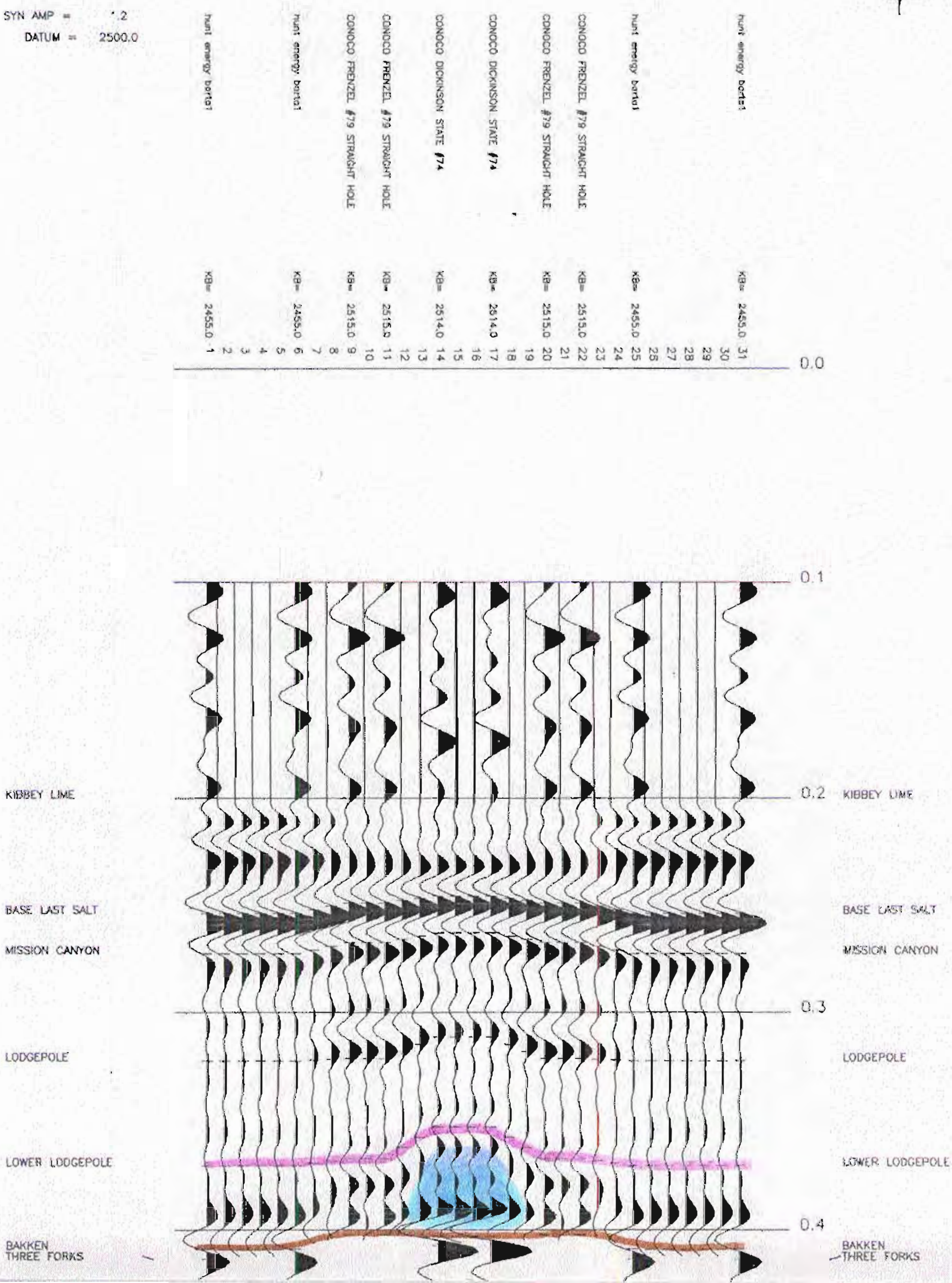
DICKINSON FIELD
STARK COUNTY, N. DAKOTA

PLOT INFORMATION:
PLOTTED BY GEOTRACE

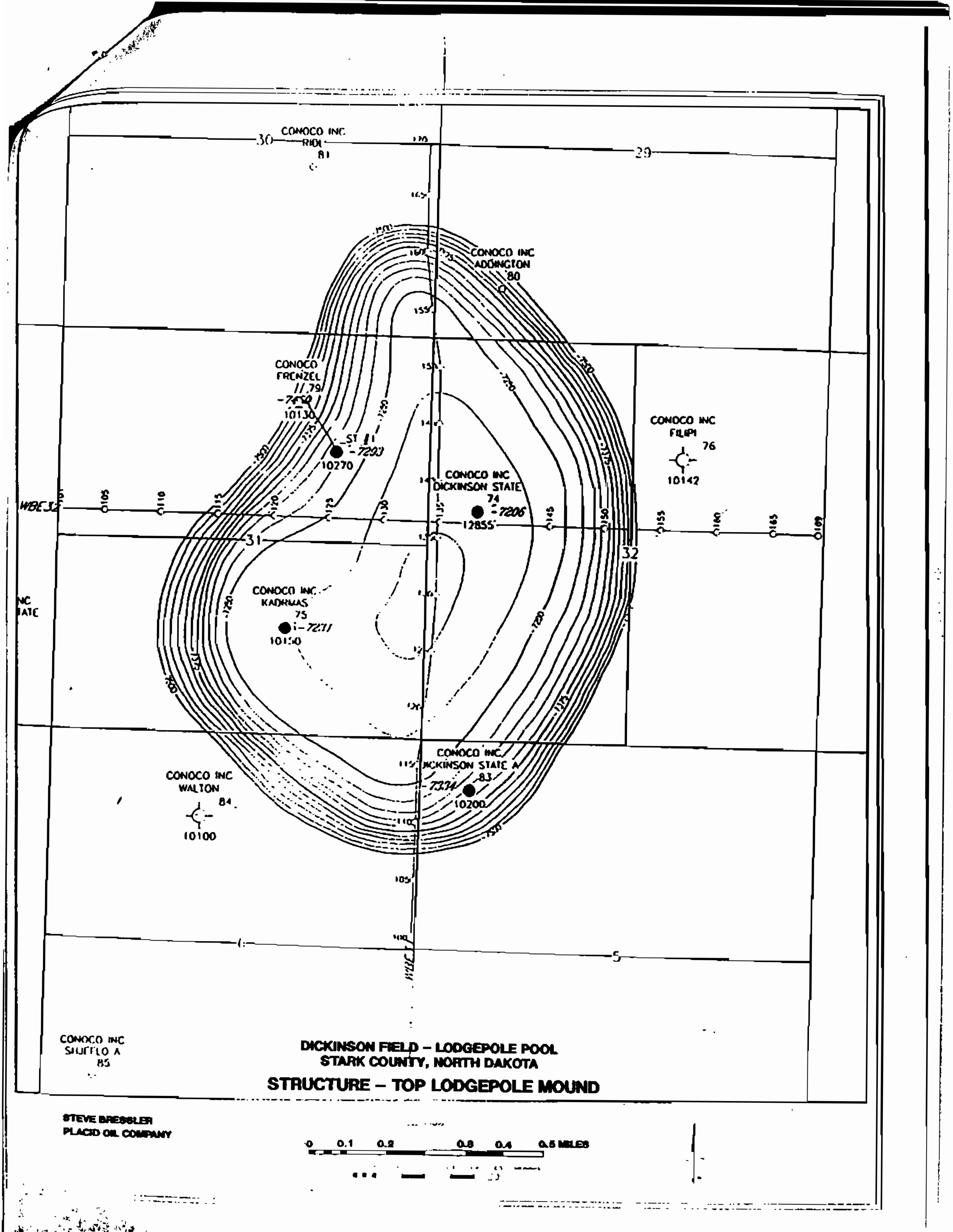
PLOT FILE NAME:	REEF.PLT
SAMPLE RATE (MS):	2.00
SEISMIC INFORMATION:	
DATUM:	2500.0
VELOCITY TO DATUM:	10000.00



SYN AMP = .2
DATUM = 2500.0

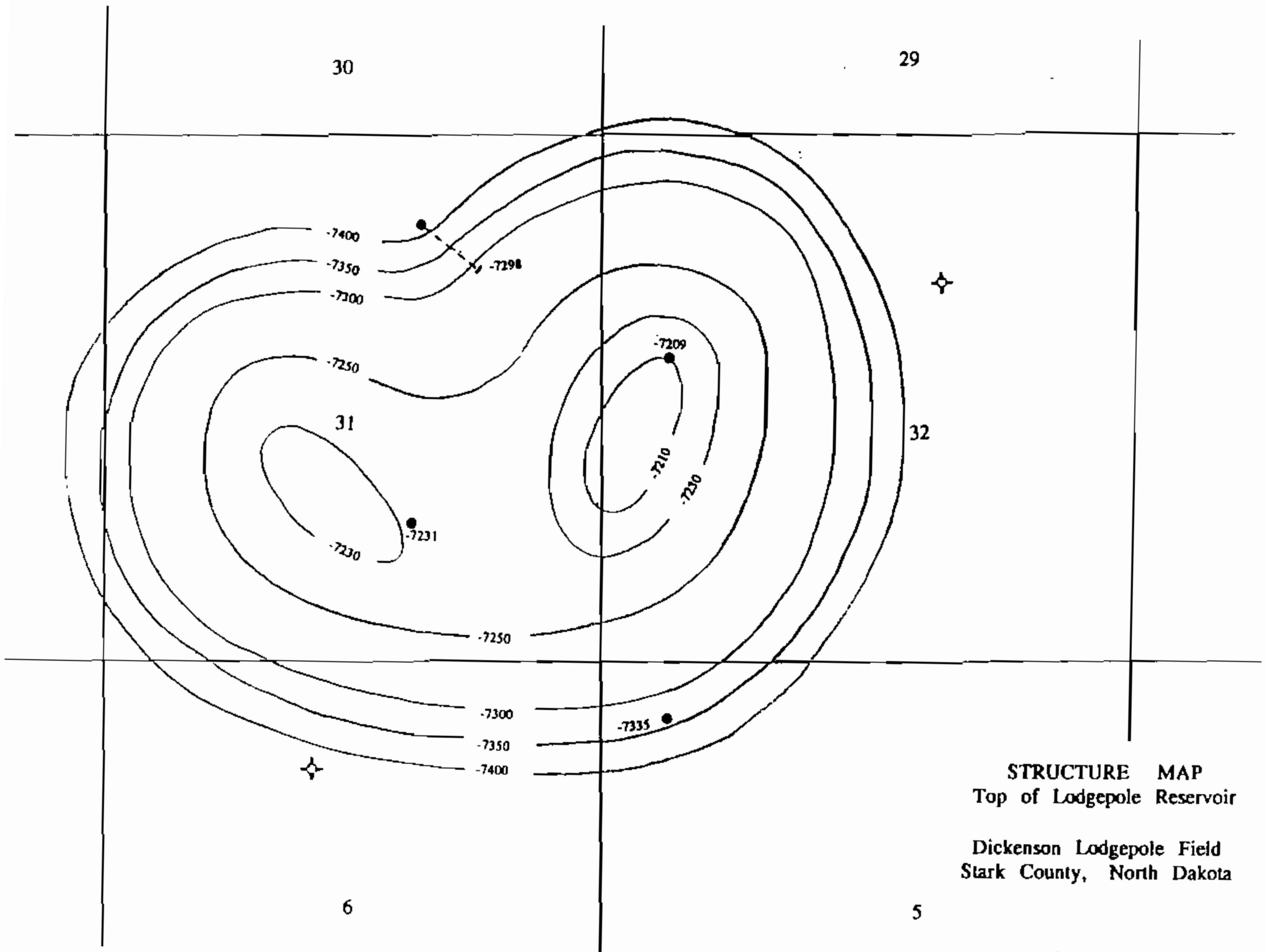


Placid #4



CONOCO INC
RIDL
81
CONOCO INC
ADDINGTON
80
CONOCO
FRENZEL
79
-7450
10130
ST #1
-7203
10270
CONOCO INC
FILIPI
76
10142
CONOCO INC
DICKINSON STATE
74
-7206
12855
CONOCO INC
KADRMAS
75
-7277
10150
CONOCO INC
DICKINSON STATE A
83
-7334
10200
CONOCO INC
WALTON
84
10100
CONOCO INC
SHUFFLO A
85
30
29
31
32
5
-7250
-7200
-7225
DICKINSON FIELD – LODGEPOLE POOL
STARK COUNTY, NORTH DAKOTA
STRUCTURE – TOP LODGEPOLE MOUND
STEVE BRESSLER
PLACID OIL COMPANY
0
0.1
0.2
0.3
0.4
0.5 MILES

Case #5933
Exhibit #3/

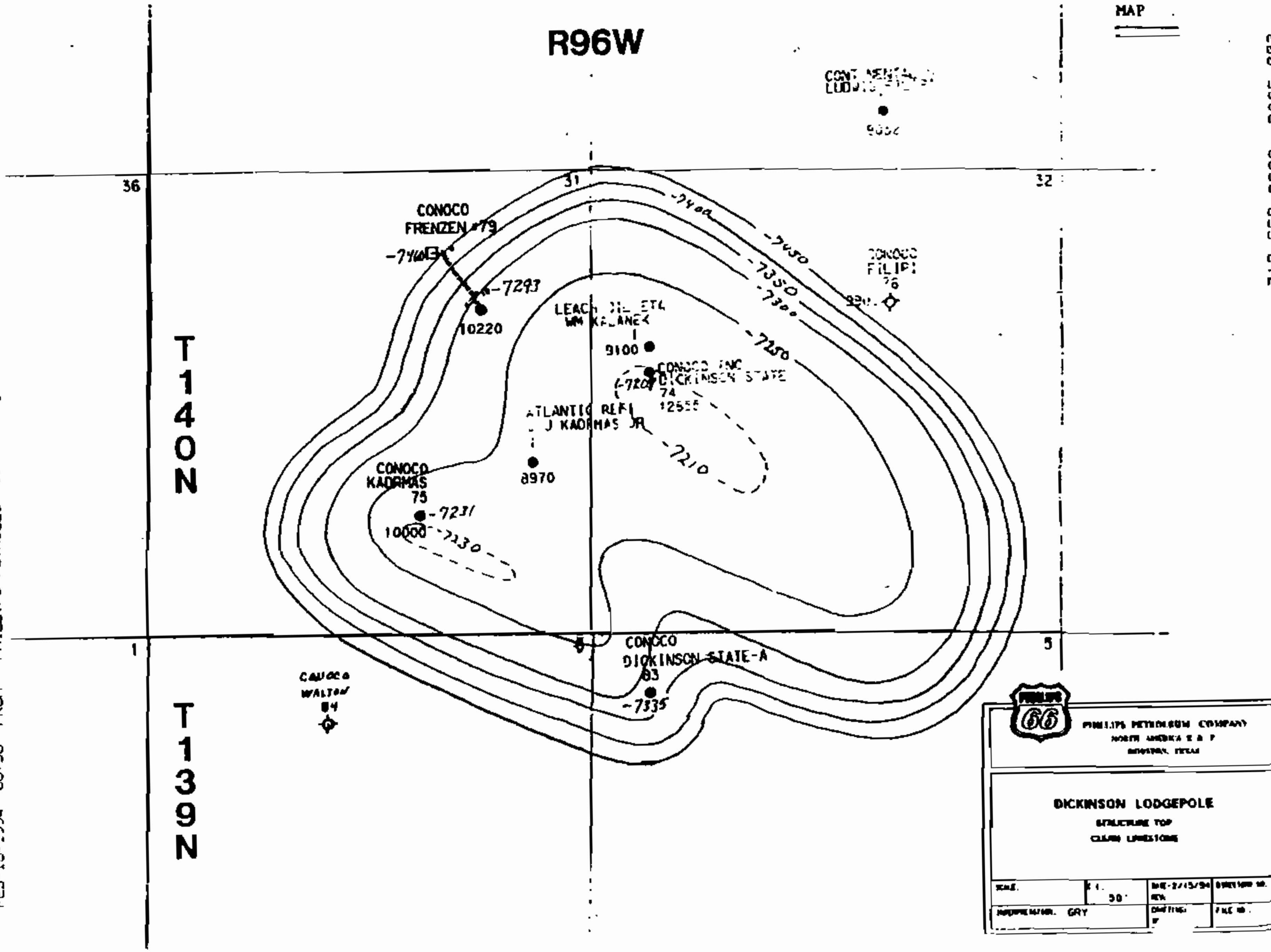


STRUCTURE MAP
Top of Lodgepole Reservoir

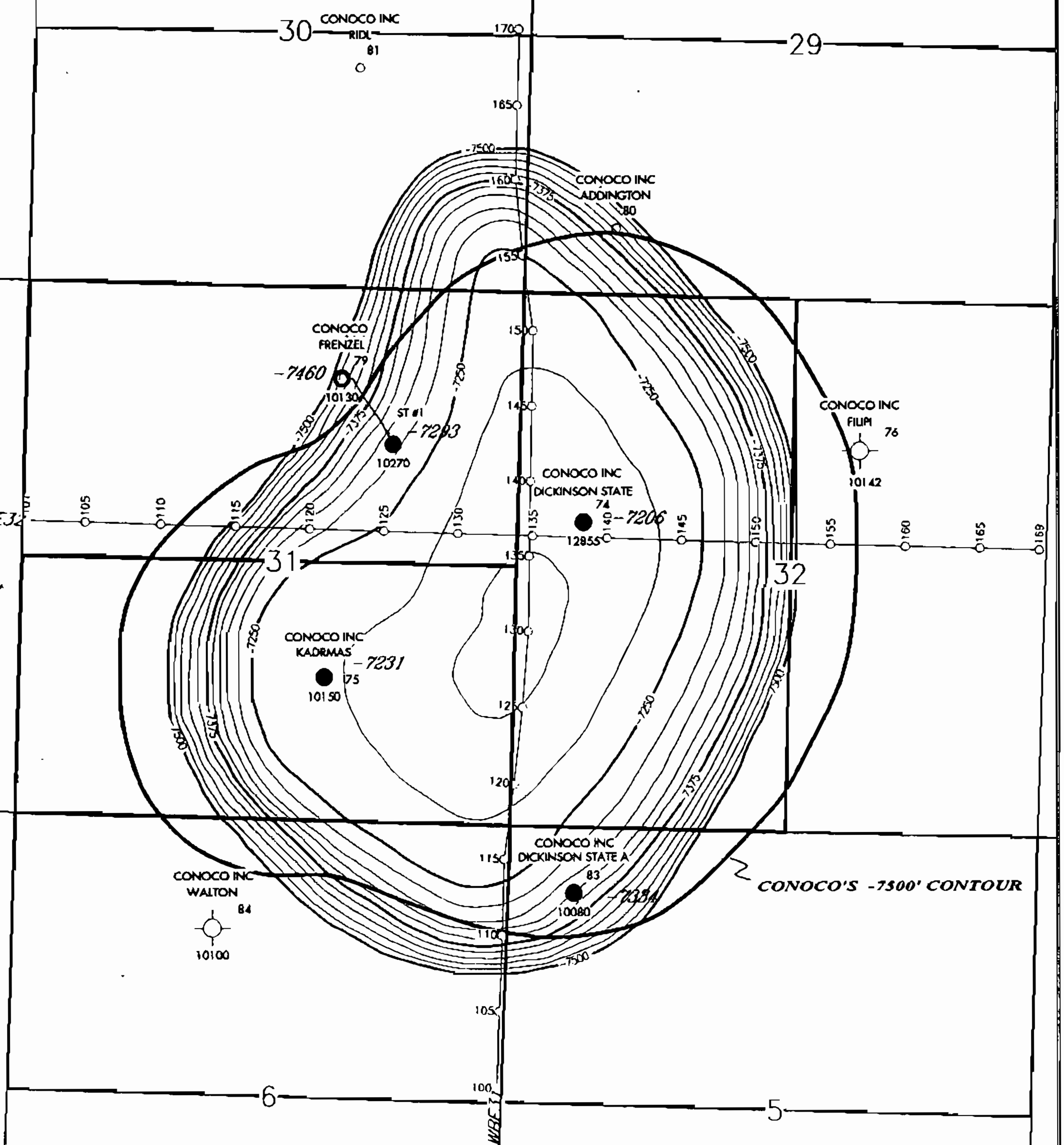
Dickenson Lodgepole Field
Stark County, North Dakota

AVIVA

Case #593
Exhibit #2



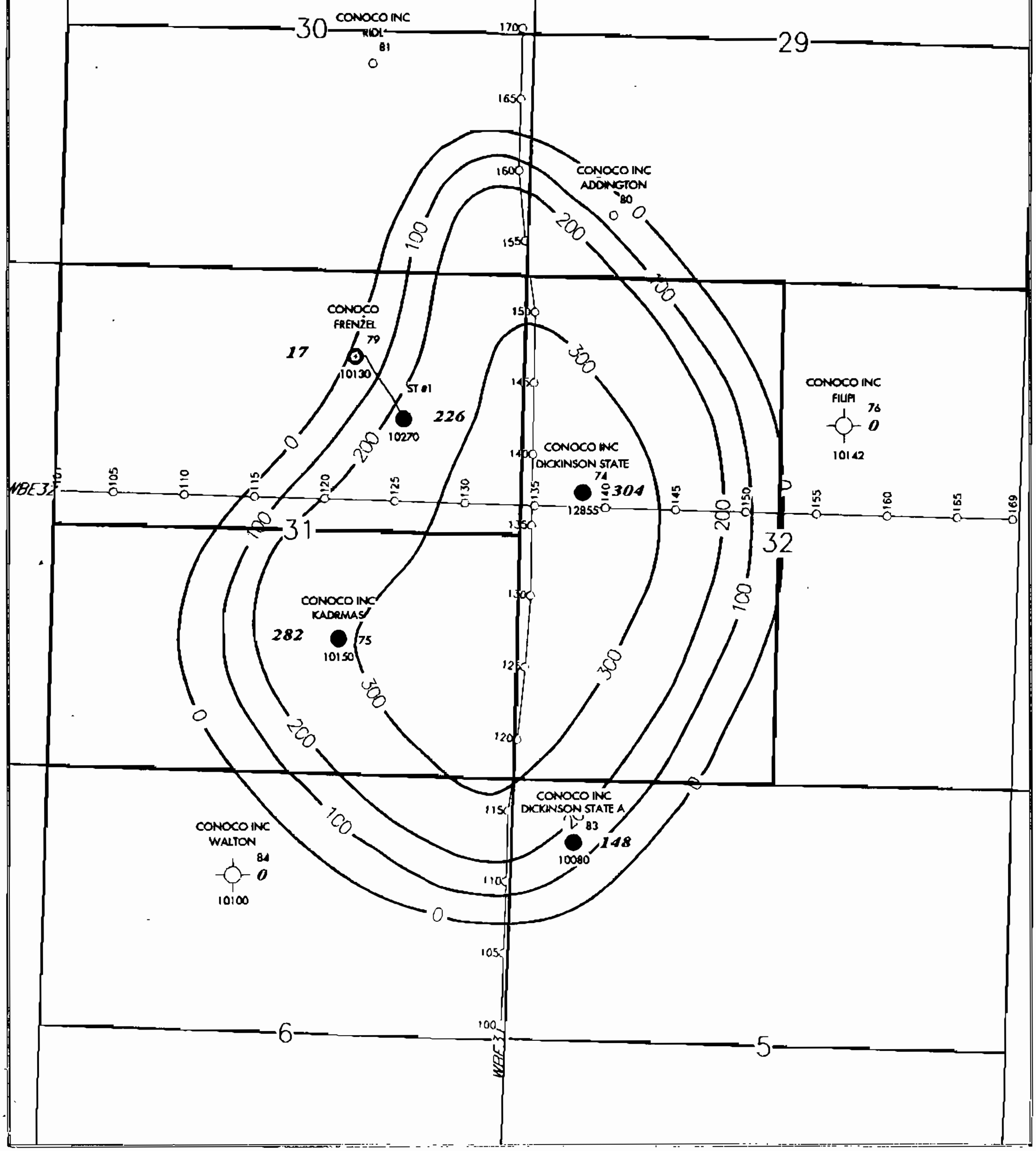
STRUCTURE - TOP LODGEPOLE MOUND



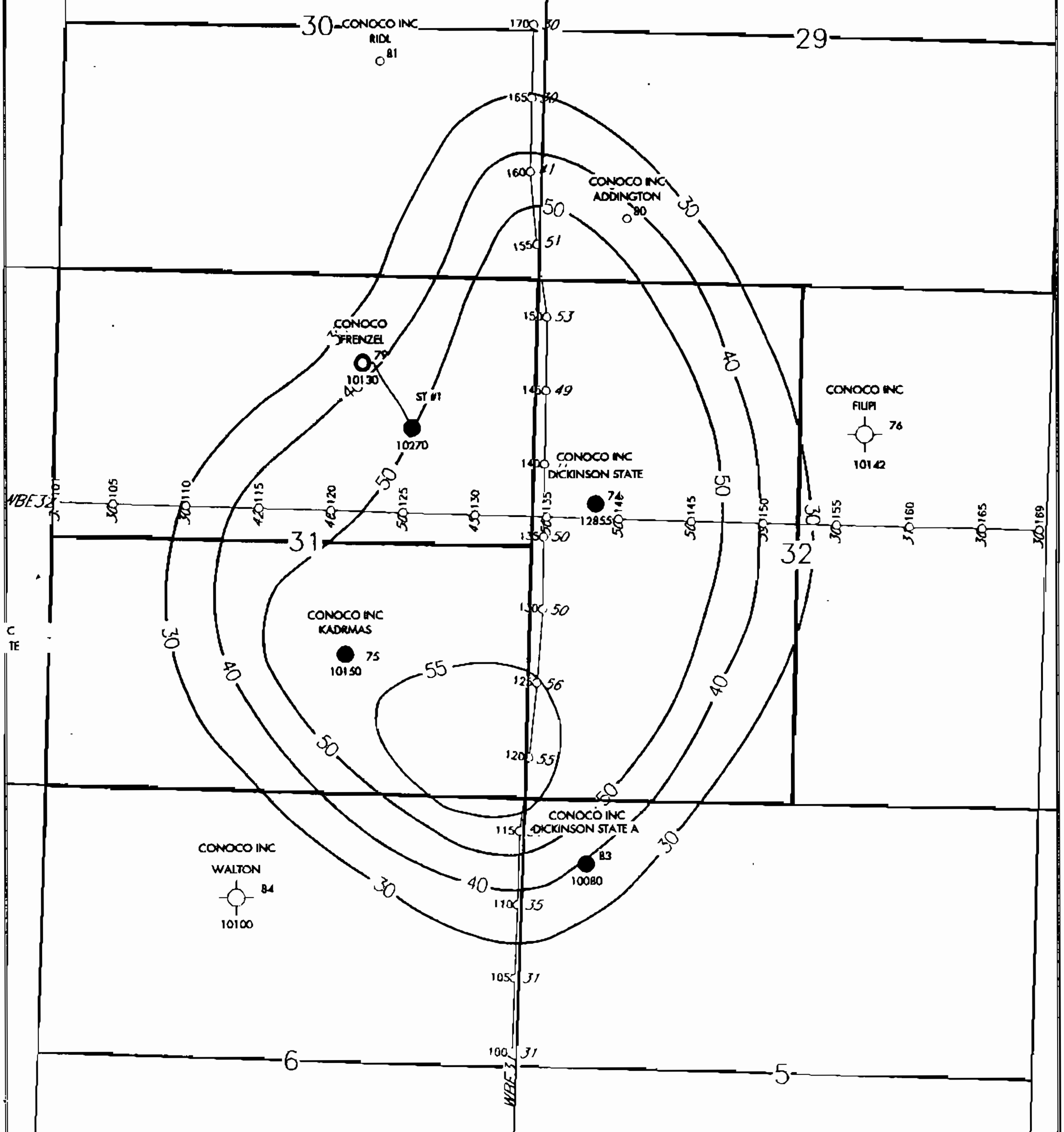
PLACID OIL COMPANY 6/7/1994

25' Contour Interval

LODGEPOLE MOUND ISOPACH

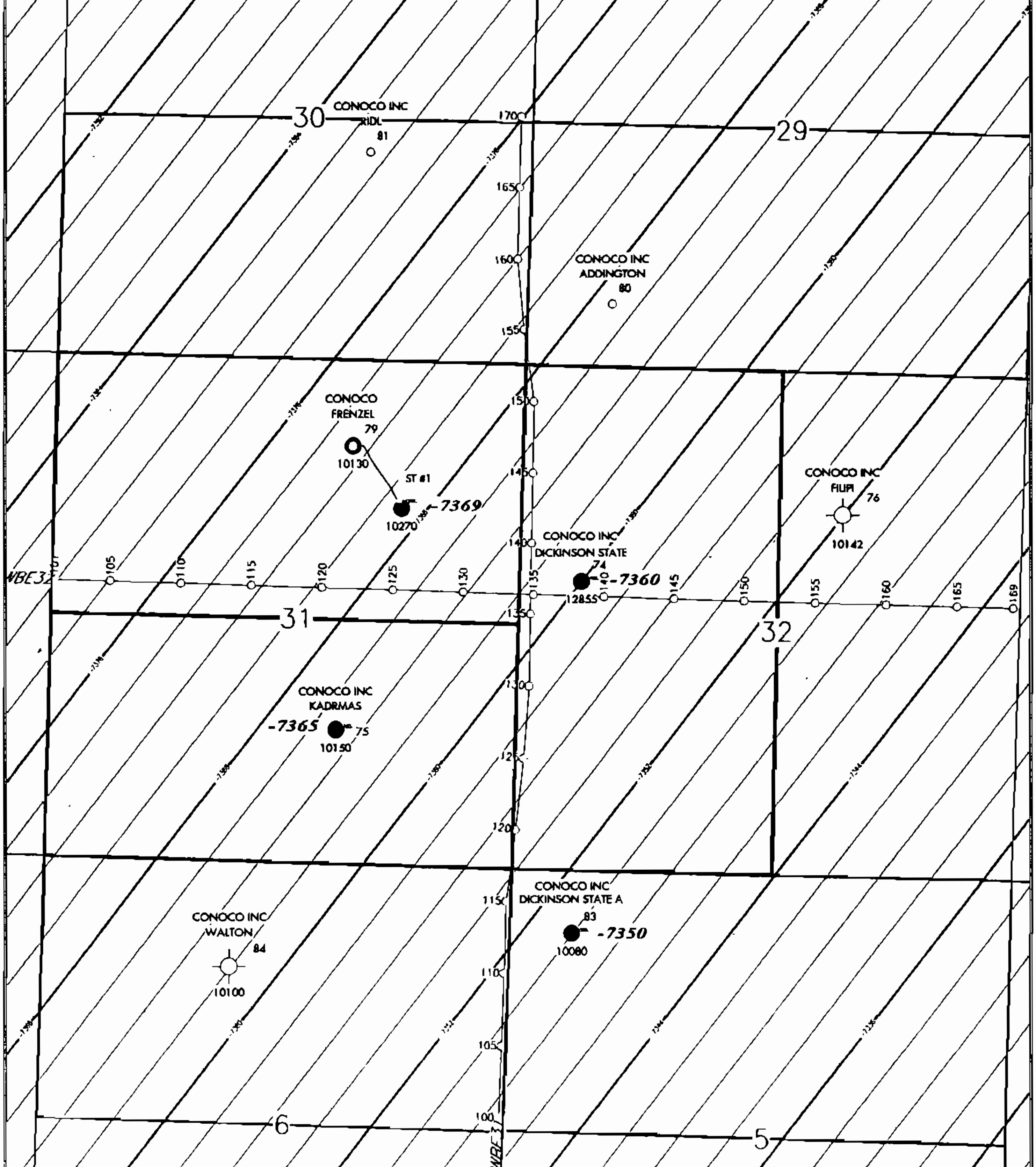


ISOCHRON - LOWER LODGEPOLE SHALE MARKER TO BAKKEN

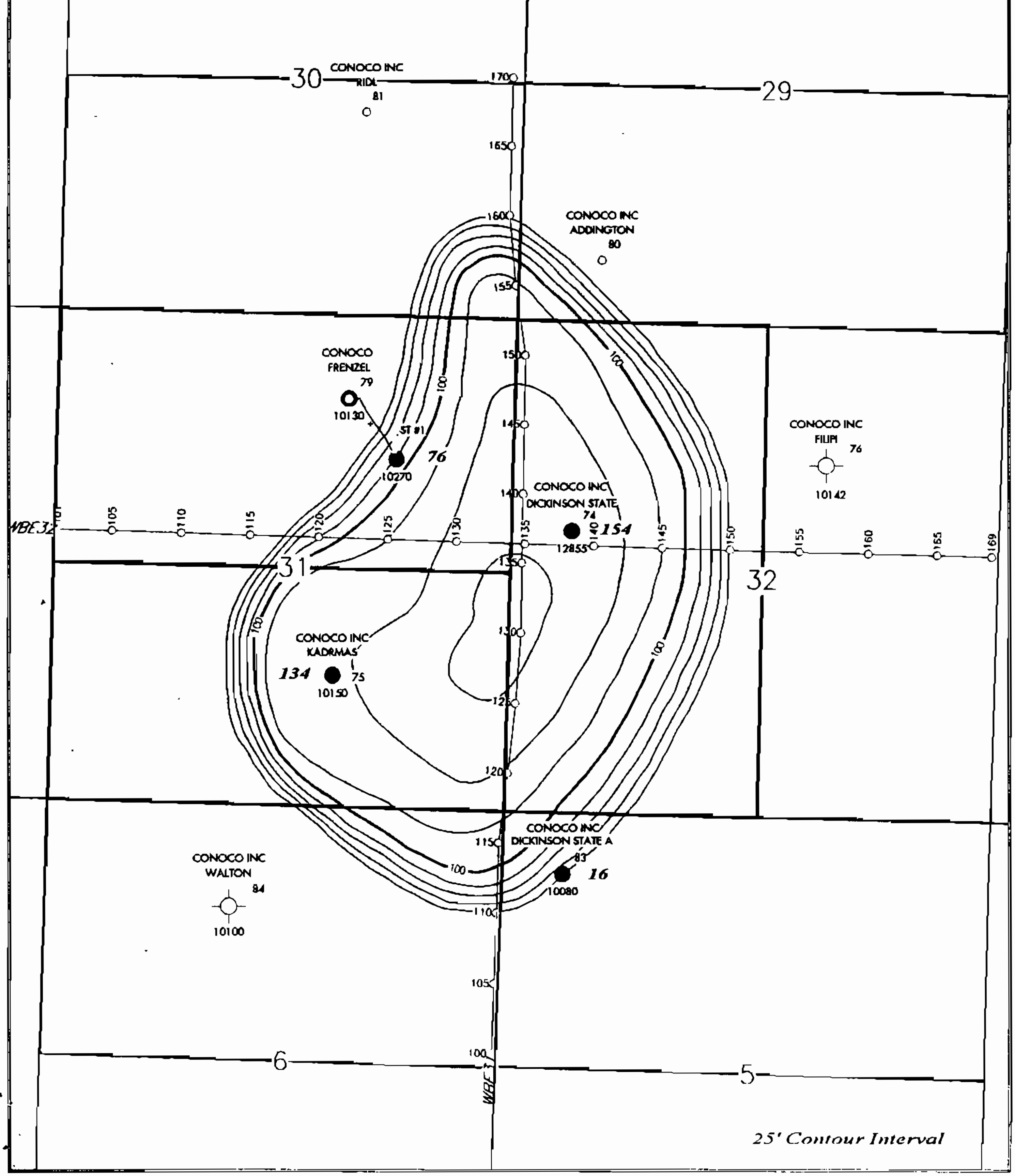


10 millisecond contour interval

OIL-WATER CONTACT



LODGEPOLE MOUND - NET PAY ISOPACH



DICKINSON LODGEPOLE UNIT

ROYALTY INTEREST OWNERSHIP PERCENTAGES

INTEREST OWNER	PHASE I INTEREST	PHASE II INTEREST
Agribank FCB	18.71827%	18.43012%
The Wiser Oil Company	10.63498%	10.21476%
Republic Royalty Company	7.32187%	7.07333%
Gerald David Kalanek	6.28087%	6.32939%
Arnold E. Kadrmas	4.14439%	3.97323%
Linda Kadrmas	4.14439%	3.97323%
Joan Schmidt	4.14439%	3.97323%
Douglas Kadrmas	4.14439%	3.97323%
Conoco Inc.	3.78948%	3.81947%
Louis W. Hill, Jr.	3.85601%	3.81100%
Virginia L. Sherron	3.17219%	3.22659%
Peggy Addington	3.17219%	3.22659%
State of North Dakota	2.77357%	3.09034%
J. Hiram Moore et al	1.73503%	1.79274%
Elizabeth H. Welch	1.58609%	1.61330%
Darlene McKinley Lane	1.58609%	1.61330%
Mary Pearl Lake	1.58609%	1.61330%
E.E. & Mildred Trumbell Jt.	1.56568%	1.57351%
J.H. Smart, Jr.	1.56568%	1.57351%
Marta Smart Bennett	1.56568%	1.57351%
Rose Frenzel	1.53883%	1.44937%
Mary Margaret Pugh	1.18957%	1.20997%
Beeman Dockery	0.91200%	0.92765%
Leslie J. May	0.79305%	0.80665%
Hunter S. Trunk	0.79305%	0.80665%

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA
Date 4/8/94 Case No. 5933
Introduced by Placid Oil Co. EX. D
Exhibit #2
John Morrison

Dodge Jones FDN	0.76538%	0.73940%
Stephen Filipi	0.25699%	0.50097%
Linda K. Jones	0.49312%	0.48917%
Clyde W. Jones	0.49312%	0.48917%
The Fasken Foundation	0.49224%	0.47553%
Victor B. Walton	0.21152%	0.41233%
Pacific West Lease Company	0.39653%	0.40332%
Baytech Inc.	0.39418%	0.38080%
William J. Grinde, Trustee	0.27785%	0.26169%
Fayette K. Stroud MD	0.23791%	0.24199%
Matt-Tex LLP	0.23702%	0.22897%
Patricia & William Dowell	0.24094%	0.22693%
Diane & Kenneth Mayer	0.24094%	0.22693%
Lester & Marlene Frenzel	0.24094%	0.22693%
Irene & Karl Hammann	0.24094%	0.22693%
May Ann & Edwin A. Fieck	0.24094%	0.22693%
Shirley Jean Larkin	0.10576%	0.20617%
Robert R. Walton	0.10576%	0.20617%
Dr. William H. Walton, Jr.	0.10576%	0.20617%
Randy Geiselman	0.17738%	0.17136%
Clark E. Jones	0.15861%	0.16133%
Zula Mae Pugh	0.15861%	0.16133%
Julia Jones Matthew	0.16660%	0.16095%
John A. Matthews, Jr.	0.11823%	0.11422%
Julia Reynolds	0.05288%	0.10308%
Elizabeth Bowers	0.05288%	0.10308%
Benjamin Deeble	0.05288%	0.10308%
Victoria Raynor	0.05288%	0.10308%
Andrews Royalty, Inc.	0.07292%	0.07045%
Mary Dpahne Hibl	0.03175%	0.06190%

Vivian Miller	0.03175%	0.06190%
Paul Karow	0.05557%	0.05234%
William R. Hoffman	0.02644%	0.05154%
James W. Hoffman	0.02644%	0.05154%
David E. Hoffman	0.02644%	0.05154%
John A. Hoffman	0.02644%	0.05154%
E.E. Trumbull	0.02041%	0.03979%
Erma Lowe Trust (Saman Yost)	0.03621%	0.03498%
Erma Lowe Trust (Carson Yost)	0.03261%	0.03498%
Erma Lowe Trust	0.03621%	0.03498%
Lois Eby Budbill	0.01713%	0.03340%
Mary H. Ayala	0.01542%	0.03006%
Lillian Ridl Life Estate	0.00919%	0.01792%
Barbara M. Comeau	0.00514%	0.01002%
Cynthia A. Comeau	0.00514%	0.01002%
Johnnie Beth Huskey	0.00428%	0.00835%
Hugh DeWitt Landis	0.00428%	0.00835%
Viola L. & Virginia Younger	0.00428%	0.00835%
Morris B. Taubman Revocable Trust	0.00334%	0.00651%
Louis Taubman Trust	0.00323%	0.00630%
Charles Taubman Revocable Trust	0.00252%	0.00492%
National Bank Tulsa, Trustee	0.00231%	0.00450%
Robert M. Taubman Revocable Trust	0.00228%	0.00444%
J.R. & Katherine A. Taylor	0.00214%	0.00417%
Janice S. Haffey	0.00214%	0.00417%
Elaine G. Konzelman	0.00214%	0.00417%
Rosalie Taubman Management Trust	0.00195%	0.00380%
Marilyn Kay Ralstin	0.00107%	0.00209%
Gerald C. Wiseman	0.00107%	0.00209%
L.N. Taubman Revocable Trust	0.00023%	0.00045%

Bank of Oklahoma, Tulsa	0.00017%	0.00033%
Anne C. Taubman Trust	0.00017%	0.00033%
Richard J. Taubman Trust	0.00017%	0.00033%
Jonathon Z. Shalom Management Trust	0.00012%	0.00023%
Karen P. Shalom Management Trust	0.00012%	0.00023%
Adina Taubman Trust	0.00007%	0.00013%
Henrik Perry Taubman Family Trust	0.00007%	0.00013%
Barbara Taubman Living Trust	0.00006%	0.00012%
Janice L. Taubman Revocable Trust	0.00003%	0.00007%
Sara K. Taubman Revocable Trust	0.00003%	0.00006%
Andrea Quijano Revocable Trust	0.00003%	0.00006%
Estate of William David Taubman	0.00003%	0.00006%
Deborah Anne Taubman Trust	0.00003%	0.00006%
Claudia P. Taubman Revocable Trust	0.00003%	0.00006%
Rebecca M. Taubman Revocable Trust	0.00003%	0.00006%
Hilary Lu Taubman Trust	0.00003%	0.00006%
Herman P. & Sophia Taubman	0.00002%	0.00005%
TOTAL:	100.00000%	100.00000%

ERNEST GOMEZ
GEOLOGIST

PERSONAL:

	Date of Birth:	November 29, 1954
	Marital Status:	Married
	Nationality:	American
	Language:	English, Spanish

EDUCATION:

B.A., Geology, State University of New York at New Paltz, 1976
M.S., Geology, Northern Arizona University, Flagstaff, Arizona, Geology, 1979

QUALIFICATIONS:

Sixteen years of technical and management experience in the petroleum industry. Expertise in most domestic U.S. basins. Strong background in exploration, development and acquisition.

WORK EXPERIENCE:

INTERA Petroleum Division, Denver, Colorado: (1992 to present)
Geologist

Review of exploration potential in Northwest Basin, Argentina. Sequence stratigraphy of First Frontier, Greater Green River Basin, southwest Wyoming, Yegua Formation, southeast, Texas.

Presidio Oil Company: Dallas, Texas: (1989 to 1992)
Senior Geologist

Responsible for exploration and development of the Jurassic Cotton Valley and Bossier of the East Texas Basin. Development of several exploratory prospects. Established a successful exploratory horizontal drilling program in the Austin Chalk of south Texas using subsurface and seismic. Development of Pennsylvanian (Red Fork, Morrow and Springer) and Devonian (Hunton) prospects in the Anadarko Basin, Oklahoma. Review of several companies and properties for acquisition in the Mid Continent and Gulf Coast, U.S. Implementation of a geological computer system comprised of a database manager (Paragon), contouring (CPS/Radian) and drafting (Autocad).

Home Petroleum Corporation; Houston, Texas: (1987 to 1989)
District Geologist

Responsible for the creation and implementation of a renewed exploration program in the onshore Gulf Coast U.S. Included supervision of staff geologists, geophysicist and landman. Development of several Yegua and Vicksberg prospects in southeast Texas, resulting in a significant discovery. Participated in generation of exploration prospects and lease sales in the OCS of Texas and

Louisiana. Resulted in discovery of a shagas field at Eugene Island. ~~Reviewed of Home's existing~~ production in the Gulf Coast for additional exploratory and development potential.

ERNEST GOMEZ
GEOLOGIST

Home Petroleum, Denver, Colorado: (1983 TO 1987)
District Geologist

Responsible for all exploration and exploitation projects in the Rocky Mountain and Mid Continent of the U.S. Included supervision of staff geologist and geophysicists.

Discovery of Wabek (Sherwood) and Plaza (Bluell) Fields in the Williston Basin, North Dakota. (Reserves 6+ MMBO). Discovery of several fields in the Cretaceous and Permian of the Powder River Basin and the Cretaceous of the Green River Basin. Successful development of Pennsylvanian (Red For, Morrow and Springer) reservoirs in the Anadarko Basin of Oklahoma.

Home Petroleum, Denver, Colorado: (1981 TO 1982)
Geologist

Responsible for Home's exploration and exploitation projects in Wyoming.

Discovery of Buck Draw Field (Dakota) in the southern Powder River Basin. Successful development of Cretaceous reservoirs in the Powder River (Teapot, Parkman, Sussex, Shannon, Frontier and Dakota) and Green River Basins (Lewis, Mesa Verde and Frontier).

Cities Service Company, Denver, Colorado: (1978 TO 1981)
Senior Geologist

Responsible for exploitation of Cretaceous fields in Wyoming. Included wellsite evaluation. Review and recommendation of possible heavy oil recovery projects in the western United States. Review of stratigraphy of central Oklahoma for incorporation in seislog field studies. Completion of company six month training program for entry level geologists.

U.S. Geological Survey, Flagstaff, Arizona: (1976 to 1978)
Geologist at Paleomagnetics Laboratory in Flagstaff

Collection and measurement of paleomagnetic samples from western United States and Antarctica. Field mapping section description on the Colorado Plateau and Transition Zone of Arizona.

PROFESSIONAL AFFILIATIONS:

- American Association of Petroleum Geologists
- Dallas Geological Society
- Houston Geological Society
- Rocky Mountain Association of Geologists

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA
Date............... Case No. 5933
Introduced by ....
Exhibit 1 (pg 3 of 3)
Identified by..................

CERTIFICATIONS:

Certified Petroleum Geologist No. 4468 (AAPG)
Professional Geologist State of Wyoming (PG-1586)

EXHIBIT NO. ______

CASE NO. 5933

DICKINSON LODGEPOLE UNIT
STARK COUNTY, NORTH DAKOTA

SUMMARY OF ORIGINAL OIL-IN-PLACE

TRACT NUMBER	LOCATION	ACRE-FEET	ORIGINAL OIL-IN-PLACE (MBO)	PERCENTAGE OF TOTAL ORIGINAL OIL-IN-PLACE
1	W/2 Sec. 32	24,554	6,779	42.1
2	S/2 Sec. 31	21,470	5,927	36.8
3	N/2 Sec. 31	7,087	1,957	12.2
4	N/2 Sec. 5	1,346	372	2.3
5	Portion N/2 Sec. 6	2,044	564	3.5
6	Portion SE Sec. 30	288	79	0.5
7	S/2 S/2 SW Sec. 29	1,491	412	2.6
8	Portion W/2 NE/4 Sec. 32	0	0	0.0
9	W/2 W/2 SE Sec. 32	0	0	0.0
TOTAL		58,280	16,090	100.0

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA

Date............ Case No. 5933

Introduced by Sorgen Trust

Exhibit B

Identified by..........

EXHIBIT NO.____

CASE NO. 5933

PRIMARY RECOVERY PREDICTIONS
DICKINSON LODGEPOLE UNITIZATION
STARK COUNTY, NORTH DAKOTA

		Conoco Model Prediction of Ultimate Primary Recovery		Ultimate Primary Recovery Used for Equity Determination	
TRACT	WELL	Millions of Barrels	Percent of Total	Millions of Barrels	Percent of Total
1	State 74	1.86	36.8	2.82	52.5
2	Kadrmas 75	2.02	39.9	1.78	33.2
3	Frenzel 79	0.81	16.0	0.65	12.1
4	State 83	0.37	7.3	0.12	2.2

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA
Date 6-8-94 Case No. 5933
Introduced by Singer Trust
Exhibit 9
Identified by K. Preston

DICKINSON LODGEPOLE UNIT

ROYALTY INTEREST OWNERSHIP PERCENTAGES

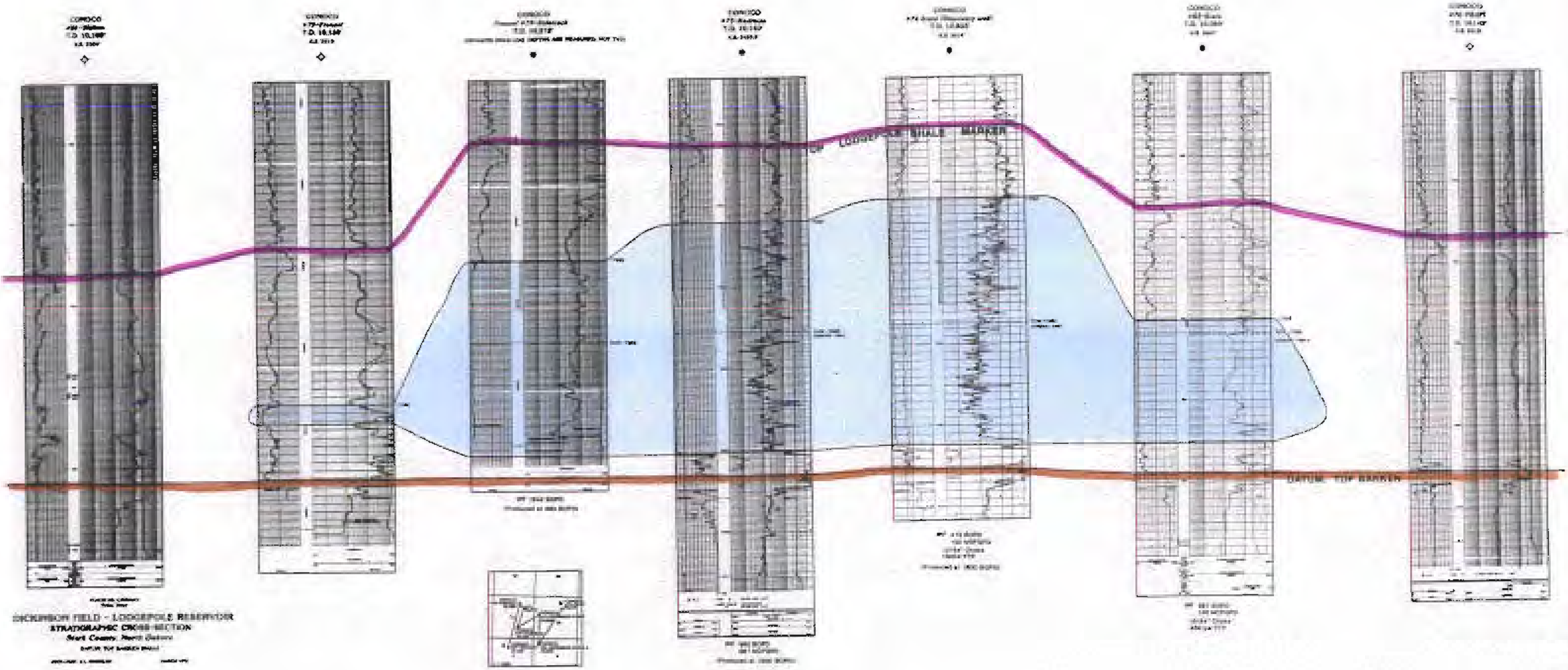
INTEREST OWNER	PHASE I INTEREST	PHASE II INTEREST
Agribank FCB	18.71827%	18.43012%
The Wiser Oil Company	10.63498%	10.21476%
Republic Royalty Company	7.32187%	7.07333%
Gerald David Kalanek	6.28087%	6.32939%
Arnold E. Kadrmas	4.14439%	3.97323%
Linda Kadrmas	4.14439%	3.97323%
Joan Schmidt	4.14439%	3.97323%
Douglas Kadrmas	4.14439%	3.97323%
Conoco Inc.	3.78948%	3.81947%
Louis W. Hill, Jr.	3.85601%	3.81100%
Virginia L. Sherron	3.17219%	3.22659%
Peggy Addington	3.17219%	3.22659%
State of North Dakota	2.77357%	3.09034%
J. Hiram Moore et al	1.73503%	1.79274%
Elizabeth H. Welch	1.58609%	1.61330%
Darlene McKinley Lane	1.58609%	1.61330%
Mary Pearl Lake	1.58609%	1.61330%
E.E. & Mildred Trumbell Jt.	1.56568%	1.57351%
J.H. Smart, Jr.	1.56568%	1.57351%
Marta Smart Bennett	1.56568%	1.57351%
Rose Frenzel	1.53883%	1.44937%
Mary Margaret Pugh	1.18957%	1.20997%
Beeman Dockery	0.91200%	0.92765%
Leslie J. May	0.79305%	0.80665%
Hunter S. Trunk	0.79305%	0.80665%

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA
Date 4/8/94 Case No. 5933
Introduced by Placid Oil Co. EX. D
Exhibit #2 John Morrison

Dodge Jones FDN	0.76538%	0.73940%
Stephen Filipi	0.25699%	0.50097%
Linda K. Jones	0.49312%	0.48917%
Clyde W. Jones	0.49312%	0.48917%
The Fasken Foundation	0.49224%	0.47553%
Victor B. Walton	0.21152%	0.41233%
Pacific West Lease Company	0.39653%	0.40332%
Baytech Inc.	0.39418%	0.38080%
William J. Grinde, Trustee	0.27785%	0.26169%
Fayette K. Stroud MD	0.23791%	0.24199%
Matt-Tex LLP	0.23702%	0.22897%
Patricia & William Dowell	0.24094%	0.22693%
Diane & Kenneth Mayer	0.24094%	0.22693%
Lester & Marlene Frenzel	0.24094%	0.22693%
Irene & Karl Hammann	0.24094%	0.22693%
May Ann & Edwin A. Fieck	0.24094%	0.22693%
Shirley Jean Larkin	0.10576%	0.20617%
Robert R. Walton	0.10576%	0.20617%
Dr. William H. Walton, Jr.	0.10576%	0.20617%
Randy Geiselman	0.17738%	0.17136%
Clark E. Jones	0.15861%	0.16133%
Zula Mae Pugh	0.15861%	0.16133%
Julia Jones Matthew	0.16660%	0.16095%
John A. Matthews, Jr.	0.11823%	0.11422%
Julia Reynolds	0.05288%	0.10308%
Elizabeth Bowers	0.05288%	0.10308%
Benjamin Deeble	0.05288%	0.10308%
Victoria Raynor	0.05288%	0.10308%
Andrews Royalty, Inc.	0.07292%	0.07045%
Mary Dpahne Hibl	0.03175%	0.06190%

Vivian Miller	0.03175%	0.06190%
Paul Karow	0.05557%	0.05234%
William R. Hoffman	0.02644%	0.05154%
James W. Hoffman	0.02644%	0.05154%
David E. Hoffman	0.02644%	0.05154%
John A. Hoffman	0.02644%	0.05154%
E.E. Trumbull	0.02041%	0.03979%
Erma Lowe Trust (Saman Yost)	0.03621%	0.03498%
Erma Lowe Trust (Carson Yost)	0.03261%	0.03498%
Erma Lowe Trust	0.03621%	0.03498%
Lois Eby Budbill	0.01713%	0.03340%
Mary H. Ayala	0.01542%	0.03006%
Lillian Ridl Life Estate	0.00919%	0.01792%
Barbara M. Comeau	0.00514%	0.01002%
Cynthia A. Comeau	0.00514%	0.01002%
Johnnie Beth Huskey	0.00428%	0.00835%
Hugh DeWitt Landis	0.00428%	0.00835%
Viola L. & Virginia Younger	0.00428%	0.00835%
Morris B. Taubman Revocable Trust	0.00334%	0.00651%
Louis Taubman Trust	0.00323%	0.00630%
Charles Taubman Revocable Trust	0.00252%	0.00492%
National Bank Tulsa, Trustee	0.00231%	0.00450%
Robert M. Taubman Revocable Trust	0.00228%	0.00444%
J.R. & Katherine A. Taylor	0.00214%	0.00417%
Janice S. Haffey	0.00214%	0.00417%
Elaine G. Konzelman	0.00214%	0.00417%
Rosalie Taubman Management Trust	0.00195%	0.00380%
Marilyn Kay Ralstin	0.00107%	0.00209%
Gerald C. Wiseman	0.00107%	0.00209%
L.N. Taubman Revocable Trust	0.00023%	0.00045%

Bank of Oklahoma, Tulsa	0.00017%	0.00033%
Anne C. Taubman Trust	0.00017%	0.00033%
Richard J. Taubman Trust	0.00017%	0.00033%
Jonathon Z. Shalom Management Trust	0.00012%	0.00023%
Karen P. Shalom Management Trust	0.00012%	0.00023%
Adina Taubman Trust	0.00007%	0.00013%
Henrik Perry Taubman Family Trust	0.00007%	0.00013%
Barbara Taubman Living Trust	0.00006%	0.00012%
Janice L. Taubman Revocable Trust	0.00003%	0.00007%
Sara K. Taubman Revocable Trust	0.00003%	0.00006%
Andrea Quijano Revocable Trust	0.00003%	0.00006%
Estate of William David Taubman	0.00003%	0.00006%
Deborah Anne Taubman Trust	0.00003%	0.00006%
Claudia P. Taubman Revocable Trust	0.00003%	0.00006%
Rebecca M. Taubman Revocable Trust	0.00003%	0.00006%
Hilary Lu Taubman Trust	0.00003%	0.00006%
Herman P. & Sophia Taubman	0.00002%	0.00005%
TOTAL:	100.00000%	100.00000%



CONOCO
LODGEPOLE SHALE MARKER
DATUM TOP BAKKEN
DICKINSON FIELD - LODGEPOLE RESERVOIR
STRATIGRAPHIC CROSS-SECTION
Stark County, North Dakota

Conoco Inc.
Case #5933
Exhibit #26

FINAL PRINT
Schlumberger

BOREHOLE COMPENSATED SONIC LOG

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA
Date 6-8-94 Case No. 5933
Introduced by Conoco
Exhibit 26
Identified by Mohl

COMPANY	CONOCO INC.		
WELL	KADRMAS 75		
FIELD	DICKINSON		
COUNTY	STARK	STATE	NORTH DAKOTA

COUNTY / FIELD / LOCATION / WELL / COMPANY

LOCATION: NW SE
1400' FSL & 900' FEL

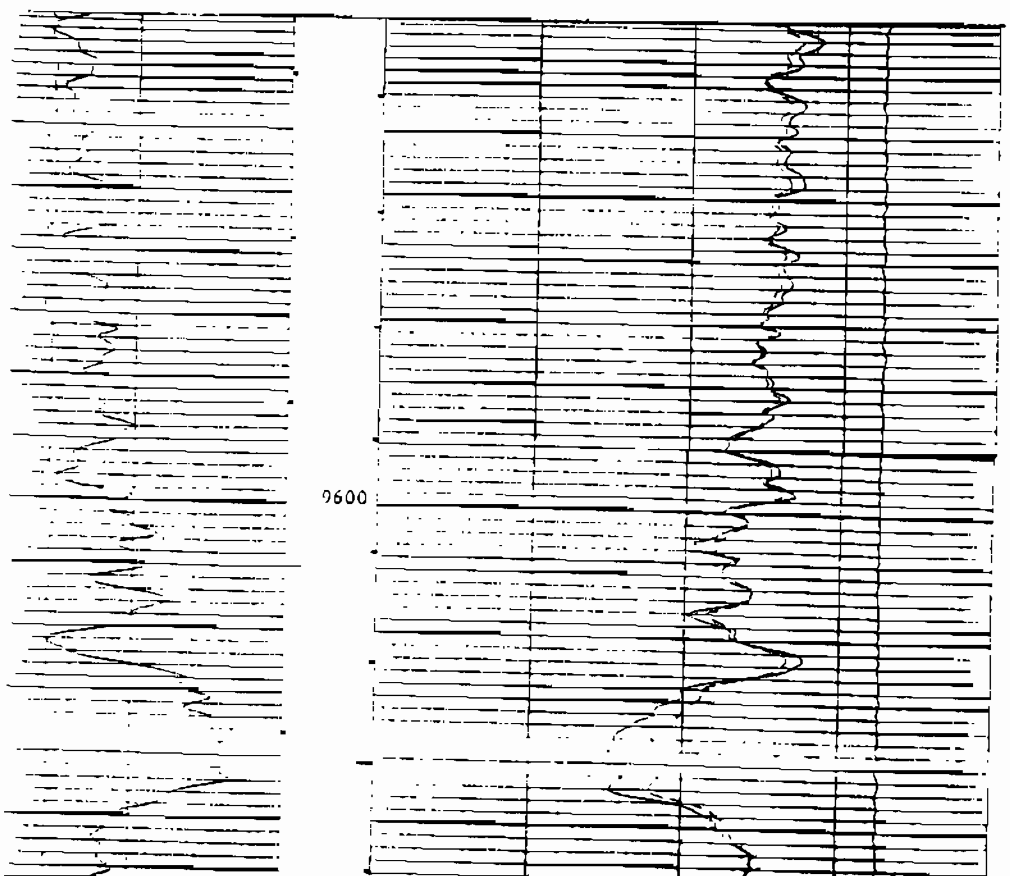
Other Services:
FDC CNL
DLL MSFL
RFT
FMS

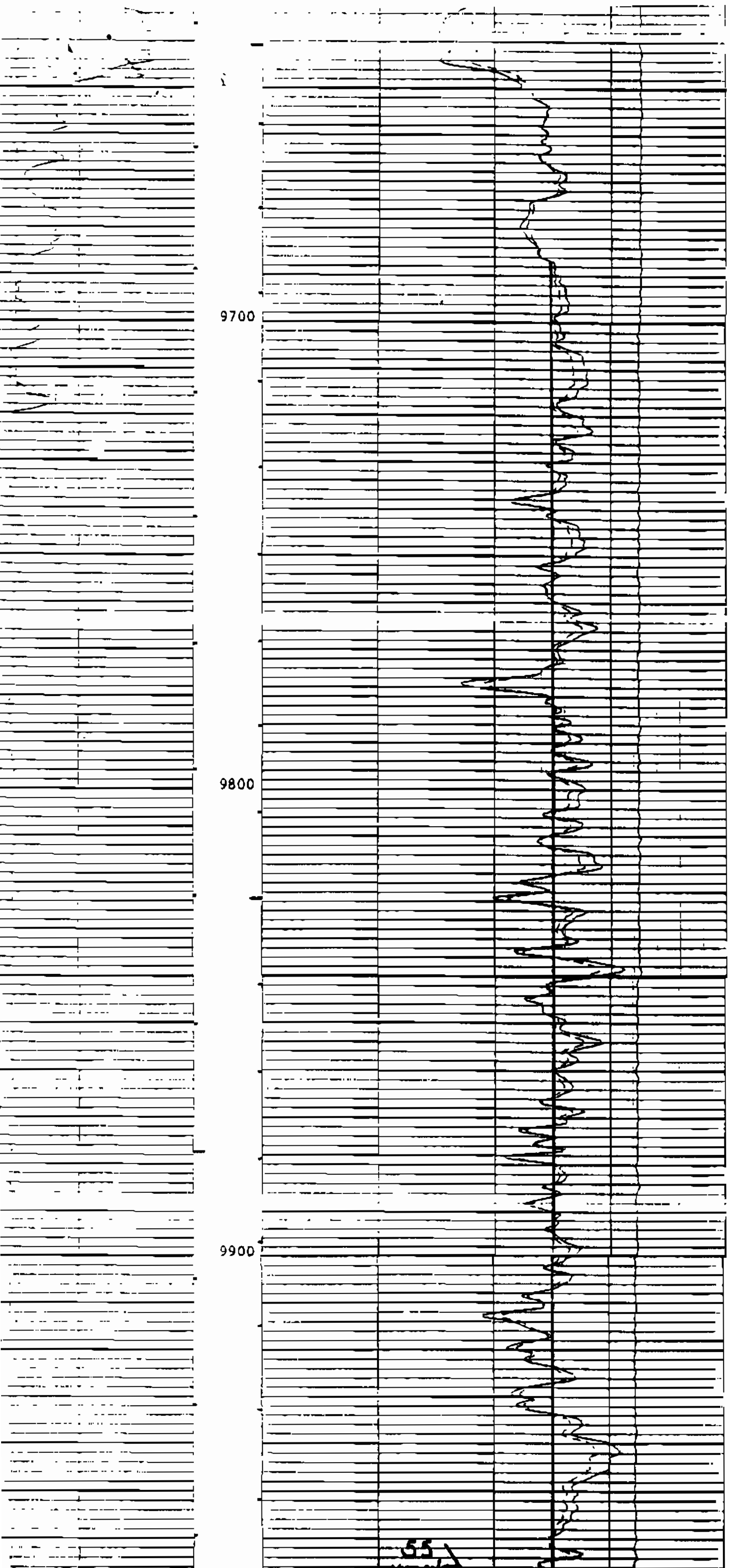
API SERIAL NO.	SECT.	TWP.	RANGE
33-089-00400	31	140N	96W

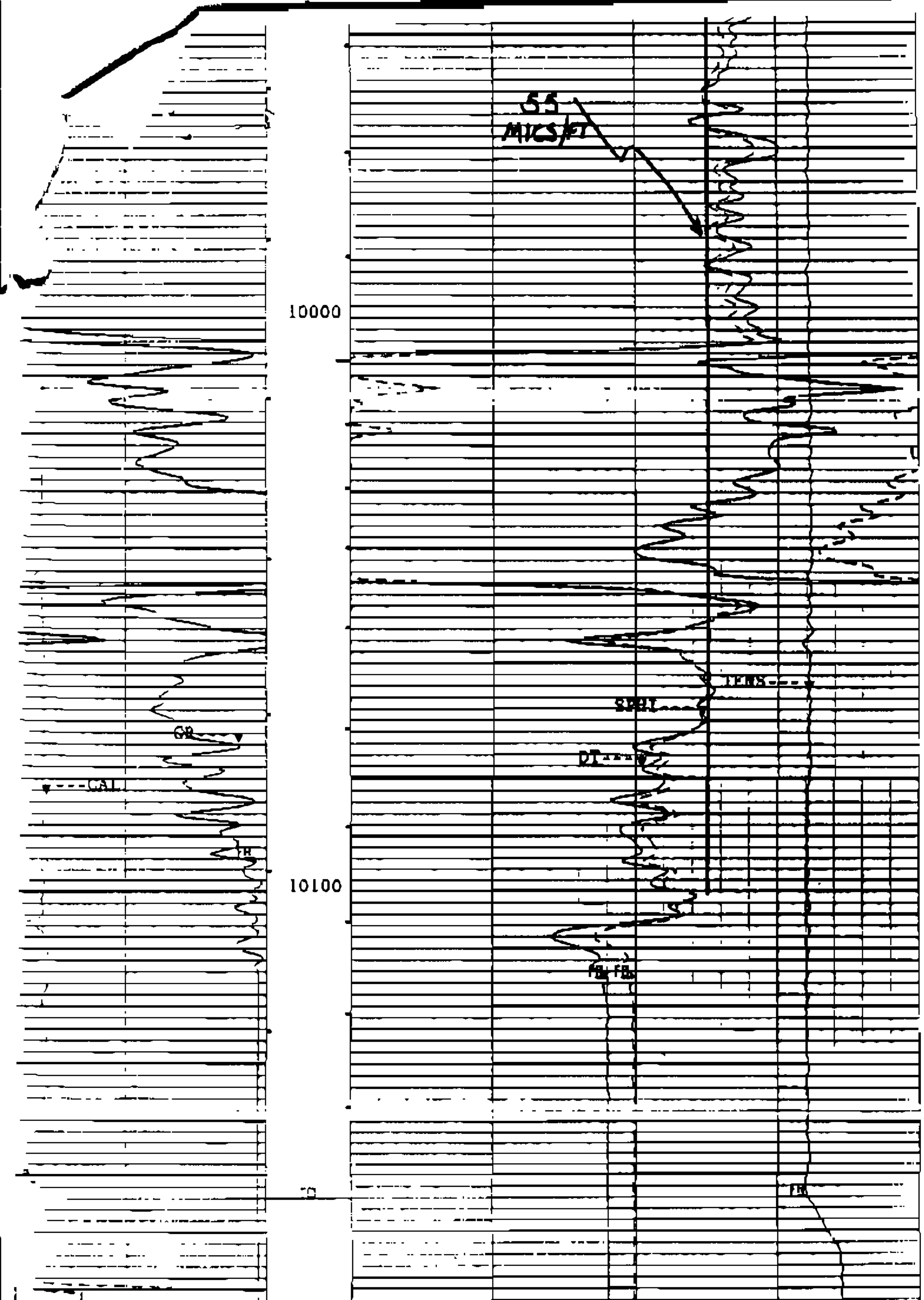
Permanent Datum	GL	Elev.	2475.5 F	Elev.: K.B. 2489.5 F
Log Measured From	KB	14.0 F	above Perm. Datum	D.F.
Drilling Measured From	KB			G.L. 2475.5 F

Date		08-AUG-1993		
Run No.		1		
Depth Driller		10150.0 F		
Depth Logger (Schl.)		10154.0 F		
Btm. Log Interval		10153.0 F		
Top Log Interval		2194.0 F		
Casing-Driller		8 5/8 @ 2198.0 F		@
Casing-Logger		2194.0 F		
Bit Size		7 7/8		@
Type Fluid in Hole		SALT MUD		
Dens.	Visc.	10.30 LB/G	34.0 S	
pH	Fld. Loss	9.5	8.0 C3	
Source of Sample		FLOWLINE		
Rm @ Meas. Temp.		.053 OHMM @ 72.0 DEGF		@
Rmf @ Meas. Temp.		.047 OHMM @ 72.0 DEGF		@
Rmc @ Meas. Temp.		.079 OHMM @ 72.0 DEGF		@
Source: Rmf	Rmc	MEAS	CALC	
Rm @ BHT		.020 OHMM @ 198. DEGF		@
TIME	Circulation Ended	8-AUG-1993 2:00		
	Logger on Bottom	9-AUG-1993 8.43		
Max. Rec. Temp.		198. DEGF		
Equip.	Location	8121	WILLISTON	
Recorded By		C. CARPENTER		
Witnessed By		GORDON RAMSEY		

The well name, location and borehole reference data were furnished by the customer




9700
9800
9900
55



5"/100'

LIMESTONE

CP 32.6   FILE 15   08-AUG-1993 16:57

INPUT FILE(S)   CREATION DATE
10   08-AUG-1993 11:07

TENS(LBF)
10000.   0.0

GR(GAPI)
100.00

SPHI(V/V)
.30000   -.1000

CAL1(IN)
16.000

DT(US/F)
80.000   40.000

SENSOR MEASURE POINT TO TOOL ZERO

DV1 14.9 FEET   CAL1 2.8 FEET

Conoco Inc. Case #5933 Exhibit #27

ATLAS WIRELINE SERVICES

Western Atlas International

BHC ACOUSTILOG
Gamma Ray Caliper

FILE NO.	COMPANY	CONOCO INCORPORATED
	WELL	FRENZEL #79
API NO.	FIELD	DICKINSON
	COUNTY	STARK — STATE N.DAKOTA

THANK YOU!

LOCATION:
NW/NE
900' FNL & 1800' FEL
SEC 31 TWP 140N RGE 96W

OTHER SERVICES
DIFL/GR

PERMANENT DATUM GROUND LEVEL ELEVATION 2501 FT.
LOG MEASURED FROM KELLY BUSHING 14 FT. ABOVE PERMANENT DATUM
DRILL. MEAS. FROM KELLY BUSHING

ELEVATIONS
KB 2515'
DF 2514'
GL 2501'

Tight Hole

DATE	8-SEPTEMBER-1993	
RUN	ONE	
SERVICE ORDER	93158	
DEPTH DRILLER	10130'	
DEPTH LOGGER	10121'	
BOTTOM LOGGED INTERVAL	10098'	
TOP LOGGED INTERVAL	SURFACE	
CASING - DRILLER	8 5/8" @2271'	
CASING LOGGER	2288'	
BIT SIZE	7 7/8"	
TYPE FLUID IN HOLE	INVERT	
DENSITY / VISCOSITY	9.5	52
PH / FLUID LOSS	-	6.8
SOURCE OF SAMPLE	MUD PIT	
RM AT MEAS. TEMP.	- @ -	
RMF AT MEAS. TEMP.	- @ -	
RMC AT MEAS. TEMP.	- @ -	
SOURCE OF RMF / RMC	-	-
RM AT BHT	- @ -	
TIME SINCE CIRCULATION	8 HRS.	
MAX. REC. TEMP. DEG. F	200 F.	
EQUIP. NO. / LOCATION	HL 6530	CASPER
RECORDED BY	PAT RASMUSSEN	
WITNESSED BY	TAN GORDON/KARLIN COSTA	

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA
Case No. 5933
Introduced by Conoco
Exhibit 27

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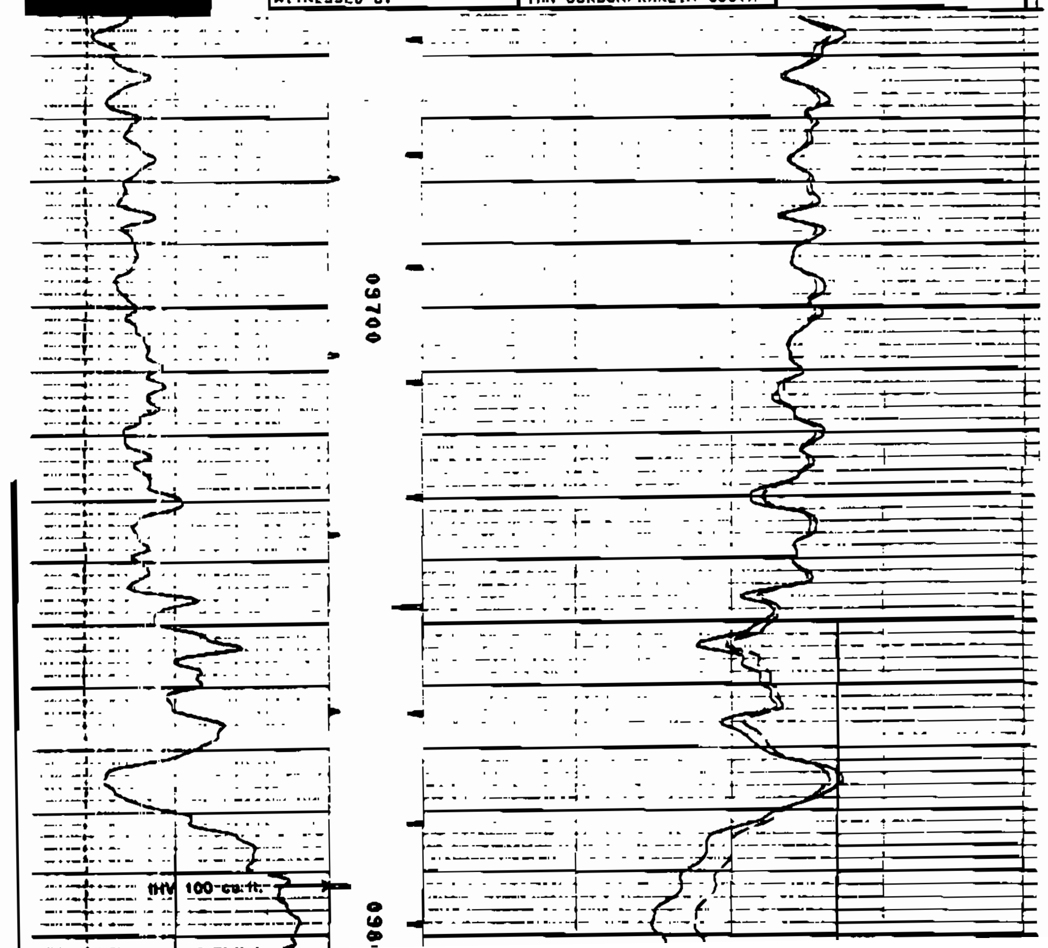

[redacted]

RUN	ONE	
SERVICE ORDER	93158	
DEPTH DRILLER	10130'	
DEPTH LOGGER	10121'	
BOTTOM LOGGED INTERVAL	10090'	
TOP LOGGED INTERVAL	SURFACE	
CASING - DRILLER	8 5/8"	@2271
CASING LOGGER	2280'	
BIT SIZE	7 7/8"	
TYPE FLUID IN HOLE	INVERT	
DENSITY / VISCOSITY	9.5	52
PH / FLUID LOSS	-	6.0
SOURCE OF SAMPLE	MUD PIT	
RM AT MEAS. TEMP.	-	@ -
RMF AT MEAS. TEMP.	-	@ -
RMC AT MEAS. TEMP.	-	@ -
SOURCE OF RMF / RMC	-	-
RM AT BHT	-	@ -
TIME SINCE CIRCULATION	0 HRS.	
MAX. REC. TEMP. DEG. F	200 F.	
EQUIP. NO. / LOCATION	HL 6530	CASPER
RECORDED BY	PAT RASMUSSEN	
WITNESSED BY	IAN GORDON/KARLIN COSTA	

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA
Case No. 6596 [illegible]
Introduced by [illegible]
Exhibit 27
Identified by [illegible]

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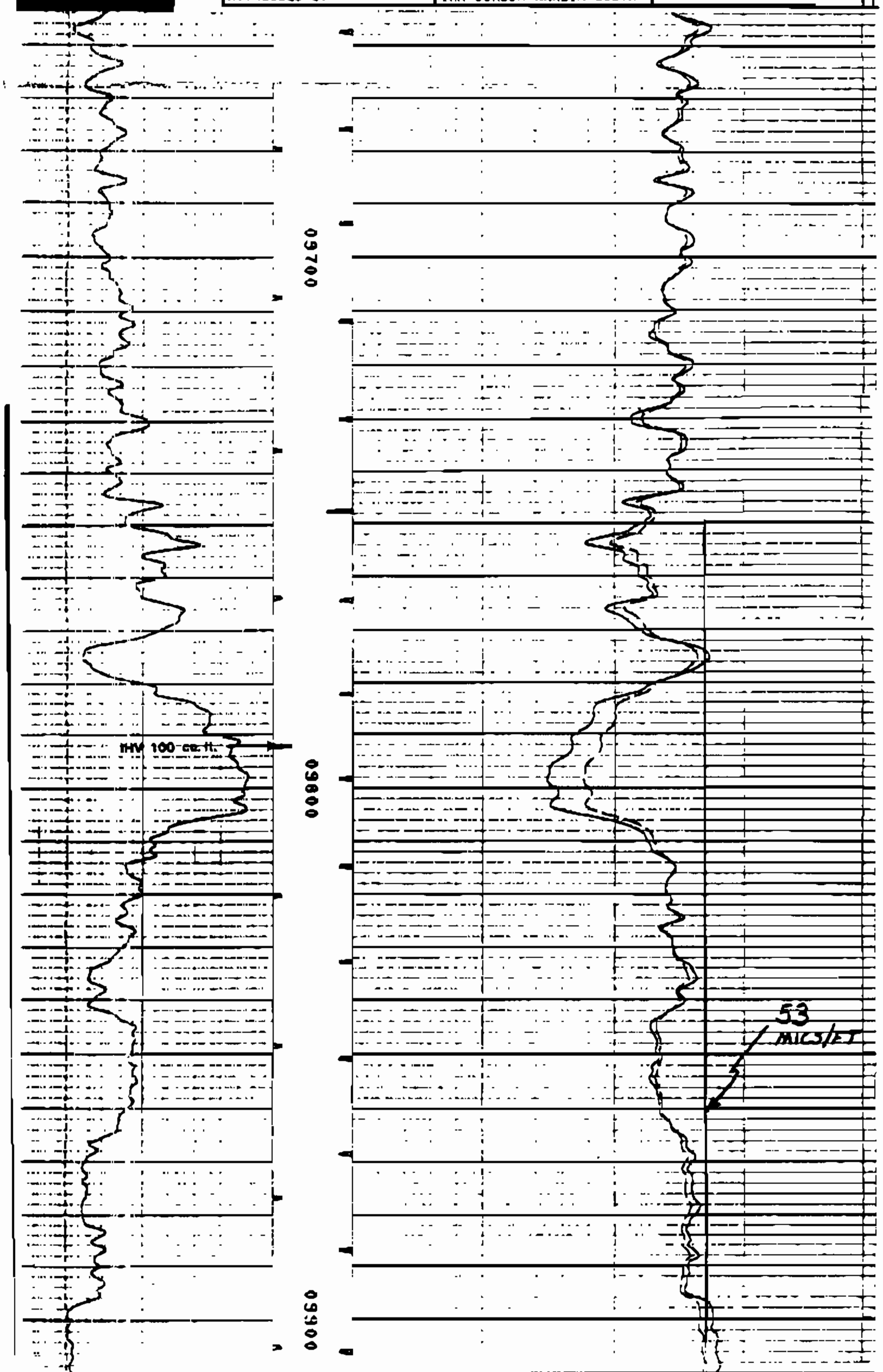

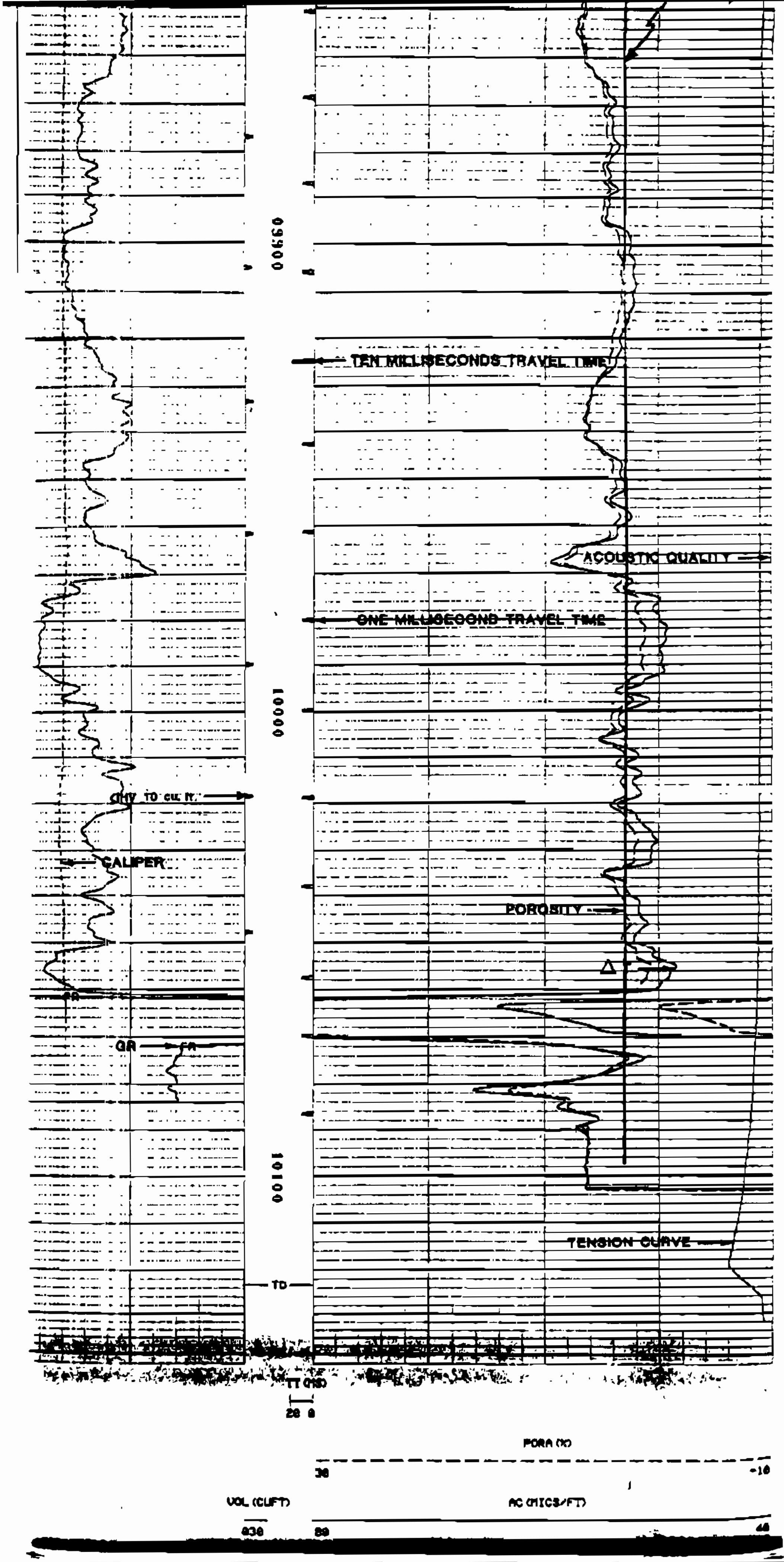

9900
TEN MILLISECONDS TRAVEL TIME
ACOUSTIC QUALITY
ONE MILLISECOND TRAVEL TIME
10000
CHV TO CU. FT.
CALIPER
POROSITY
GR
10100
TENSION CURVE
TD
TT (MS)
20 0
PORA (%)
30
-10
VOL (CUFT)
AC (MICS/FT)
830
80
40

EXHIBIT NO. ______

CASE NO. 5933

DICKINSON LODGEPOLE UNIT
STARK COUNTY, NORTH DAKOTA

SUMMARY OF ORIGINAL OIL-IN-PLACE

TRACT NUMBER	LOCATION	ACRE-FEET	ORIGINAL OIL-IN-PLACE (MBO)	PERCENTAGE OF TOTAL ORIGINAL OIL-IN-PLACE
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5	Portion N/2 Sec. 6	2,044	564	3.5
6	Portion SE Sec. 30	288	79	0.5
7	S/2 S/2 SW Sec. 29	1,491	412	2.6
8	Portion W/2 NE/4 Sec. 32	0	0	0.0
9	W/2 W/2 SE Sec. 32	0	0	0.0
TOTAL		58,280	16,090	100.0

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA

Date ________ Case No. 5933

Introduced by Singer Trust

Exhibit 8

Identified by ________

EXHIBIT NO.____

CASE NO. 5933

PRIMARY RECOVERY PREDICTIONS
DICKINSON LODGEPOLE UNITIZATION
STARK COUNTY, NORTH DAKOTA

		Conoco Model Prediction of Ultimate Primary Recovery		Ultimate Primary Recovery Used for Equity Determination	
TRACT	WELL	Millions of Barrels	Percent of Total	Millions of Barrels	Percent of Total
1	State 74	1.86	36.8	2.82	52.5
2	Kadrmas 75	2.02	39.9	1.78	33.2
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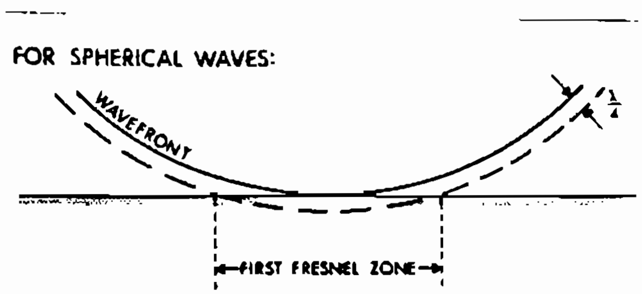
4	State 83	0.37	7.3	0.12	2.2

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA
Date 6-8-94 Case No. 5933
Introduced by [redacted] Singer Trust
Exhibit 9
Identified by K. Preston

Conoco Inc.
Case #5933
Exhibit #28



Limit of Lateral Resolution for Stack Seismic Data

$$rf = \frac{V_a}{2}\sqrt{\frac{t}{f_d}}$$

rf = radius of the fresnel zone

Va = average velocity to target

t = two way time in seconds

f_d = dominant frequency in hertz

Limit of lateral resolution for migration seismic data

$$\lambda = \frac{V_i}{f_d}$$

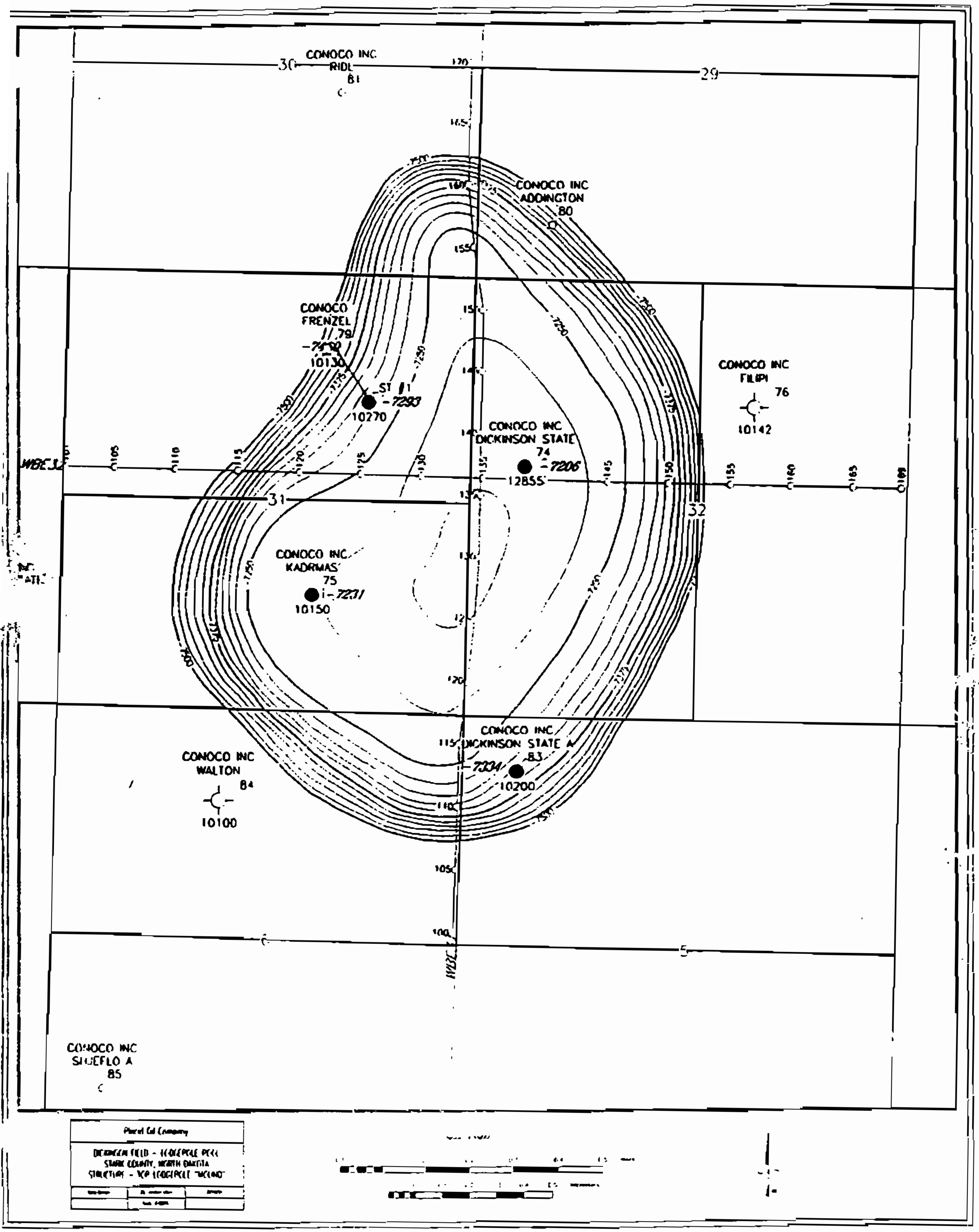
λ = wavelength (horizontal resolution)

v_i = interval velocity of target

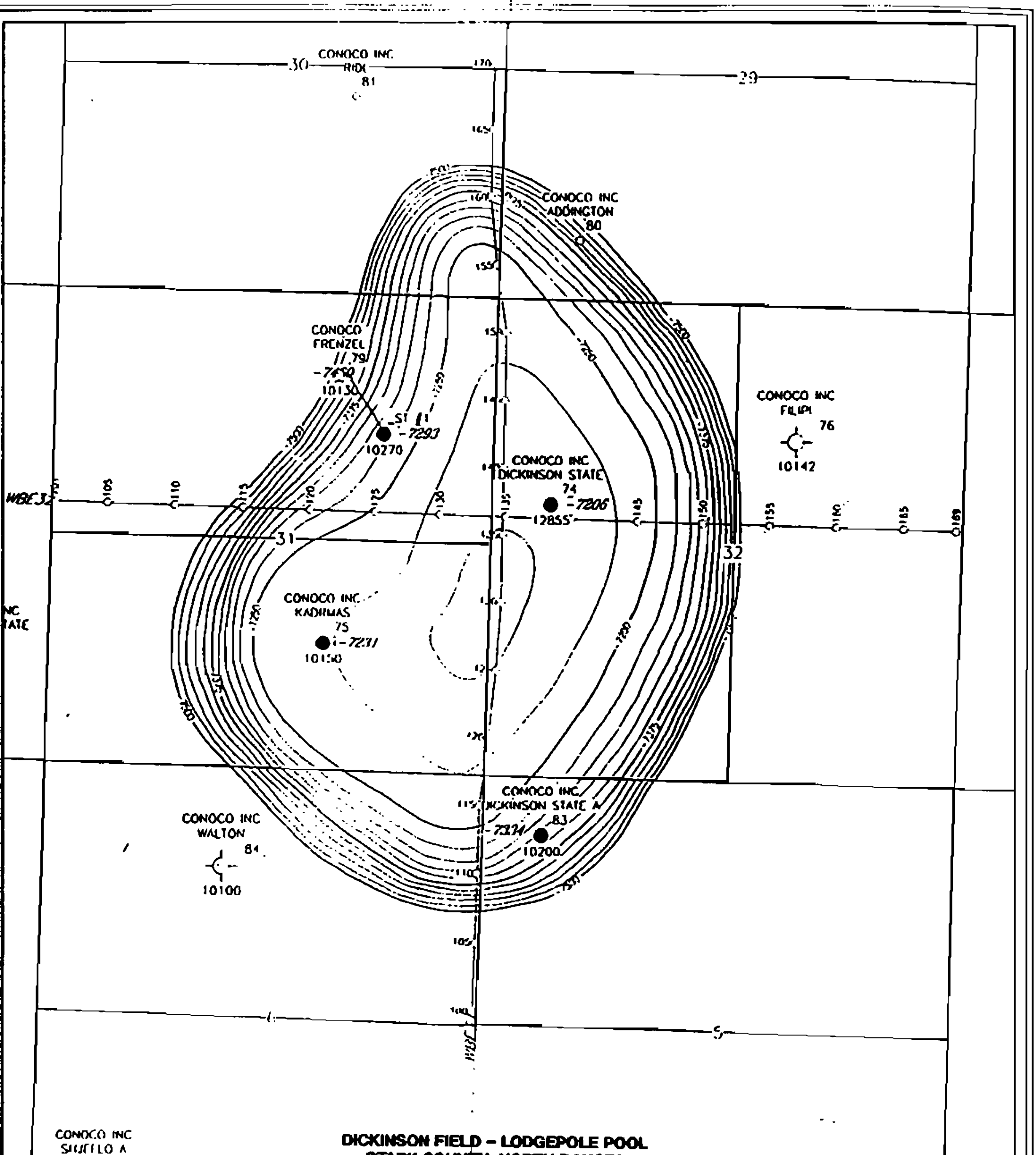
f_d = dominant frequency

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA
Date 6-8-94 Case No. 5933
Introduced by Conoco
Exhibit 28
Identified by Mohl

Conoco Inc.
Case #5933
Exhibit #29



PLACID MAP #2

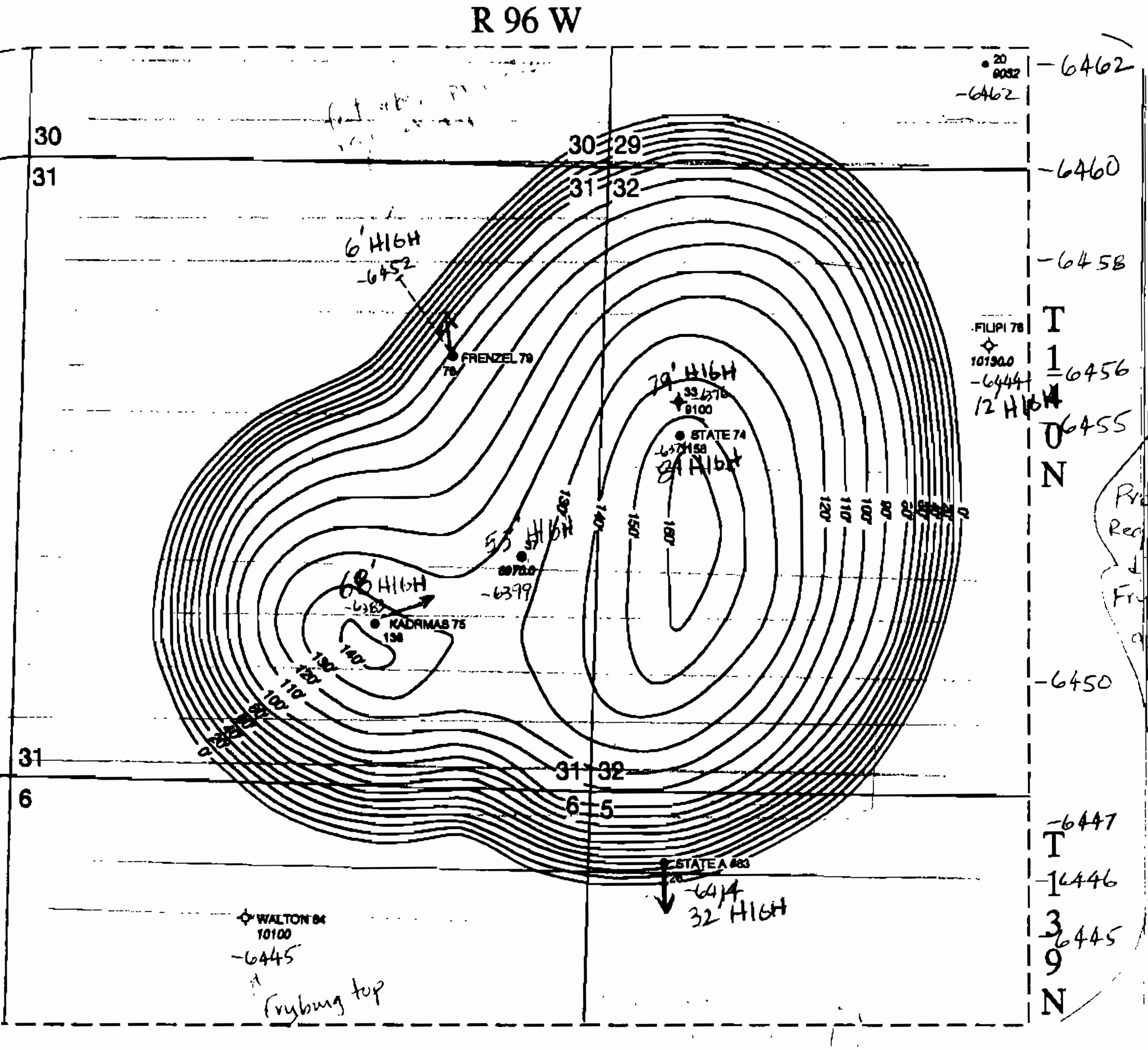


DICKINSON FIELD – LODGEPOLE POOL
STARK COUNTY, NORTH DAKOTA

STRUCTURE – TOP LODGEPOLE MOUND

STEVE BRESSLER
PLACID OIL COMPANY

0 0.1 0.2 0.3 0.4 0.5 MILES



Contour Interval: 10 Feet
Min: 0 Max: 160

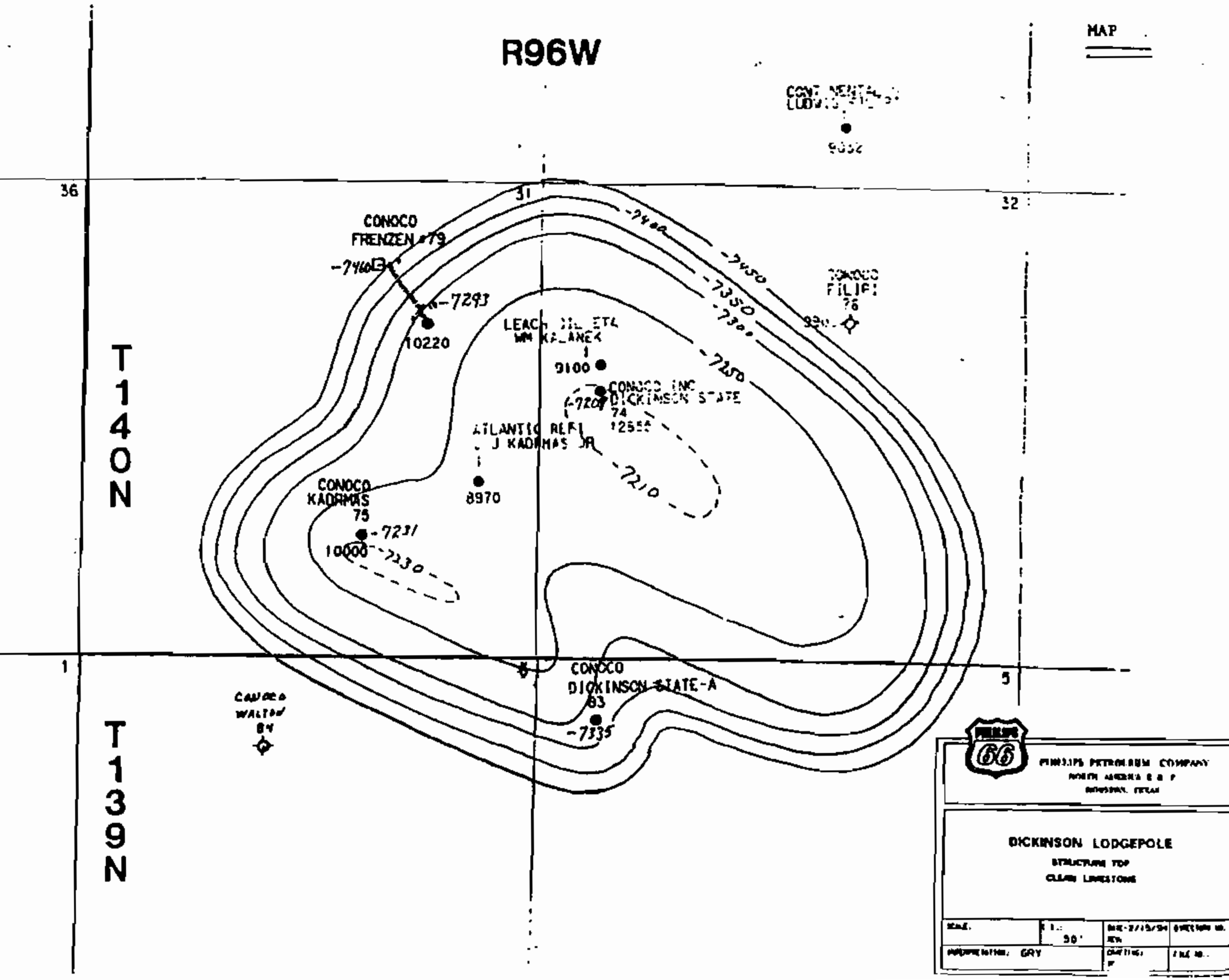
ISOPACH OF LODGEPOLE PAY
Dickinson Field
Stark Co., North Dakota

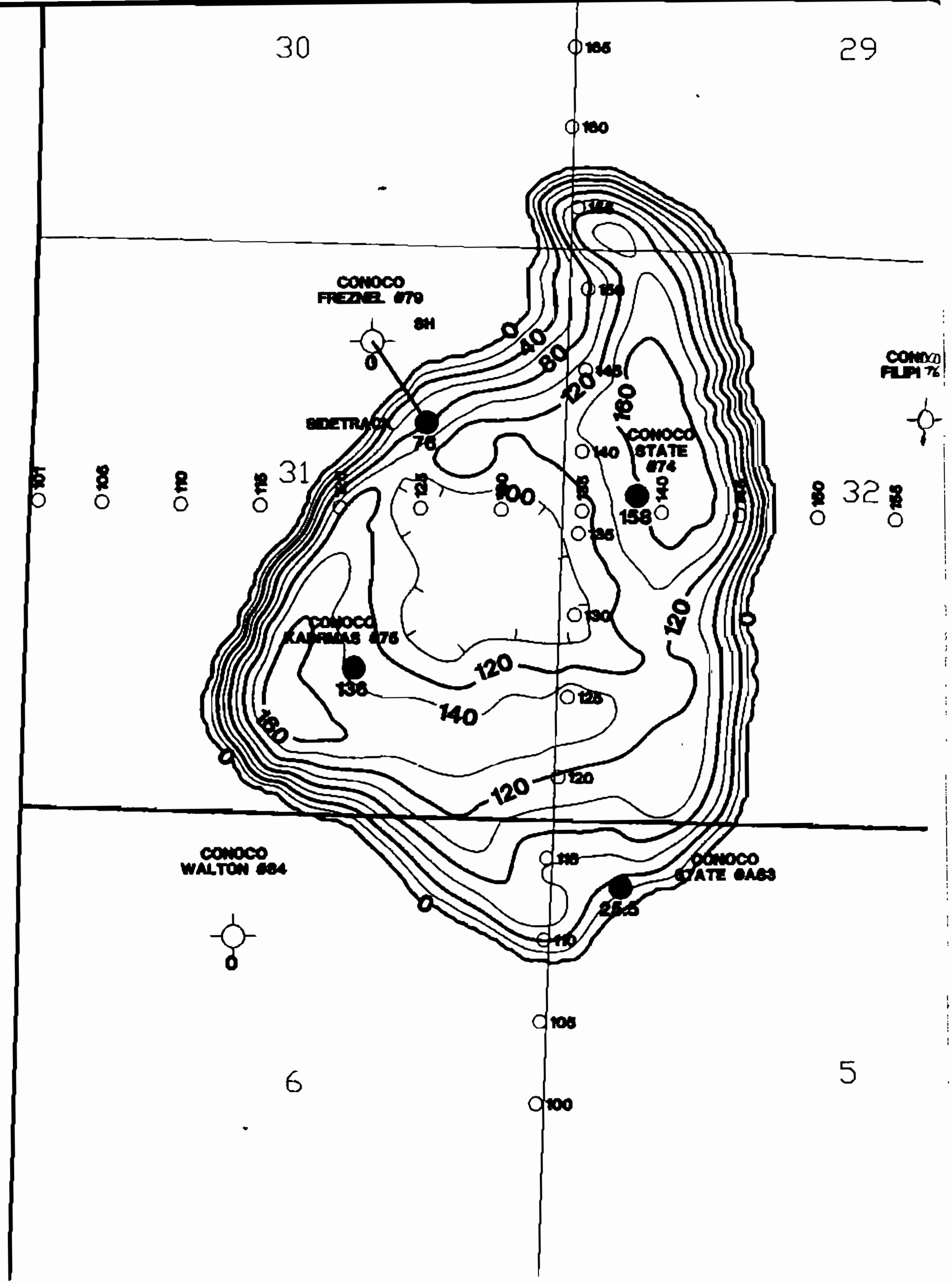
Waterzone depleted from 4+ #12.

Note: Fryburg highs (above the regional dip) reflect the underlying structure of the mound.

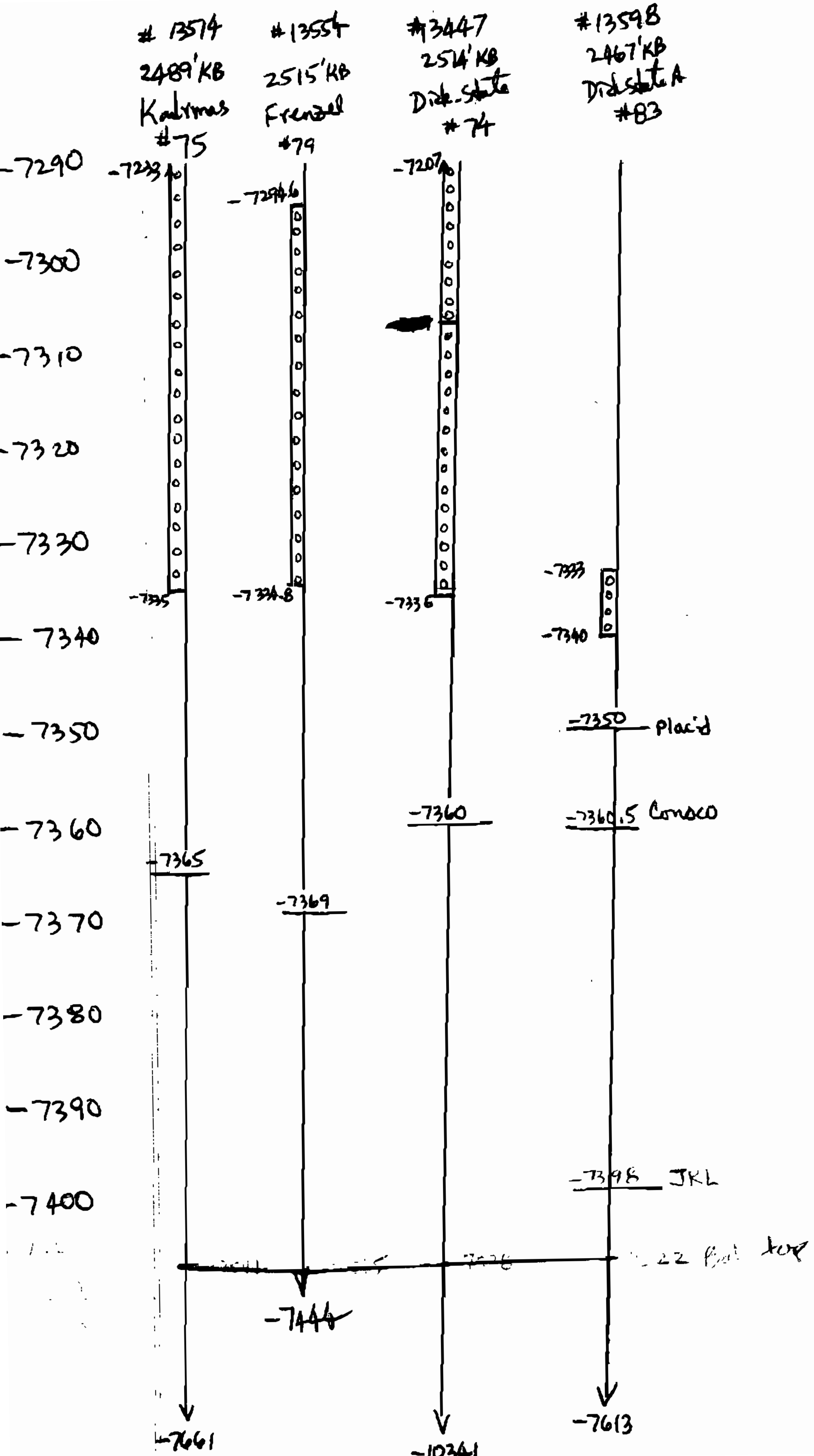
CONOCO INC.
Case No. 5933
Exhibit No. 13

Case #59
Exhibit




30
29
CONOCO
FREZNEL #79
SH
SIDETRACK
76
31
32
CONOCO
STATE
#74
158
CONOCO
KARMAS #75
136
CONOCO
WALTON #84
CONOCO
STATE #A63
25.5
6
5
0
40
80
120
160
100
140

ASPRT
#7



13574
2489' KB
Kadrmas
#75
13554
2515' KB
Frenzel
#79
#13447
2514' KB
Dick State
#74
#13598
2467' KB
Dick State A
#83
-7290
-7300
-7310
-7320
-7330
-7340
-7350
-7360
-7370
-7380
-7390
-7400
-7233
-7335
-7294.6
-7334.8
-7207
-7336
-7333
-7340
-7350
Placid
-7360
-7360.5
Conoco
-7365
-7369
-7398
JKL
-7444
-7661
-10341
-7613

TD 10100'
P&A (1/94)

TD 10150'

Cored 9750-71' (Lodgepole):
Rec: 21'
LS: gry., vuggy, oil stn.

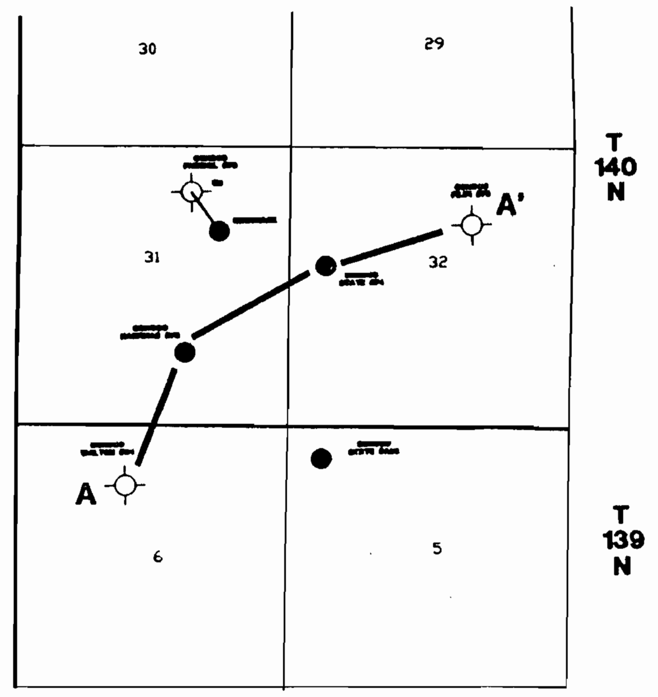
Perf 9722-9824'
IPF 960 BOPD
960 MCF/D (9/93)
16/64" ck; FTP 1020#

TD 12846'

Perf 9721-9820' (Lodgepole)
IPF 419 BOPD
130 MCF/D (2/93)
(16 hr. test)
12/64" ck; 1500# FTP

TD 10142'
P&A (10/93)

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA
Date 6-8-94 Case No. 5933
Introduced by Singer Trust
Exhibit 2
Identified by Gomez



INTERA EXHIBIT #

ANDREA SINGER POLLACK REVOCABLE TRUS

CROSS SECTION A - A'

Date: 6/8/94

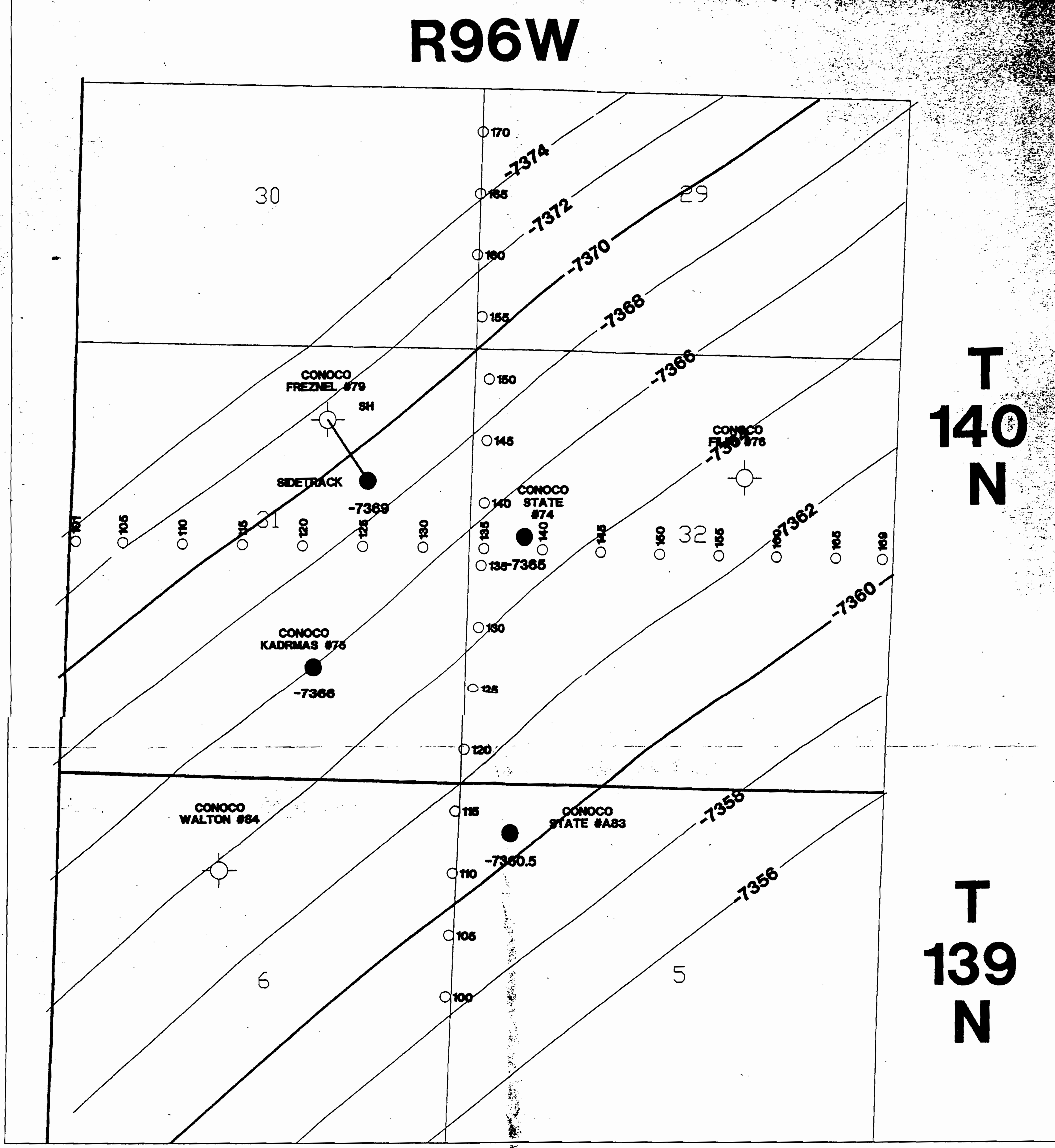
INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA
Date 6-8-94 Case No. 5933
Introduced by Singer Trust
Exhibit 3
Identified by Gomez

INTERA EXHIBIT #

ANDREA SINGER POLLACK REVOCABLE TRUS

CROSS SECTION B - B'

Date: 6/8/94



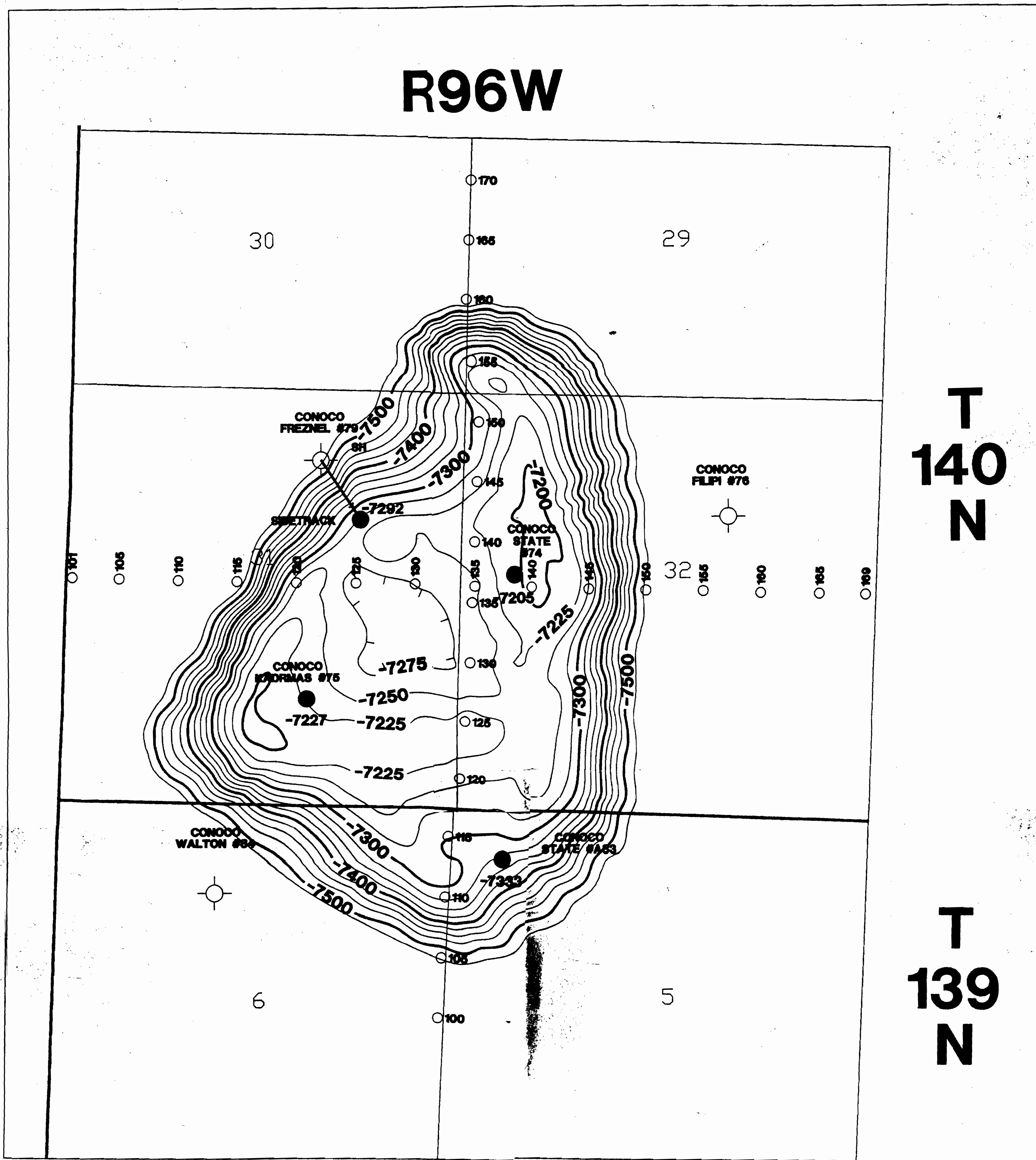
INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA
Date 6-8-94 Case No. 5933
Introduced by Singer Trust
Exhibit 6
Identified by Gomez

INTERA EXHIBIT #

ANDREA SINGER POLLACK REVOCABLE TRUST

STRUCTURE OIL/WATER CONTACT

Scale: 1"=1000'	Contour Interval=2 FEET	Date: 6/8/94



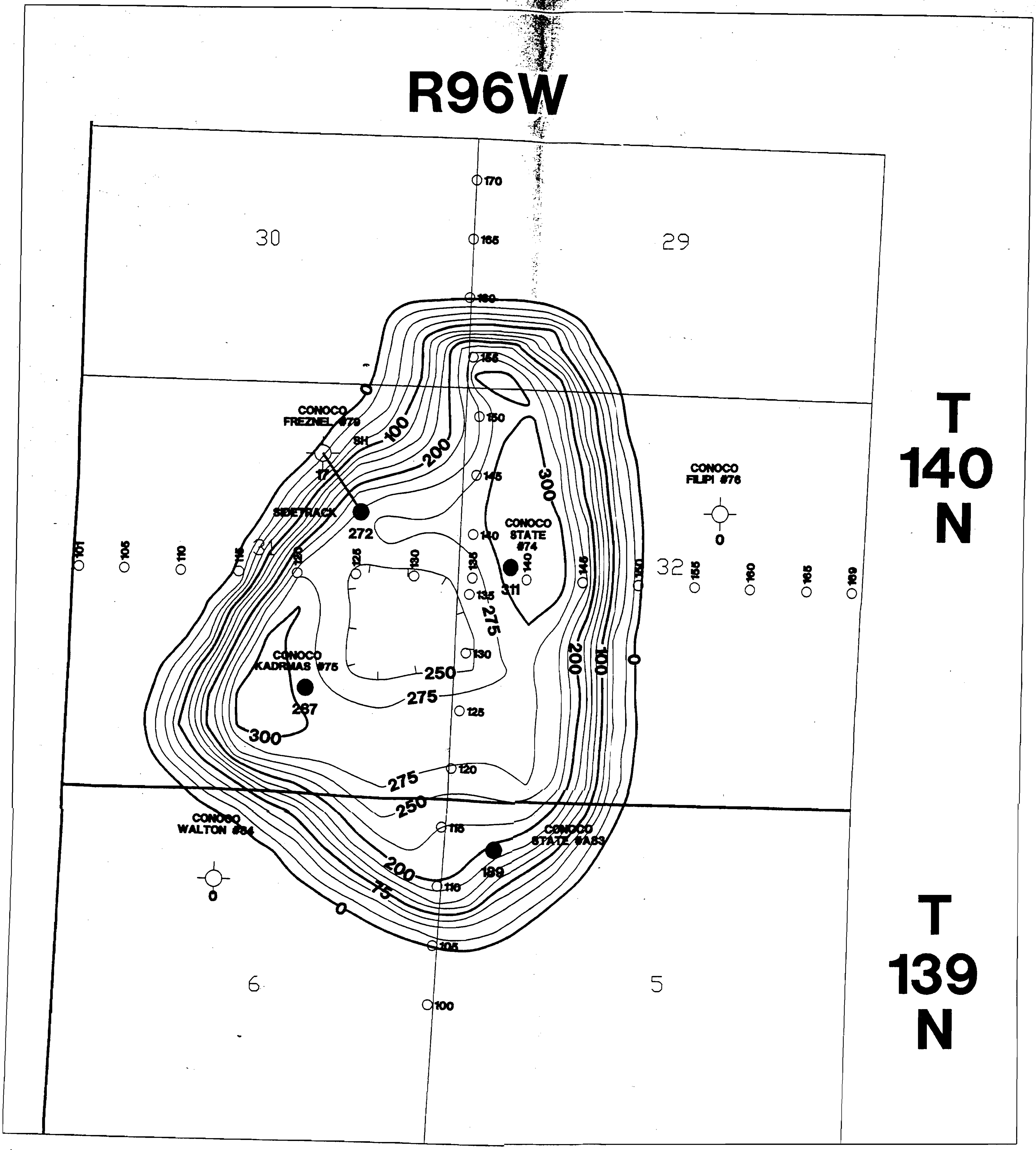
INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA
Date 6-8-94 Case No. 5933
Introduced by Singer Trust
Exhibit 5
Identified by Gomez

INTERA EXHIBIT #

ANDREA SINGER POLLACK REVOCABLE TRUST

STRUCTURE TOP LODGEPOLE MOUND

Scale: 1"=1000'	Contour Interval=25 FEET	Date: 6/8/94



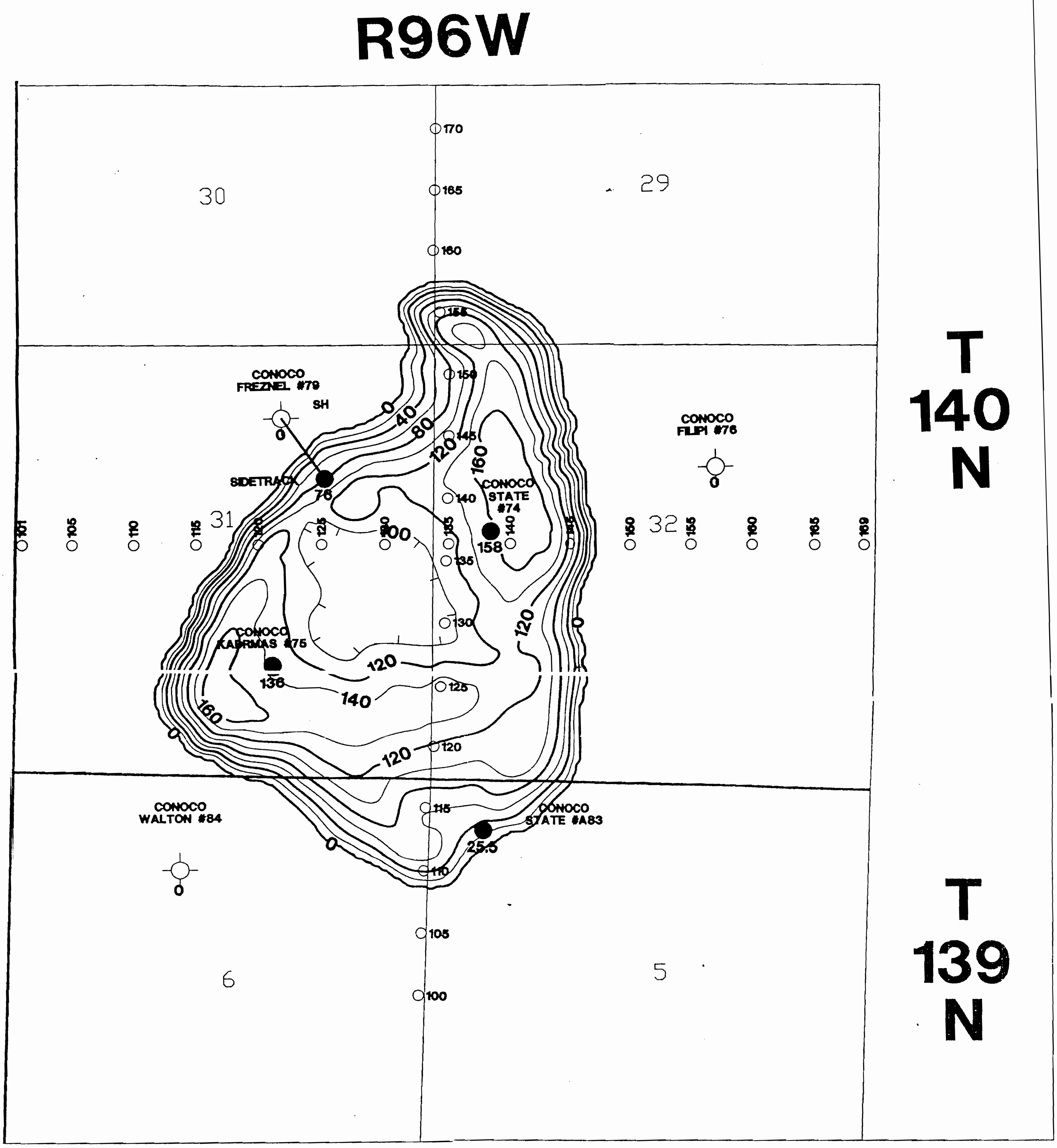
INDUSTR·AL COMMISSION
STATE OF NOR·H DAKOTA
Date 6-8-94 Case No. 5933
Introduced by Singer Trust
Exhibit 4
Identified by Gomez

INTERA EXHIBIT #

ANDREA SINGER POLLACK REVOCABLE TRUS

GROSS ISOPACH LODGEPOLE MOUNI

Scale: 1"=1000'	Contour Interval=25 FEET	Date: 6/8/9



INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA
Date 6-8-94 Case No. 5933
Introduced by Singer Trust
Exhibit 7
Identified by Gomez

INTERA EXHIBIT #

ANDREA SINGER POLLACK REVOCABLE TRUST

LODGEPOLE NET PAY

Scale: 1"=1000'	Contour Interval=20 FEET	Date: 6/8/94

NOTICE OF PUBLICATION
NORTH DAKOTA
INDUSTRIAL COMMISSION
BISMARCK, NORTH DAKOTA

The State of North Dakota by its Industrial Commission hereby gives notice pursuant to law and the rules and regulations of said Commission promulgated thereunder of the following public hearing to be held at 9:00 a.m. on June 8, 1994, Brynhild Haugland Room, State Capitol, Bismarck, North Dakota. For the purpose of this hearing, the Commission, any member thereof acting as Examiner, or an Examiner appointed by the Commission will receive testimony and exhibits.

ATTENTION PERSONS WITH DISABILITIES: If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the North Dakota Industrial Commission at 701-224-3722 by May 25, 1994.

STATE OF NORTH DAKOTA TO:

All named parties and persons having any right, title, interest, or claim in the following cases and notices to the public. CASE NO. 5933: ON A MOTION OF THE COMMISSION TO CONSIDER THE PETITION OF CONOCO INC. FOR AN ORDER PROVIDING FOR THE UNITIZED MANAGEMENT, OPERATION, AND FURTHER DEVELOPMENT OF THE DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OR UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION; VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE. CASE NO. 5935: ON A MOTION OF THE COMMISSION TO CONSIDER THE APPLICATION OF CONOCO INC. FOR AN ORDER DETERMINING THAT THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA, STARK COUNTY, NORTH DAKOTA, HAS BEEN SIGNED, RATIFIED OR APPROVED BY OWNERS OF INTEREST OWNING THAT PERCENTAGE OF THE WORKING INTEREST AND ROYALTY INTEREST WITHIN SAID UNIT AS IS REQUIRED BY APPLICABLE STATUTES AND RULES OF THE COMMISSION.

Signed by,
Edward T. Schafer, Governor
Chairman, ND
Industrial Commission
(Published May 4, 1994)

ok

CERTIFICATE OF PUBLICATION
THE DICKINSON PRESS
Dickinson, North Dakota

STATE OF NORTH DAKOTA, }
County of Stark. }

Belle L. Krank, of said state and county, being first duly sworn, on oath says: That s he is the bookkeeper of the Dickinson Press, Inc., publisher of **THE DICKINSON PRESS, a daily newspaper** of general circulation, printed and published at Dickinson, in said county and state, and has been such during the time hereinafter mentioned; and that advertisement headed

Legal--Case No. 5933 Case No. 5935
$31.80

a printed copy of which is hereunto annexed, was printed and published in **The Dickinson Press,** and in the regular and entire issue of each and every number 1 consecutive weeks, commencing on the 4 day of May A.D. 19 94, and ending on the 4 day of May A.D., 1994, both inclusive.

Belle L. Krank

Sworn to and subscribed before me this 5th day of May A.D. 19 94.

PAID

Marilyn Wanner

MARILYN WANNER
Notary Public, STARK COUNTY, N. DAK.
My Commission Expires APRIL 28, 2000

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5-11-94
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NOTICE OF PUBLICATION
NORTH DAKOTA
INDUSTRIAL COMMISSION
BISMARCK, NORTH DAKOTA

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ATTENTION PERSONS WITH DISABILITIES: If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the North Dakota Industrial Commission at 701-224-2722 by May 25, 1994.

STATE OF NORTH DAKOTA TO:

All named parties and persons having any right, title, interest, or claim in the following cases and notices to the public. CASE NO. 5933: ON A MOTION OF THE COMMISSION TO CONSIDER THE PETITION OF CONOCO INC. FOR AN ORDER PROVIDING FOR THE UNITIZED MANAGEMENT, OPERATION, AND FURTHER DEVELOPMENT OF THE DICKINSON-LODGEPOLE UNIT AREA, CONSISTING OF LANDS WITHIN THE DICKINSON FIELD IN STARK COUNTY, NORTH DAKOTA; FOR APPROVAL OF THE UNIT AGREEMENT AND UNIT OPERATING AGREEMENT CONSTITUTING THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA; FOR APPROVAL OF THE PLAN OF OPERATION, VACATING THE APPLICABLE SPACING ORDERS; AND FOR SUCH FURTHER AND ADDITIONAL RELIEF AS THE COMMISSION DEEMS APPROPRIATE. CASE NO. 5935: ON A MOTION OF THE COMMISSION TO CONSIDER THE APPLICATION OF CONOCO INC. FOR AN ORDER DETERMINING THAT THE PLAN OF UNITIZATION FOR THE DICKINSON-LODGEPOLE UNIT AREA, STARK COUNTY, NORTH DAKOTA, HAS BEEN SIGNED, RATIFIED OR APPROVED BY OWNERS OF INTEREST OWNING THAT PERCENTAGE OF THE WORKING INTEREST AND ROYALTY INTEREST WITHIN SAID UNIT AS IS REQUIRED BY APPLICABLE STATUTES AND RULES OF THE COMMISSION.

Signed by,
Edward T. Schafer, Governor
Chairman, ND Industrial Commission
5/4 - 1000

AFFIDAVIT OF PUBLICATION
STATE OF NORTH DAKOTA } ss
County of Burleigh }
BEFORE ME, A NOTARY PUBLIC FOR THE STATE OF NORTH DAKOTA, PERSONALLY APPEARED Cleta Martin WHO, BEING DULY SWORN, DEPOSES AND SAYS THAT HE/SHE IS THE CLERK OF THE BISMARCK TRIBUNE COMPANY, AND THAT THE ABOVE PUBLICATIONS Notice of Pub WERE MADE THROUGH THE AFORESAID NEWSPAPER AT THE DATES SHOWN 5/4 SIGNED Cleta Martin
SWORN AND SUBSCRIBED TO BEFORE ME THIS 10 DAY OF May 1994
[illegible signature]
Notary Public in and for the State of North Dakota, Residing at Bismarck

PATRICIA J. NELSON
Notary Public, State of North Dakota
My Commission Expires ..., 1997

PAYMENT TERMS
Due 10th of month following charges

Thank You!

AMOUNT DUE 32.86