EERC Energy & Environmental Research Center
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NATURAL GAS UTILIZATION AND STAKEHOLDERS MEETING

NORTH DAKOTA OIL & GAS UPDATE

EERC – Grand Forks – November 7, 2011

NORTH DAKOTA
DMR
Department of Mineral Resources

OIL & GAS UPDATE

- **North Dakota results**
- **Tyler**
- **Spearfish**
- **Uranium and Potash**

Bruce E. Hicks
Assistant Director
NDIC-DMR-OGD
Bismarck, ND

North Dakota Department of Mineral Resources

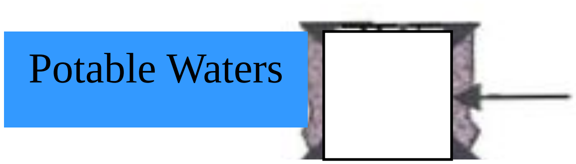
NDGS
Research Arm

OGD
Regulatory
Arm

https://www.dmr.nd.gov/oilgas/   *https://www.dmr.nd.gov/ndgs/*

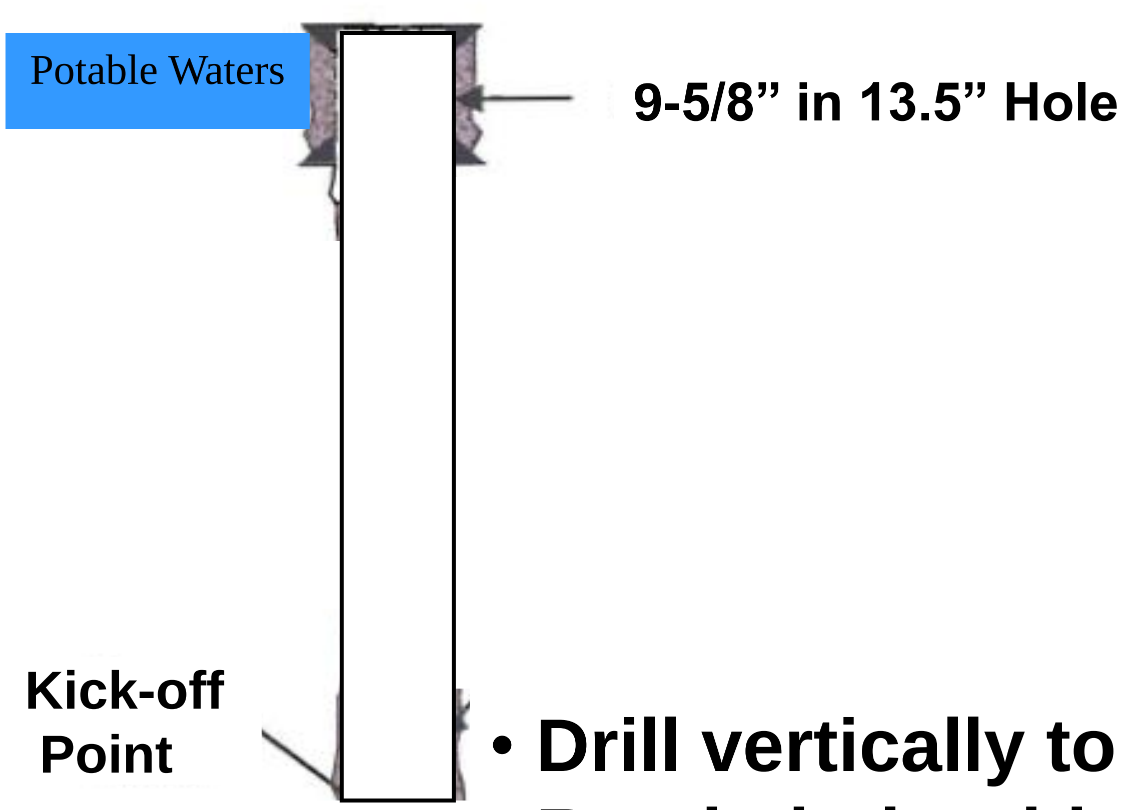
600 East Boulevard Ave. - Dept 405
Bismarck, ND 58505-0840
(701) 328-8020   (701) 328-8000

TYPICAL HORIZONTAL OIL WELL



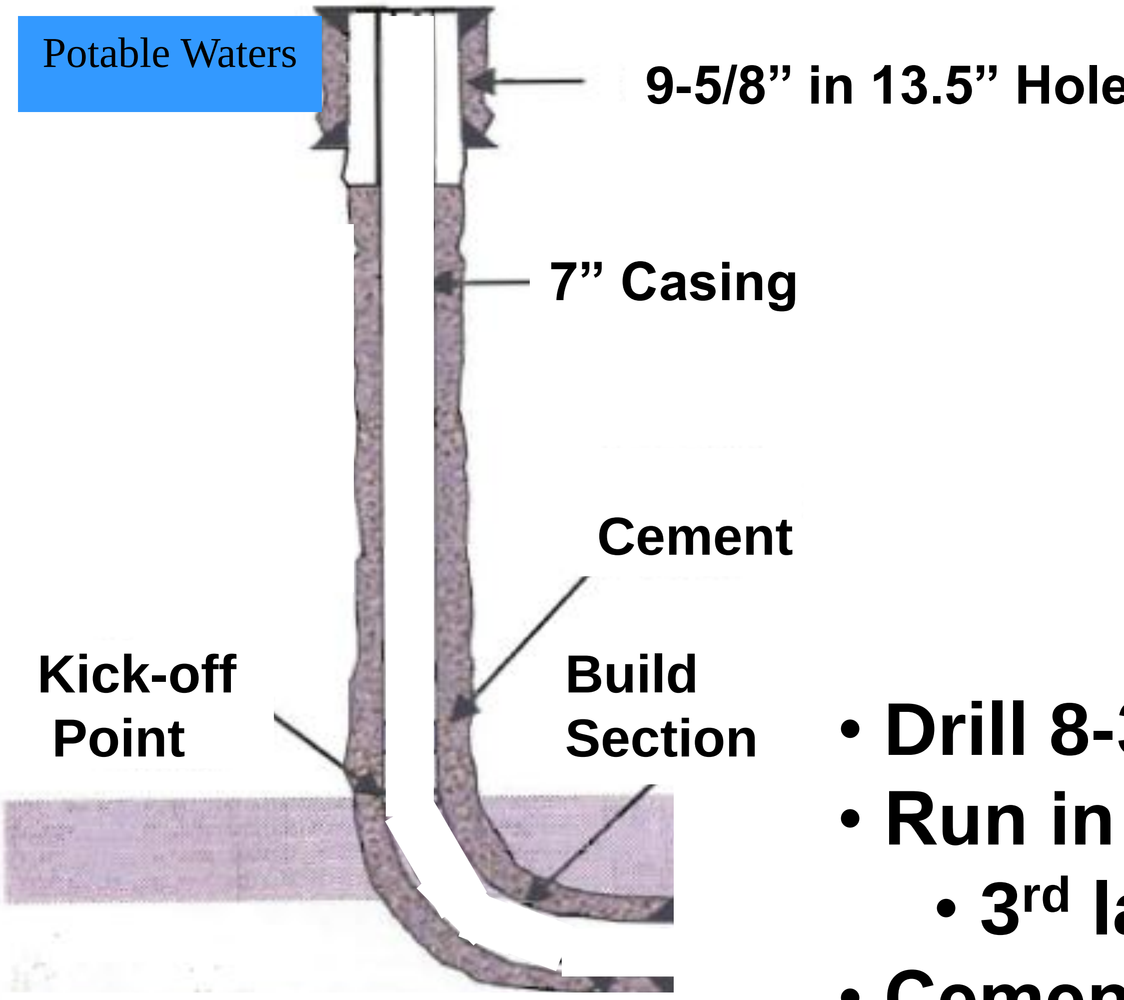
- **Drill with fresh water**
- **Total depth below lowest potable water**
- **Run in hole with surface casing**
  - **1st layer of surface water protection**
- **Cement casing back to surface of ground**
  - **2nd layer of surface water protection**

TYPICAL HORIZONTAL OIL WELL



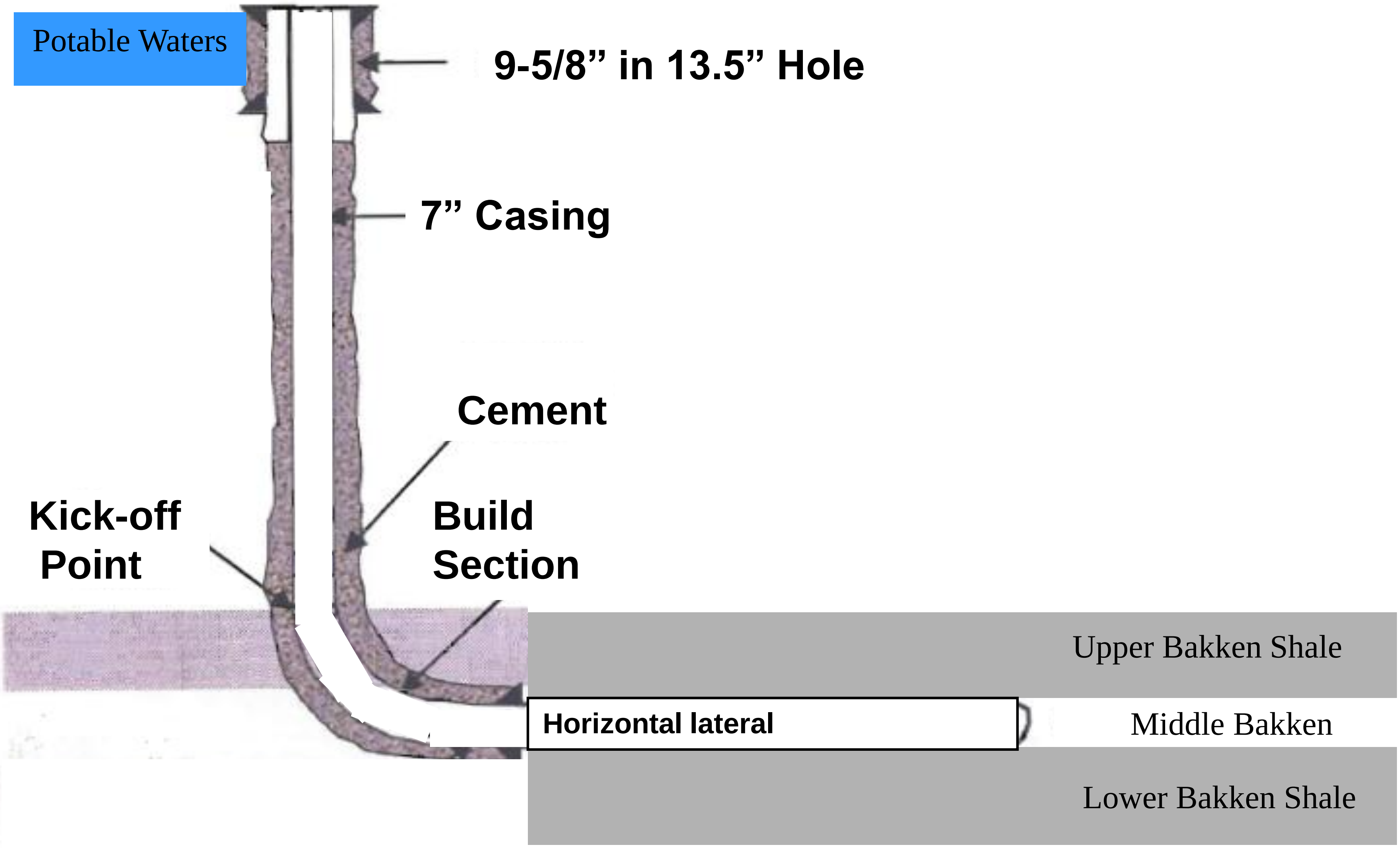
- Drill vertically to kick-off point
- Run in hole with bent assembly
- Downhole mud motor

TYPICAL HORIZONTAL OIL WELL



- Drill 8-3/4" hole to pay
- Run in hole with 7" casing
    - 3rd layer of protection
- Cement 7" casing
    - 4th layer of protection

TYPICAL HORIZONTAL OIL WELL



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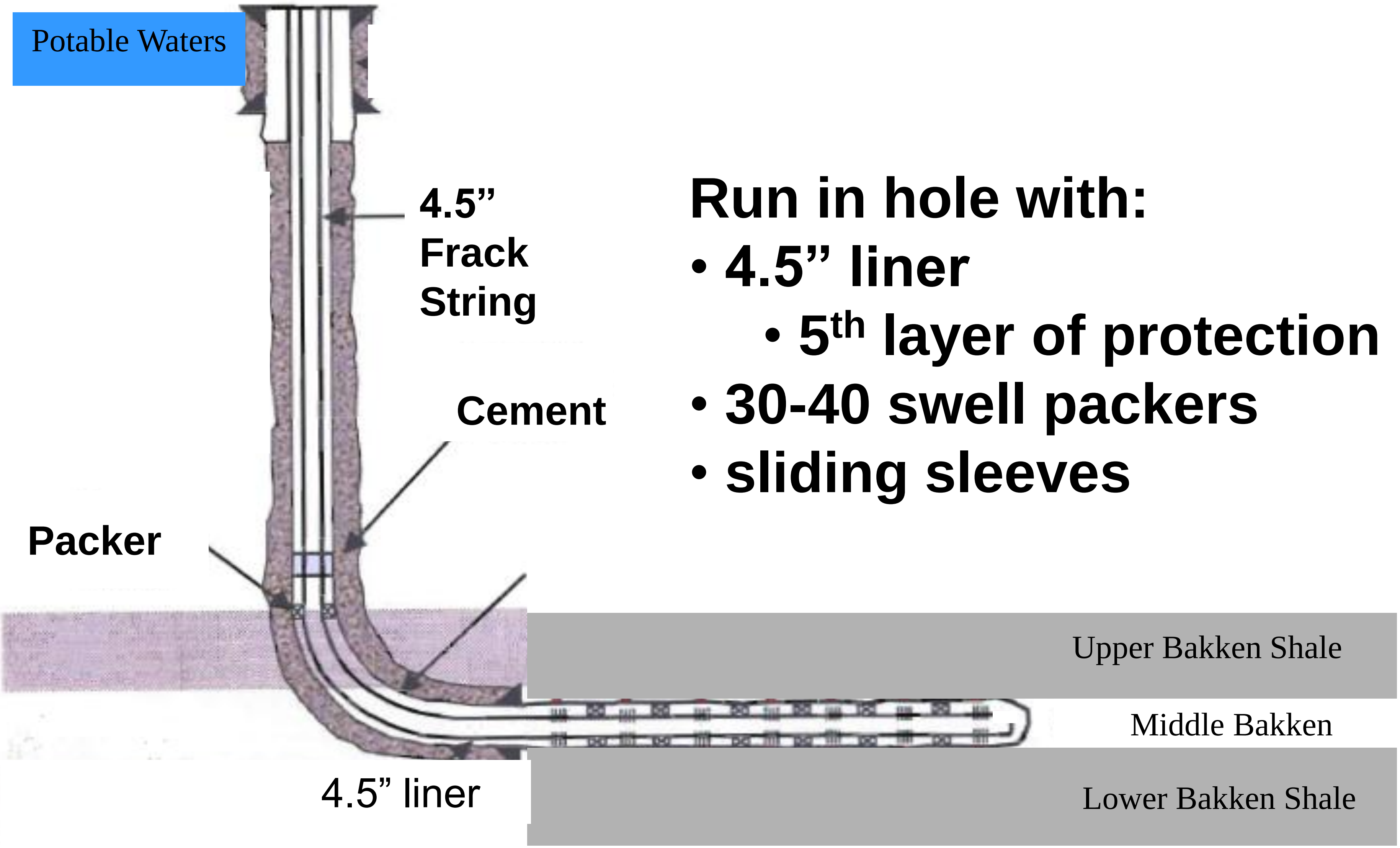
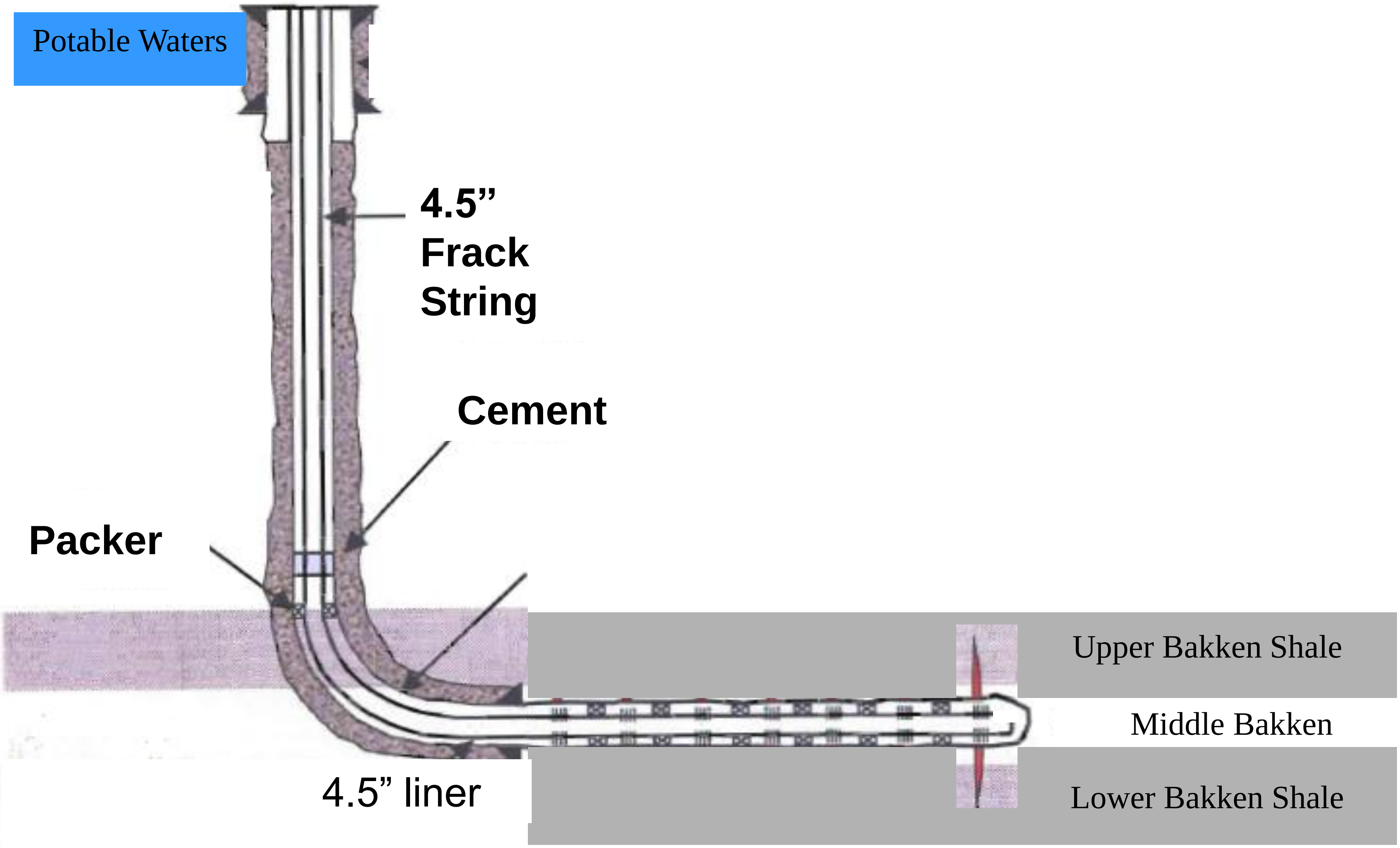


Run in hole with:

- **4.5" liner**
  - **5th layer of protection**
- **30-40 swell packers**
- **sliding sleeves**

TYPICAL HORIZONTAL OIL WELL



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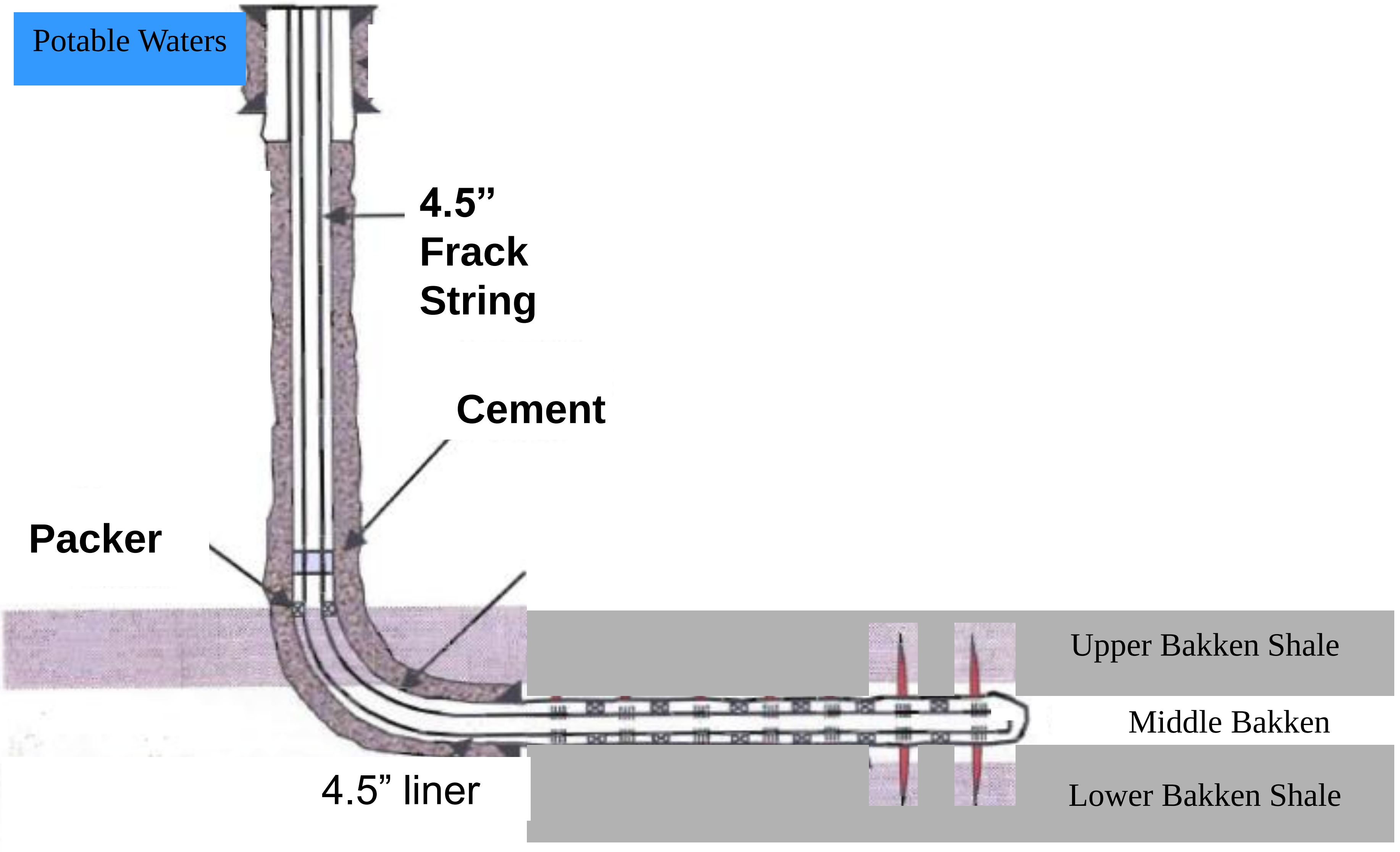

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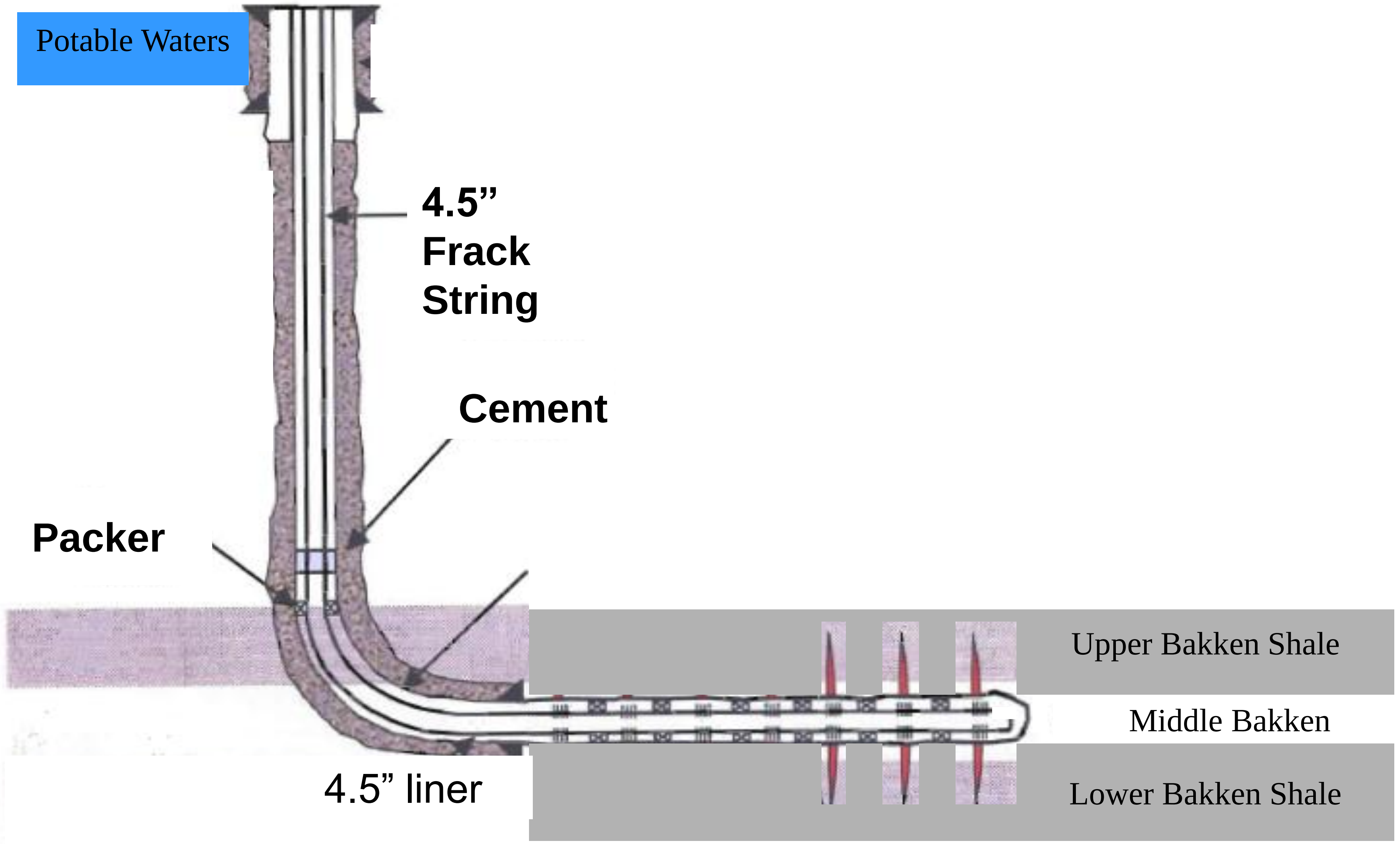

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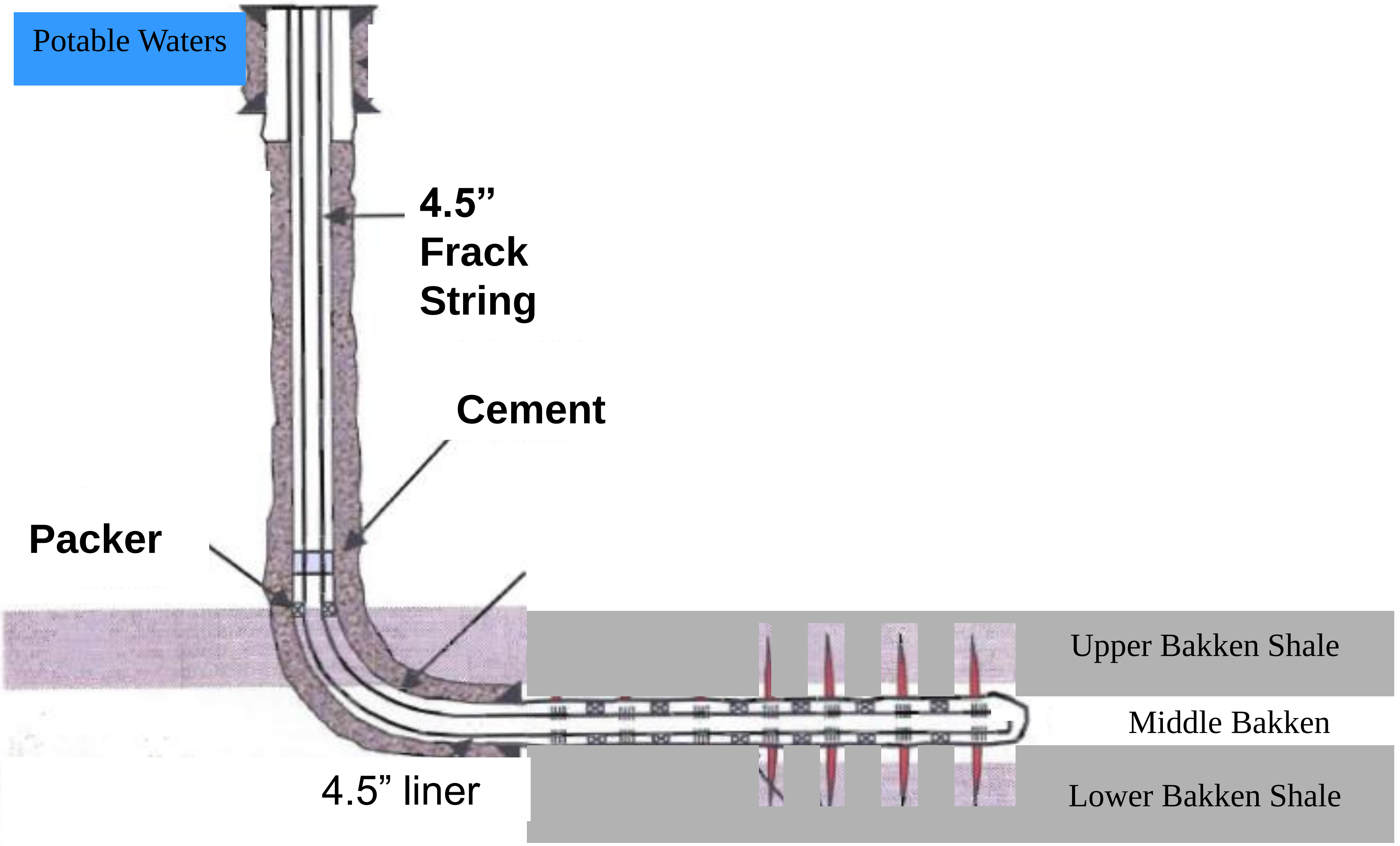

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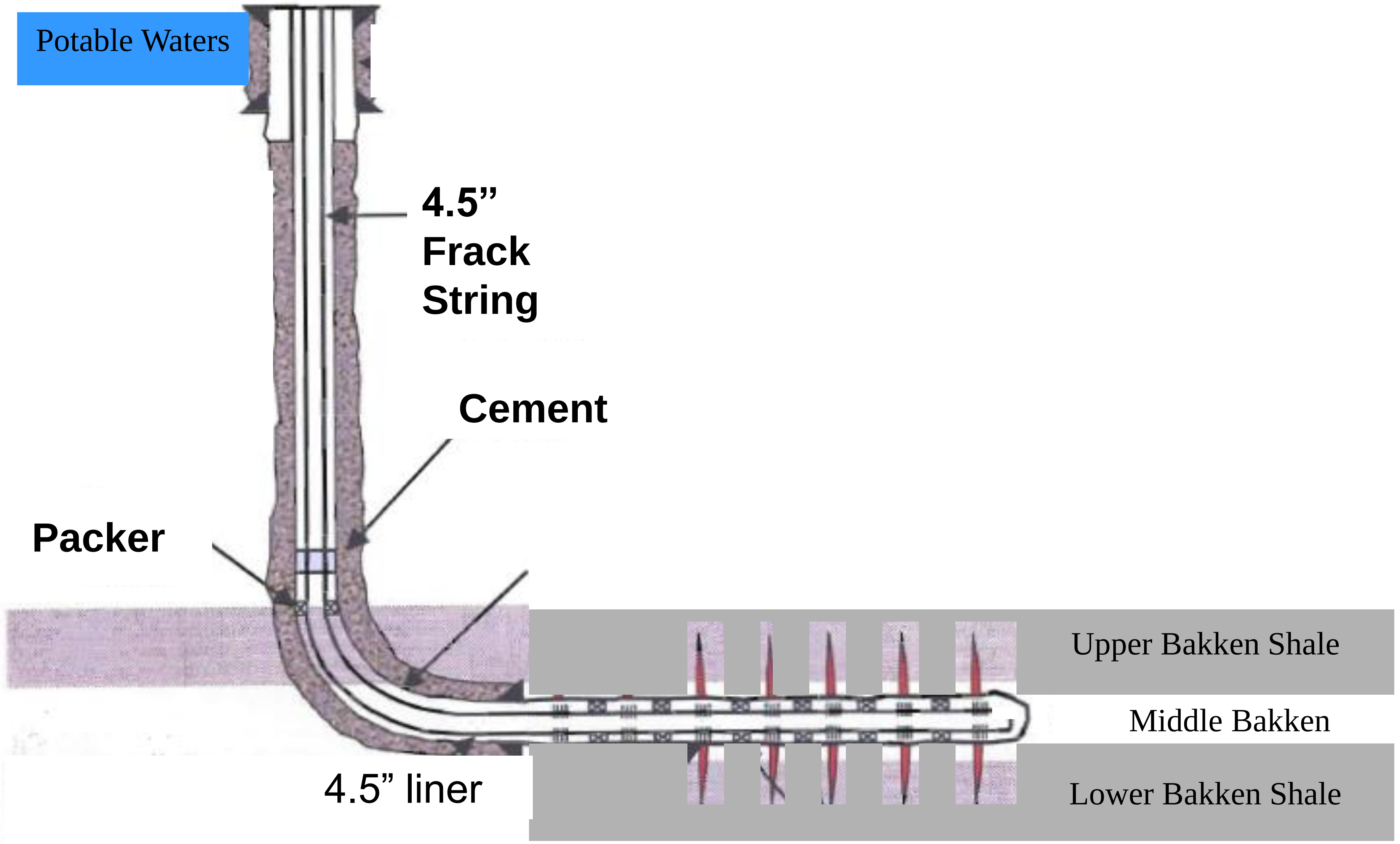

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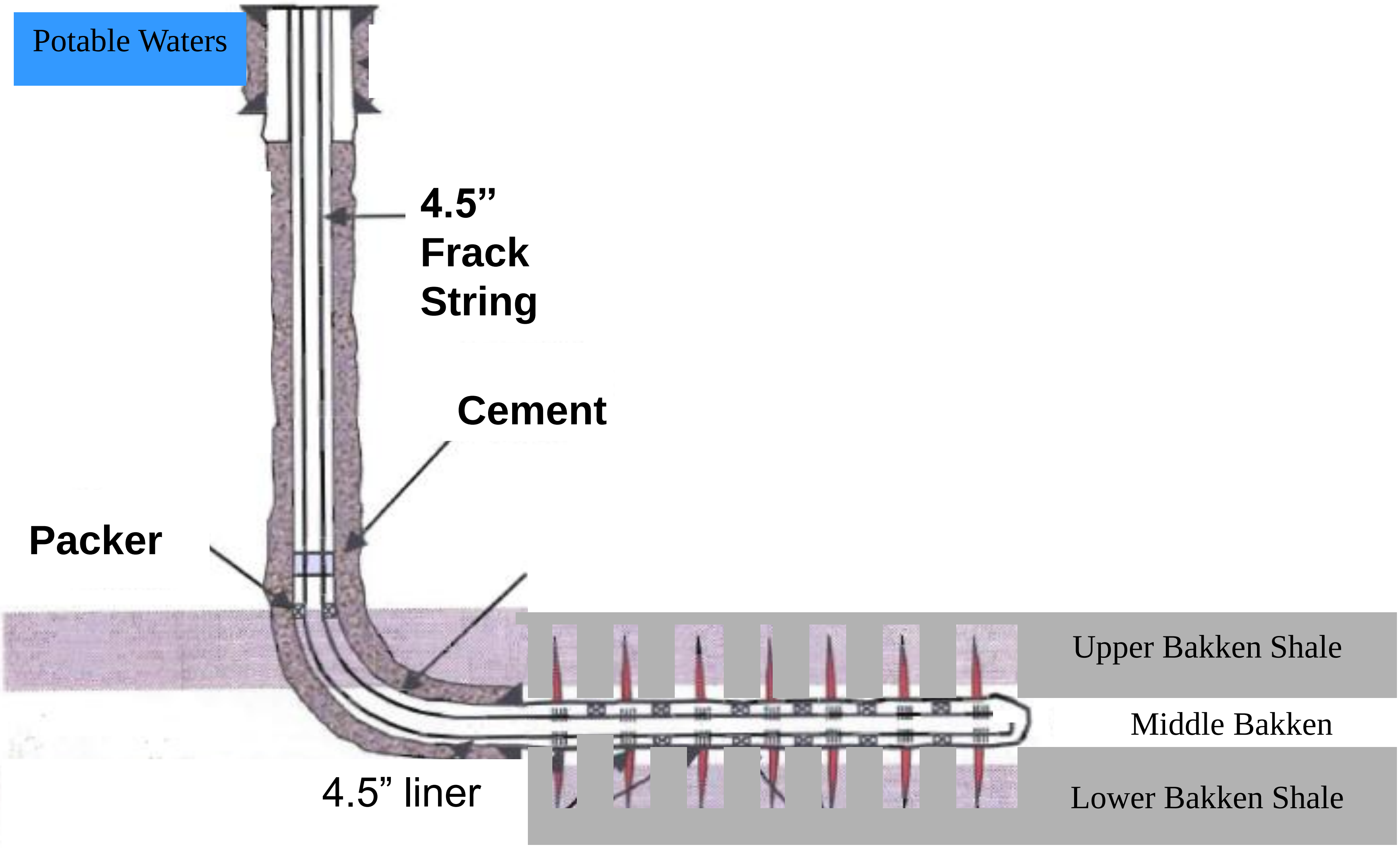
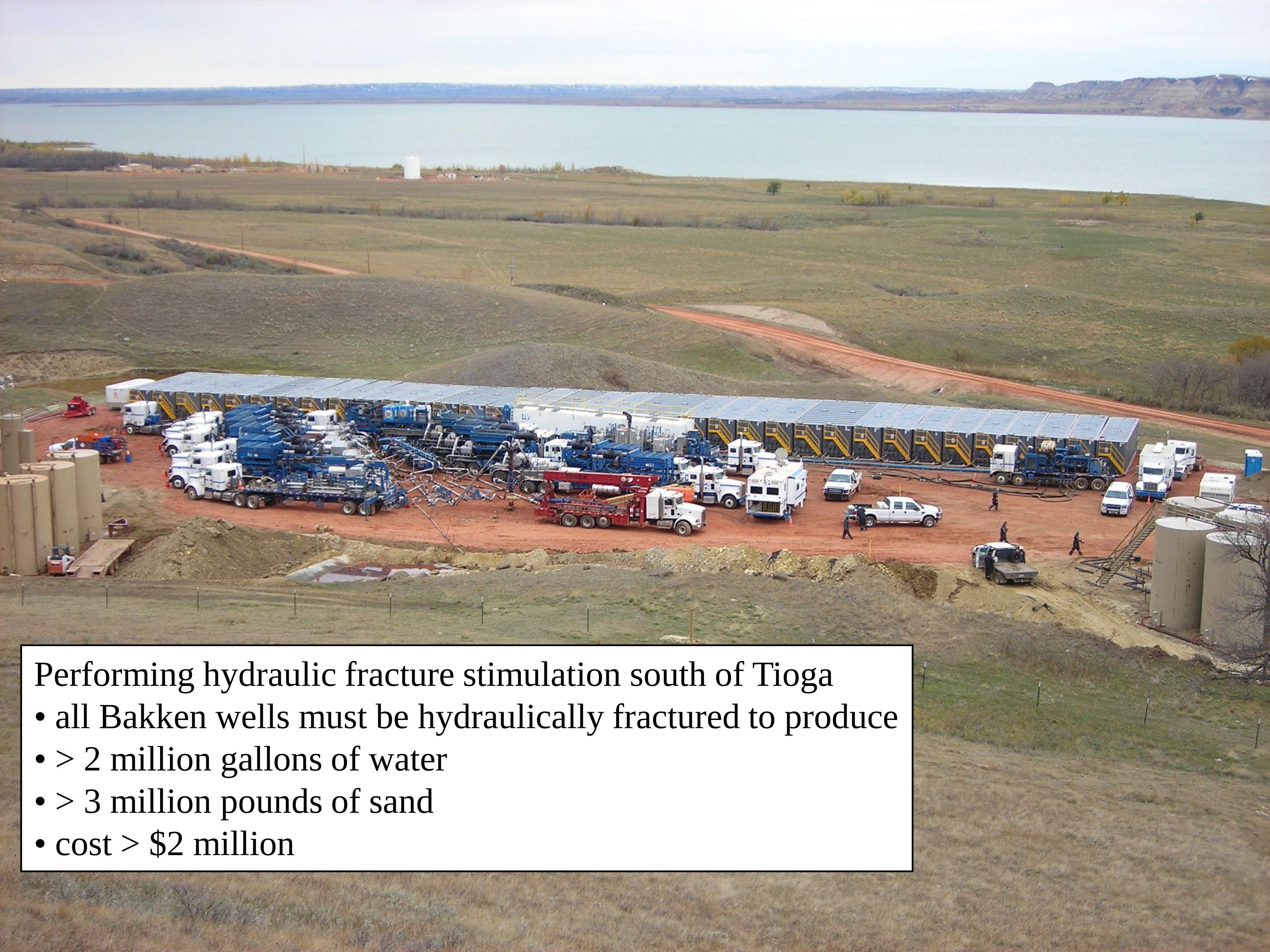




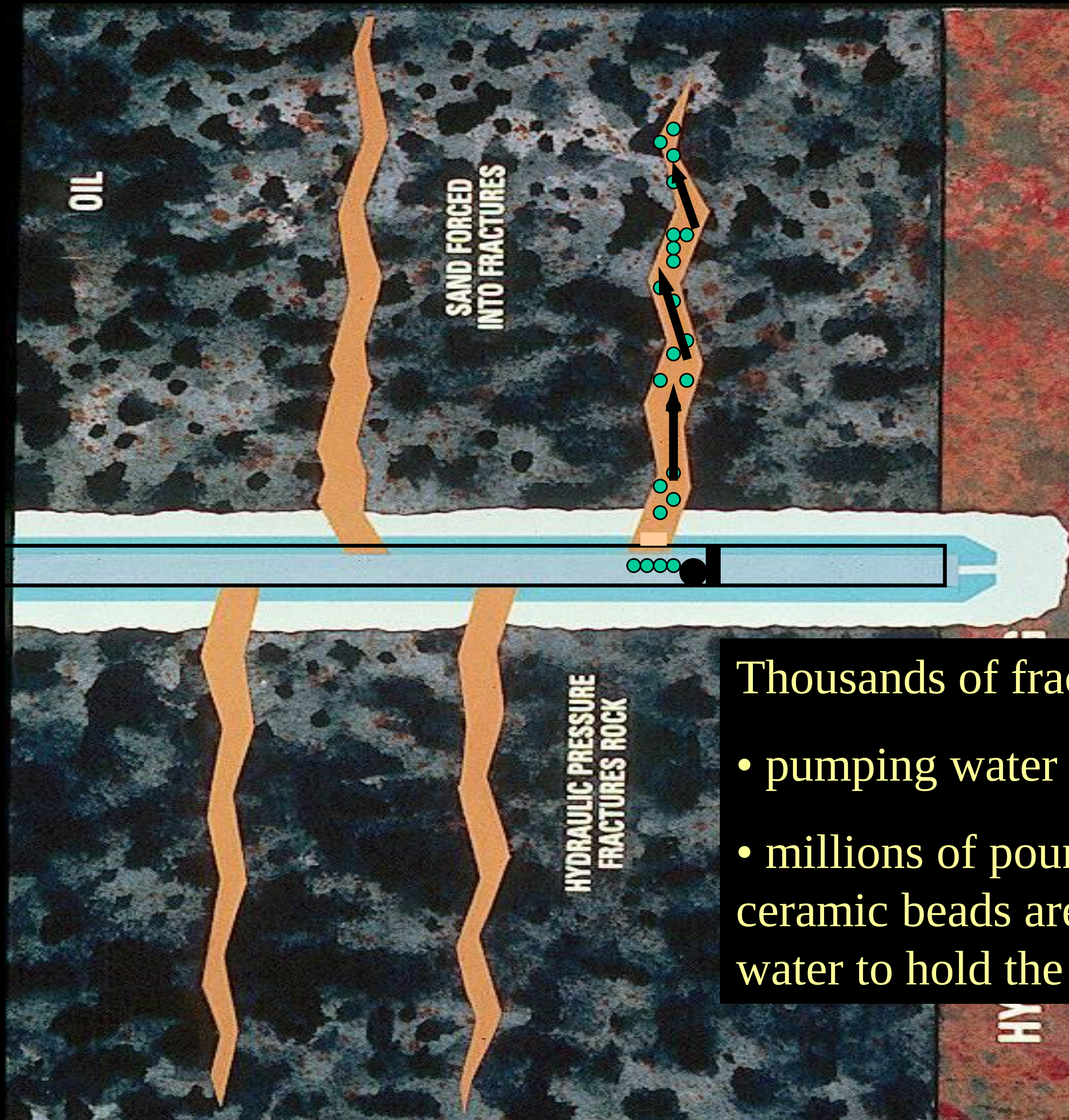
Performing hydraulic fracture stimulation south of Tioga

- all Bakken wells must be hydraulically fractured to produce
- > 2 million gallons of water
- > 3 million pounds of sand
- cost > $2 million

WHY FRACK THE ROCK?

- **already developed easy oil**
  - **oil flows easily without fracking**

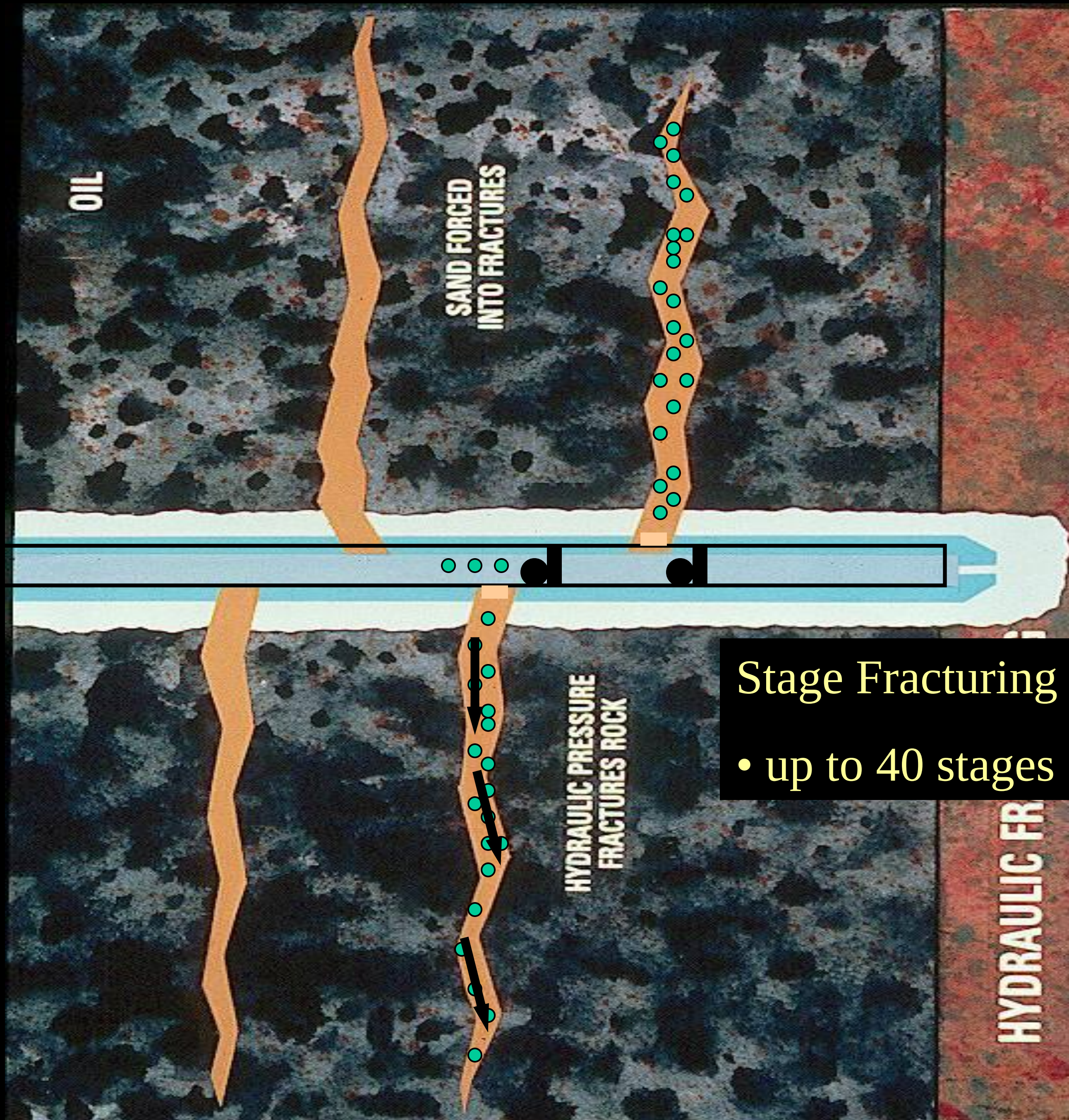
- **Unconventional Reserves**
  - **reservoirs are tight**
  - **uneconomic to produce w/o fracking**
  - **must create a path for oil to flow**



Thousands of fractures are created

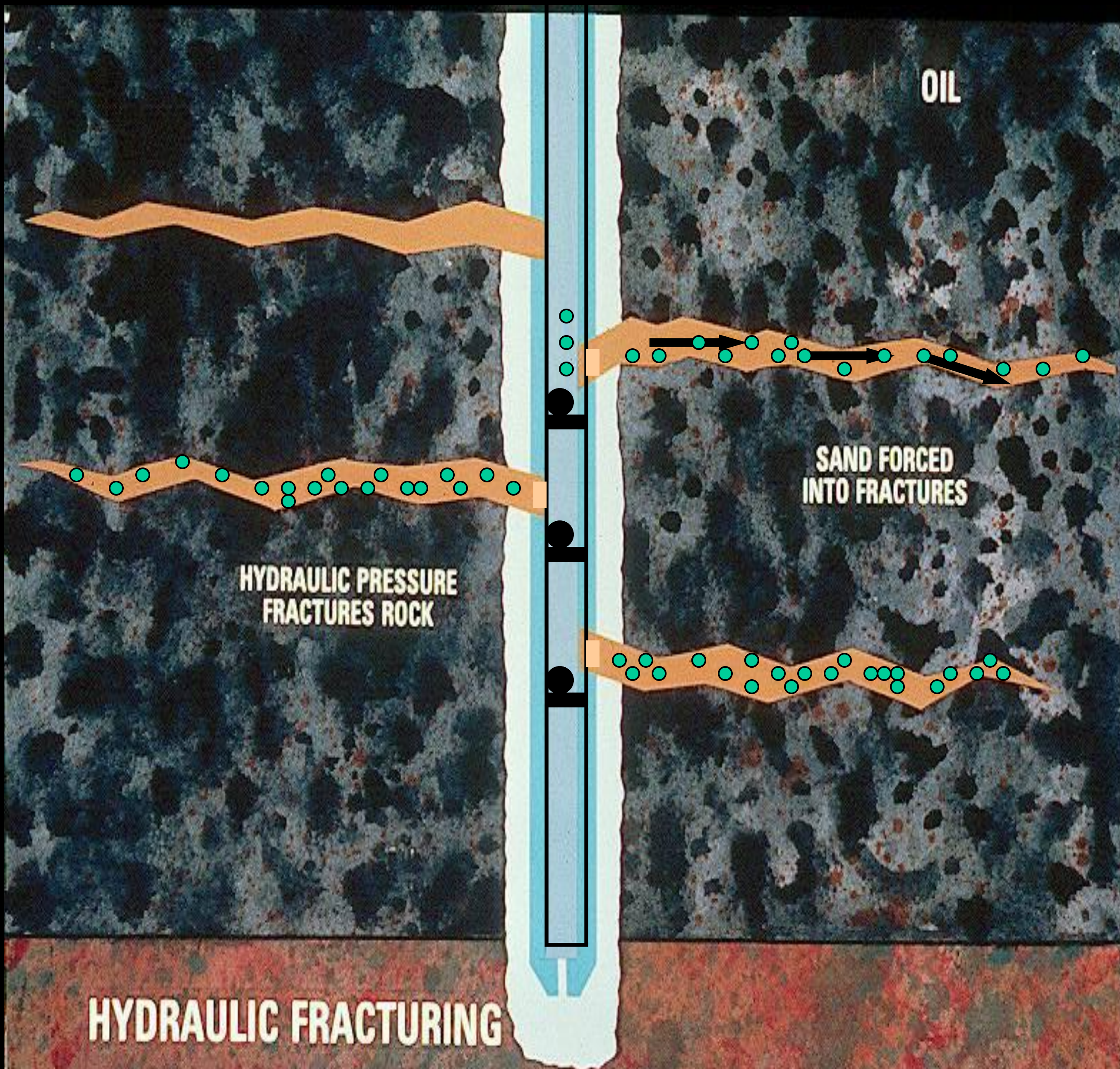
• pumping water at 6,000-9,000 psi

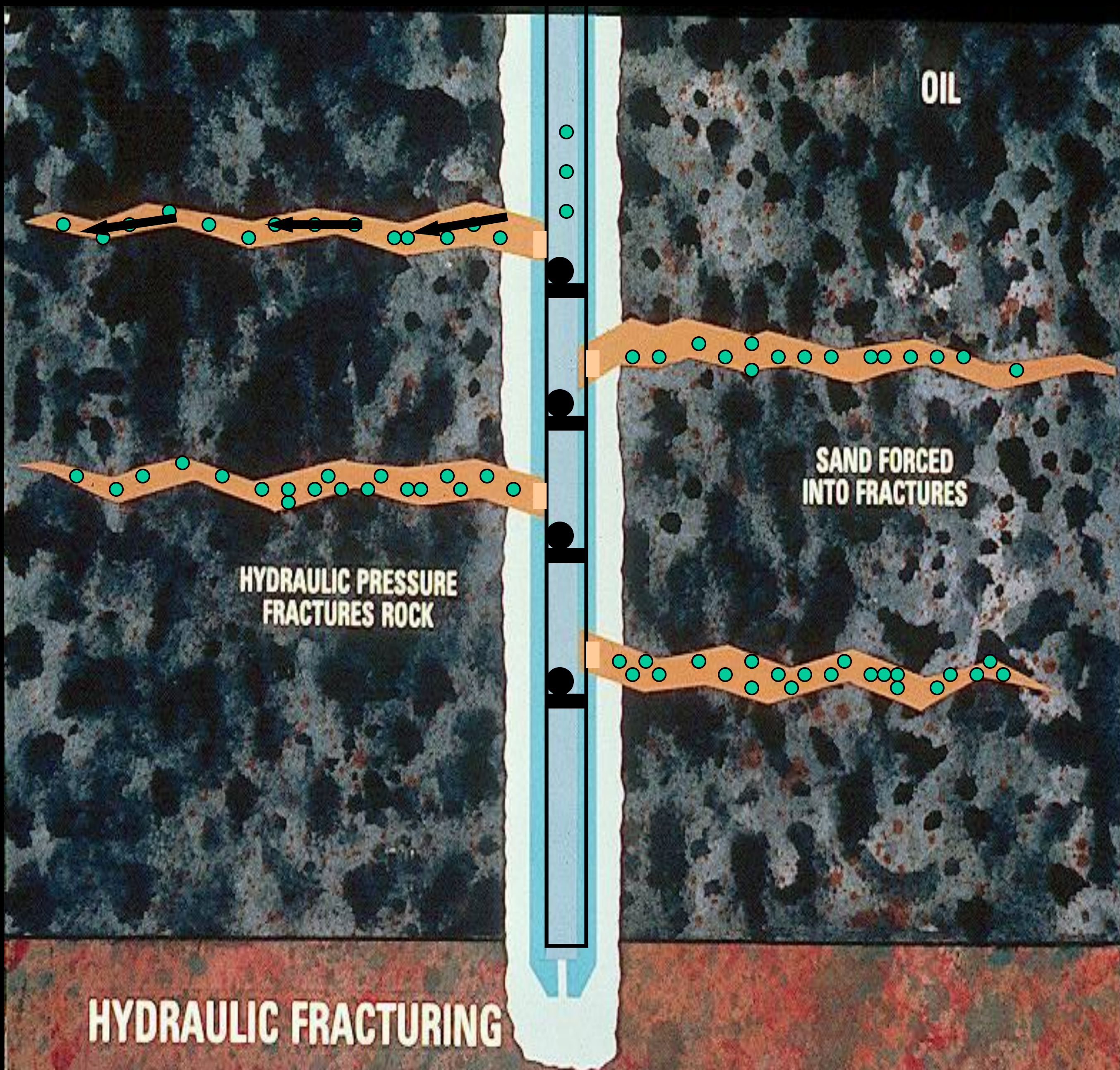
• millions of pounds of sand and ceramic beads are pumped with the water to hold the fractures open.



Stage Fracturing

- up to 40 stages


OIL
SAND FORCED
INTO FRACTURES
HYDRAULIC PRESSURE
FRACTURES ROCK
HYDRAULIC FRACTURING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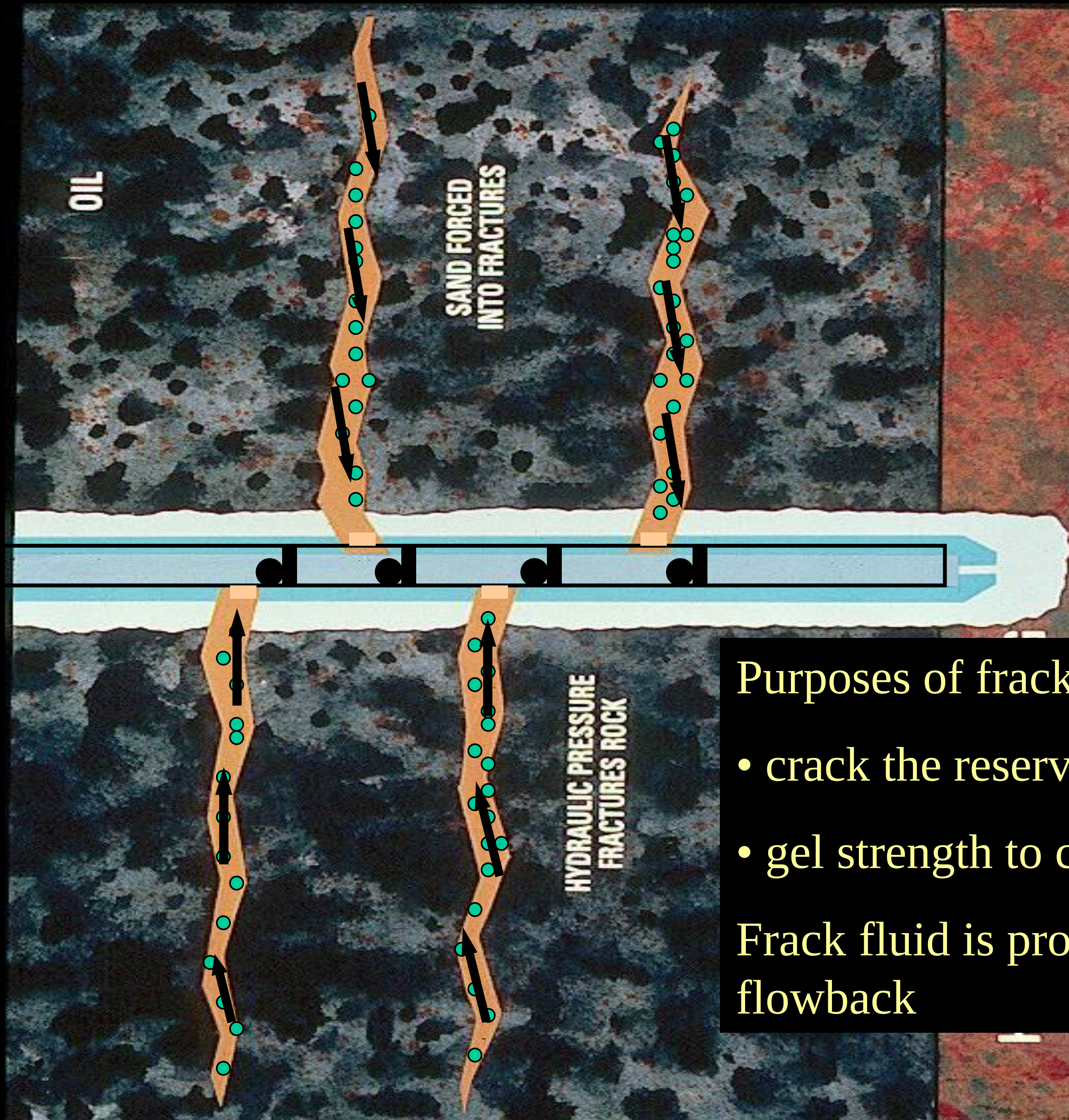
HYDRAULIC PRESSURE FRACTURES ROCK
HYDRAULIC FRACTURING

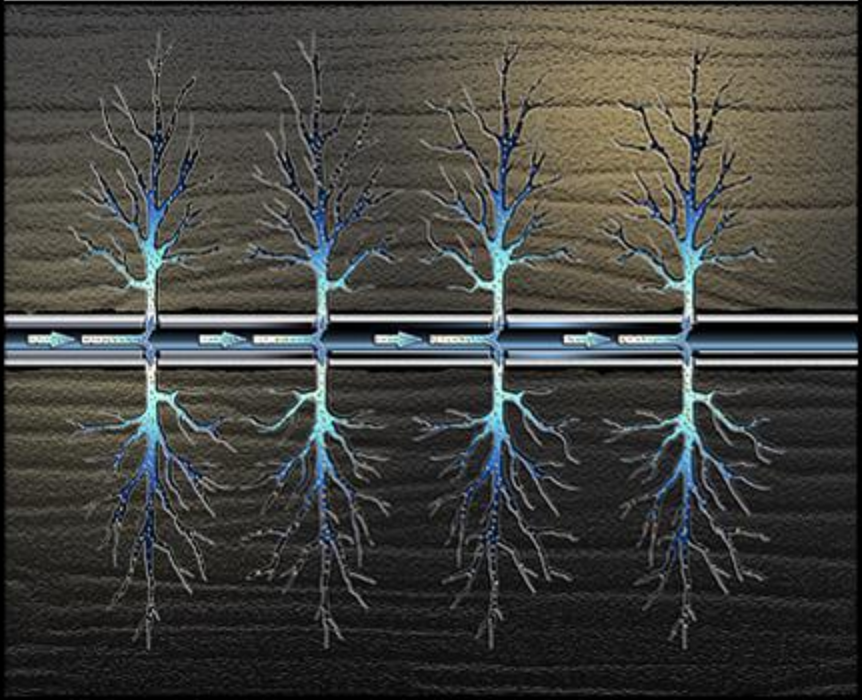


Purposes of frack fluid

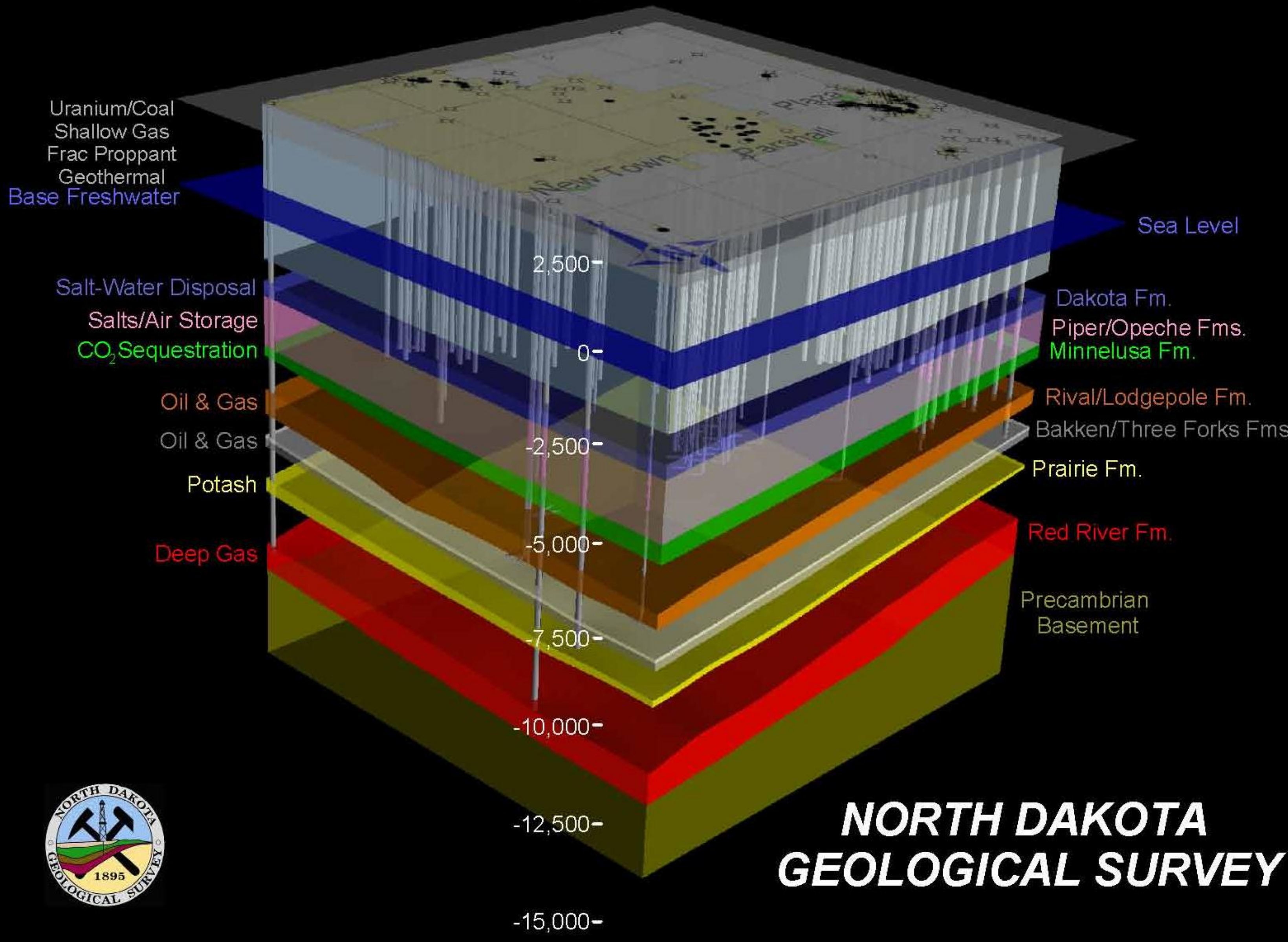
- crack the reservoir
- gel strength to carry sand

Frack fluid is produced back as flowback

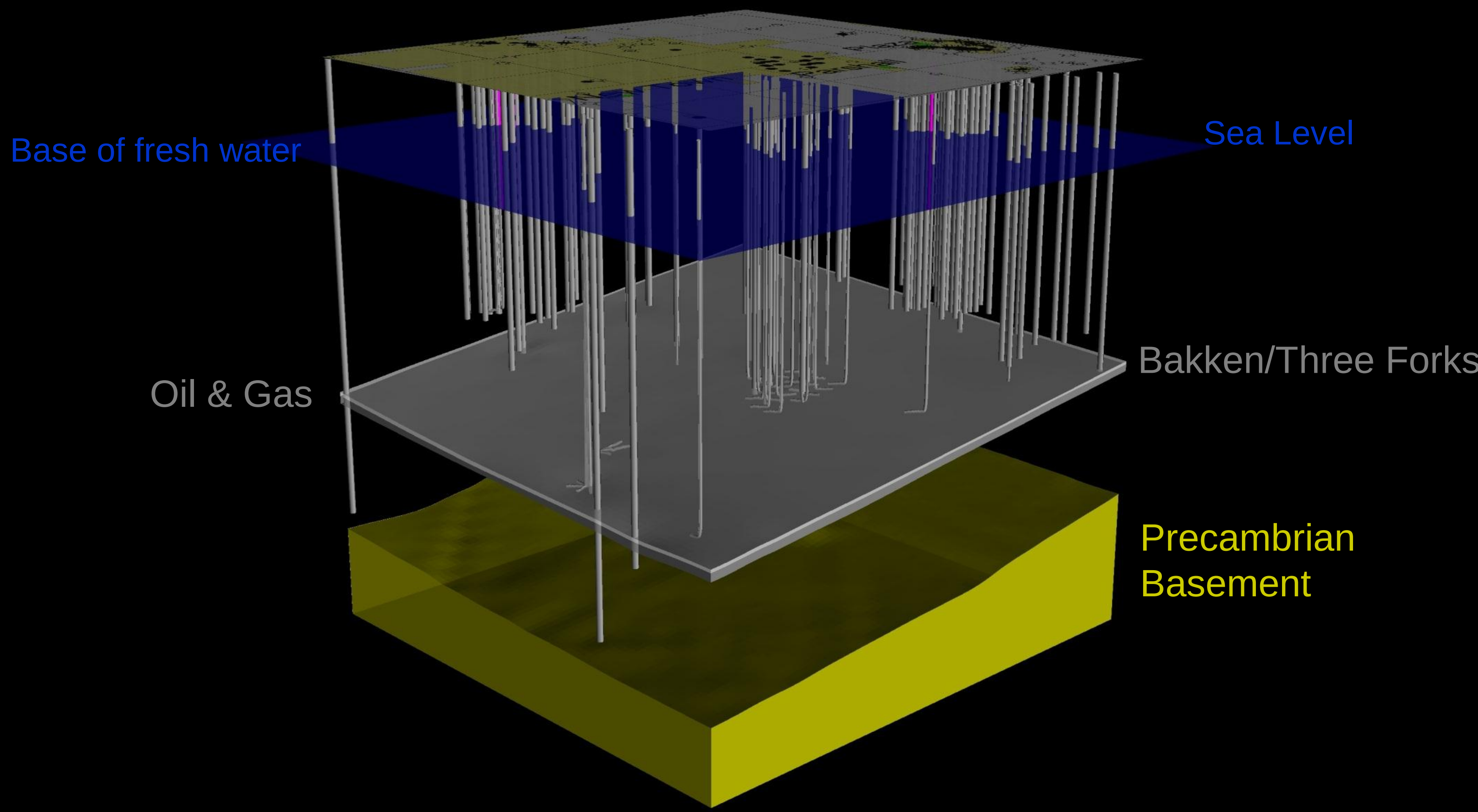
Hydraulic Fracturing: Mixture of water, sand and chemicals pressurized and pumped into the well to form microscopic fractures in shale.



Three-Dimensional Geologic Model of the Parshall Area



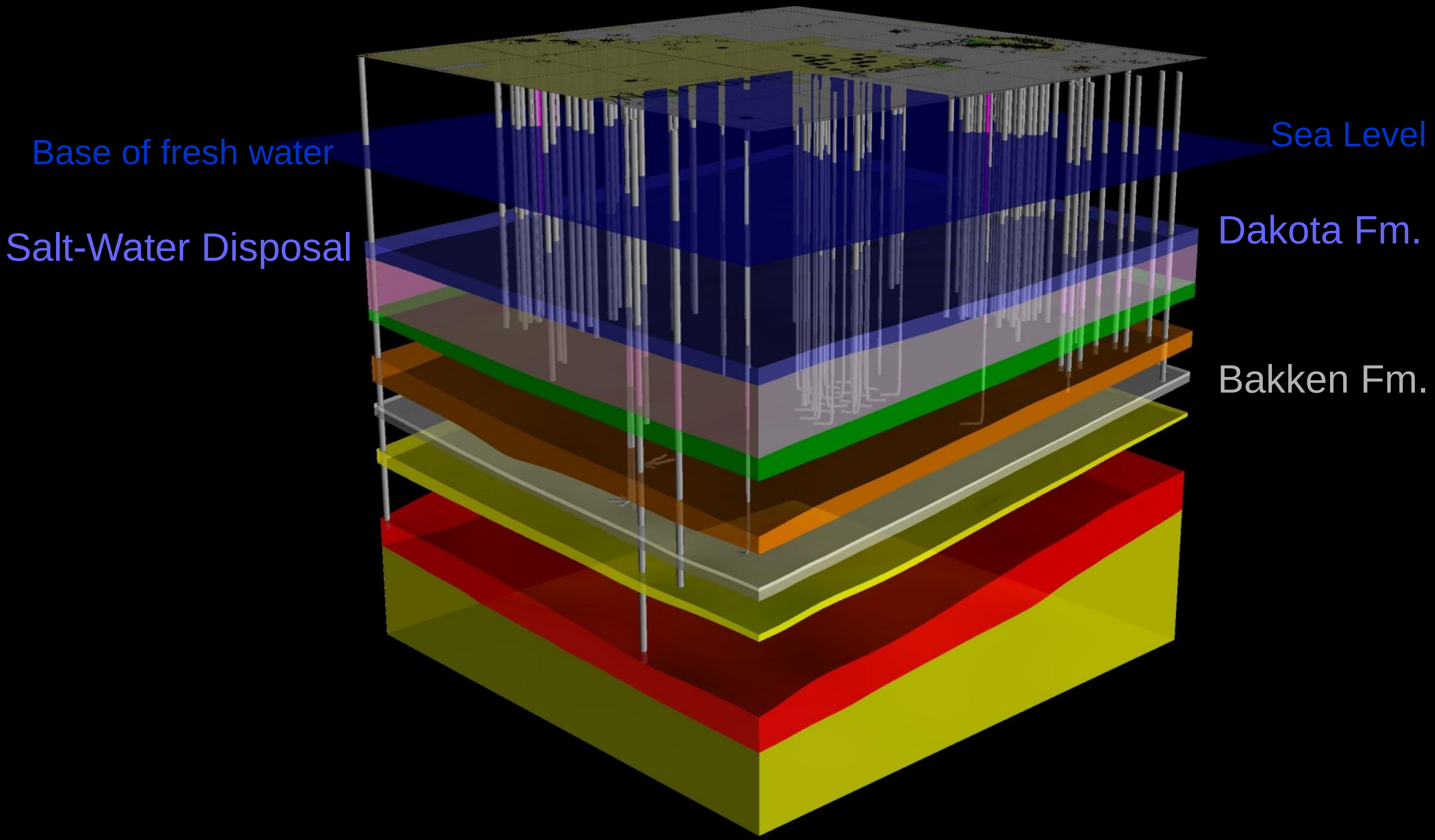
NORTH DAKOTA GEOLOGICAL SURVEY



Base of fresh water
Sea Level
Oil & Gas
Bakken/Three Forks
Precambrian
Basement

Industrial Commission Regulation

- Water flowback after frack
  - Storage in open pits prohibited
  - Disposal wells permitted through Underground Injection Program
  - Disposal zone is 2,500 feet below potable waters


Base of fresh water
Sea Level
Salt-Water Disposal
Dakota Fm.
Bakken Fm.

Thirsty Horizontal Wells

- 2,500 wells / year
- 15-25 years duration
- 20 million gallons water / day

FRAC WATER NEEDS

- Lake Sakakawea best water resource
  - one inch contains 10 billion gal water
    - 5000 wells @ 2mil gal wtr/well
    - 2-year supply

FRAC WATER ADDITIVES

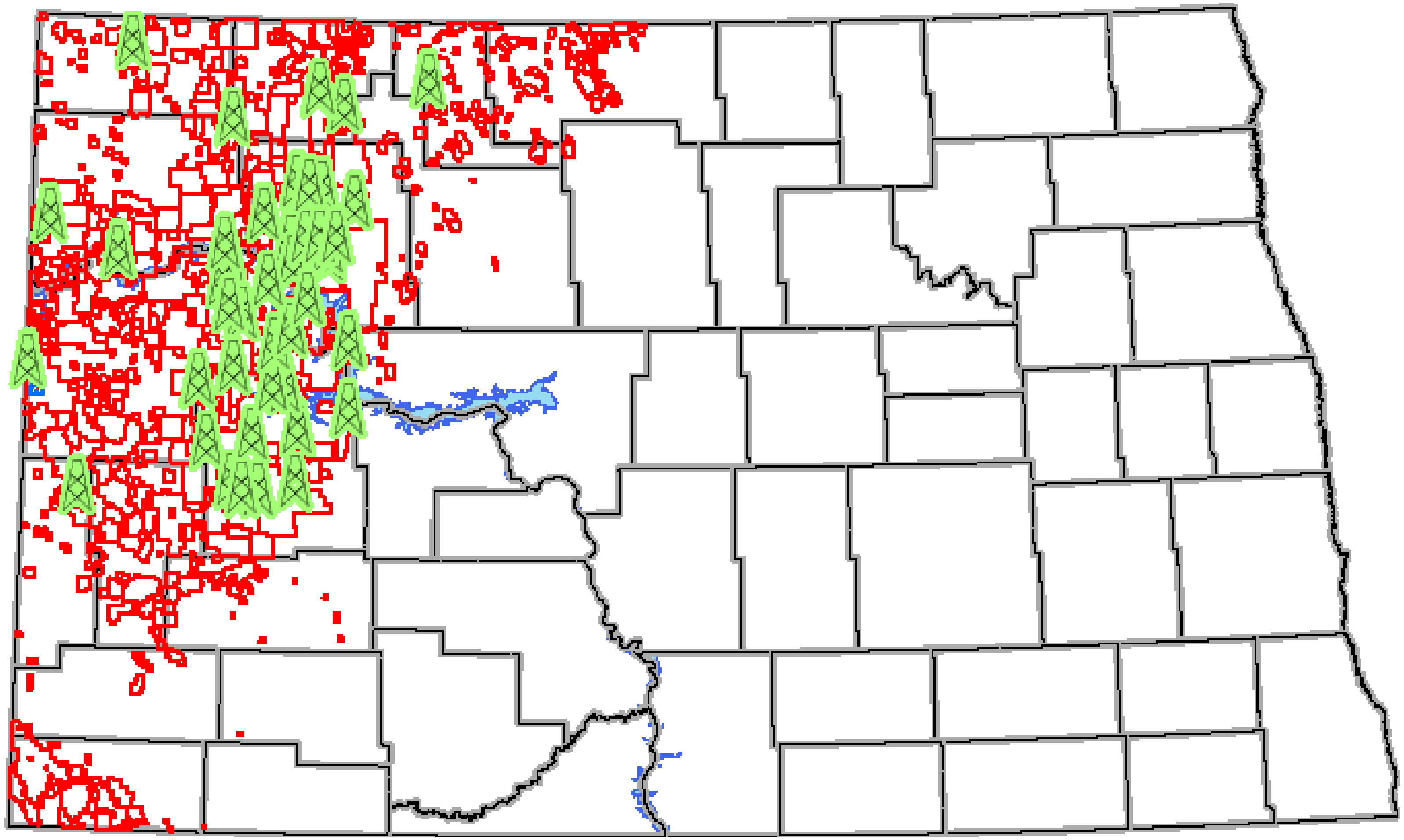
- 99.5% water and sand
  - 80.5% water
  - 19.0% proppant
  - 0.5% chemicals
    - most are found in every household

- **Compound**
  - **Purpose**
    - **Common application**

- Fresh **Water** – 80.5%
- Proppant – 19.0%
  - Allows the fractures to remain open so the oil and gas can escape
    - Drinking water filtration, **play ground sand**
- Acids - 0.12%
  - Help dissolve minerals and initiate fractures in rock (pre-fracture)
    - **Swimming pool cleaner**
- Petroleum distillates – 0.088%
  - Dissolve polymers and minimize friction
    - **Make-up remover**, laxatives, and candy
- Isopropanol – 0.081%
  - Increases the viscosity of the fracture fluid
    - **Glass cleaner**, antiperspirant, and hair color
- Potassium chloride – 0.06%
  - Creates a brine carrier fluid
    - Low-sodium **table salt substitute**
- Guar gum – 0.056%
  - Thickens the water to suspend the sand
    - **Thickener used in cosmetics**, baked goods, ice cream, toothpaste, sauces, and salad dressing
- Ethylene glycol – 0.043%
  - Prevents scale deposits in the pipe
    - Automotive **antifreeze**, household cleansers, deicing, and caulk

- Sodium or potassium carbonate – 0.011%
  - Improves the effectiveness of other components, such as cross-linkers
    - Washing soda, detergents, **soap**, water softeners, glass and ceramics
- Sodium Chloride – 0.01%
  - Delays break down of the gel polymer chains
    - **Table Salt**
- Polyacrylamide – 0.009%
  - Minimizes friction between fluid and pipe
    - **Water treatment**, soil conditioner
- Ammonium bisulfite – 0.008%
  - Removes oxygen from the water to protect the pipe from corrosion
    - Cosmetics, **food and beverage processing**, water treatment
- Borate salts – 0.007%
  - Maintain fluid viscosity as temperature increases
    - Used in laundry **detergents**, hand soaps and cosmetics
- Citric Acid – 0.004%
  - Prevents precipitation of metal oxides
    - **Food additive**; food and beverages; lemon juice
- N, n-Dimethyl formamide – 0.002%
  - Prevents the corrosion of the pipe
    - Used in **pharmaceuticals**, acrylic fibers and plastics
- Glutaraldehyde – 0.001%
  - Eliminates bacteria in the water
    - **Disinfectant**; Sterilizer for medical and dental equipment

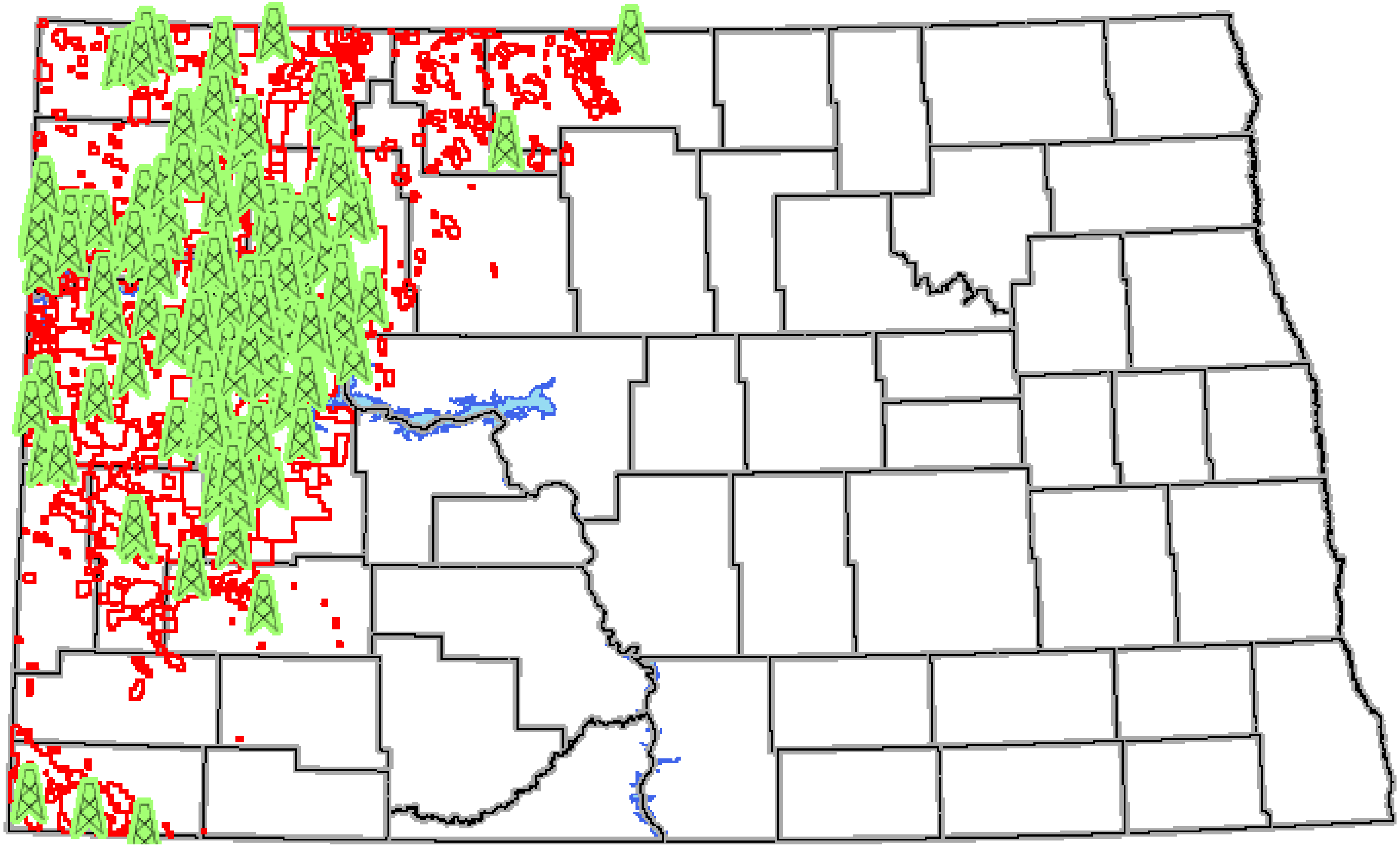
NORTH DAKOTA – 54 DRILLING RIGS – Nov 2009



One year ago, drilling activity was focused

in Mountrail and Dunn Counties.

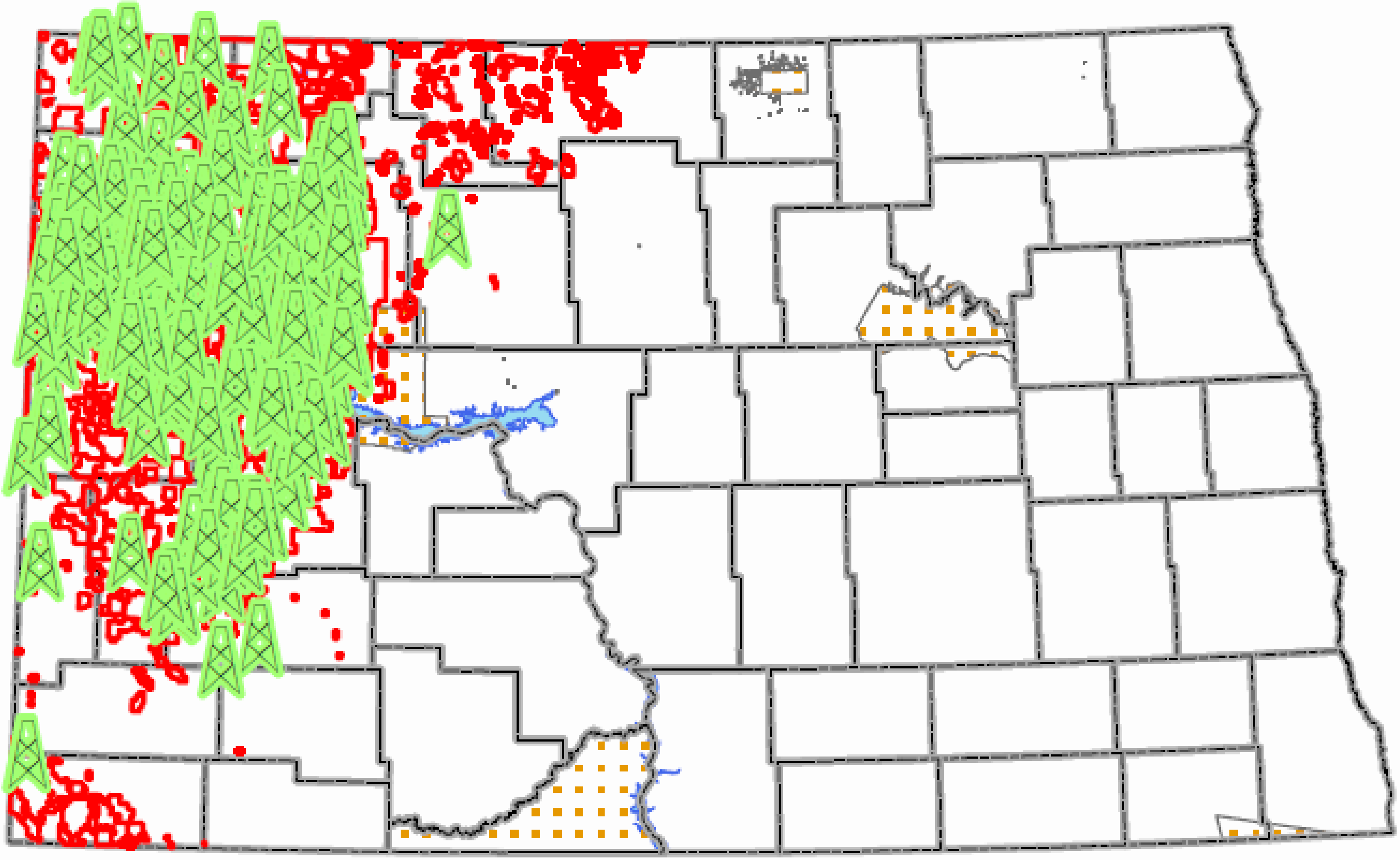
NORTH DAKOTA – 153 DRILLING RIGS – Nov 2010



Current drilling activity is focused

in Mountrail, Dunn, McKenzie, and Williams Counties.

NORTH DAKOTA – 198 DRILLING RIGS – Nov 2011



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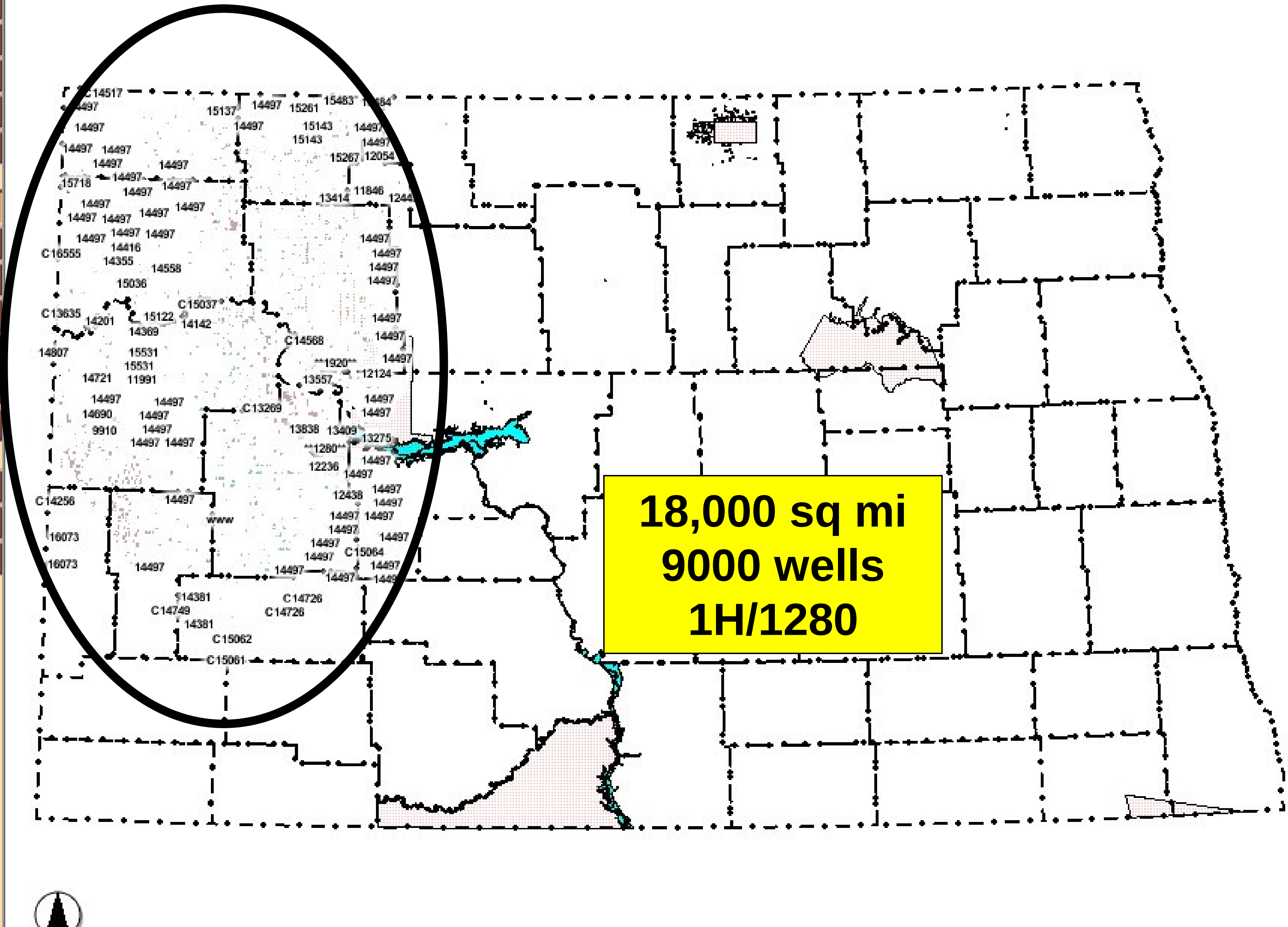
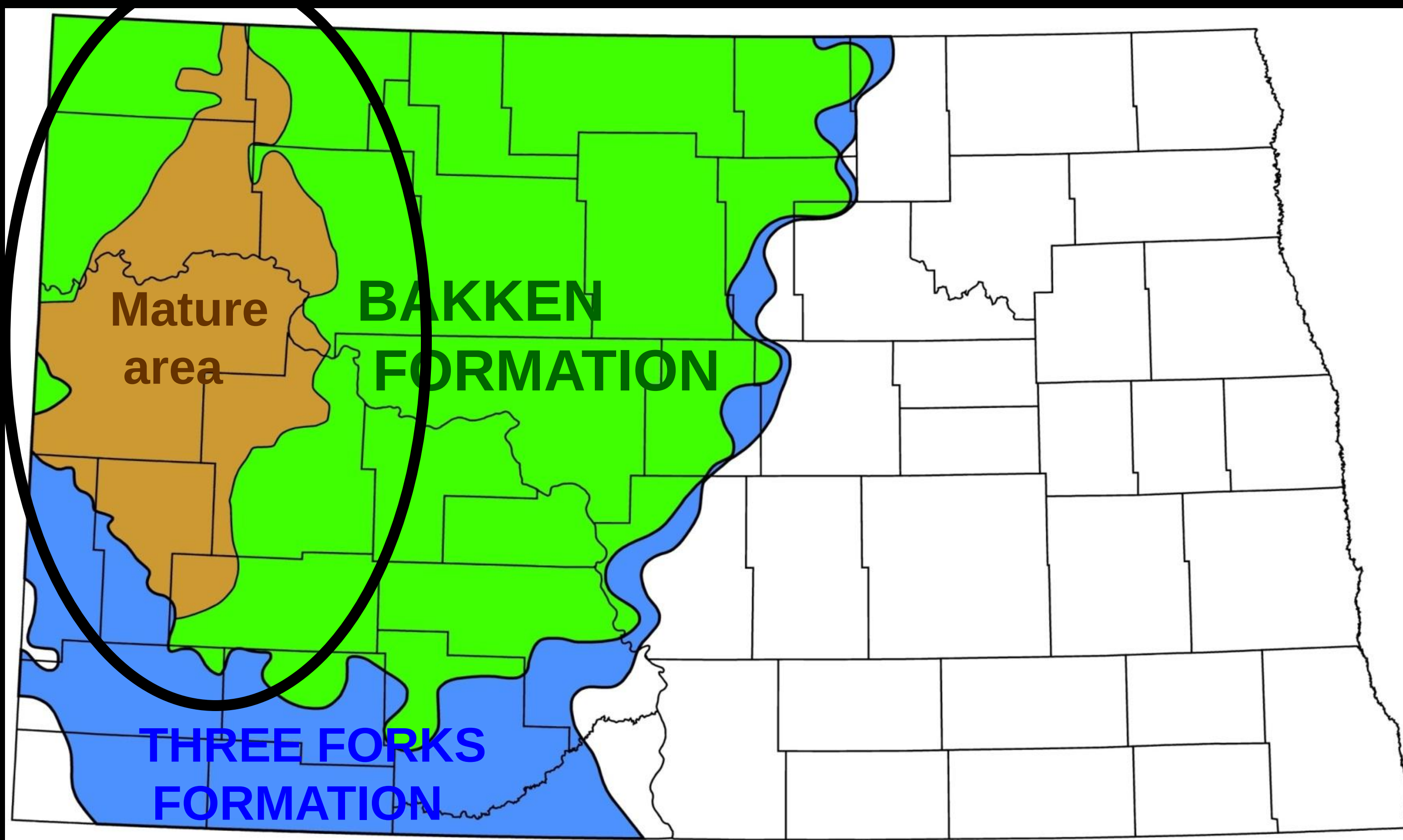
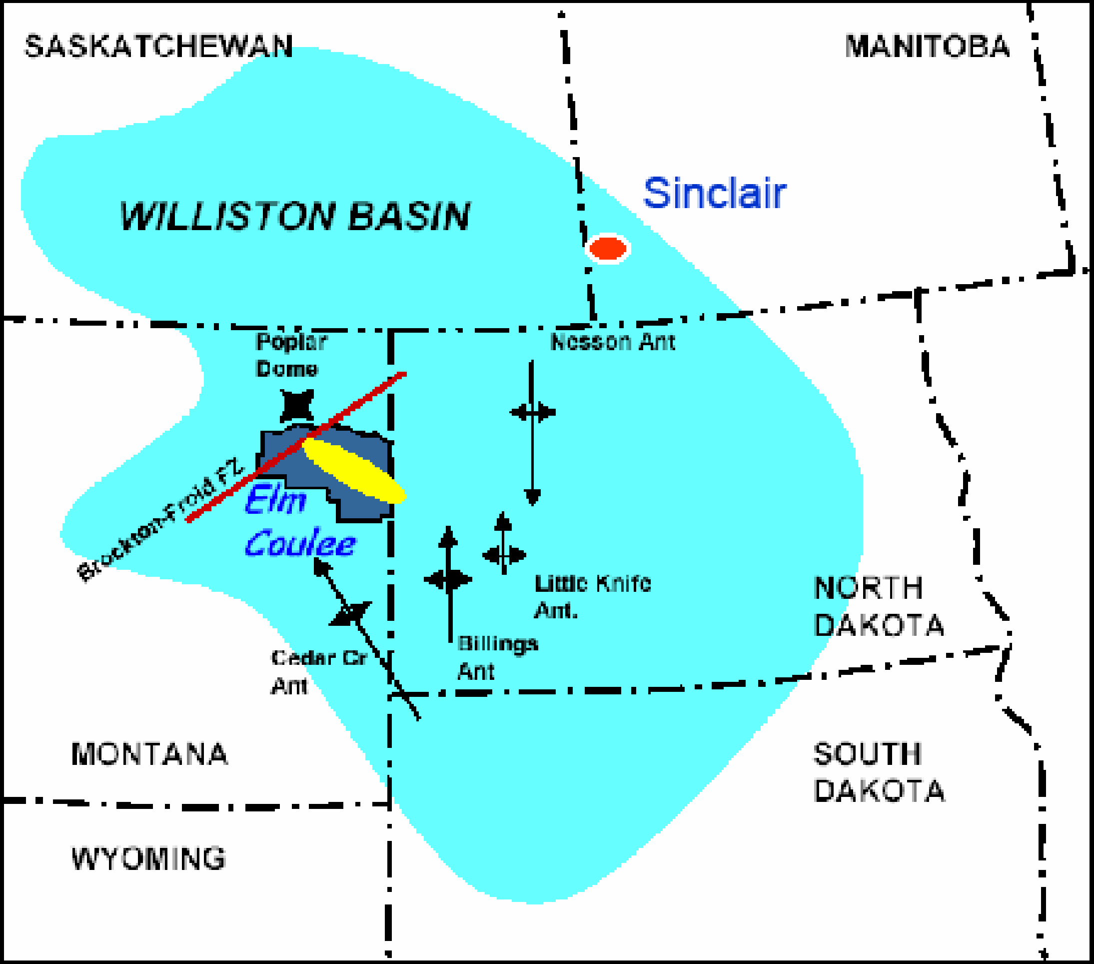


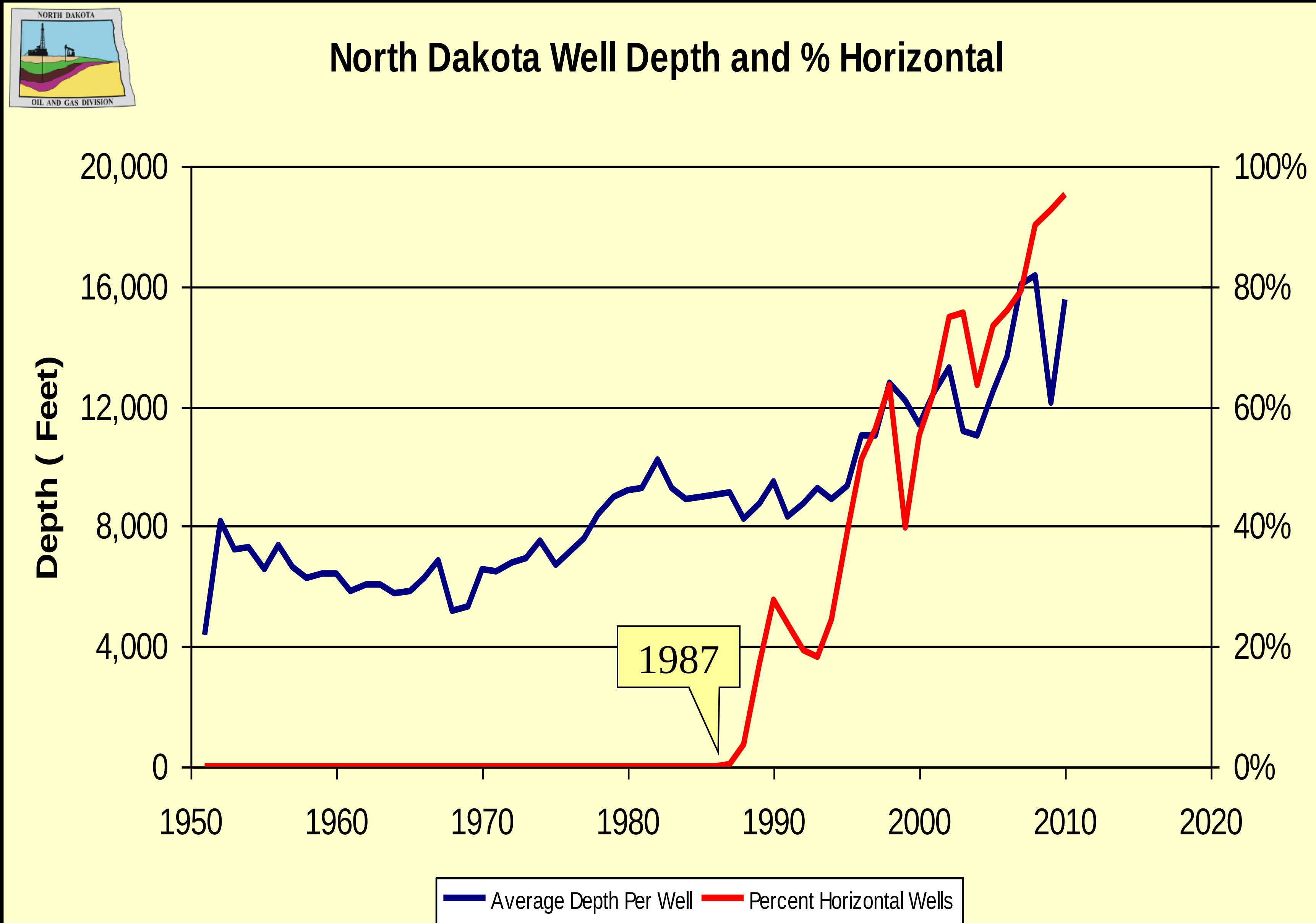
18,000 sq mi
9000 wells
1H/1280

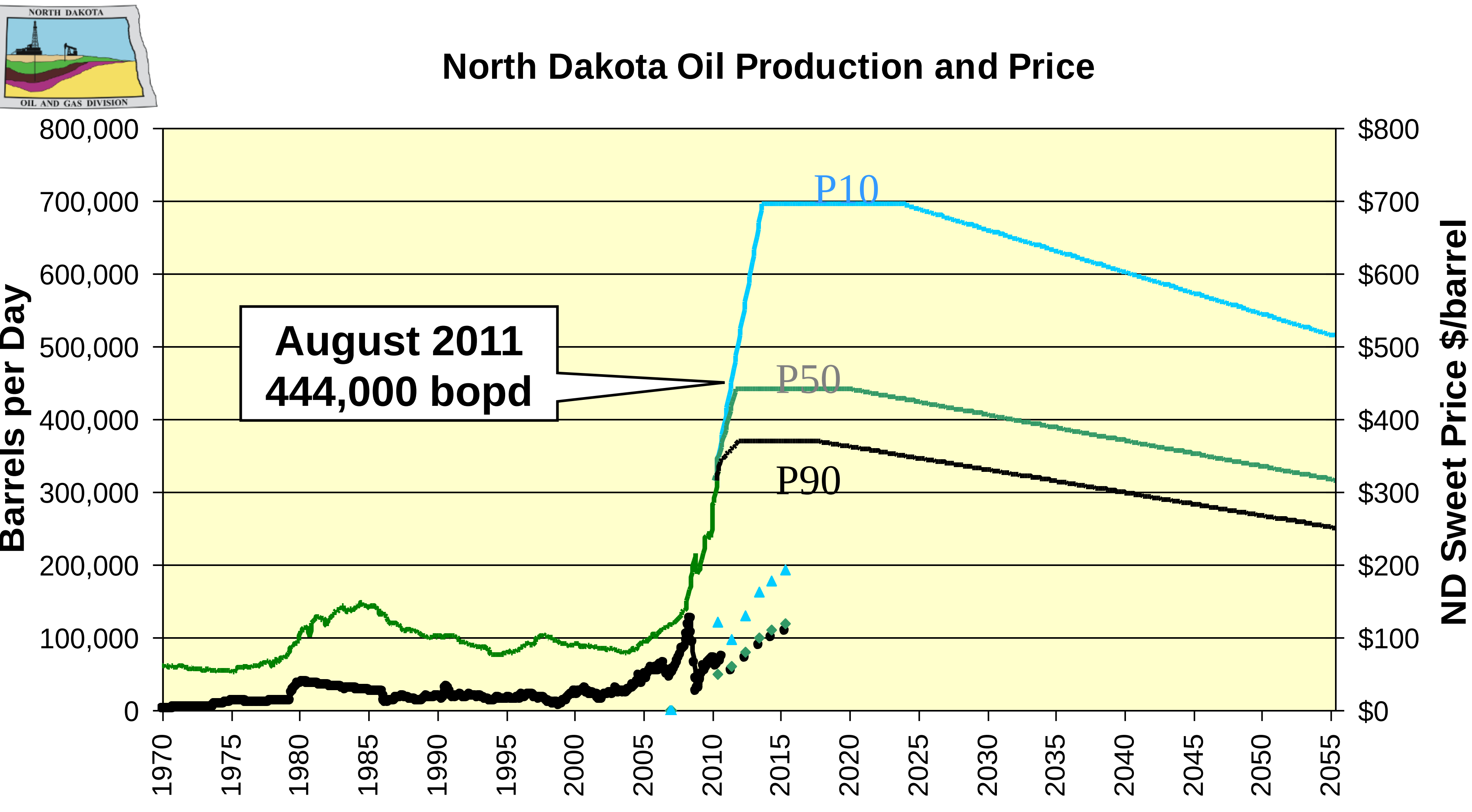
ESTIMATED MATURE AREA OF THE BAKKEN FORMATION



(Nordeng, 2010)


SASKATCHEWAN
MANITOBA
WILLISTON BASIN
Sinclair
Poplar Dome
Nesson Ant
Brockton-Froid FZ
Elm Coulee
Little Knife Ant.
Billings Ant
Cedar Cr Ant
NORTH DAKOTA
MONTANA
SOUTH DAKOTA
WYOMING


NORTH DAKOTA
OIL AND GAS DIVISION
North Dakota Well Depth and % Horizontal
Depth (Feet)
20,000
16,000
12,000
8,000
4,000
0
100%
80%
60%
40%
20%
0%
1950
1960
1970
1980
1990
2000
2010
2020
1987
Average Depth Per Well
Percent Horizontal Wells

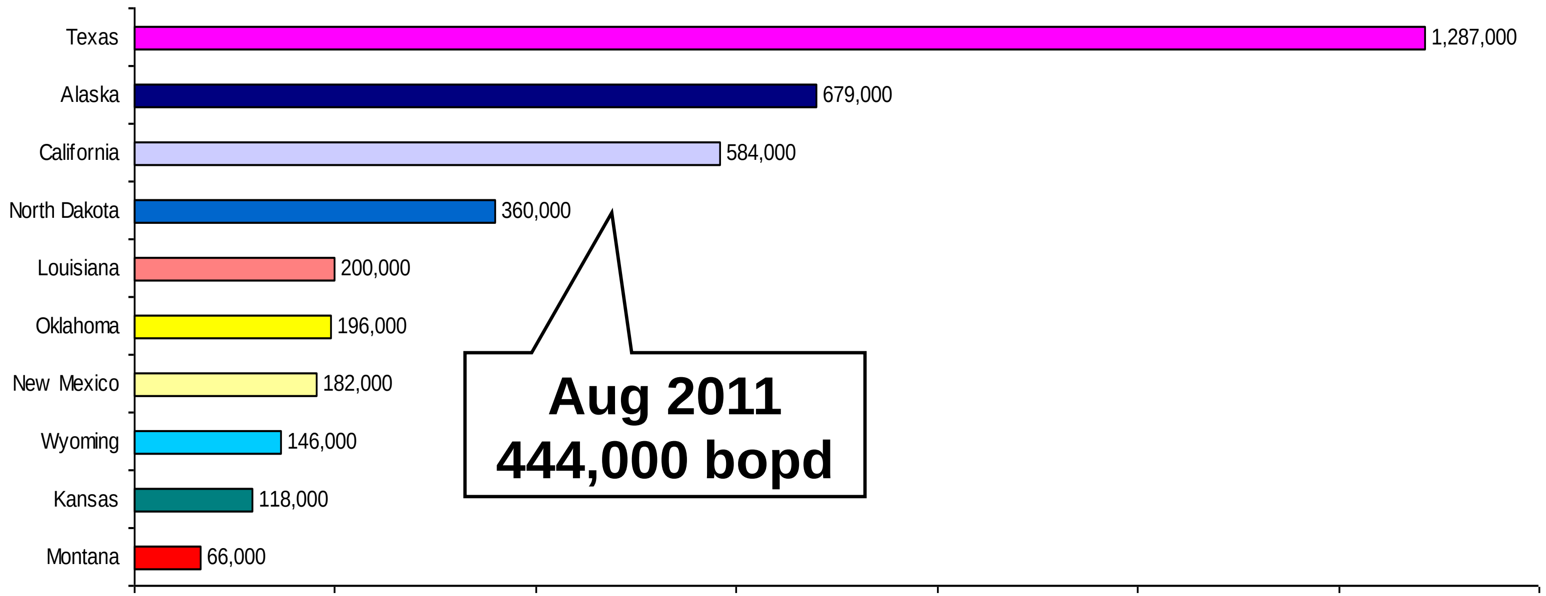


2,500 **Bakken and Three Forks wells drilled and completed**

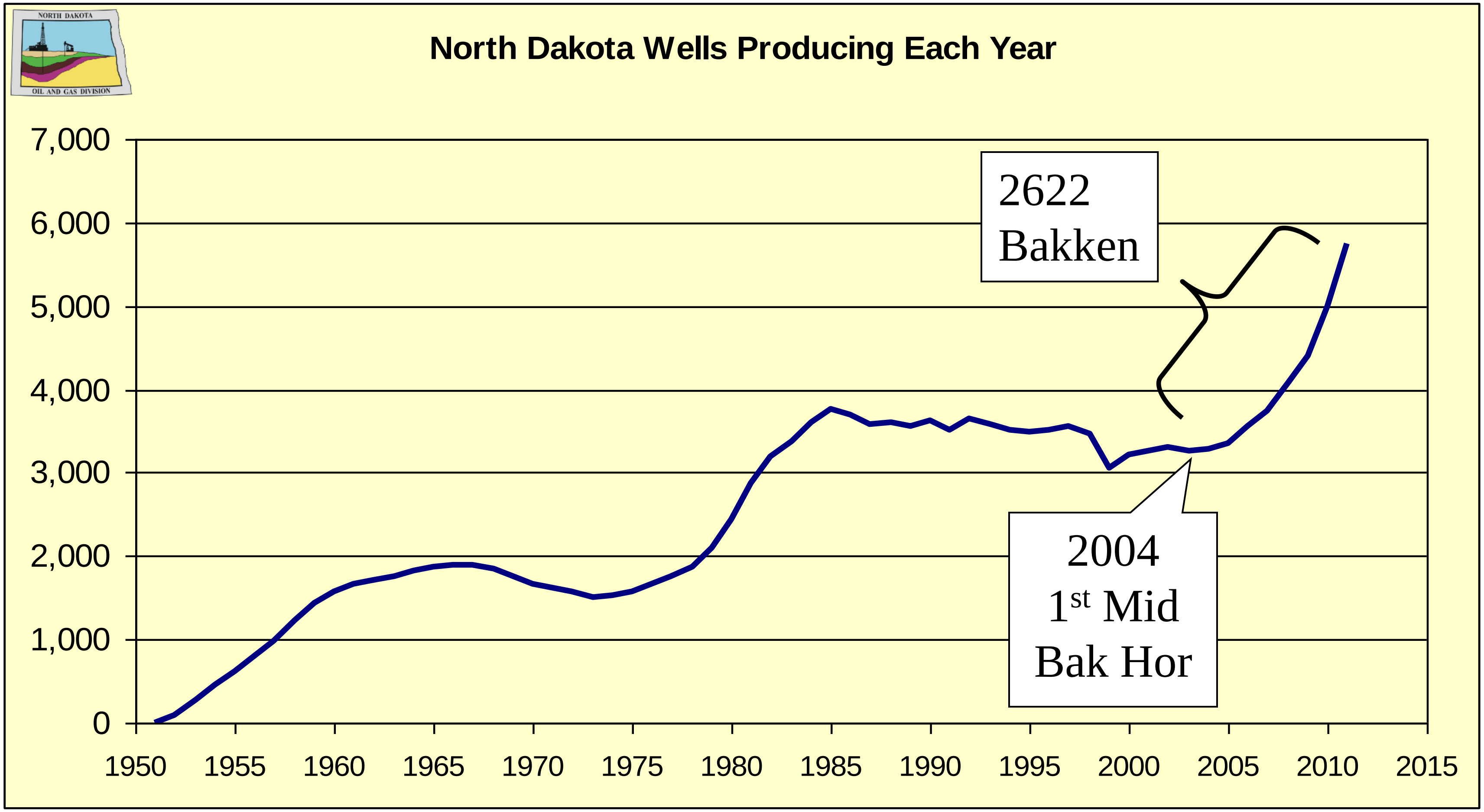
19,000 – 47,000 **more new wells possible in thermal mature area**

P90=5 BBO – P50=7 BBO – P10=11 BBO (billion barrels of oil)

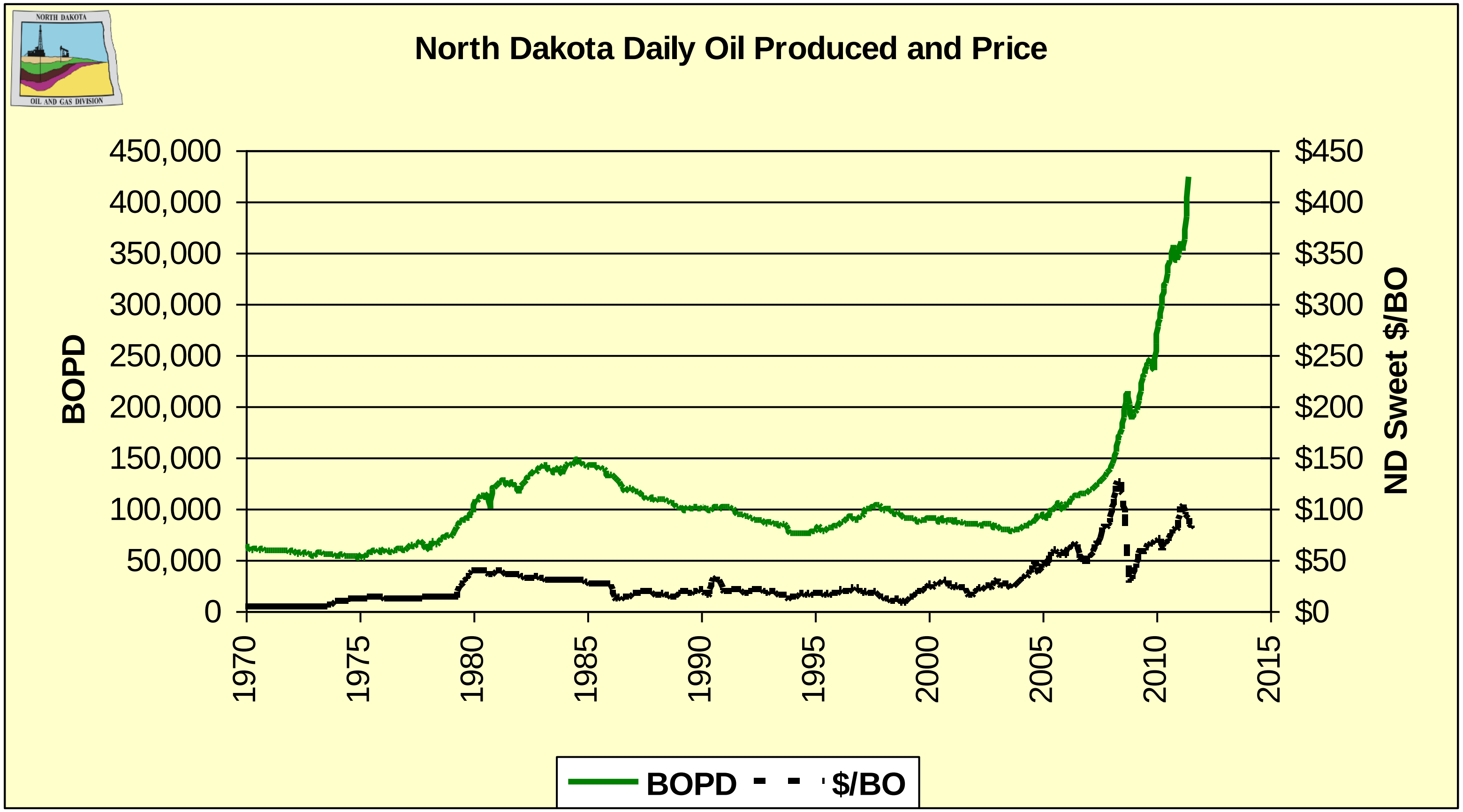
United States Daily Oil Production -- March 2011



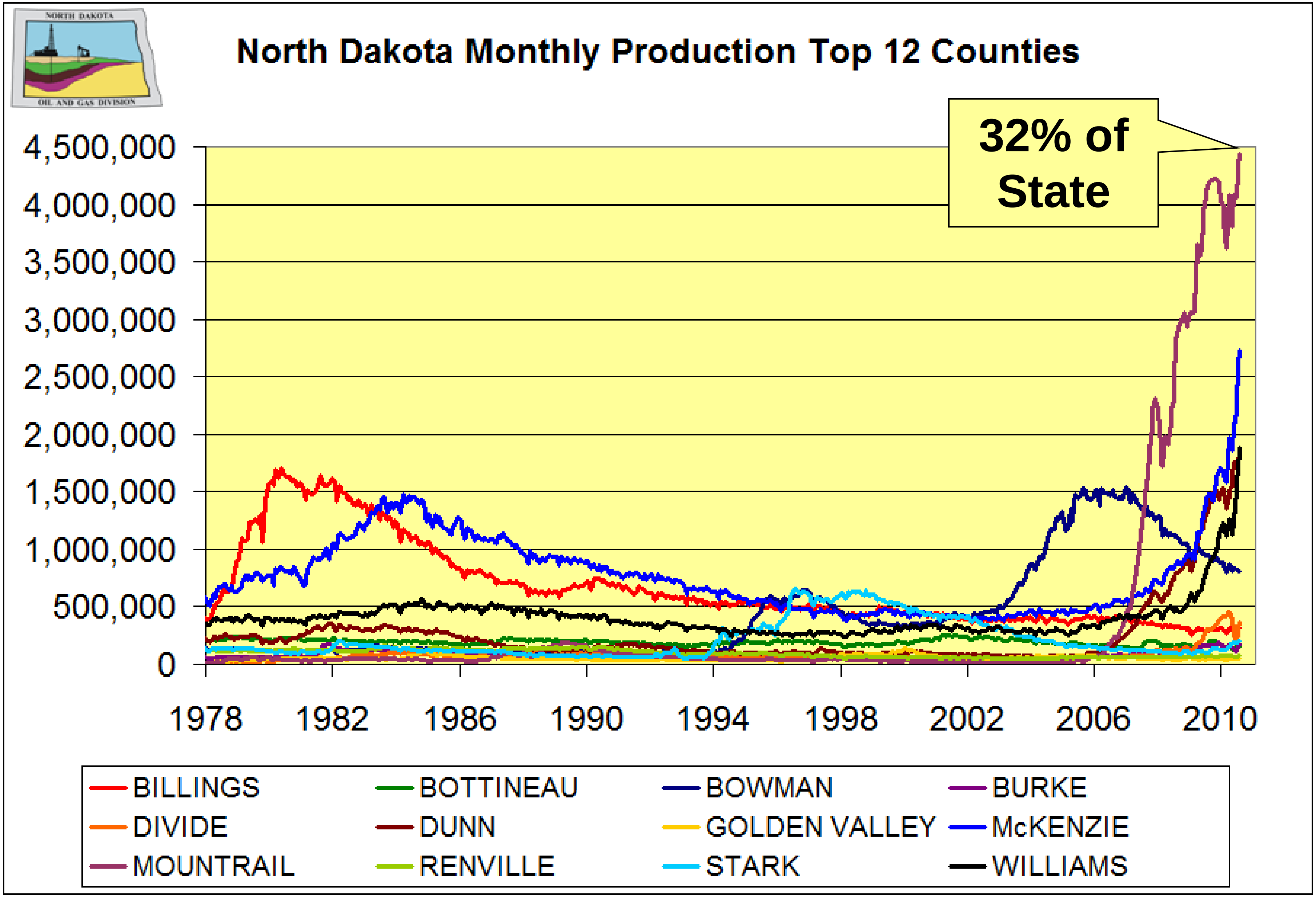
Data from US Energy Information Administration



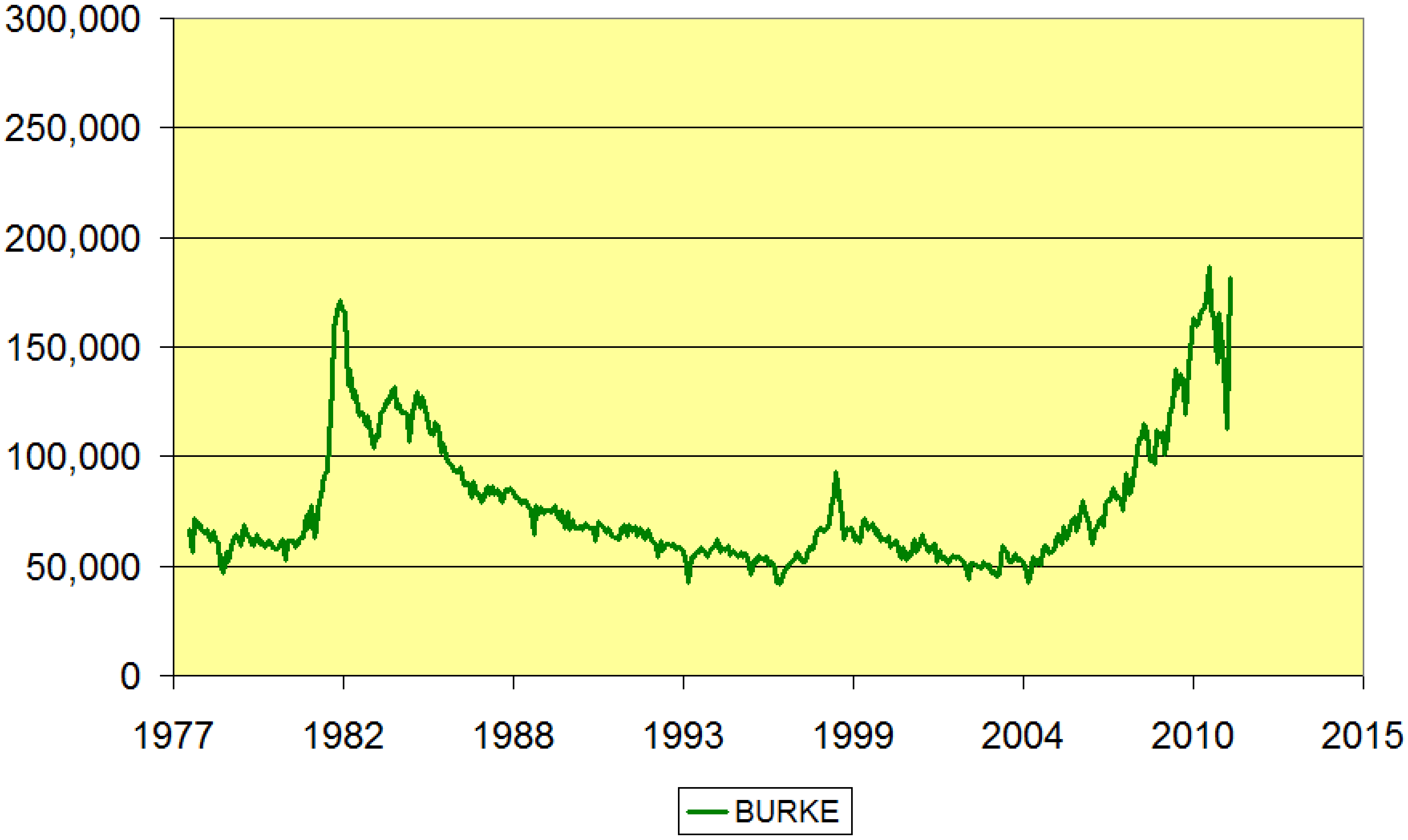
5951 total wells – 2622 Bakken horizontal (44.0%)



Production 444,000 bopd (appr 379,000 from Bakken—85.4%)


North Dakota Monthly Production Top 12 Counties
NORTH DAKOTA
OIL AND GAS DIVISION
32% of State
4,500,000
4,000,000
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
1978
1982
1986
1990
1994
1998
2002
2006
2010
BILLINGS
BOTTINEAU
BOWMAN
BURKE
DIVIDE
DUNN
GOLDEN VALLEY
McKENZIE
MOUNTRAIL
RENVILLE
STARK
WILLIAMS

MONTHLY OIL PRODUCTION FOR LOCAL COUNTIES



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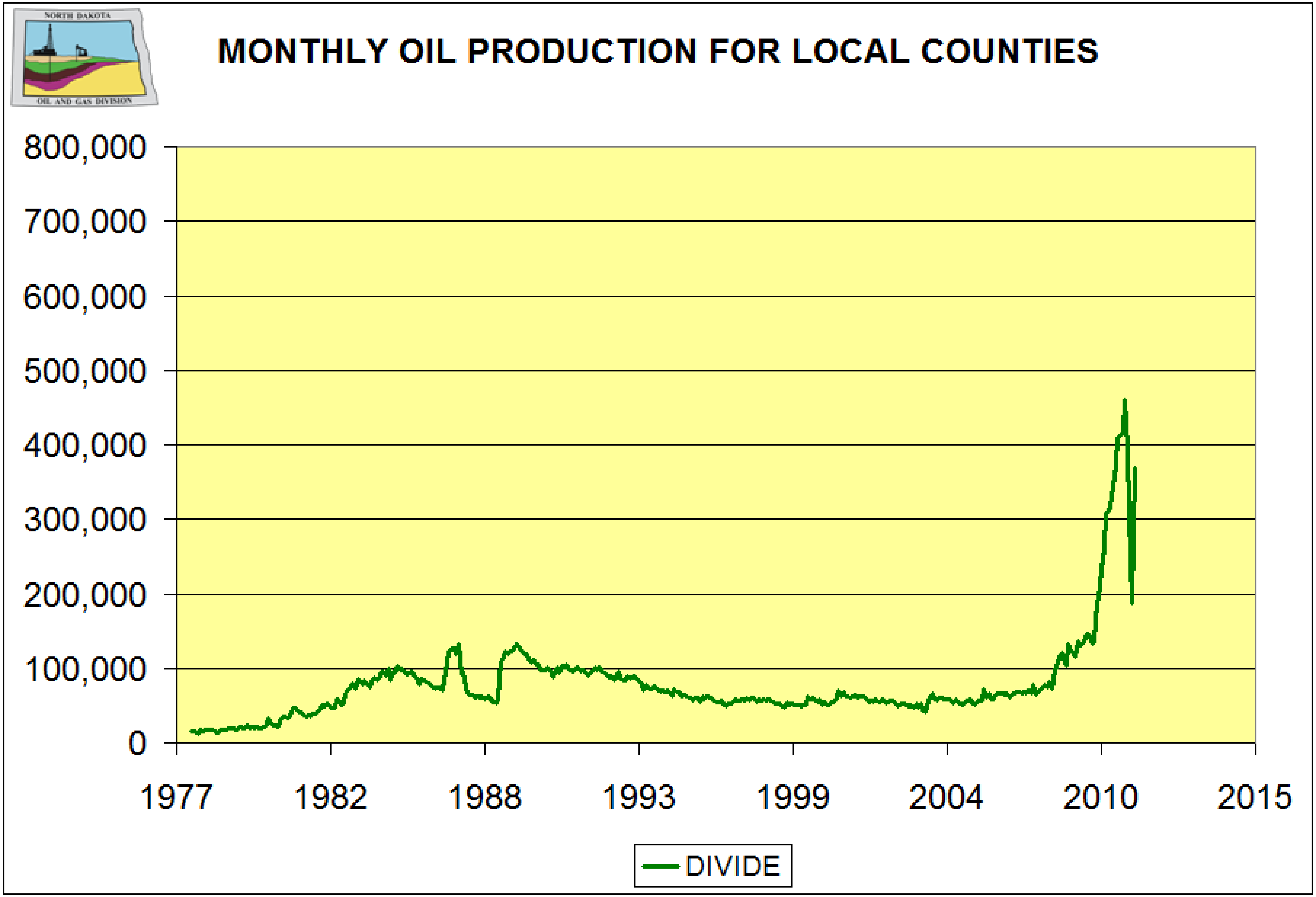

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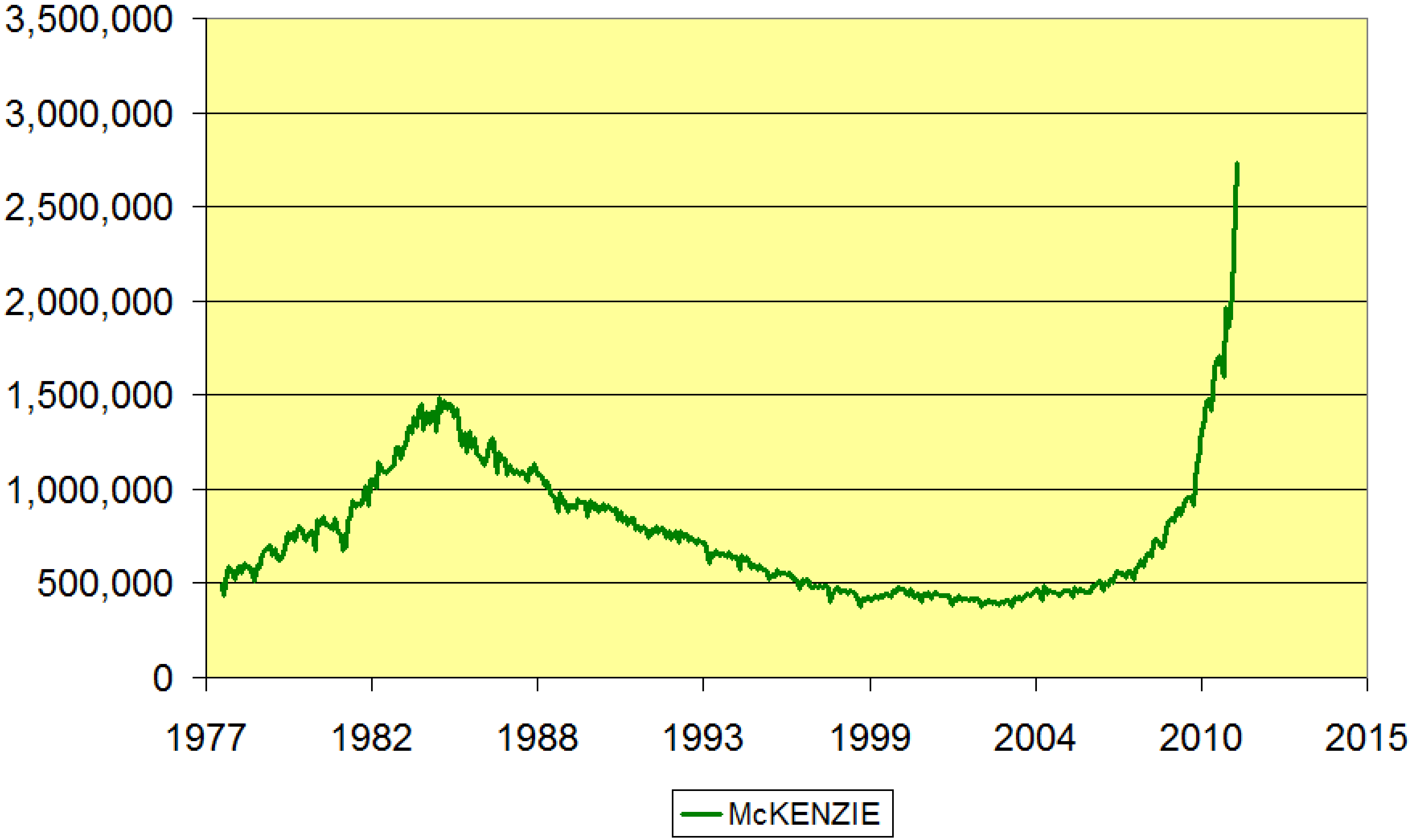

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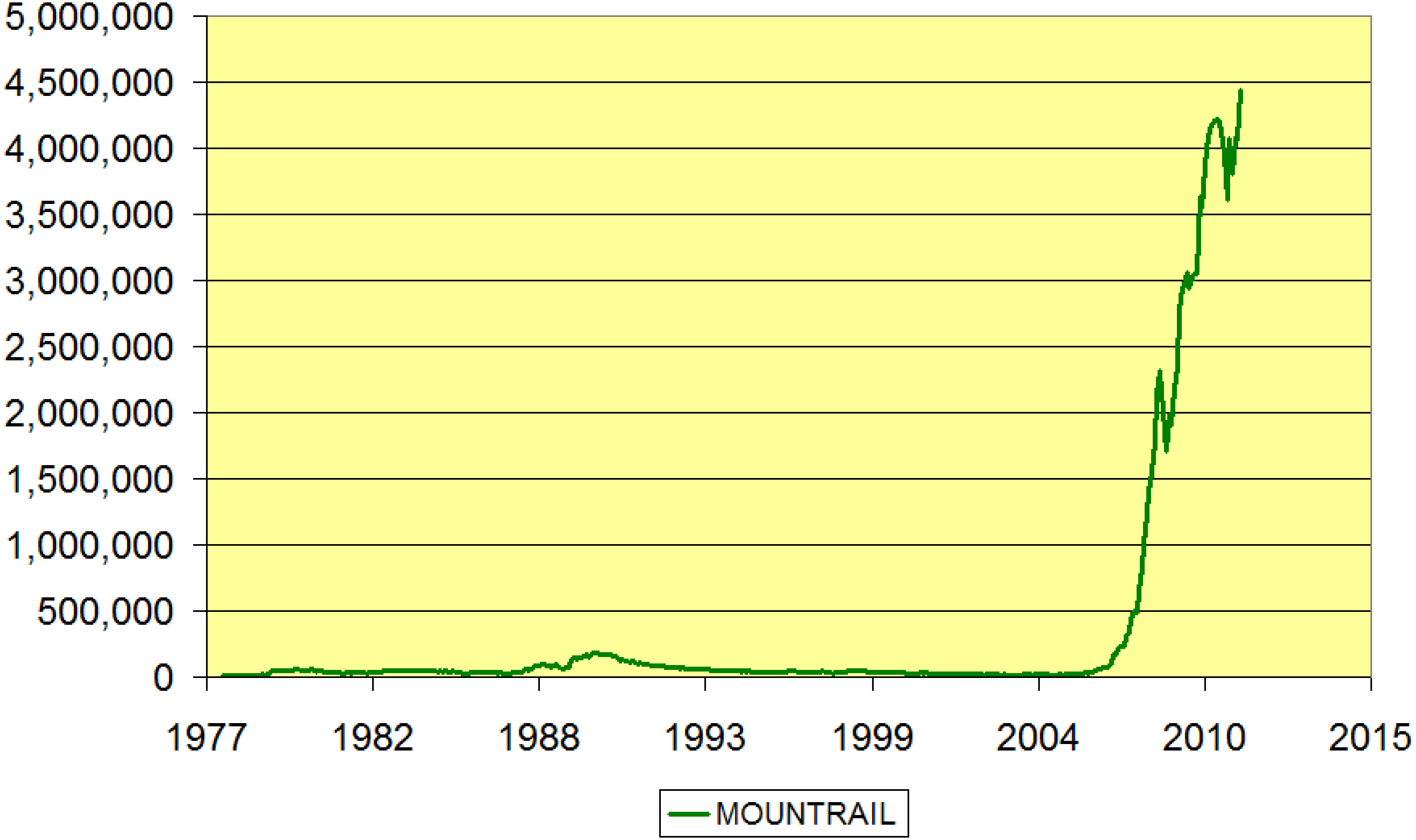
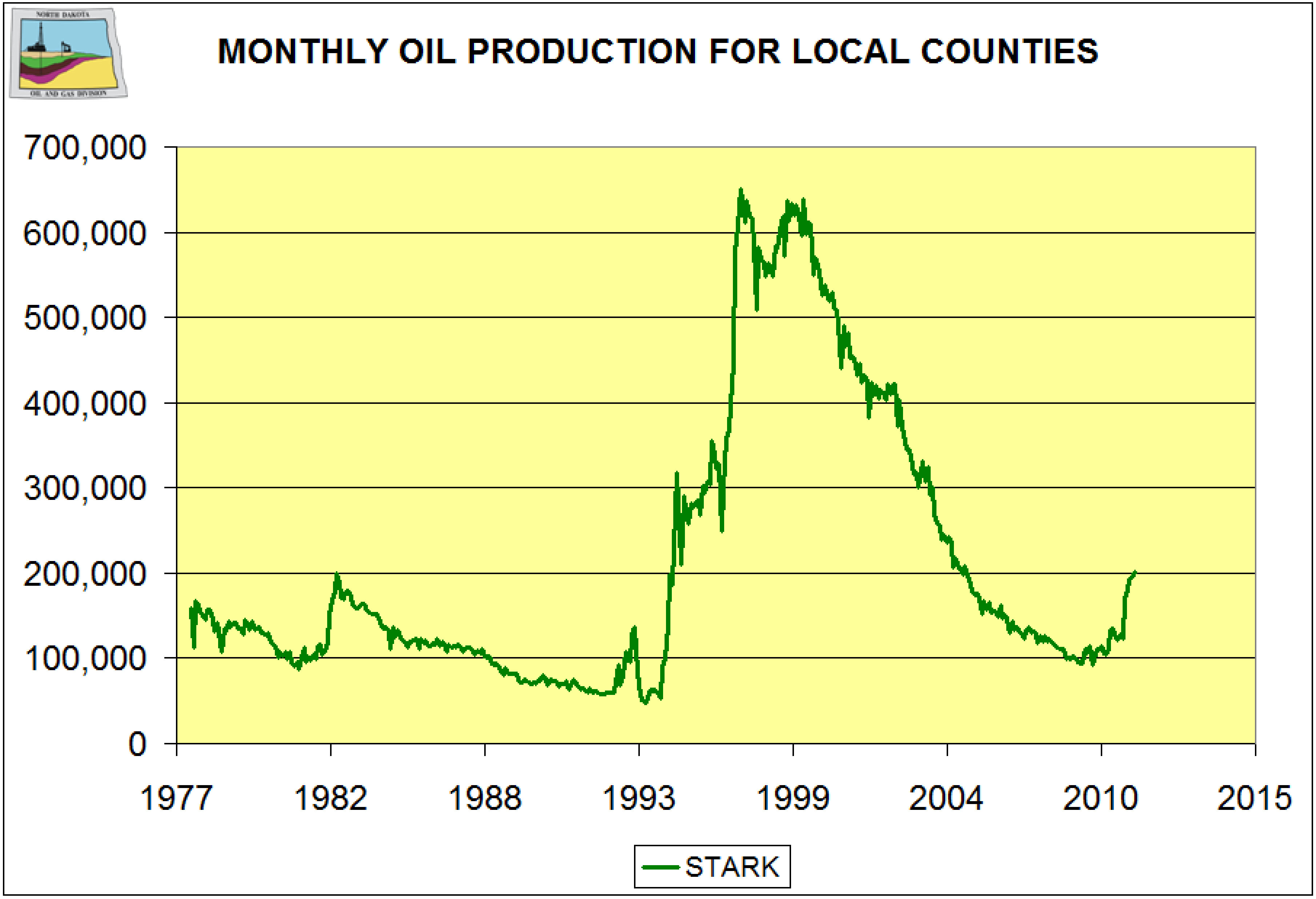
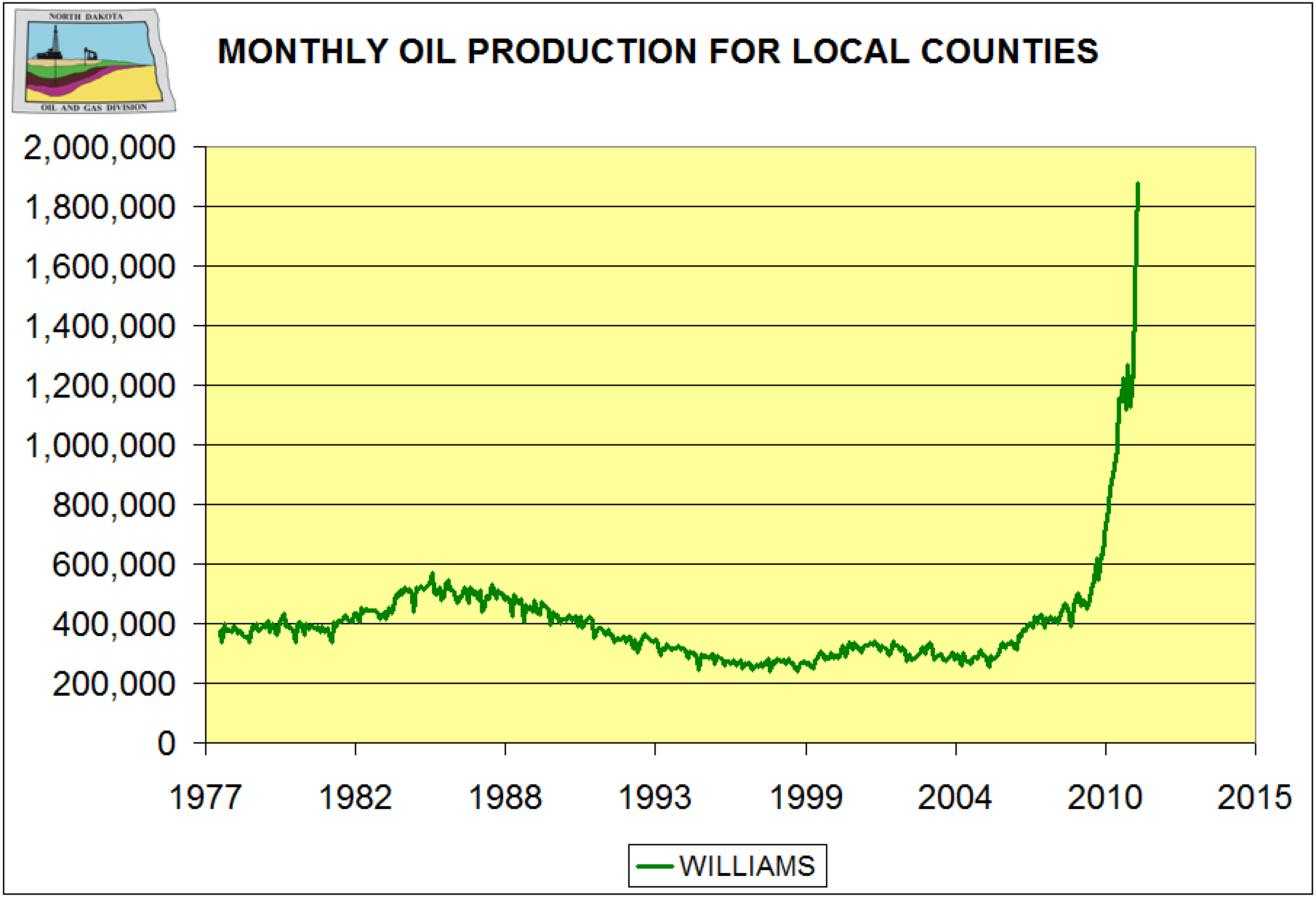
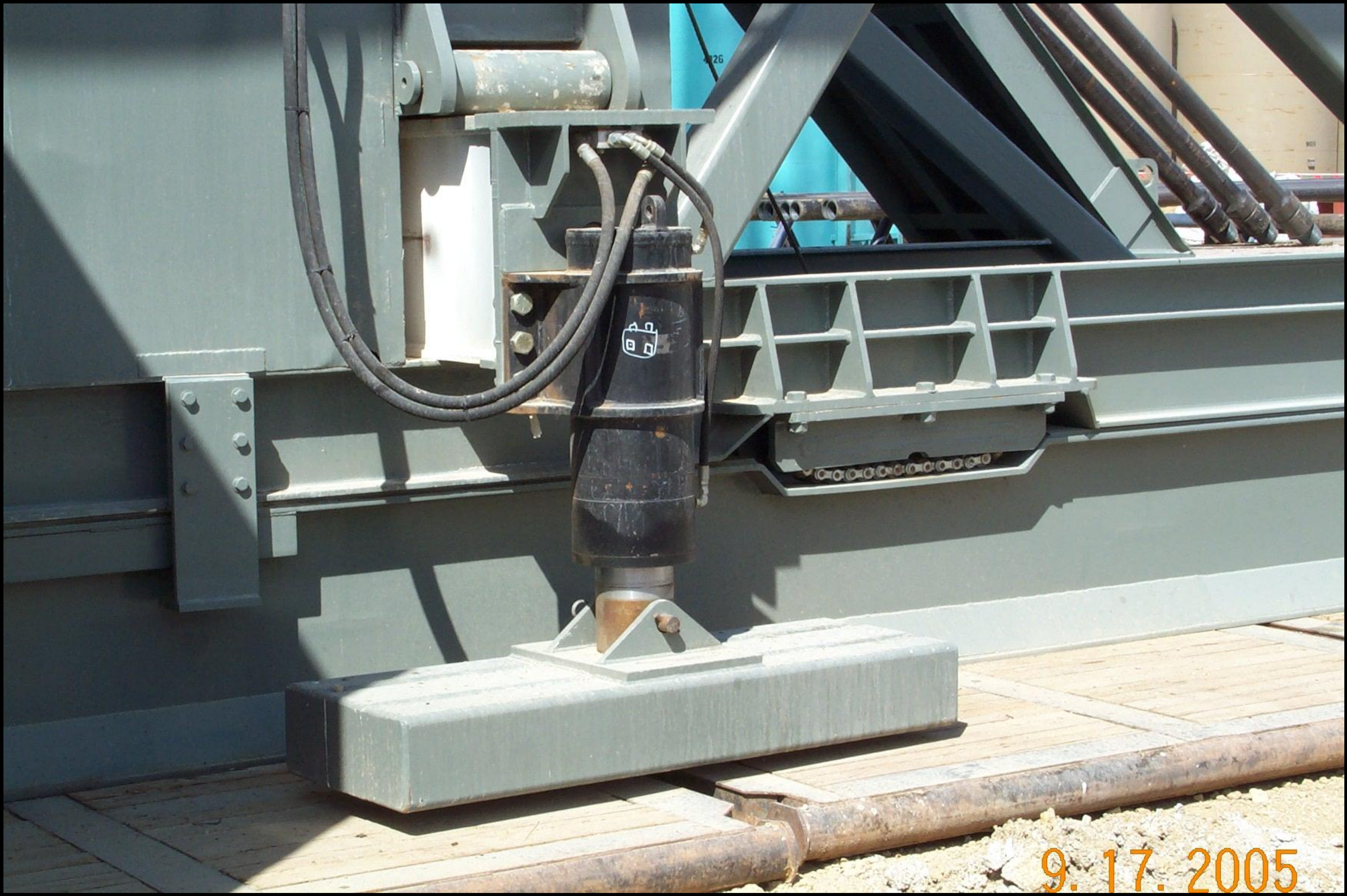
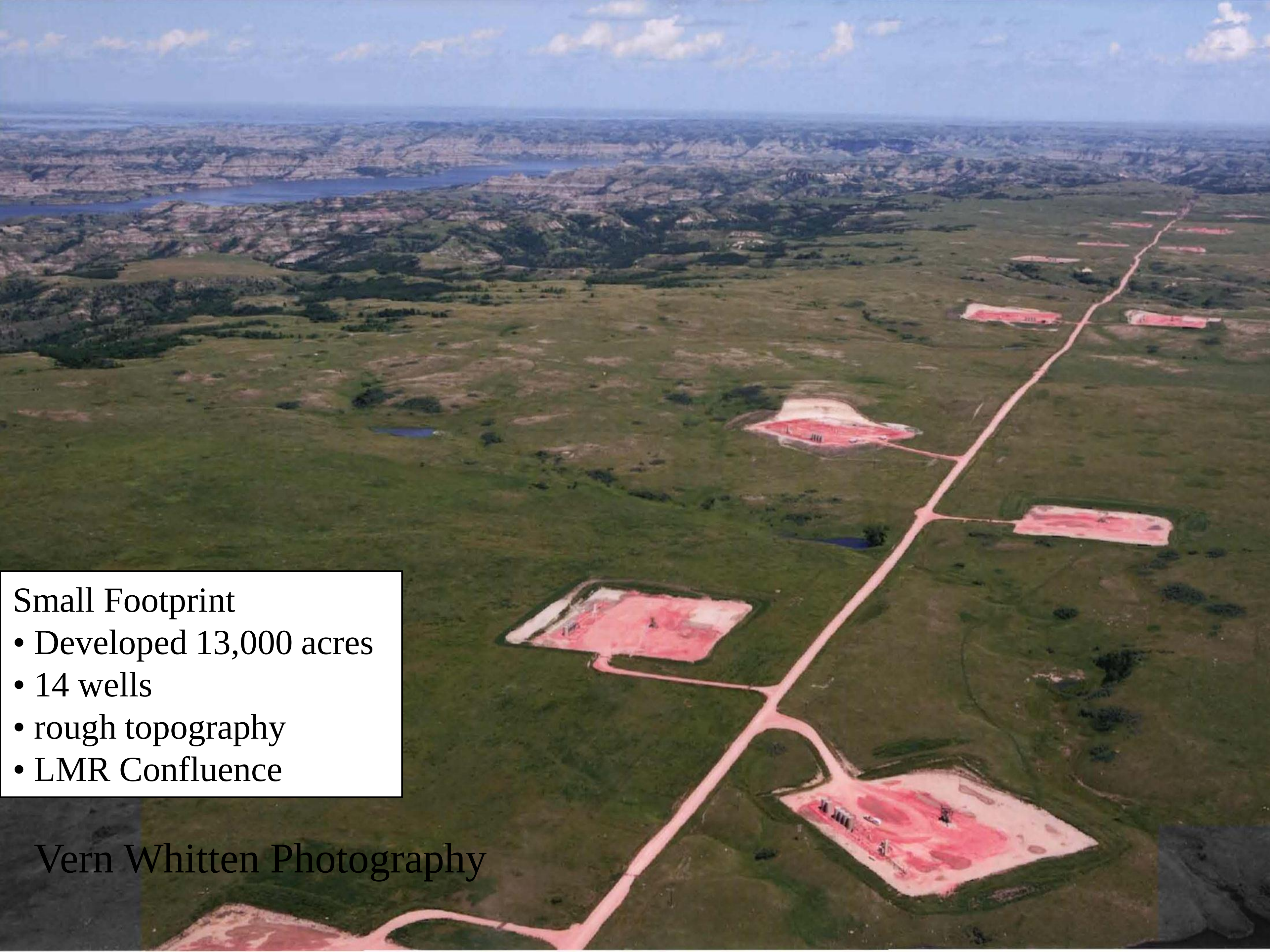



MONTHLY OIL PRODUCTION FOR LOCAL COUNTIES
700,000
600,000
500,000
400,000
300,000
200,000
100,000
0
1977
1982
1988
1993
1999
2004
2010
2015
STARK


MONTHLY OIL PRODUCTION FOR LOCAL COUNTIES
2,000,000
1,800,000
1,600,000
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
1977
1982
1988
1993
1999
2004
2010
2015
WILLIAMS

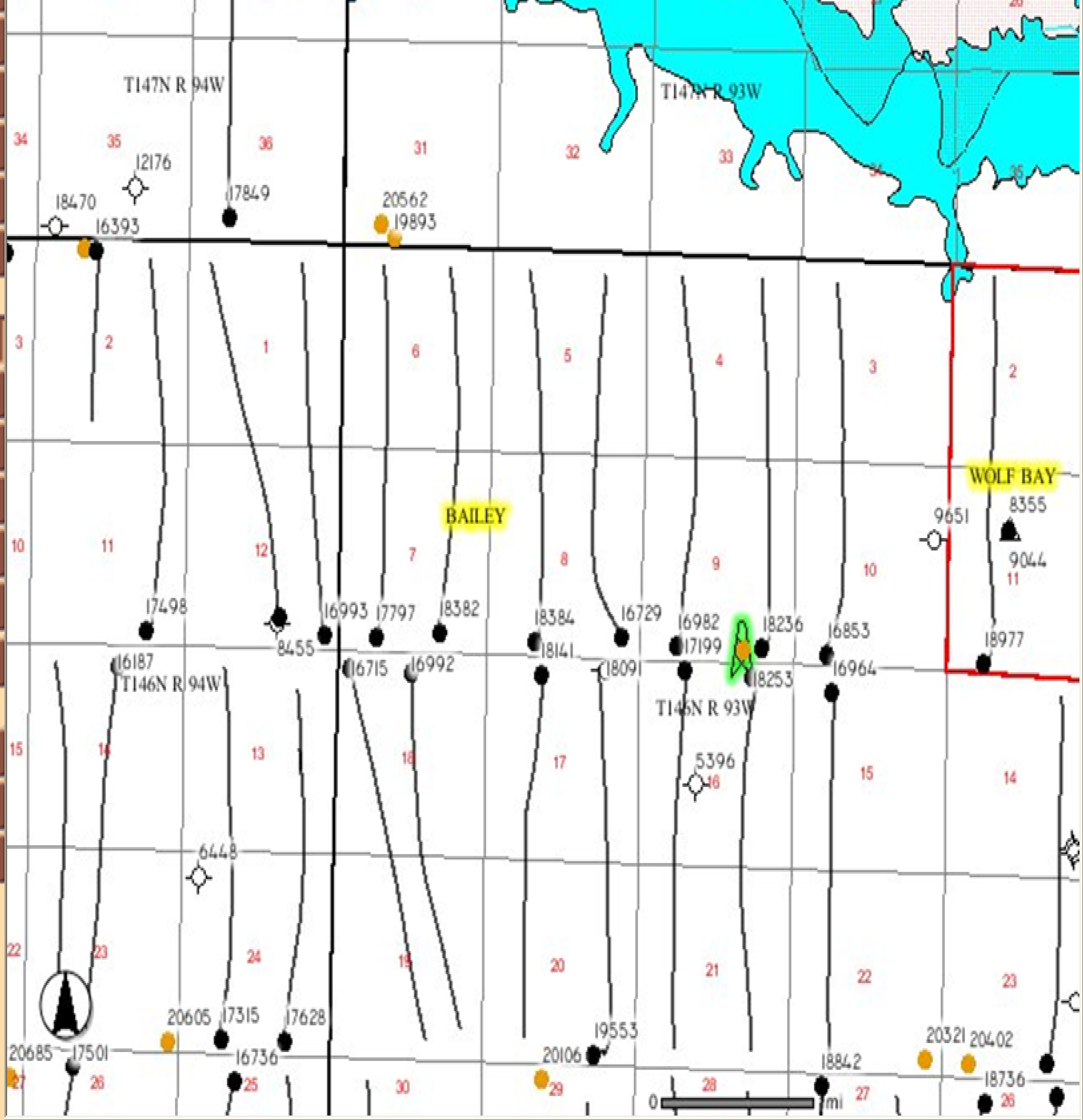

9. 17. 2005


Small Footprint
• Developed 13,000 acres
• 14 wells
• rough topography
• LMR Confluence
Vern Whitten Photography

w Entire State
revious View
ear Selection
Search
enerate PDF

Zoom In
Zoom Out
Pan
Rect Identify
elect Object
Buffer
Distance

Find Well
nd Field/Unit
Find Section



Major Rivers

Selection cleared.

Wells
Rig Location
Directional Surveys
Directional Legs
Horizontal Surveys
Horizontal Legs
Cases Docketed
Oil Fields
Unit Boundaries
Inspector Areas
Drilling / Spacing
Seismic
Gas Plants
Other
Reservations
Corporate Boundaries
Rivers and Roads
County Roads
Major Roads
Major Rivers
Missouri River
Land Ownership
Imagery
Topo/DRG 250k
Topo/DRG 100k
NAIP 2009

Refresh Map

Auto Refresh

Help:

A closed group, click to open.

An open group, click to close.

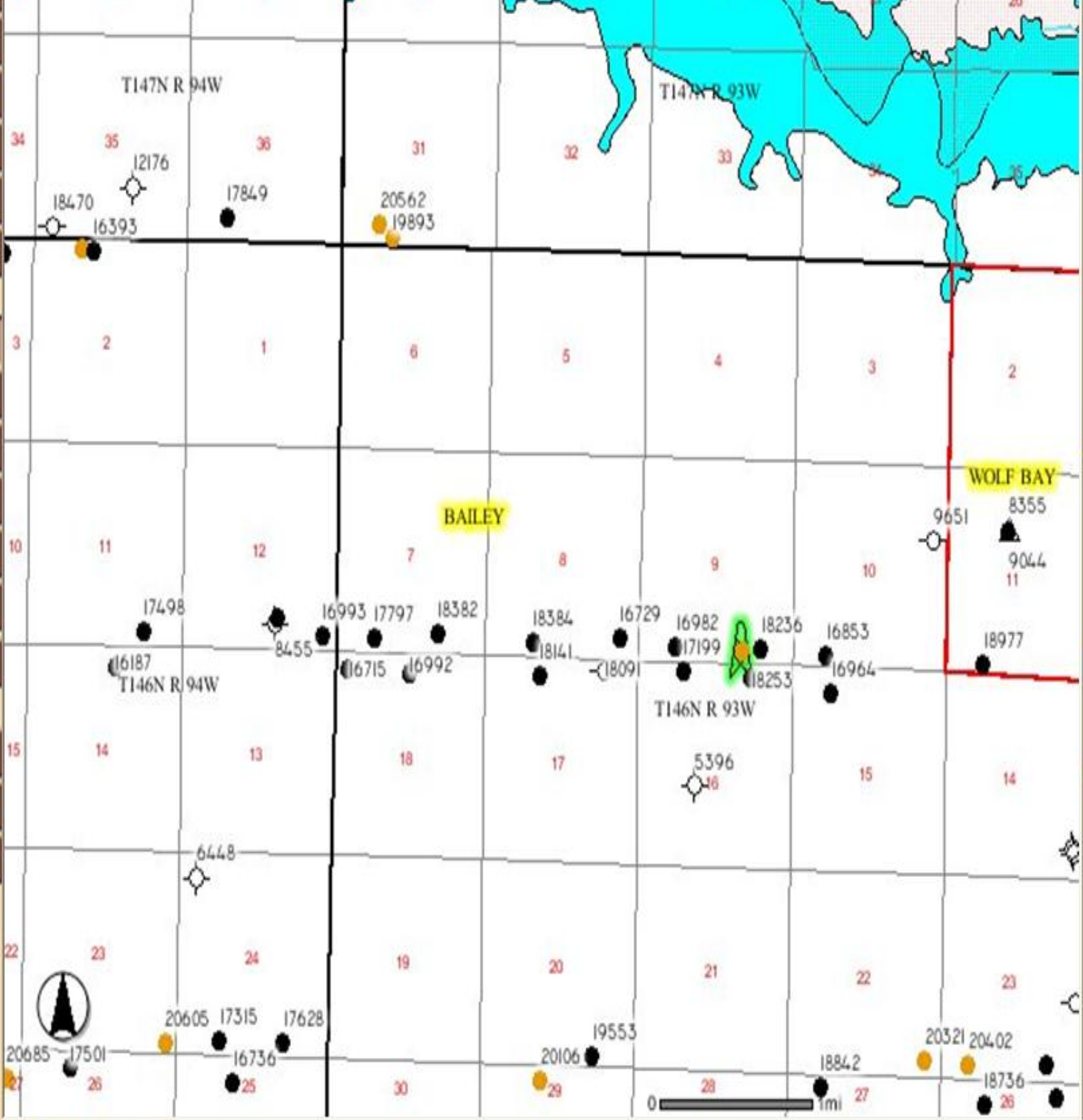
A map layer.

A hidden group/layer, click to make visible.

w Entire State
revious View
ear Selection
Search
enerate PDF

Zoom In
Zoom Out
Pan
Rect Identify
elect Object
Buffer
Distance

Find Well
nd Field/Unit
Find Section



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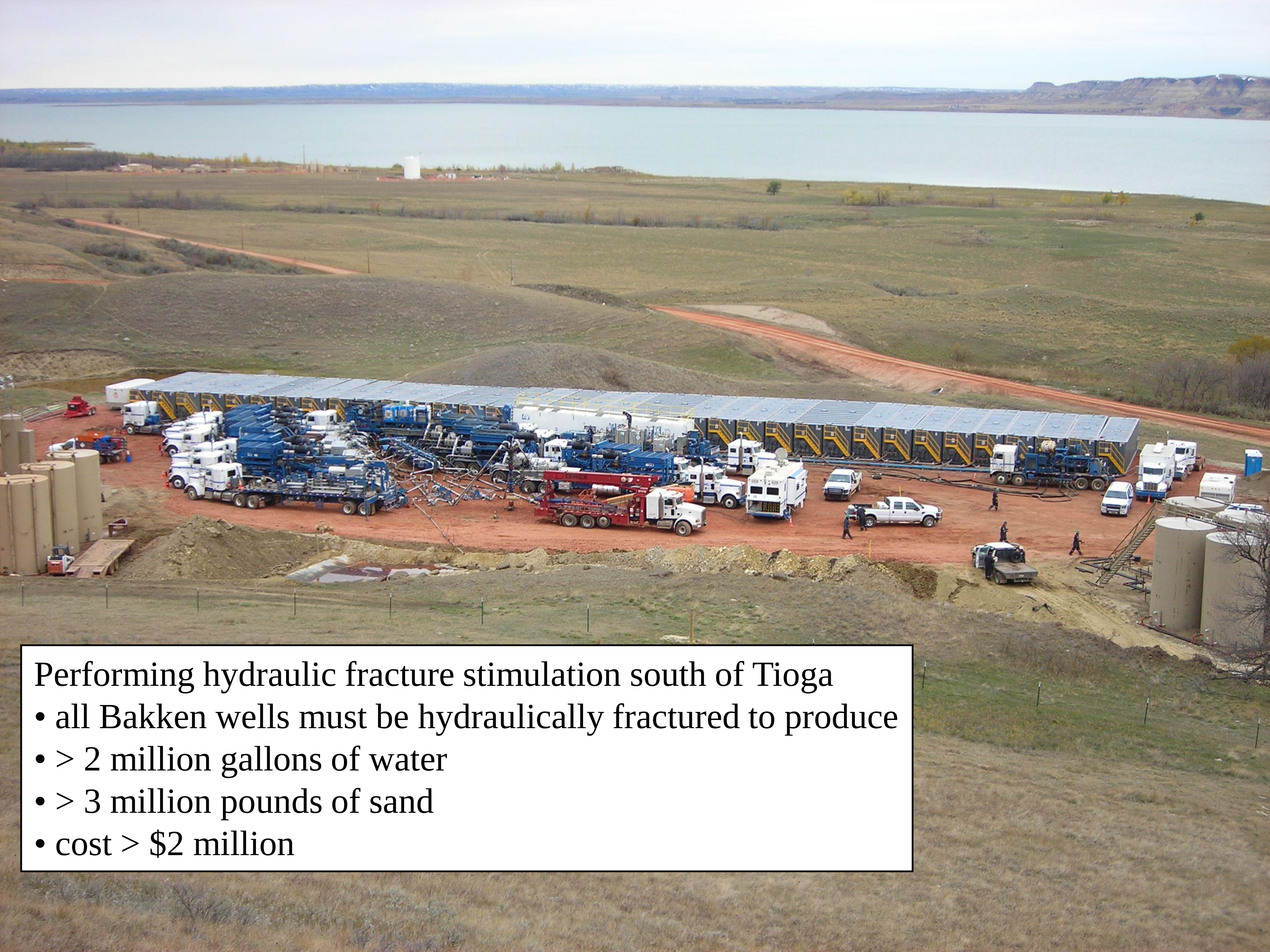

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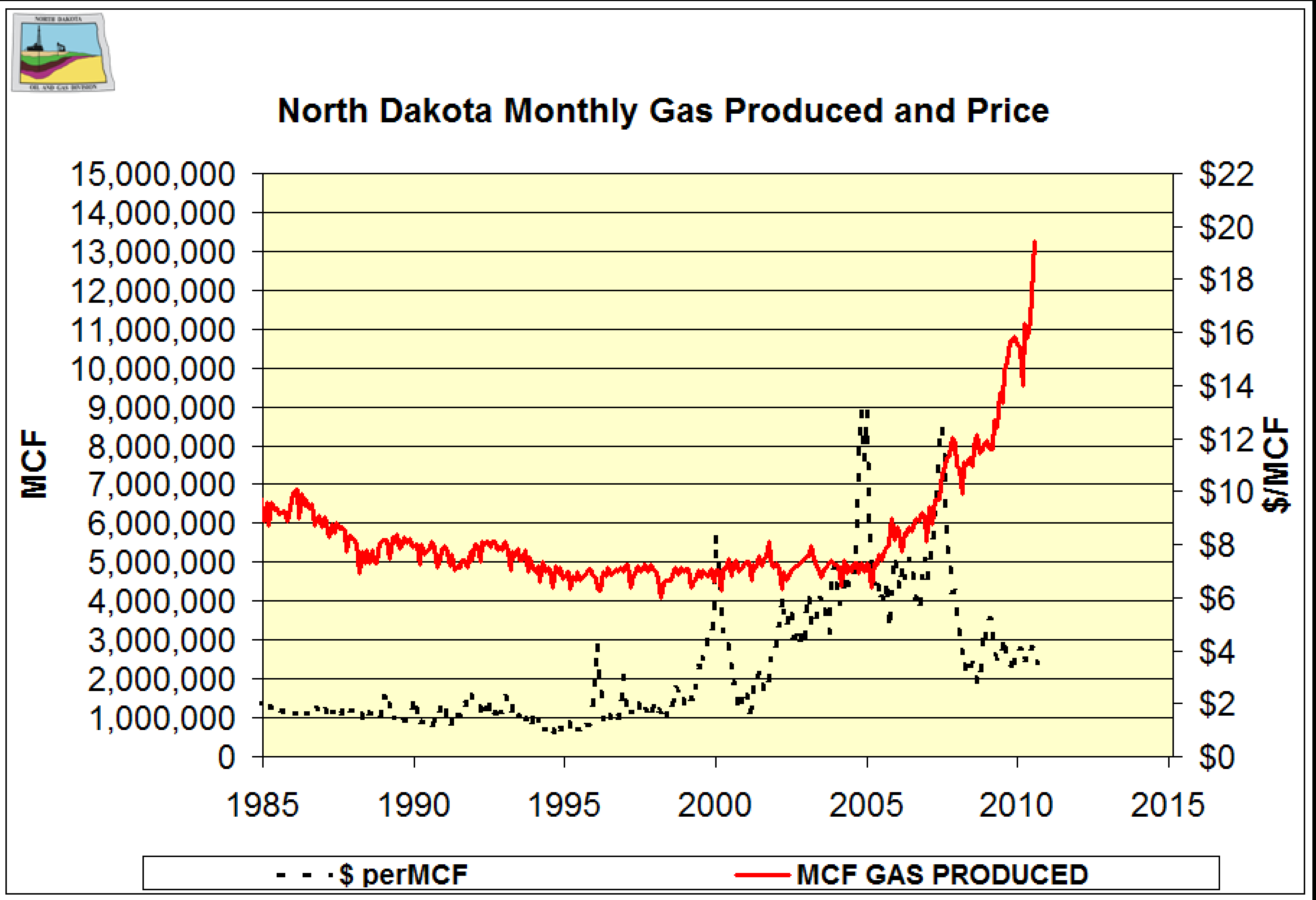

North Dakota Monthly Gas Produced and Price
MCF
$/MCF
15,000,000
14,000,000
13,000,000
12,000,000
11,000,000
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9,000,000
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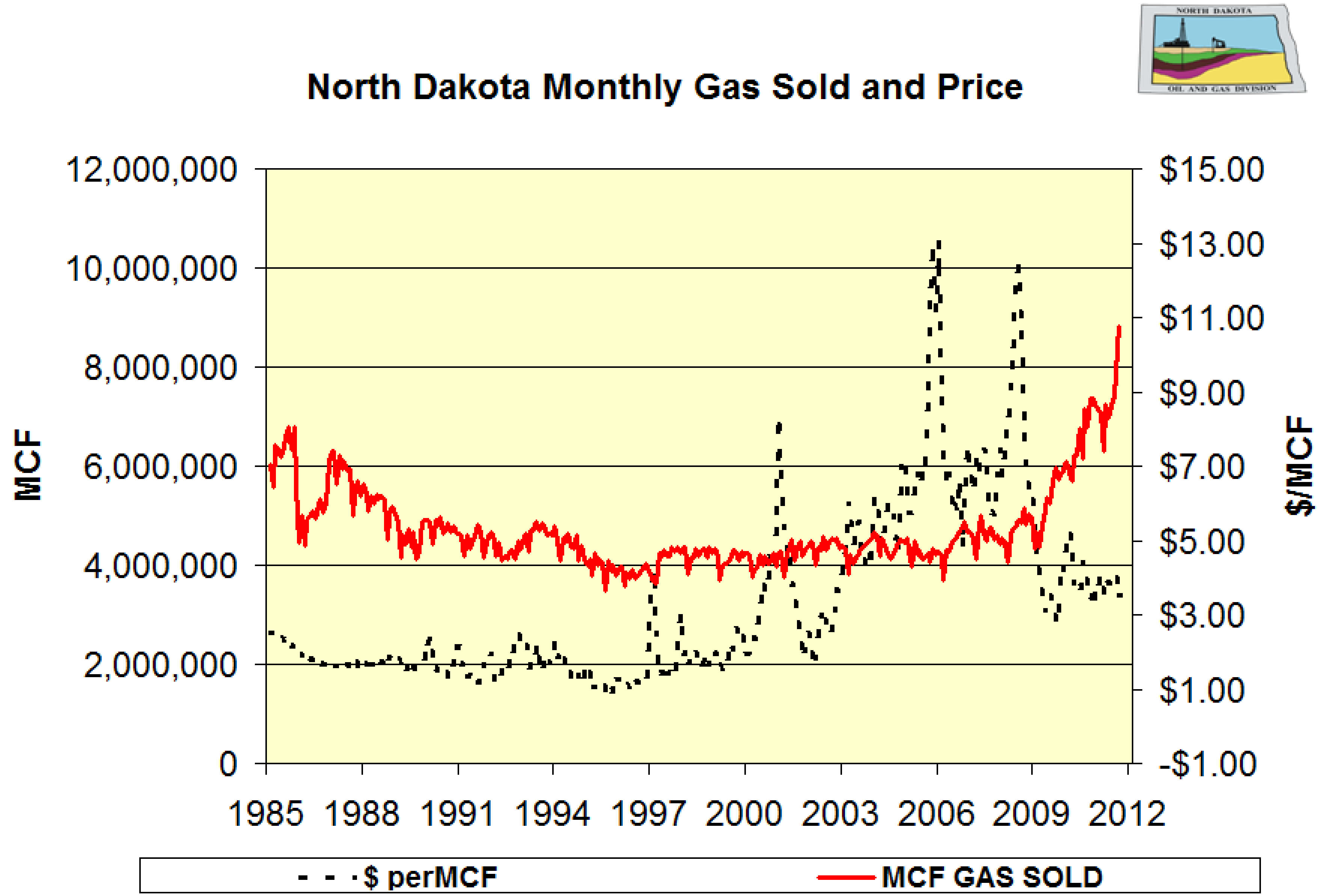
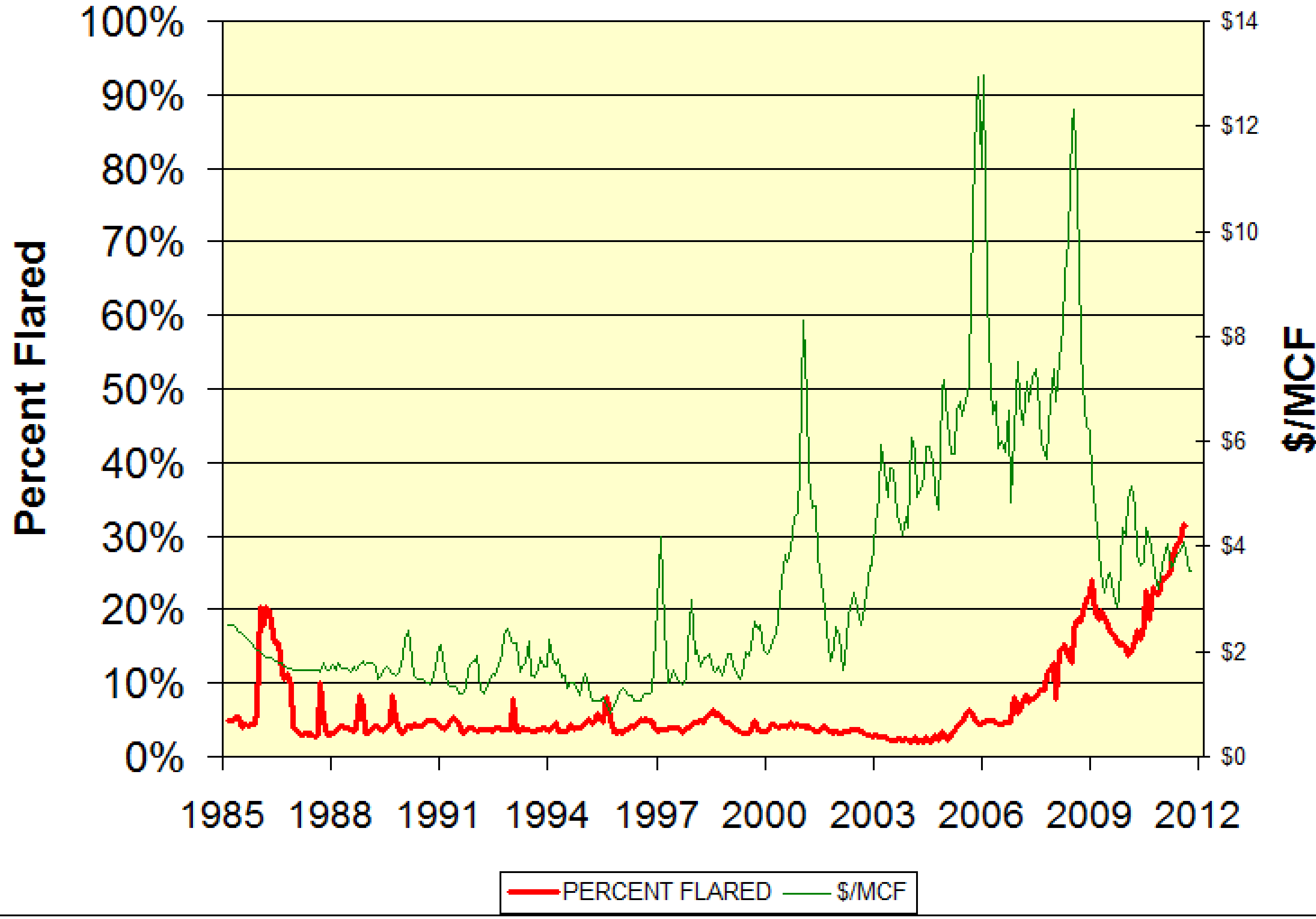
0
$22
$20
$18
$16
$14
$12
$10
$8
$6
$4
$2
$0
1985
1990
1995
2000
2005
2010
2015
$ perMCF
MCF GAS PRODUCED

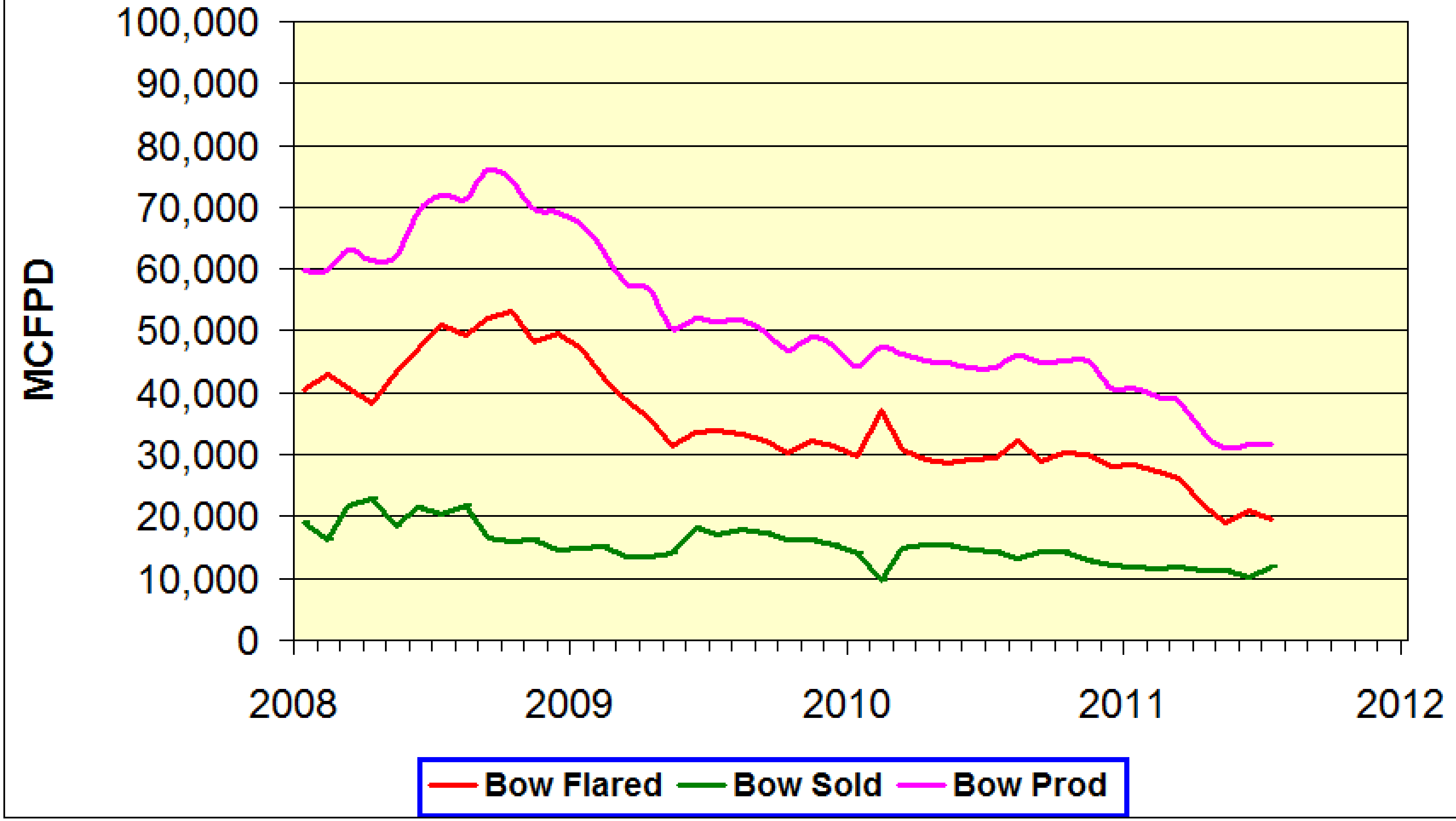
North Dakota Monthly Gas Sold and Price



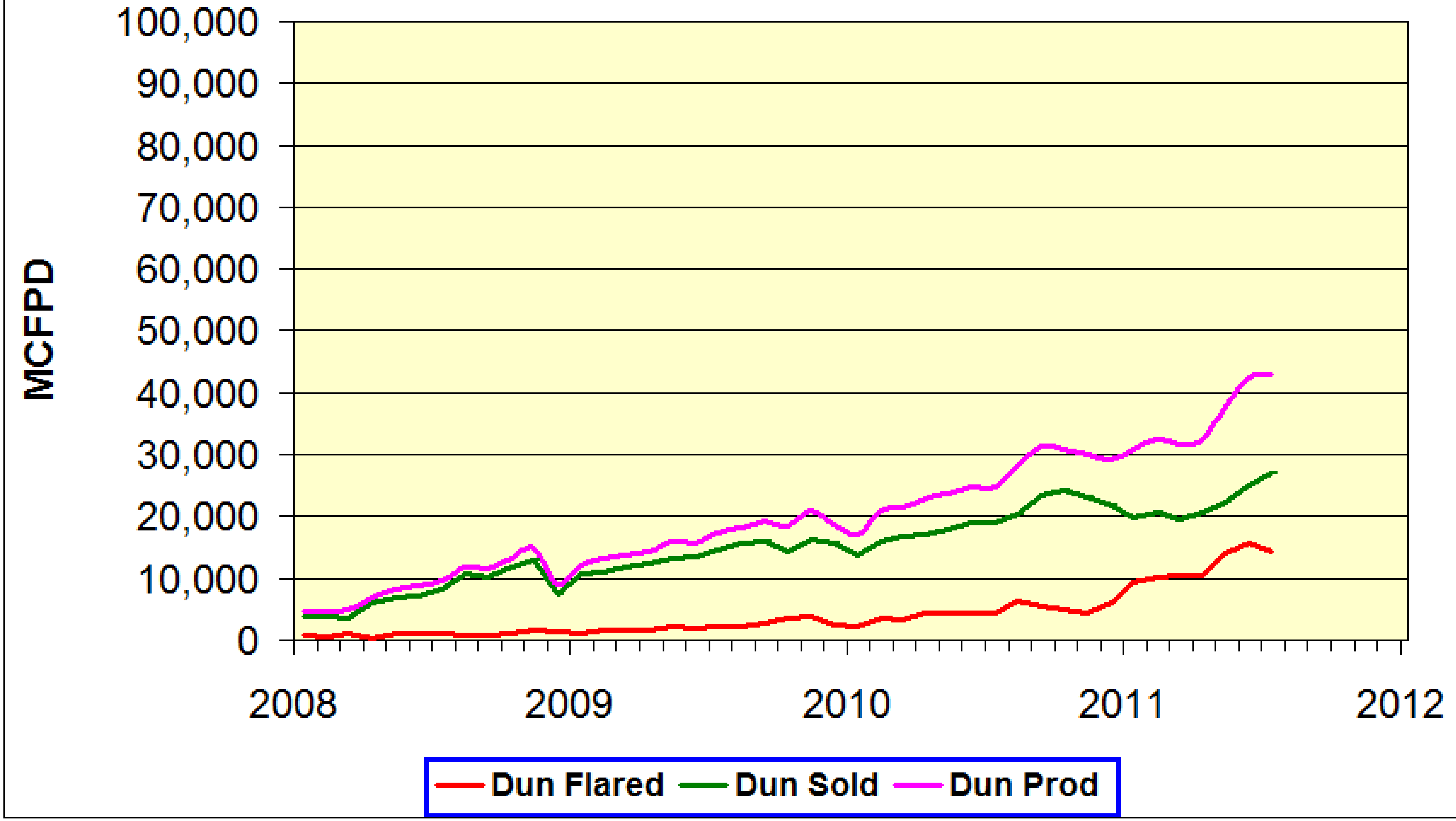
North Dakota Monthly Gas Flared



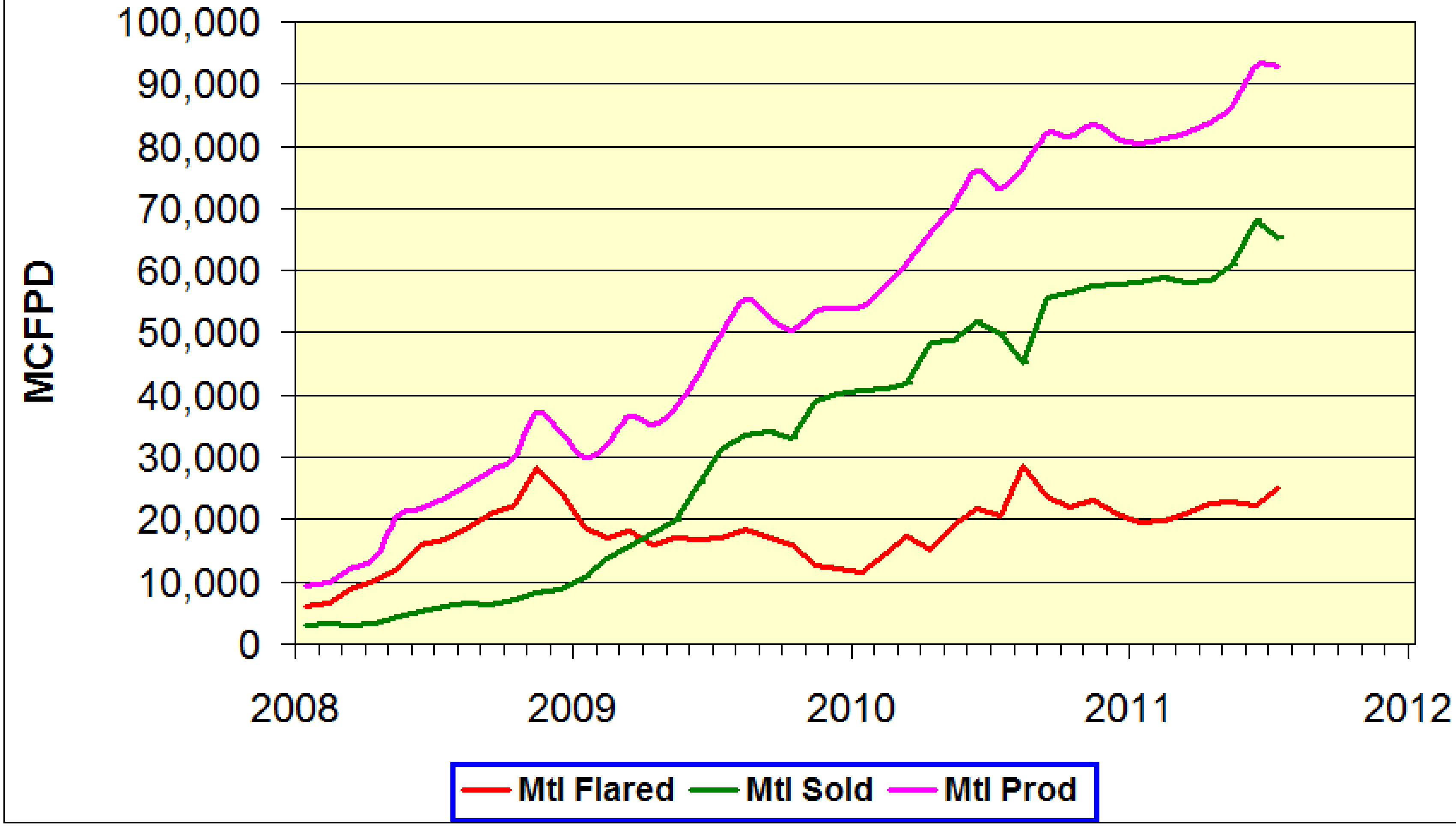
Bowman County Daily Gas Volumes



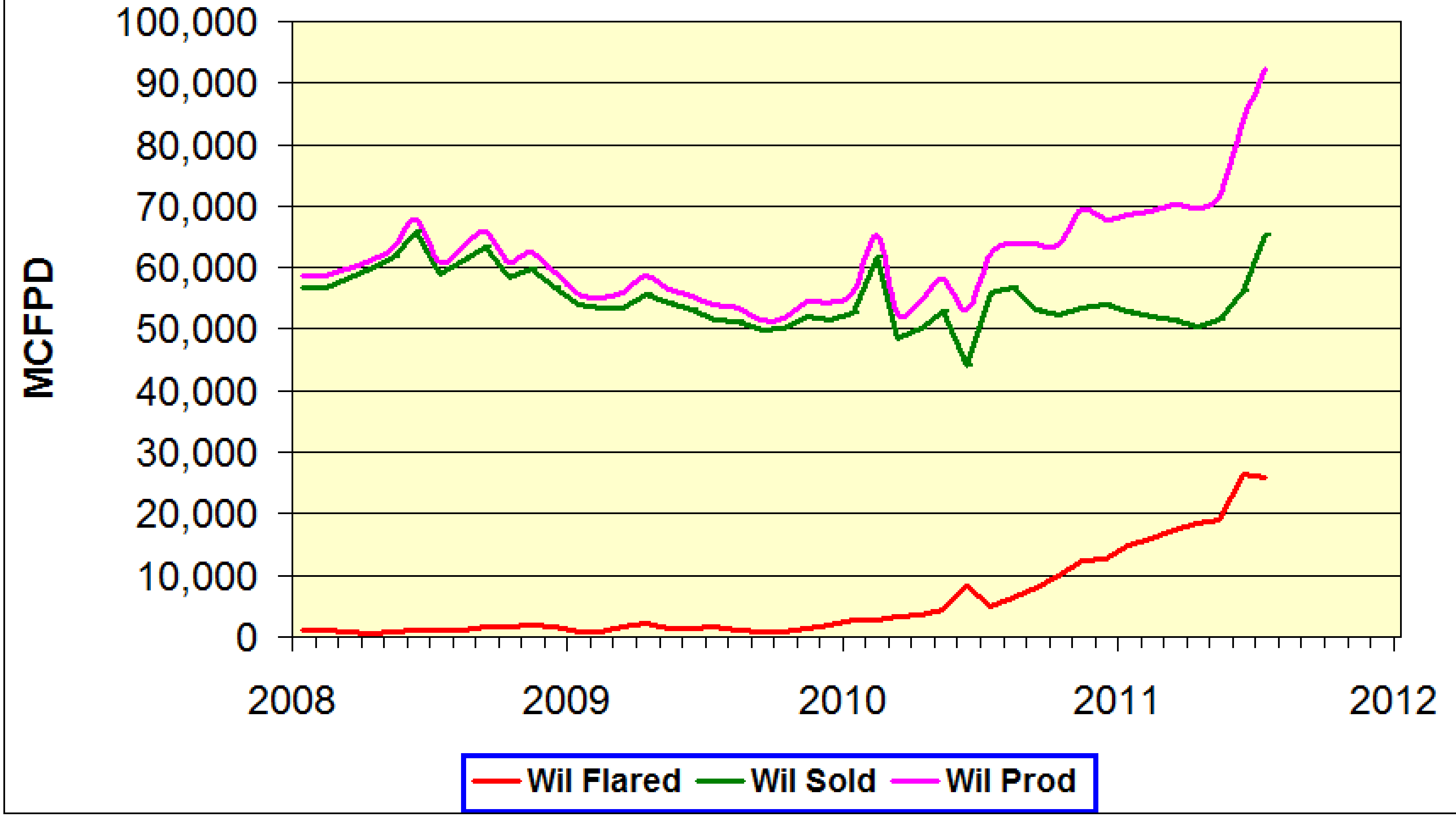
Dunn County Daily Gas Volumes



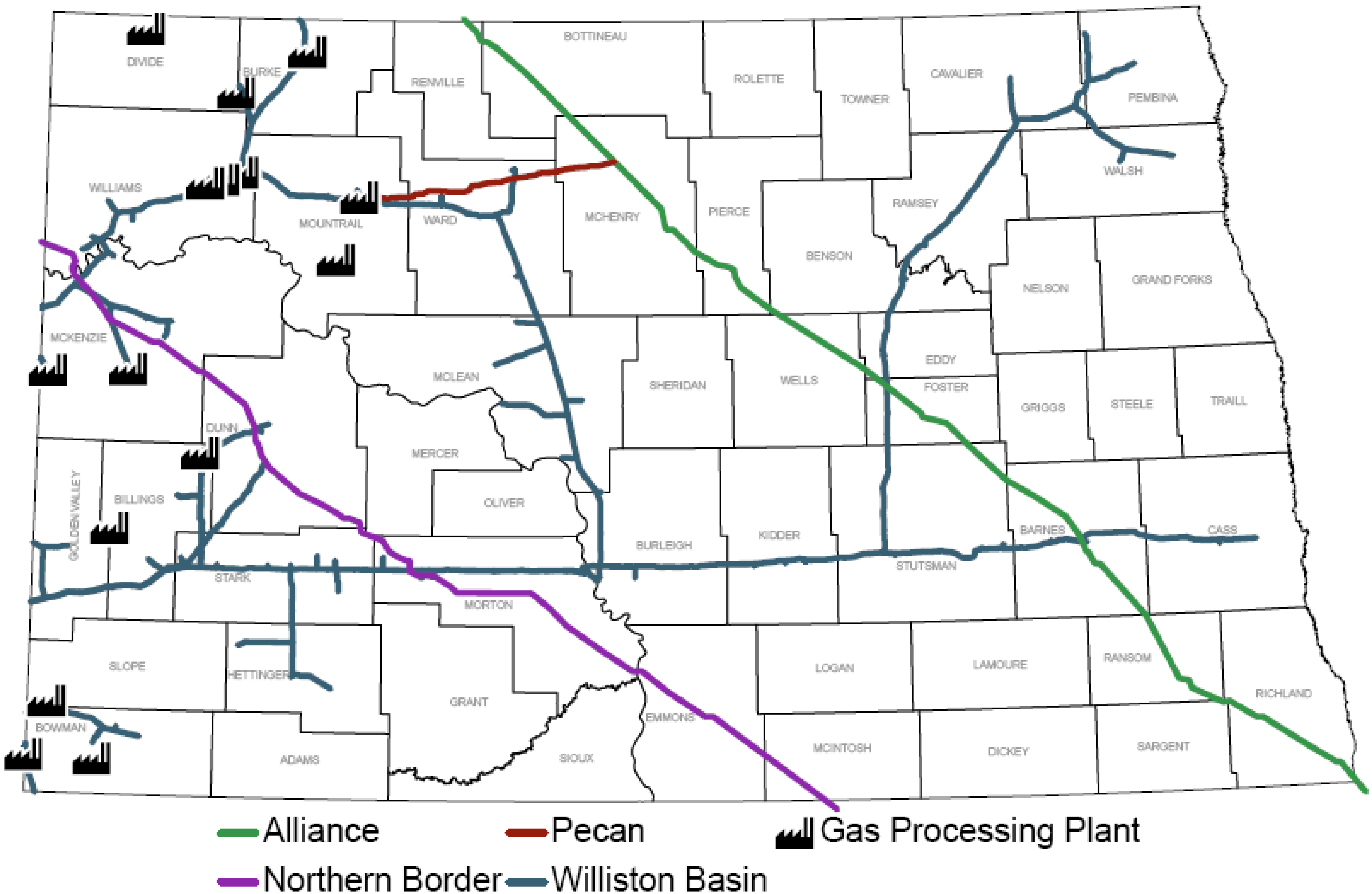
Mountrail County Daily Gas Volumes

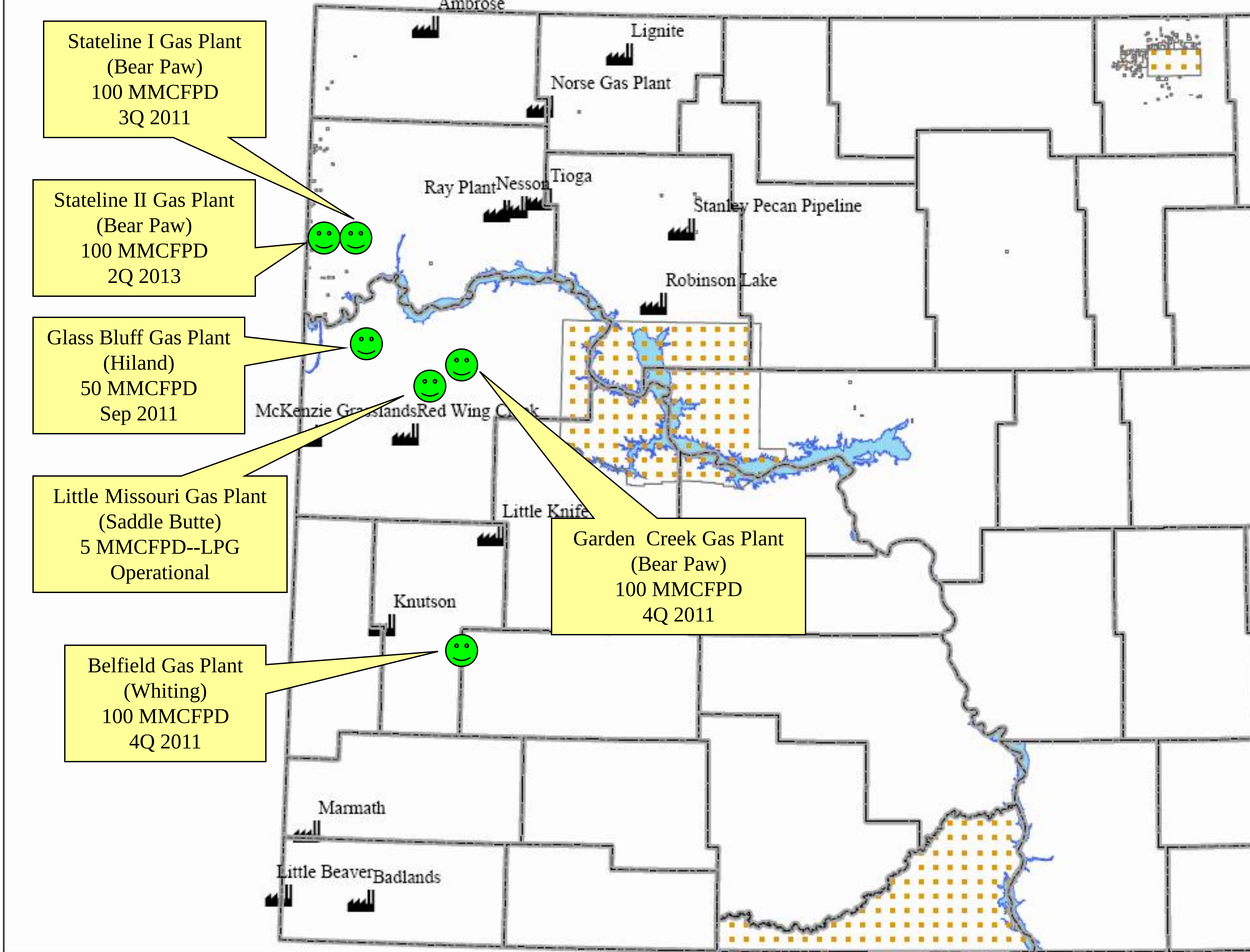


Williams County Daily Gas Volumes



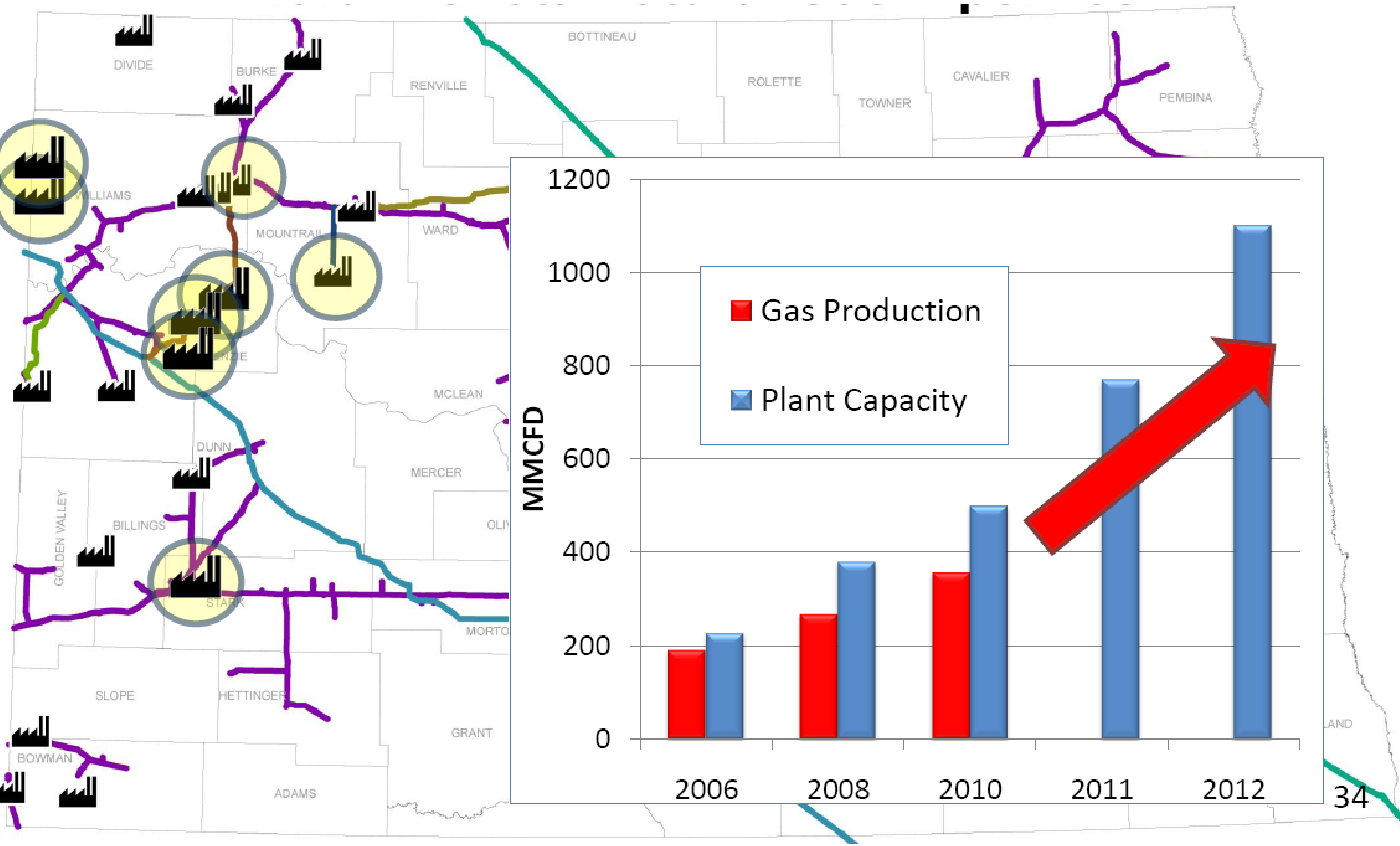
North Dakota Natural Gas Pipelines





Stateline I Gas Plant
(Bear Paw)
100 MMCFPD
3Q 2011
Stateline II Gas Plant
(Bear Paw)
100 MMCFPD
2Q 2013
Glass Bluff Gas Plant
(Hiland)
50 MMCFPD
Sep 2011
Little Missouri Gas Plant
(Saddle Butte)
5 MMCFPD--LPG
Operational
Belfield Gas Plant
(Whiting)
100 MMCFPD
4Q 2011
Garden Creek Gas Plant
(Bear Paw)
100 MMCFPD
4Q 2011
Ambrose
Lignite
Norse Gas Plant
Ray Plant
Nesson
Tioga
Stanley Pecan Pipeline
Robinson Lake
McKenzie Grasslands
Red Wing Creek
Little Knife
Knutson
Marmath
Little Beaver
Badlands

New or Expanding Gas Plants



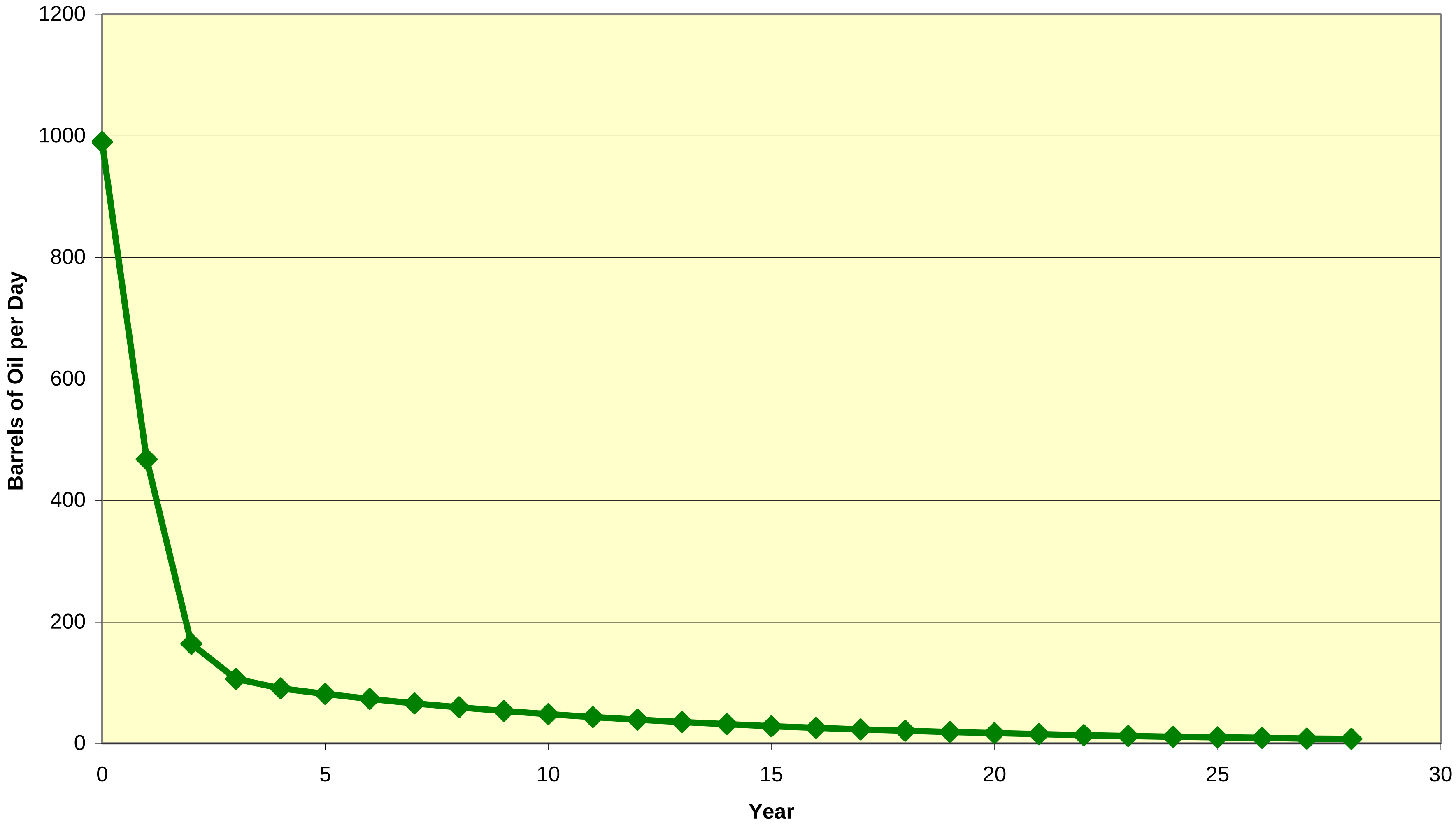
Job Opportunities

- 170 – 225 rigs
  - 20,000 jobs in drilling
- 15 – 25 years
  - 28,000 additional wells
  - 28,000 long term jobs

Western North Dakota

- 1,100 to 2,700 wells/year = 2,000 expected
  - 100-225 rigs = 12,000 – 27,000 jobs = 20,000 expected
  - 225 rigs can drill the 5,000 wells needed to secure leases in 2.5 years
  - 225 rigs can drill the 28,000 wells needed to develop spacing units in 14 years
  - 33,000 new wells = thousands of long term jobs

Typical Bakken Well Production



What Does Every New Bakken Well Mean to North Dakota

A typical 2011 North Dakota Bakken well will produce for 28 years

If economic, enhanced oil recovery efforts can extend the life of the well

In those 28 years the average Bakken well:

Produces approximately 550,000 barrels of oil

Generates over $20 million net profit

Pays approximately $4,360,000 in taxes
- $2,100,000 gross production taxes
- $1,900,000 extraction tax
- $360,000 sales tax

Pays royalties of $7,600,000 to mineral owners

Pays salaries and wages of $1,600,000

Pays operating expenses of $2,300,000

Costs $7,300,000 to drill and complete

NDSU Economic Impact Study

- Calendar Year 2009 Impact Study
  - $5 billion direct impact
  - $13 billion secondary impact
  - $822 million taxes
  - 18,328 direct jobs
    - 52 rigs + $52.35/bo
- Calendar Year 2010 Impact Study
    - 126 rigs + $69.74/bo

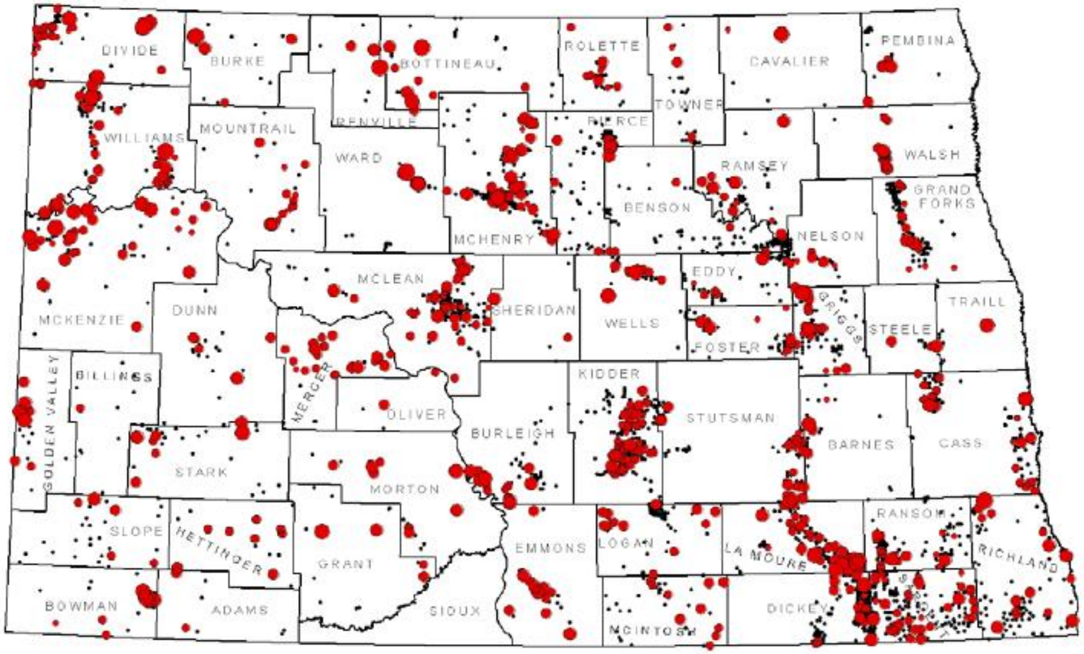
SHALLOW GAS PROJECT

The Geological Survey tested 4,325 NDSWC monitoring wells for methane in 52 of the 53 counties in North Dakota from 2006-2010.

The Geological Survey recently completed phase I of a study of shallow natural gas in North Dakota. We investigated 9,400 ND State Water Commission monitoring well sites, tested 4,325 wells, and detected methane in 905 wells. Approximately 20% of the wells contained detectable gas.

During the second phase of the project, thirty groundwater samples, primarily from eastern North Dakota, will be analyzed for dissolved gas composition, isotopes, and general chemistry. This will enable us to determine the source of the gas and identify chemical groundwater signatures that might assist the oil and gas industry in natural gas exploration.

Methane bubbling to the surface in a two-inch NDSWC monitoring well.



Monitoring wells that contained methane are indicated with red dots, black dots are wells that contained no detectable methane. The red dots are sized to reflect the concentration of methane -- the higher the concentration, the larger the dot.

North Dakota Geological Survey
Geologic Investigations No. 127

RESOURCE POTENTIAL OF THE TYLER FORMATION

Stephan H. Nordeng and Timothy O. Nesheim

Edward C. Murphy, State Geologist
Lynn D. Helms, Director Dept. of Mineral Reources
2010

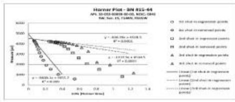


Figure 1. Horner plot of pressures measured during the shut-in periods of an open hole drill stem test (DST) of the Tyler Formation (8180-8282 ft. M.D.) in Pennzoil Co. & Depco's BN#15-44 (Figure 5, #6848). The extrapolated shut in pressures (Horner, 1951) from the 2nd and 3rd shut in periods of the DST indicate that the Tyler formation fluid pressure is ~4525 psi at a depth of 8230 ft., which yields a pressure gradient (0.55 psi/ft.) above the expected hydrostatic pressure range (0.43-0.46 psi/ft.). The 1st shut-in period did not reach "steady-state" conditions and therefore does not yield a reliable extrapolated formation pressure. The fluid recovered in this test was 354' of gas cut mud. This well was spudded on February 2nd, 1979 (DST run on March 18th, 1979) in the Flat Top Butte field, where only one well produced just 446 bbls of oil from the Tyler-Heath Formation over a four month period in 1960 (Texaco Inc.'s Mary Pace #1; API: 33-053-00461-00-00; NDIC: 2667; Sec. 14, T146W, R101W). There is no record of injection within the Flat Top Butte field.

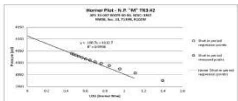


Figure 2. Horner plot of pressures measured during the shut-in period of an open hole drill stem test (DST) of the Tyler Formation (7743-7776 ft. M.D.) in Amerada Petroleum Corp.'s N.P. "M" TR# 2, shown on Figure 5 by #3867. Both the maximum pressure recorded (4039 psi = 0.52 psi/ft.) and the extrapolated formation pressure (4112.7 psi = 0.53 psi/ft.) are above the hydrostatic pressure range expected for the depth tested (3300-3560 psi = 0.43-0.46 psi/ft.). The DST fluid recovery was 2.5 BBLS oil, reversed out 69.54 BBLS oil. Cumulative production for this well was 1,440,113 BBLS of oil. This well was spudded on May 2nd, 1965 (DST run on May 15th, 1965) in the Medora field, where initial production began in June, 1964 and initial injection in February, 1970.

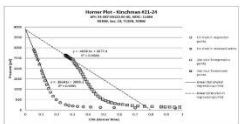


Figure 3. Horner plot of pressures measured during the shut in periods of a conventional bottom hole drill stem test (DST) on the Tyler Formation (7540-7556 ft. M.D.) in Milestone Petroleum's Kirschman #21-24, shown on Figure 5 by #11484. The calculated fluid pressure of the Tyler formation (the average of the extrapolated pressures from the two DST shut in periods) is ~3883 psi at a depth of 7545 ft., which yields a pressure gradient (0.51 psi/ft.) above the hydrostatic pressure expected for this depth (0.43-0.46 psi/ft.). The DST fluid recovered was 0.03 bbls of oil and 0.48 bbls of water. Kirschman #21-24 was a wildcat well drilled outside areas of production and injection for the Tyler Formation.

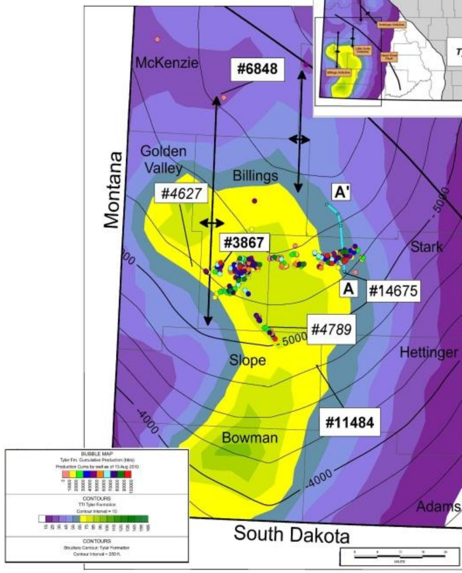


Figure 5. Detail map showing the distribution of Tyler production (Total Bbls) in North Dakota together with Time-Temperature contours and the location of wells from which pressure gradients (#6848, #3867, #11484) and Rock Eval data (#4627, #4789) were obtained. The color-filled contours represent the Time-Temperature Index of the Tyler Formation and are keyed to the color bar located in the lower left corner. Shades of yellow and green (>65) represent the TTIs that correspond with the oil window. TTIs less than 65 and above 15 are in shades of blue and purple and represent conditions that could generate oil. This map lies within the black outline on Figure 6. Cumulative production from the Tyler Formation (barrels oil) is represented by the color of the circles centered on the wells that have and/or are producing oil from the Tyler Formation. The solid contour lines on the detail map represent the mean sea level elevation of the top of the Tyler Formation.

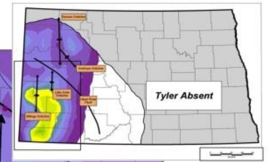


Figure 6. Time-Temperature Index map of the Pennsylvanian Tyler Formation in the Williston Basin of North Dakota. The color-filled contours represent the Time Temperature Index of the Tyler Formation. Areas in which the Tyler is absent are in gray (modified from Anderson, 1974).

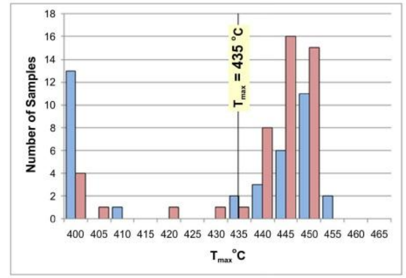


Figure 7. A frequency diagram showing that most of the samples of the Tyler Formation collected from the Government Taylor A-1 (#4627) in red, and the State of North Dakota #41-36 (#4789) in blue, have been thermally matured beyond the threshold that marks the onset of oil generation (Tmax ~435oC).

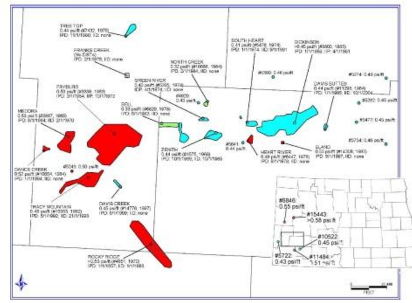


Figure 8. Field map showing the producing Tyler Fields in southern Billings, Slope, and Stark counties. For each field the Initial Pressure Gradient (IPG), Initial Production Date (IPD), and Initial Injection Date (IID) are given. Fields with evidence of initial fluid overpressure in the Tyler are colored in red, fields that were initially at hydrostatic pressure are colored in blue, and fields that were underpressured prior to production are colored green. Most of the western Tyler fields all contain evidence of overpressuring prior to injection with the exception of Davis Creek. The eastern Tyler fields were at or below hydrostatic pressure, with the exception of the Heart River and Eland fields. Field boundaries are approximate. In the bottom right corner is an index map of North Dakota showing the Tyler DST's of interest with their NDIC well numbers that are located outside the main area of Tyler production. DST results indicate that the Tyler Formation is over-pressured in three wells and at hydrostatic pressure within two wells outside the area of main production.

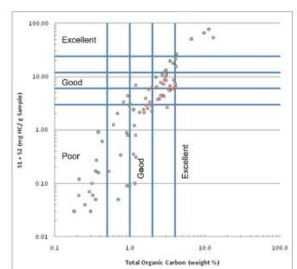


Figure 9. A kerogen quality diagram (Dembicki, 2009) constructed from the Total Organic Carbon (TOC) versus the mass of existing (S1) and potential (S2) hydrocarbons contained in samples of the Tyler Formation. The samples are from the Government Taylor A-1 (green circles) and the State of North Dakota #41-36 (red squares).

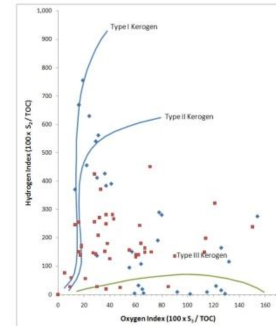


Figure 10. A modified van Krevelen diagram that classifies kerogen on the basis of the Hydrogen Index (HI) and Oxygen index (OI) derived from Rock Eval pyrolysis data. The blue diamonds represent the data from the Government Taylor A-1 (NDIC # 4627, SESE, Sec. 9, T139N, R103W) and the red squares refer to data from the State of North Dakota #41-36 (NDIC #: 4789, NE NE, Sec. 36, T137N, R100W). The data suggest that kerogen within the Tyler Formation includes oil prone Type I and Type II, gas prone Type III as well as mixtures of both oil and gas prone kerogen.

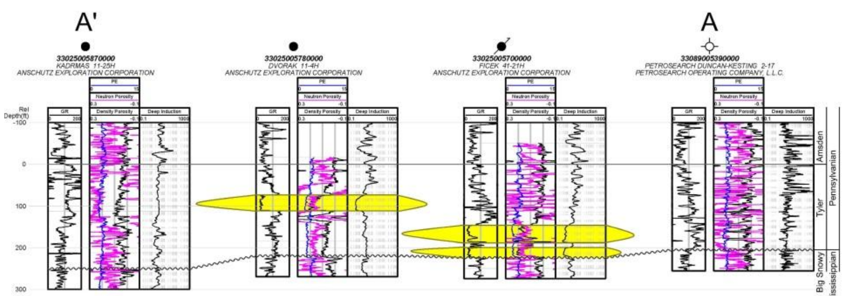


Figure 4. Cross-section extending from A to A' along the light blue line in Figure 5. The Kesting 2-17 (#14675 on Figure 5) corresponds to the point labeled A. Conventional sandstone reservoirs are shown in yellow. The section illustrates the discontinuous nature of the conventional sandstone reservoirs of the Tyler Formation.

Discussion

The purpose of this study is to examine the pressures within the Pennsylvanian aged Tyler Formation with the intent of determining whether or not the formation exhibits pressure-depth relationships consistent with a source system that is hydraulically isolated from the over and underlying formations. Hydraulic isolation is one of the key elements that Schmoker (1996) used to define a basin-centered petroleum accumulation. Meissner (1978) recognized several of these elements in the Bakken Formation in the Williston basin. In these accumulations, the source rock and reservoir rock are either one and the same or lie in very close proximity to one another. This occurs because the rocks that encase the source beds lack sufficient permeability to allow petroleum generated within the source beds to escape and migrate away. As a result, pressures within the source beds and associated reservoir rocks typically exhibit abnormally high or low formation fluid pressures relative to the pressure expected in a reservoir that is in hydraulic communication with the overlying rocks. The "expected" pressure in this study assumes hydrostatic conditions so that the expected pressure would be consistent with a hydrostatic gradient of between 0.43 and 0.49 psi/ft. Therefore, abnormally low or high pressure would yield hydraulic gradients (pressure/depth) that lie outside the range of gradients that correspond with fresh water (0.43 psi/ft) or saltwater (0.49 psi/ft).

The Tyler Formation is a regionally extensive, organically-rich, Pennsylvanian unit deposited during the earliest stages of the Absaroka Sequence. Terrestrial sediments derived from source areas south of the Williston basin are interbedded with nearshore, marine limestone and shale (Gerhard and Anderson, 1988). The Tyler Formation is bounded below by an erosional surface developed on Mississippian aged rocks formed during tectonic uplift in the Late Mississippian and Early Pennsylvanian. A variety of lithologies consistent with progradation of sediments into the basin overly the Tyler except along the eastern margin of the basin where these rocks have been truncated by the erosional surface that marks the Absaroka – Zuni sequence boundary (Anderson, 1972; Gerhard and Anderson, 1988).

Pressure gradients were obtained from pressure build up curves and pressure recorder depths used during drill stem tests of the Tyler Formation. Estimates of formation pressures are obtained by constructing Horner plots in which formation pressures are plotted against the logarithm of Horner time (Horner Time = [total Flow Time + ΔShut-in time]/ΔShut-in time). The formation pressure is determined from the Horner plot by finding the y-intercept of the best-fit line that passes through the pressures recorded during the last part of the shut-in periods (See Figures 1-3).

The range of initial pressure gradients present in the Tyler Formation suggest that the formation is frequently over-pressured and in a few cases under-pressured. Several fields were initially over-pressured and prior to injection: Dance Creek, Eland, Flat Top Butte, Fryburg, Heart River, Medora, Rocky Ridge, and Round Top Butte (Figure 8). Most of these over-pressured fields are located on the western side of the producing Tyler fields. Two fields may have been under-pressured prior to production, Bell and North Creek, which are located in the central area of most of the producing Tyler Fields (Figure 8). These results lead to the conclusion that the Tyler Formation is not always in hydraulic communication with the units above or below it and thus suggests that the Tyler may be sufficiently isolated so as prevent the petroleum generated within the Tyler Formation to escape.

The Time-Temperature Index (TTI) map of the Tyler Formation, constructed from modern geothermal heat flow measurements (SMU Geothermal Lab, 2010) and stratigraphic interval thickness data shows that oil production from the Tyler Formation is from rocks that are mature enough to generate oil. RockEval data also indicates that at least some of the organic-rich rocks within the Tyler are good to excellent source rocks even though there is probably more than one type of kerogen present. The available Rock Eval data also confirms the presence of thermally mature shales in vicinity of current Tyler production (Figures 5 & 7).

The limited data available today suggest the Tyler Formation is a regionally extensive unit that may contain good to excellent quantities of oil prone kerogen (Figures 9 & 10) that is sufficiently mature (Figure 7) to generate oil within a hydraulically compartmentalized environment (Figure 8). If so, then the Tyler Formation possesses the elements needed to qualify as a basin centered petroleum accumulation.

References

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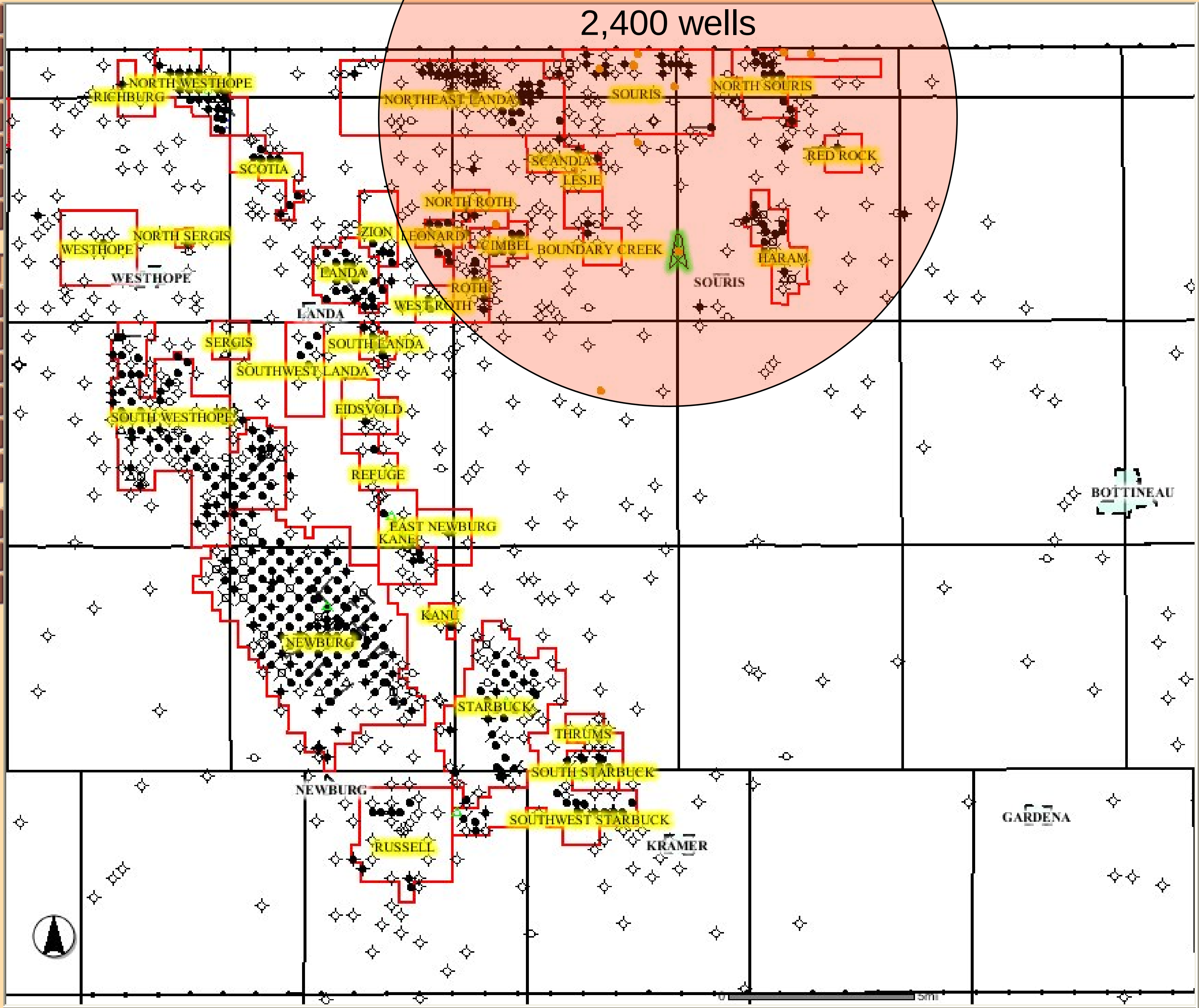
Oil and Gas : ArcIMS Viewer

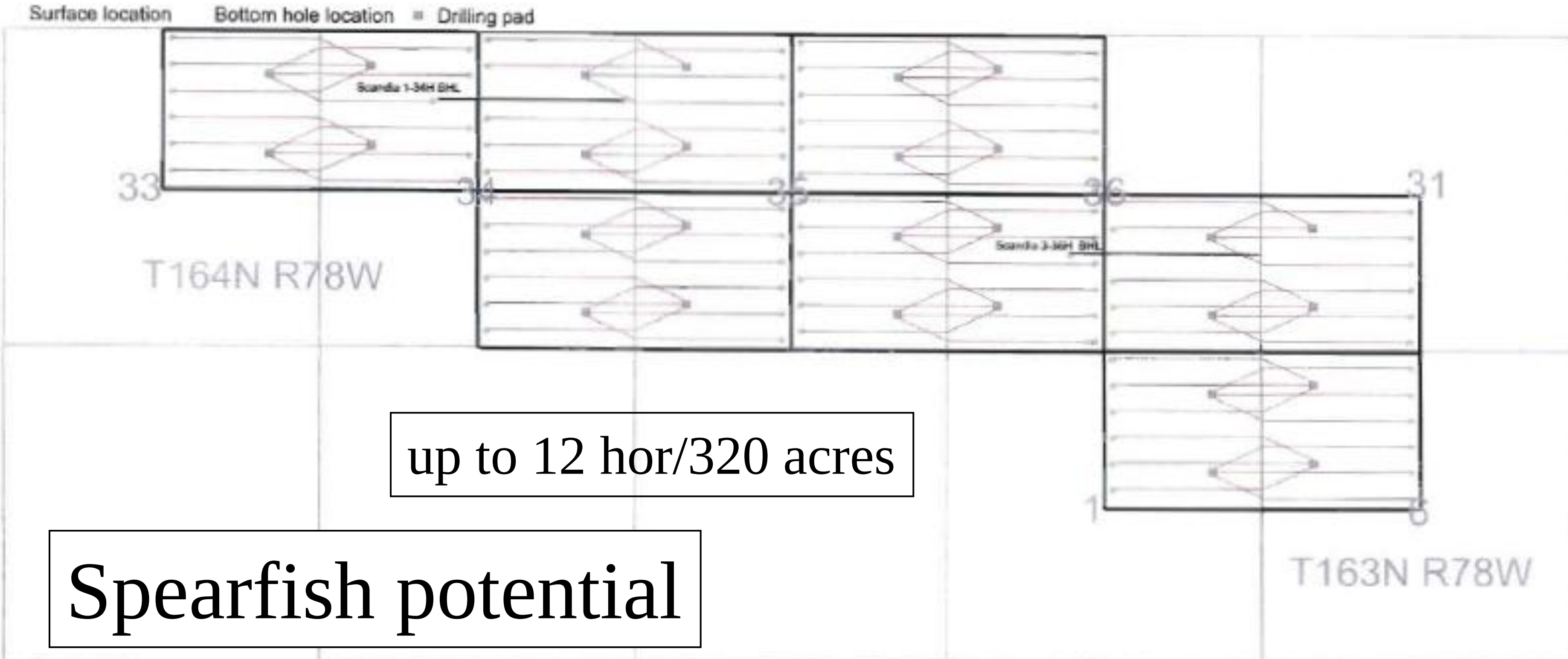
- Legend / Layers
- Overview Map
- View Entire State
- Previous View
- Clear Selection
- Search
- Generate PDF

- Zoom In
- Zoom Out
- Pan
- Rect Identify
- Select Object
- Buffer
- Distance

- Find Well
- Find Field/Unit
- Find Section

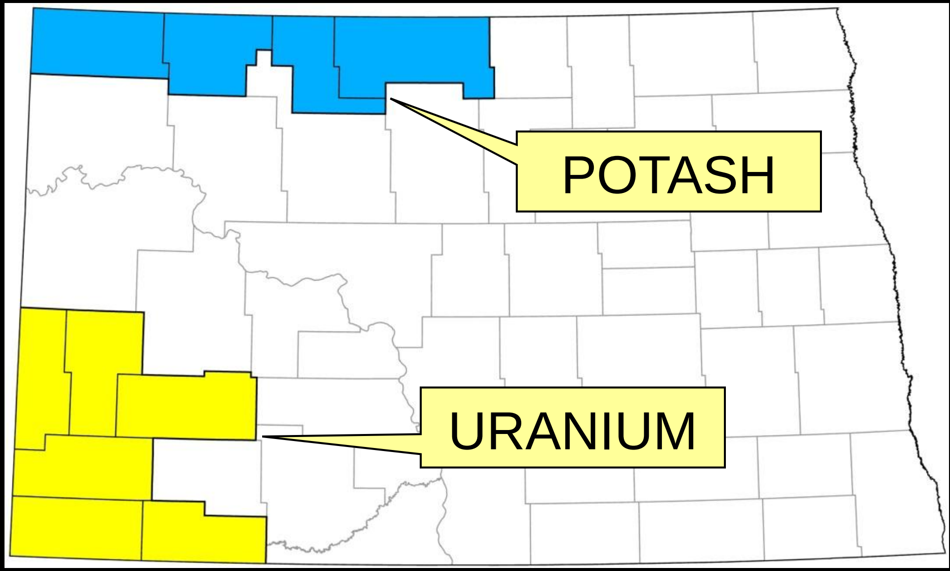


Proposed Maximum Wellbore Spacing

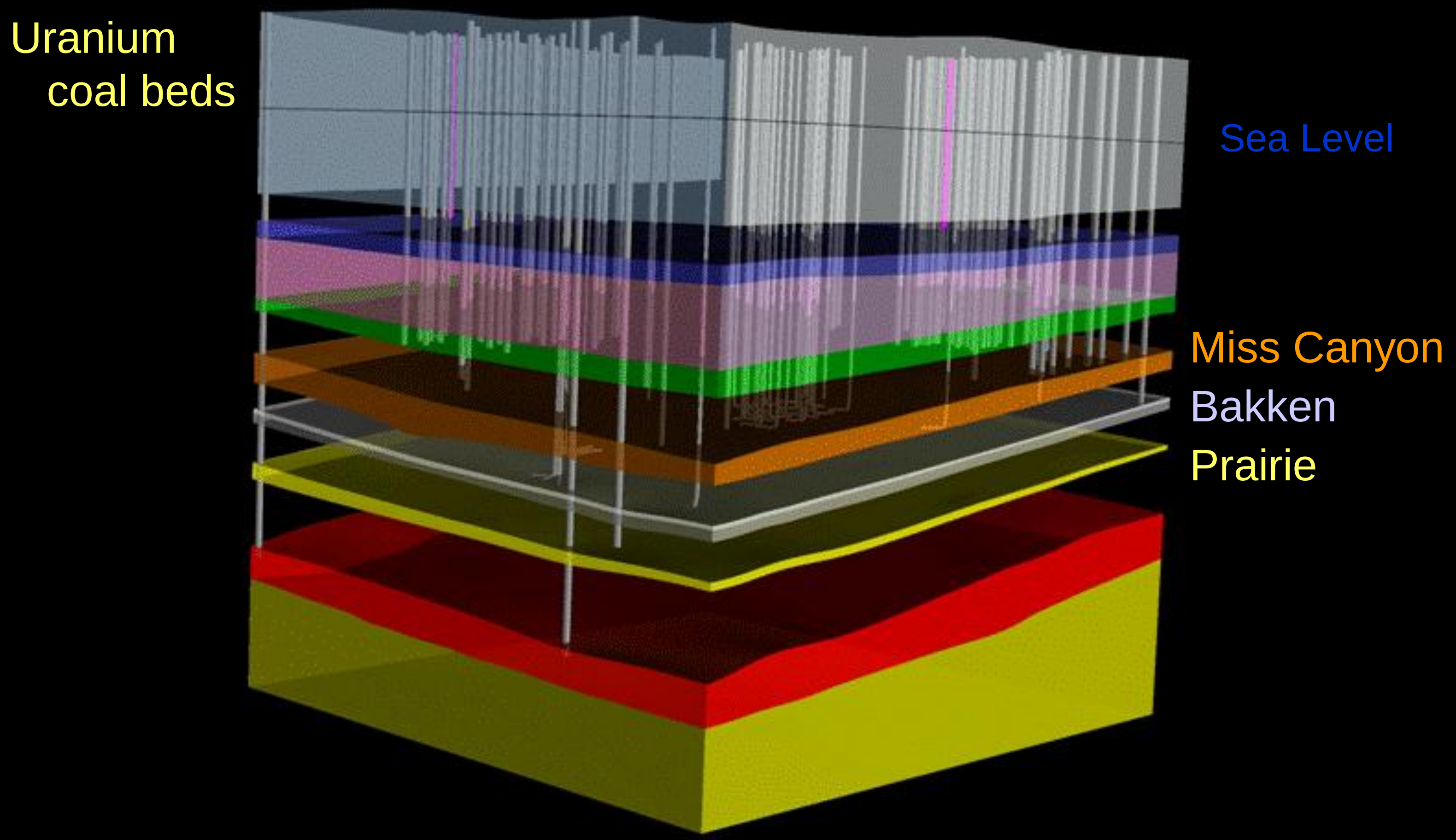


Estimate 20-50 billion tons of ND Mineable Reserves

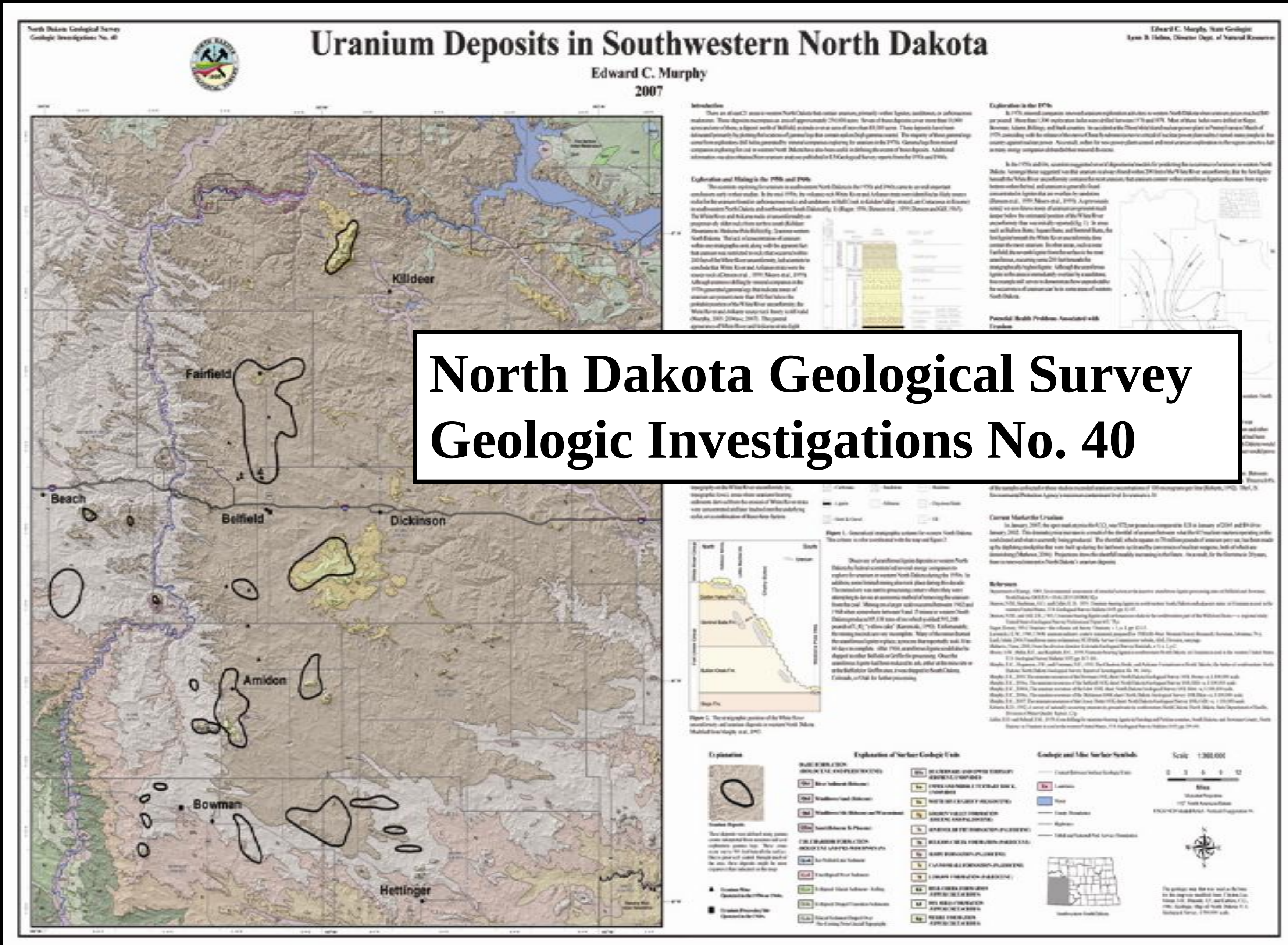
$6 trillion -15 trillion



Three-dimensional Geologic Model



North Dakota Geological Survey

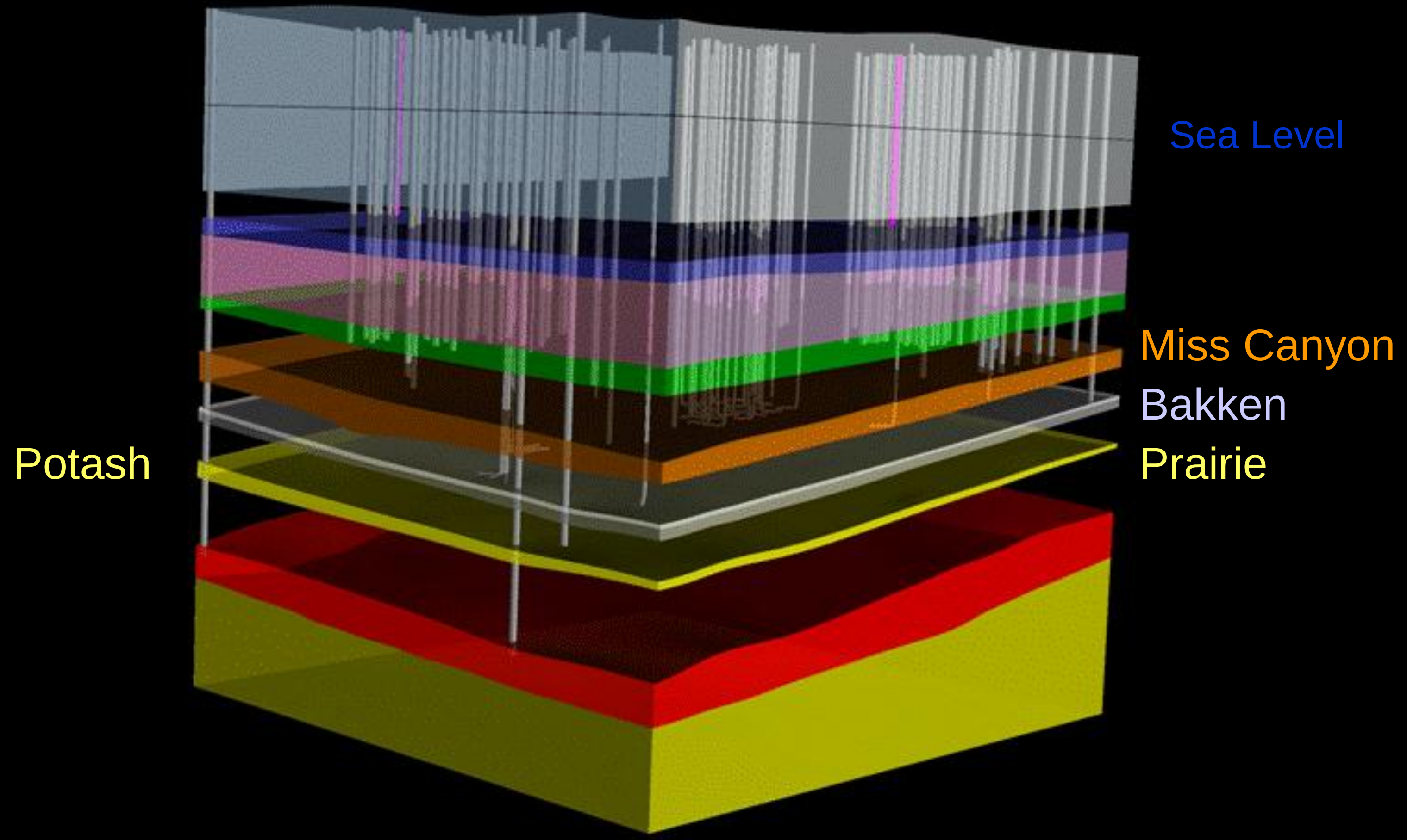


North Dakota Geological Survey
Geologic Investigations No. 40

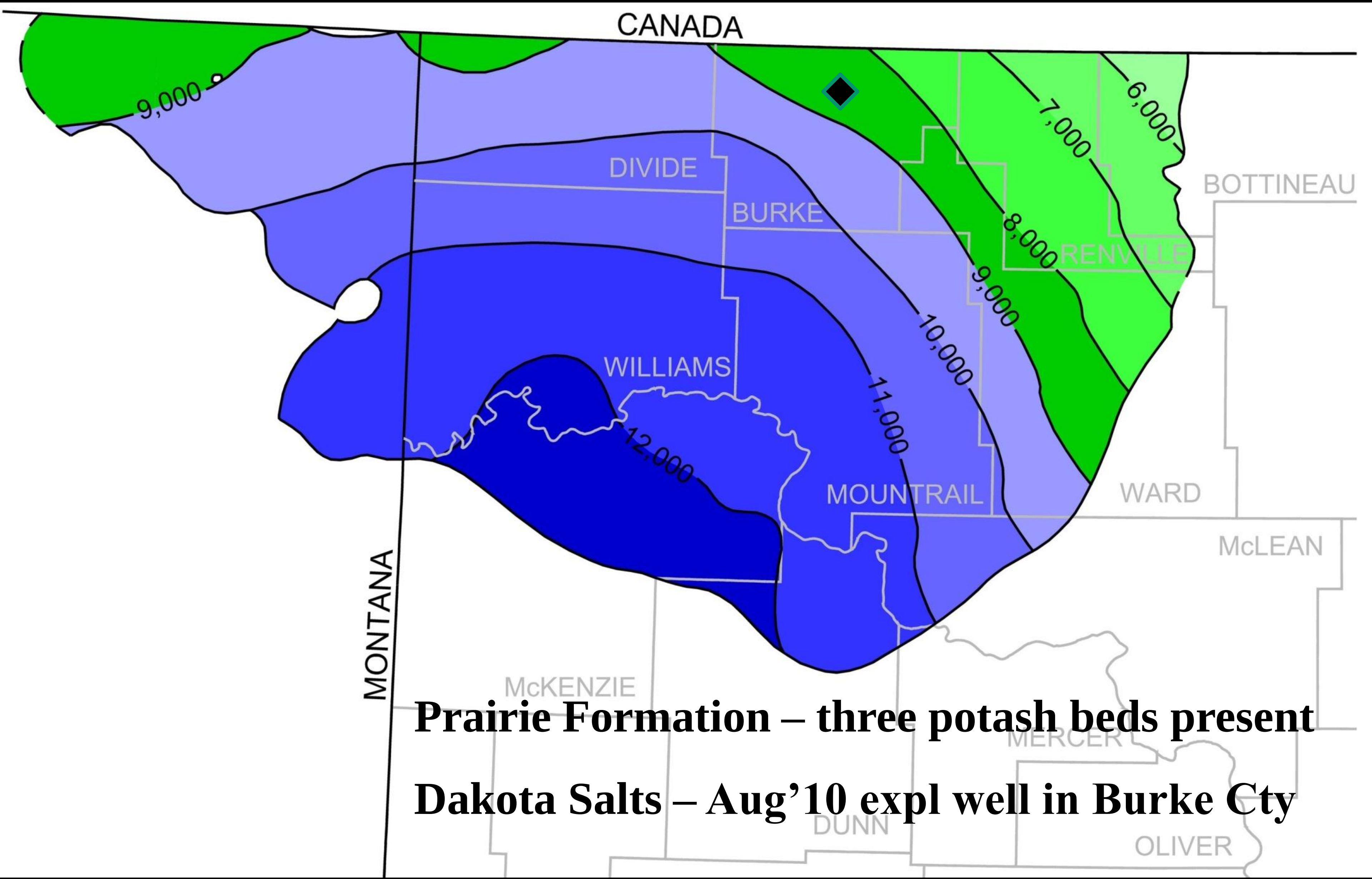
URANIUM

- found in lignite beds as deep as 500’
- SW ND greatest potential
- molybdenum—Element Mo
  - high-temp steels (melts @ 4730 F)
- germanium—Element Ge
  - semiconductor (fiber-optics)
- future mining in-situ leaching
- shortfall for current reactors (435)

Three-dimensional Geologic Model



North Dakota Geological Survey



Prairie Formation – three potash beds present

Dakota Salts – Aug'10 expl well in Burke Cty

POTASH

- found in salts 9000 feet deep
- gross thickness of 83 feet
- Northern ND greatest potential
- potassium salts used in fertilizer
- solution mining in future (2013)
- increasing demand

File No. 15092
Armstrong #1-5 Hanson
Sec 5-T155N-R102W
Williams County, ND