SWD Effects on Bakken Drilling

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Outline

1) Water disposal in the Williston Basin, ND
2) Case studies: Drilling through the Dakota Sands
3) Geologic Background
4) Challenges predicting Dakota water flow
5) Bakken Casing design
6) Appraisal Well Program
7) Operational and Cost Impact
8) Future in the Bakken – Unanswered Question’s
9) Questions
Dakota Water Disposal – North Dakota

- Over 15,000 horizontal wells in ND (Bakken/Three Forks)
- ~2.4 billion bbls oil produced
- SWD well count growing
- Injection Interval - Dakota Sands

*Data obtained from North Dakota Oil and Gas Division (dmr.nd.gov)
Case Study: Pad 1

- Initial Dakota water flow seen in Q1 2018
- Offset SWD
  - 3.1MM bbl cum injected volume*
  - 950 psi surface injection pressure *
- Dakota water flow while drilling w/ 10.5 ppg mud weight
- Required 11.6 ppg mud weight
- Drilled ahead to Mission Canyon and lost returns
- Unable to recover wellbore
- Redesign of well construction required re-drill of surface on all wells on pad

*Data obtained from North Dakota Oil and Gas Division (dmr.nd.gov)
Case Study: Pad 2

- 4 well pad

- Offset SWD
  - 17.7MM bbl cum injected volume*
  - 1,100 psi surface injection pressure*

- Drilled Dakota w/ 10.6-10.9 ppg OBM, no flow

*Data obtained from North Dakota Oil and Gas Division (dmr.nd.gov)
Case Study: Pad 3

- 6 well pad (45’ well spacing)
- Offset SWD
  - 517K bbl cum injected volume*
  - 1,100 psi surface injection pressure*
- Well 1 – Drilled Dakota w/ 10.1 ppg, water influx, required 11.1 ppg
- Well 2 – Drilled Dakota w/ 11.1 ppg, no flow
- Well 3 – Drilled Dakota w/ 11.1 ppg, water influx, required 12.5 ppg
- Set intermediate casing across Dakota on remaining wells on pad

*Data obtained from North Dakota Oil and Gas Division (dmr.nd.gov)
Geologic Setting

- Inyan Kara (Dakota)
  - Lower Cretaceous

- Western Interior Seaway Transgression

- Fluvial/Deltaic System
Depositional Environment

- **Inner Delta Front**
  - I. Fluvial & Distributary Channels
  - II. Delta Progradation
- **Outer Delta Front**
  - I. Prograding Distal Bars
  - II. Tidal Channels
  - III. Central Bay/Prodelta
Standard Well Design

Surface
- 9-5/8” set at ~2,000’ TVD

Intermediate
- 7” set at ~11,150’ TVD/ 11,500’ MD
- Casing set at end of curve

Production Liner
- 4-1/2” Cemented liner from TD to KOP
Over pressured Dakota Sands

**Dakota Group:** Injection zone can be up to 2.5 ppg over normal pressure gradient

**Mission Canyon:** Known loss circulation zone above 10.8 – 11.0 ppg
“4 String” Well Design

Surface
• 13-3/8” set at ~2,000’ TVD

Intermediate 1
• 9-5/8” set at ~6,100’ TVD
• Casing shoe ~100’ below Dakota Base

Intermediate 2
• 7” set at ~11,150’ TVD/ 11,500’ MD
• Casing set at end of curve

Production Liner
• 4-1/2” Cemented liner from TD to KOP
Appraisal Well

Surface
- 13-3/8” set at ~2,000’ TVD

Intermediate
- 12-1/4” hole to Dakota Base, if no flow then 8-3/4” hole to end of curve
- 7” set at ~11,150’ TVD/ 11,500’ MD
- Casing set at end of curve

Production Liner
- 4-1/2” Cemented liner from TD to KOP
Operation Impact

Average Vertical Days

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<th>18Q4</th>
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- **Standard Well**
- **4 String Well Design**

Cost Breakdown:
- Well Cost: $2.56M
- Surface: $70K
- Spreadrate: $100K
- Casing: $150K
- Cement: $100K
- Misc: $150K
- Well Cost (4 String): $30K

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Percent of Potential 4 String Wells

- 2014: 10.0%
- 2015: 12.0%
- 2016: 14.0%
- 2017: 16.0%
- 2018: 18.0%
- 2019: 20.0%
- 2020: 22.0%
- 2021: 24.0%
- 2022: 26.0%
- 2023: 28.0%

Wells/Rig/Year

- 2014: 10.0
- 2015: 12.0
- 2016: 14.0
- 2017: 16.0
- 2018: 18.0
- 2019: 20.0
- 2020: 22.0
- 2021: 24.0
- 2022: 26.0
- 2023: 28.0

50% Increase

Percent of Potential 4 String Wells

- 2014: 0%
- 2015: 20%
- 2016: 40%
- 2017: 60%
- 2018: 80%
- 2019: 100%

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50% Increase

Wells/Rig/Year

- 2014: 100
- 2015: 120
- 2016: 140
- 2017: 160
- 2018: 180
- 2019: 200
- 2020: 220
- 2021: 240
- 2022: 260
- 2023: 280
What’s Next – Unanswered Questions

• Will Dakota injection affect the well life of current producers?

• How can the Dakota sands be mapped to better predict drilling impacts?

• Economics and viability of alternative injection intervals above and below the Bakken/ Three Forks?
Questions?