Case Nos. 23686 and 23687; OCD Exhibit No. 1

CURRICULUM VITAE

BRANDON POWELL

SUMMARY

Mr. Powell is the Oil Conservation Division's (OCD) Deputy Director overseeing the Engineering and Environmental bureaus. He has served with OCD for more than seventeen years. He began his career in 2006 as an environmental specialist overseeing environmental releases and remediation. In 2011, he was promoted to inspection and enforcement supervisor for OCD's district office in Aztec. In that position, he supervised down-hole engineering and compliance with OCD rules. In 2019, he was promoted to District Supervisor, which involved oversight of day-to-day operations for the San Juan Basin. In 2020 he was promoted to the Engineering Bureau Chief and then in 2023 was promoted to Deputy Director. Mr. Powell has extensive experience applying OCD rules to all aspects of oil and gas development and has testified as an expert in OCC rulemakings, including the pit rule (19.15.17 NMAC), the produced water rule (19.15.34 NMAC), the release rule (19.15.29 NMAC) and the natural gas waste rules (19.15.27 and 19.15.28 NMAC).

EMPLOYMENT

May 2023- Current
New Mexico Oil Conservation Division
Deputy Director

- As Deputy Director, I provide oversight and management for the OCD's Engineering Bureau and Environmental Bureau. In my position I have 2 direct reports which are the Environmental Bureau Chief and Engineering Bureau Chief. I also have ~48 additional indirect reports in those groups.
    - The Engineering bureau currently has 34 employees and is in the process of filling additional positions. The Engineering bureau is made up of 4 major groups Inspection Compliance Program, Underground Injection Control (UIC) Program, Administrative Permitting Program, Engineering Projects and Hearings group.
    - The Environmental bureau is currently has 16 employees and is currently in the process of filling additional positions. The environmental program contains 3 major groups, Permitting, Environmental Special Projects and Incident/Inspections.

November 2020 – May 2023
New Mexico Oil Conservation Division
Chief, Engineering Bureau

- Oversight and Management of the OCD's Engineering Bureau which includes
    - Administrative Compliance Program
    - Underground Injection Control (UIC) Program
    - Administrative Permitting Program.
- Ensures that OCD goals and objectives are met by assigning and directly supervising the work of the Administrative Compliance, UIC, and Administrative Permitting Programs.
- Conducts training and performance evaluations of personnel and acts upon leave requests. This position designs and develops programs to address new technical issues as they arise and as technical advances in the oil and gas industry are implemented.

May 2019- November 2020
New Mexico Oil Conservation Division
District Supervisor

- Managed operations for OCD’s Northern District, ensuring the proper management of more than 24,000 oil and gas wells and associated facilities to protect public health and the environment.
- Managed relations with four tribes and allottees, federal agencies including Bureau of Land Management, Bureau of Reclamation, and Forest Service, and private landowners.
- Supervised seven staff members, including geologist, compliance officers, and environmental specialists.
- Managed office assignments, fleet repair and maintenance, and the District’s Reclamation Fund (RFA) plugging program.
- Coordinated with the Engineering and Environmental Bureaus to ensure consistency in permitting and enforcement across the state.
- Supervised the District’s UIC activities and coordinated with the UIC Program Manager to ensure consistency in testing and compliance.
- Conducted training for OCD and District staff.
- Assisted in the tasks described below when necessary for District operations, particularly in the absence of staff.
- Served as the District’s representative on the New Mexico Oil and Gas Northwest Public Lands Committee.
- Assisted in development of standard operating procedures for wide range of OCD’s business practices.
- Participated in strategic planning for OCD, including crisis management, electronic transition, enforcement, and rulemaking.

April 2011-May 2019
New Mexico Oil Conservation Division
Staff Manager & Inspection and Enforcement Supervisor

- Supervised four district compliance officers and their activities regarding oil, gas, injection, brine and non-hazardous waste wells to protect public health, fresh water and other natural resources, including the review and approval of applications the conduct of investigations, and the recommendation of engineering solutions.
- Supervised environmental specialists, geologists, and data managers when the District Supervisor was not available and after he retired.
- Substituted for the geologist and environmental specialists during their absence and position vacancy for two years, including reviewing pools, logs and formation tops.
- Reviewed drilling, production, and closure of wells and other oil and gas facilities to ensure compliance with OCD rules, including:
  - Scheduled and conducted field inspections;
  - Initiated enforcement actions;
  - Reviewed applications for well work-overs, completion and plugging; and
  - Observed field activities.
- Provided technical assistance to OCD staff and operators.
- Coordinated office activities, including the review and approval of personnel documents and the conduct of other supervisory duties on behalf of the District Supervisor.
- Assisted in the development of rules.
- Served as the District’s representative for the New Mexico Oil and Gas Northwest Public Lands Committee.

April 2006 thru April 2011 New Mexico Oil Conservation Division
Environmental Specialist, Deputy Oil and Gas Inspector, and Loss Control Officer

- I Supervised industries operations to ensured proper remediation of releases.
- I would respond to urgent releases which endangered the environment or the public.
- Reviewed permits for work requested to be performed, and subsequent reports for work already performed.
- I would draft environmental compliance and enforcement documents
- Testify in environmental compliance and enforcement cases.
- Work with other governmental agencies to find solutions to problems that arise
- Prepare and give environmental training to industry and other agencies.
- Work with Companies to ensure their continual compliance.
- Track District internal injuries and incidents and prepare yearly OSHA forms.

- Respond to citizen complaints.

June 2004-April 2006 Envirotech, Inc.

Sr. Environmental Technician, Soil Remediation Facility Manager, and Mold Inspector.

- Prepared reports for various agencies for the on-site documentation for various types of releases.
- Managed the soil remediation facility and subsequent personnel which averaged 1-3 people. I categorized waste to determine if wastes were acceptable pursuant to the facility permits.
- Performed hazardous waste characterization and disposal of oil field and non-oilfield waste.
- Project manager and field supervisor which included supervising multiple people.
- Prepared job quotes and project summaries.

TESTIMONY IN RULEMAKING PROCEEDINGS

19.15.17 NMAC – *Pits, Close-Loop Systems, Below-Grade Tanks and Sumps, 2008 and 2013*
19.15.34 NMAC – *Produced Water, Drilling Fluids, and Liquid Oil Field Waste, 2015*
19.15.29 NMAC – *Releases, 2018*
19.15.27 NMAC – *Venting and Flaring of Natural Gas, 2021*
19.15.28 NMAC – *Natural Gas Gathering Systems, 2021*

CERTIFICATIONS AND TRAINING

Hazardous Waste Management Certification, Lion Technologies, September 2004
Hazmat Site Supervisor Training, High Desert Safety, 2005
Confined Space Certification, High Desert Safety, 2005
Hot Work Certification, High Desert Safety, 2005
OSHA Forty Hour Certification, 2005
Surveillance Detection Course for Commercial Operators, Department of Homeland Security, 2008

PHILLIP R. GOETZE
UIC Group, Oil Conservation Division, EMNRD
Albuquerque, NM

Over 40 years of experience developing and implementing a variety of projects with environmental, hydrologic, or regulatory applications.

PROFESSIONAL EXPERIENCES:

February 2013 to Present: UIC Manager / Petroleum Geologist / Geohydrologist
Engineering Bureau, Oil Conservation Division, Energy, Minerals and Natural Resources Department
1220 South St. Francis Drive, Santa Fe, NM 87505

Administrative permitting for development and management of oil and gas resources under the state Oil and Gas Act. These projects include technical review of administrative applications and preparation of orders for non-standard locations, pool delineations, and non-standard proration units. Lead technical reviewer of applications for all Class II wells (including saltwater disposal wells and enhanced oil recovery (EOR) projects) under the New Mexico primacy agreement with the United States Environmental Protection Agency (USEPA) for its Underground Injection Control (UIC) Program under the Safe Drinking Water Act. Hearing examiner for Division hearings for cases regarding both protested and unprotested applications for approval of non-standard oil and gas circumstances that cannot be administratively permitted. Additional assignments related to the position:

- Provide technical assistance to District personnel and General Counsel staff regarding compliance issues for disposal and EOR wells.
- Development of protocols and recommended guidance for UIC related subjects such as induced seismicity, exempted aquifers and Class II disposal impacts on producing intervals.
- Prepare quarterly reports for review by the UIC coordinator for submission to the USEPA.
- Recommend changes in policy reflecting application of new technology or processes (e.g. injection rules per 19.15.26 NMAC).
- Provided expert testimony before the Oil Conservation Commission for applications and in support of rulemaking (e.g. acid gas injection well applications, casing requirements in the Roswell Artesian Basin, and reporting requirements for fracturing fluids).
- Provided expert testimony before the New Mexico Water Quality Control Commission (NMWQCC) in support of rulemaking (e.g. expanded authority for UIC Class I hazardous disposal wells).

Appointed as hearing examiner by the Division Director under 19.15.4.18 NMAC.

March 2007 to February 2013: Hydrogeologist / Environmental Scientist / Project Manager
Gloreita Geoscience, Incorporated
1723 Second Street, Santa Fe, NM 87505

Multiple projects for environmental, hydrologic, and natural resource assessments including:

- Los Alamos National Laboratory (LANL): contract team leader for ground-water sampling (including springs, shallow wells, monitoring wells with Baski and Westbay systems) in support of the Ground Water Stewardship Program; four years of sediment mapping and soil sampling for contaminants as part of the LANL assessment of geomorphic influences following the Cerro Grande and Las Conchas fires; waste characterization sampling following LANL and New Mexico Environment Department (NMED) protocols.
- Oversight of drilling, logging, and construction of deep exploration wells as part of Rio Rancho's City Water Program and the NM Office of the State Engineer (Ft. Sumner project).
- Hydrologic modeling and ground-water abatement plan development for multiple dairy facilities in southern and eastern New Mexico.

- Numerous Phase I Environmental Site Assessments (ESAs) for commercial, industrial, and undeveloped properties in northern New Mexico, Nevada, and Texas.
- Establish protocols, sampling requirements, and compile data for annual reporting for clients with Closure and Post Closure plans for landfills.
- Oversight of petroleum storage tank removals, closures, and Minimum Site Investigations following closure.
- Preparation and annual reporting of NPDES permits for commercial clients in New Mexico.
- Preparation and implementation of Stage I Abatement Plans for dairies in violation of the NMWQCC ground-water standards.
- Quality assurance for ground-water modeling and various sampling programs including mandatory monitoring and special client-specific events.

April 2006 to January 2007: Hydrogeologist / Project Manager
Tetra Tech EM Incorporated
6121 Indian School Road NE, Suite 205, Albuquerque, NM 87110

This position included responsibility for redevelopment of previous client relationships while maintaining obligations to state, Federal and private projects. Most significant projects include the following:

- Supervising geologist for drilling, construction, and development of deep monitoring wells at Kirtland Air Force Base for Long-Term Monitoring Program.
- Preparation of sampling and analysis plans for Texas Department of Criminal Justice landfills.

September 1999 to March 2006: Hydrogeologist / Project Manager
ASCG Incorporated *of New Mexico* (now the WH Pacific Corporation)
6501 Americas Parkway NE, Suite 400, Albuquerque, NM 87110

Responsible for a variety of environmental services for site assessment and remediation of contaminated sites associated with Federal, state, and private clients in New Mexico, Arizona, and the Navajo Nation. Significant projects entail the following:

- Field Technical Leader (as subcontractor) for drilling, construction, and development of deep and shallow monitoring wells at LANL for 2005.
- Developed and supervised assessment drilling programs for Risk-Based Corrective Action assessments of petroleum-contaminated NMED and Bureau of Indian Affairs (BIA) sites in New Mexico and Arizona.
- Responsible for project development and management of soil and ground-water remediation of hydrocarbon and solvent-contaminated sites including quarterly water sampling events and air monitoring for compliance.
- Supervised and participated in resolution of correction actions identified under USEPA CA/CO 1998-02 at approximately 35 Bureau of Indian Affairs federal facilities including review of asbestos programs, PCB investigations and remediations, Phase I ESAs for property transfer, AST/UST removals, hazardous waste disposal activities, environmental audits, and validation sampling of previous remedial activities.
- Completed development and oversight of voluntary corrective actions of hazardous wastes cited in notice of violations at the Southwestern Polytechnic Indian Institute.
- Provided sampling program for the AMAFCA Storm Water Study for assistance in compliance of the MS4 for the City of Albuquerque.
- Completed assessment for hydrocarbon contamination and prepared plans for remedial actions for five locations at BIA facilities during the last quarter of 2004.

July 1996 to August 1999: Geologist / Environmental Scientist; General Contractor
Phillip R. Goetze, Consulting Geologist, Edgewood, New Mexico

Subcontractor for environmental firms providing on-site technical support and report preparation. Primary contractors included the following:

Billings and Associates, Inc., Albuquerque, New Mexico

Responsible for acquisition of both soil and water data for assessment and for installation of remediation systems for hydrocarbon-contaminated sites.

Roy F. Weston Inc., Albuquerque, New Mexico

Temporary position with responsibilities for on-site supervisor for data acquisition (three drilling rigs), for health and safety monitoring, and for quality assurance of installation of multiple ground-water wells at a Department of Energy tailings remediation (UMTRA) site near Tuba City, Arizona.

January 1993 to July 1996: Project Geologist / Project Manager
Billings and Associates, Inc.
6808 Academy Pkwy, E-NE, Suite A-4, Albuquerque, NM 87109

Responsible for acquisition of air, soil, and water data for site assessments related to leaking underground storage tanks throughout New Mexico. Participated and supervised installation, operation, and maintenance of biosparging/SVE remediation systems at five New Mexico locations. Site assessment activities included preparation of health and safety plans, drilling supervision, water and soil sampling preparation, chain-of-custody maintenance, analytical data review and compilation, and report preparation.

June 1985 to December 1992: Independent Geologist and Environmental Scientist
Phillip R. Goetze, Consulting Geologist, Albuquerque, New Mexico

Subcontracting services for data acquisition in geophysics and mineral exploration. Primary contractors included:

Charles B. Reynolds and Associates, Albuquerque, New Mexico

Performed functions of seismologist and crew chief for consulting group specializing in shallow seismic geophysics for environmental and engineering applications. Projects included USGS hydrologic assessment of Mesilla Bolson; plume and paleosurface mapping at Johnson Space Center facility north of Las Cruces; plume and paleosurface mapping in Mortandad Canyon and TA-22 site, LANL; plume and paleosurface mapping at Western Pipeline facility at Thoreau, NM; plume and paleosurface mapping at UNC Partners mill and tailings site north of Milan; engineering assessment of collapsible soils at Tanoan residential development and along the east edge of Albuquerque.

Glorieta Geoscience, Inc., Santa Fe, New Mexico

Initiated and conducted sampling program for assessing economic potential of low-grade gold occurrence in southwest New Mexico.

November 1983 to September 1984: Fluid Minerals Geologist
Bureau of Land Management, Department of Interior, Cheyenne, Wyoming

Temporary detail to Casper office to alleviate backlog of assessments of federal oil and gas leases in Wyoming and Nebraska. Assessments required geologic evaluation of oil and gas potential for lands in Powder River, Wind River, Big Horn and Denver-Julesburg Basins. Determination of “known geologic structures (KGSs)” per Secretarial Order for categorizing federal oil and gas minerals into competitive and non-competitive status. Deposed as expert witness and provide expert summaries and affidavits for cases before the Interior Board of Land Appeals (example: Case No. IBLA 84-798 for protest of KGS delineation).

June 1982 to September 1983: Field Geologist
United States Bureau of Mines, Department of Interior, Lakewood, Colorado

Assisted primary authors with field inventory and evaluation of mineral occurrences in 15 wilderness areas in Colorado (Central Mineralized Region), southern Wyoming, and eastern Utah. Field work included field mapping and sampling of abandoned mines and mineral occurrences within these areas and adjacent areas with potential impacts on wilderness designation.

July 1979 to January 1982: Geologist
United States Geological Survey, Department of Interior, Casper, Wyoming and Lakewood, Colorado

First two years exclusively mapping, drilling, and classifying coal resources in south central Wyoming. Detailed for two years to special team for preparation of impact statement: one of four principle authors for the Cache Creek-Bear Thrust Environmental Impact Statement which documented effects of two proposed oil and gas wells in designated wilderness area near Jackson, Wyoming. Deposed as expert witness in federal court. Final year primarily responsible for assessments of federal oil and gas leases for lands in Wyoming and Nebraska.

July 1977 to July 1979: District Geologist
Bureau of Land Management, Department of Interior, Socorro District Office, Socorro, New Mexico

Responsible for District minerals program for federal lands in west central portion of state. Assisted in environmental reports for land exchanges, classification of saleable mineral sites, mining claim validity determinations, inspection of surface reclamation for mineral extractions, inspection of oil exploration and geothermal gradient wells, and assessments for location of water wells in support of grazing projects.

EDUCATION:

New Mexico Institute of Mining and Technology, Socorro, New Mexico
Bachelor of Science in Geology, 1977

Additional Courses: EPA course requirements for Asbestos Inspector (10 years as active inspector); completion of state program for Licensed Contractor (NM; GS-29); EPA course requirements for Lead-Based Paint Risk Assessor (EPA Regions VI and IX; two years as active inspector); GSI Course *Application of Ground Penetrating Radar*; NGWA Course *Monitoring Natural Attenuation of Contaminants*.

PROFESSIONAL MEMBERSHIPS, LICENSES, OR CERTIFICATIONS:

American Institute of Professional Geologist, Certified Professional Geologist No. 6,657
Alliance of Hazardous Materials Professionals, CHMM No. 11,401
ASTM International, Member No. 1,314,118 (Voting Member); Committees D18 (Soil and Rock) and E50 (Environmental Assessment, Risk Management and Corrective Action)
OSHA 40HR and 8HR Refresher Hazardous Waste Operations and Emergency Response (Current)
OSHA Hazardous Waste Operations and Emergency Response Manager/Supervisor (Current)
State of Alaska, Licensed Professional Geologist; No. 514
State of Arizona, Registered Professional Geologist; No. 40,812
State of Texas, Licensed Professional Geologist; No. 2,278

Case Nos. 23686 and 23687; OCD Exhibit No. 3

Million Gebremichael

Petroleum Engineer

UIC Group, Oil Conservation Division, EMNRD

RELEVANT EXPERIENCE

More than 10 years of professional experience working both for oil and gas companies and provincial government of Alberta oil and gas regulatory department. Currently working for the Energy, Minerals and Natural Resources Department as part of the group responsible for oversight of the Underground Injection Control (UIC) program for the Oil Conservation Division. Examples of various skills and experience applicable to the current position:

- Applied Production Engineering Principles and computer models to carry out well surveillance tasks to find short term and long-term optimization opportunities.
- Experienced in well intervention to mitigate production bottlenecks: Liquid loading mitigation (plunger lift optimization), Wax maintenance, Swabbing, Chemicals and solvents, Methanol injections to prevent hydration formations, Plunger's optimization, Backside foam injection, Built and maintained PI Process Book and Exception based tools for daily surveillance.
- Monitored and mitigated Acid Gas Injection (AGI) wells and made sure of regulatory requirements of mechanical integrity tests of injection wells are done in close adherence to regulatory requirements and writing programs for matrix well stimulation of the wells for optimal injection works.
- Experienced in reviewing and approving OCD’s C-108 applications for Saltwater Disposal (SWD) and Acid Gas Injection (AGI) wells in State of New Mexico.
- Experienced in reviewing and approving sundry notes for well workovers and injection pressure increases.
- Experienced in analyzing subsurface mechanical integrity tests: sonic and temperature logs, caliper and magnetic flux logs, cement bond logs.
- Wrote well testing procedures and coordinated asset well-testing campaigns: well Integrity testing- Wellhead integrity test (WIT), Subsurface integrity test (SIT), Packer integrity testing, well suspension compliance, production casing integrity and tubing tests and Surface casing vent flow.
- Calculated well operating pressure envelops- maximum allowable annulus surface pressure (MAASP) for production and injection wells to make sure wells are operating safely and compliant with regulatory requirement.
- Good understanding why a particular size and material grade is used in the well completion design.
- Experienced in Well Reservoir Facilities Management (WRFM) surveillance work.
- Experienced in reserve determination utilizing Volumetric, Decline Curve Analysis and Material Balance Techniques

- Experienced in reservoir engineering principles employed by regulatory jurisdictions- Pool Delineation schemes and Pressure studies, determining and writing notices to operators on Commingling, Good Production Practices (GPP) and Maximum Rate Limitation Orders (MRL)
- Experienced in implementing regulatory requirement for hydraulic fracturing by adhering to respective regulatory directives by applying AccuMap to determine wells –active and idle within injection zone and dispatching notices to other operators to take appropriate preventative measures during the operation.
- Experienced in data mining and analyzing utilizing software programs like AccuMap, ARC GIS, SharePoint, fetching data from various sources.

SPECIALIZED TRAINING

Courses provided through Shell International [Canada, USA, and the Netherlands]:

- Well Reservoir and Facility Management (11/05/2014) (Online)
- Artificial Lift Foundation Course (06/30/2015) Houston, Texas, USA
- Production Chemistry for unconventional Gas assets (11/08/2016), Calgary, Canada
- Well Reservoir and Facility Management Advanced Course (09/30/2016), Calgary, Canada
- Production Technology Foundation Course A-well and production System Modelling (11/29/2016), Rijswijk, Netherlands
- Material and Corrosion for Unconventional wells (11/17/2016), Calgary, Canada
- Advanced Well Integrity (04/12/2017), Houston, Texas
- Production Technology Foundation Course B (Well Construction) (12/07/2017), Houston, Texas, USA
- Production Technology for Unconventionals (10/23/2017) Calgary, Canada

EDUCATION

Bachelor’s Degree, Petroleum Engineering, (2012)
Southern Alberta Polytechnic, Canada.

Core courses include Reservoir Engineering, Reservoir Simulation, Production and Completion Engineering, Drilling Engineering, Geology, Formation Evaluation, Phase Behaviors, Petrophysics and Petroleum**.**

Case Nos. 23686 and 23687; OCD Exhibit No. 4

Delaware Mountain Group

NEW MEXICO ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

August 2022

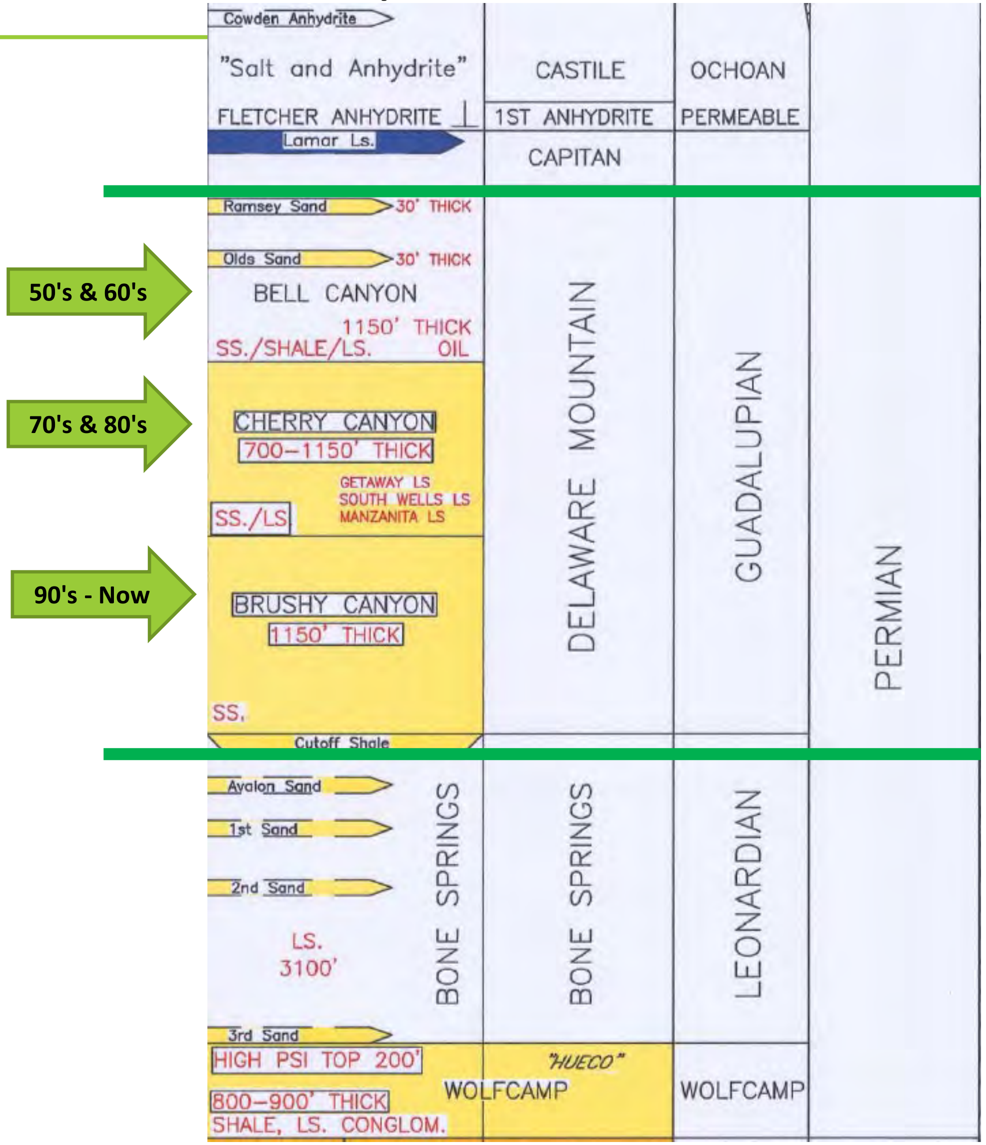
Production History

- The Delaware Mountain Group (DMG) has a history of Oil and Gas production in the State
  - 1948 was the first production from the pool
  - 1950's and 1960's production was from the Bell Canyon portion of the pool
  - 1970's and 1980's production was from the Cherry Canyon portion of the pool
  - 1990's production was from the Brushy Canyon portion of the pool
  - 2000's started some horizontal production in the Brushy Canyon

- In 2007 there were 250 productive pools in the DMG

- Through 2010 cumulative production has been 234 MMBO, 523 Bscf, and 742 MMBW

Key production years per formation



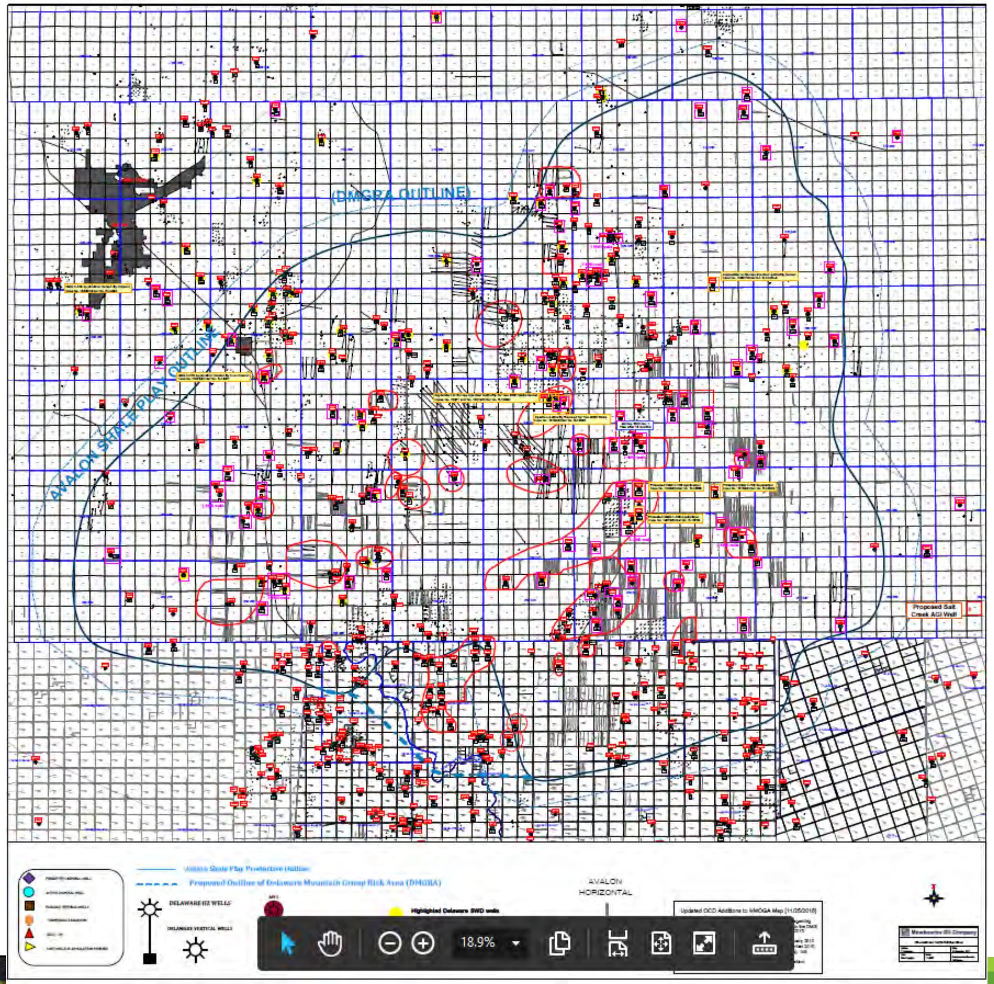
H. S. Nance (2006)

Historical Practices and Issues

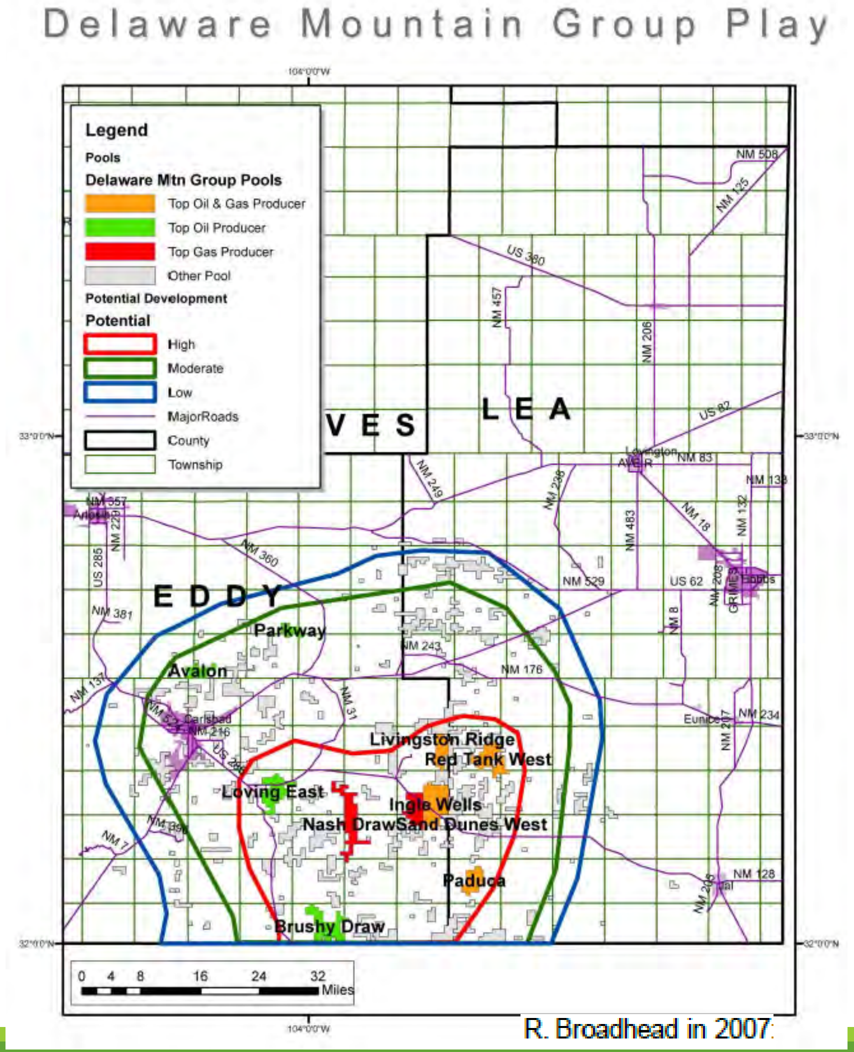
- Pre 2010 most DMG disposal wells were smaller, centrally located and field based
- 2018 there were 27 well permits added to the 241 active DMG Disposal wells, DMG was 32% of active disposal wells
- 2016 Midstream companies started submitting DMG applications
- In 2014 BOPCO filed cases 15192, 15219, 15231 BOPCO applied for hearing to revoke injection authority on 4 wells. 2 midstream wells were plugged and 2 smaller wells continued operation as a result of the hearing applications. BOPCO demonstrated their production was negatively impacted by the injection.
  - One of the impacted wells was shut in 2020 and has yet to recover from the impact of the water flows from 2014. Part of the cause was shown to be low parting pressure of the formation.
- As a result of growing interest and issues in the DMG disposal, NMOGA provided an exclusion area map for restricting DMG injection to protect correlative rights and reduce drilling complications in the area.

Productive Areas

NMOGA Identified protectable area



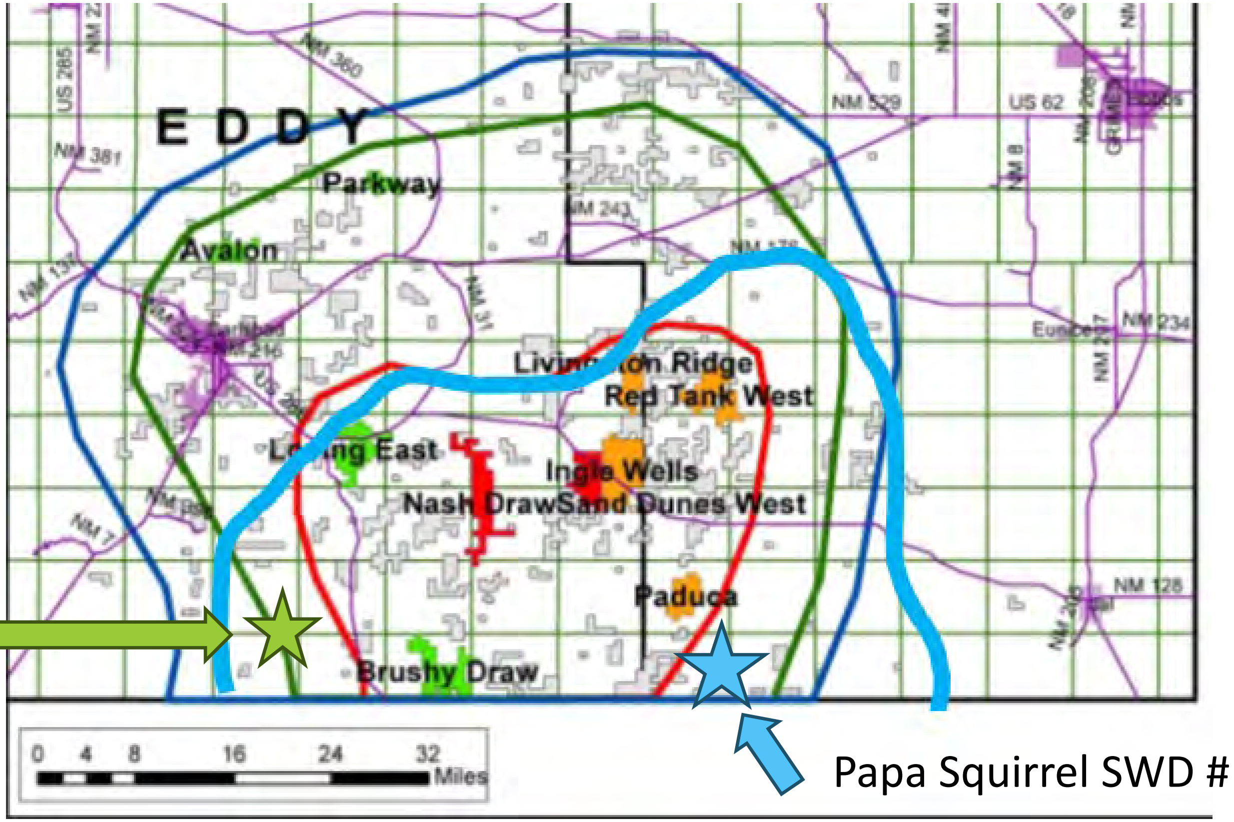
Historical producing areas



NEW MEXICO emnrd Energy, Minerals and Natural Resources Department

Productive Areas

Rough Combined Overlay



Severitas 2 State SWD #1 approximate location

Papa Squirrel SWD #1 approximate location

Case Nos. 23686 and 23687
OCD Exhibit No. 5

MIDDLE PERMIAN BASINAL SILICICLASTIC DEPOSITION IN THE DELAWARE BASIN: THE DELAWARE MOUNTAIN GROUP (GUADALUPIAN)

H. S. Nance

Bureau of Economic Geology
Jackson School of Geosciences
The University of Texas at Austin
Austin, Texas

ABSTRACT

The Delaware Mountain Group (DMG) of the Delaware Basin of Texas and New Mexico comprises up to 4,500 ft (1,375 m) of Guadalupian-age arkosic to subarkosic sandstone, siltstone, and detrital limestone that was deposited in deep water, mainly during lowstand and early transgressive sea-level stages. Primary depositional processes include density-current flow and suspension settling. Regionally extensive organic-rich siltstones record largely highstand deposition and provided hydrocarbons to sandstone reservoirs. Authigenic illite and chlorite are present, but there is little detrital clay. The DMG is restricted to the slope and basin, was sourced from shelf-sediment source areas through poorly exposed incised valleys, and generally is not depositionally correlative with siliciclastics on the shelf. Interbedded carbonate units thicken shelfward and are typically correlative to “reef”-margin-complex carbonate sources along the shelf margin.

Gamma-ray and porosity logs are useful for differentiating primary sandstone, siltstone, and carbonate end-member rock types, although application of outcrop models is critical for differentiating channel, levee, and splay sandstone subfacies using well logs.

The basin succession is formally divided into the Brushy Canyon, Cherry Canyon, and Bell Canyon Formations. The Brushy Canyon, the coarsest grained, contains little detrital carbonate. The other formations contain prominent carbonate members that are used extensively for subsurface correlations and to subdivide the intervals into informally named productive units. The DMG has been interpreted to contain 28 high-frequency depositional sequences aggregated into 6 composite sequences.

The DMG contains more than 260 hydrocarbon reservoirs at 900 to 9,820 ft depth (274–2,993 m) that have produced more than 262.2 MMbbl of oil and 280,517,264 Mcf of gas from channel/lobe complexes and associated levee and splay facies deposited by turbidites. Hydrocarbon source beds are intraformational, organic-rich siltstones that accumulated by suspension settling between episodes of turbidite activity. Hydrocarbon traps include both stratigraphic and structural components. Stratigraphic traps are formed where reservoir sandstone facies pinch out laterally into siltstone. Siltstone and calcite cements form stratigraphic seals. Hydrocarbon-bearing and water-bearing intervals alternate stratigraphically. Hydrocarbon migration is focused into stratigraphic traps that are located favorably on structural highs or in updip positions on structural ramps.

Structure is variably controlled by four processes, two of which are regional and two of which are reservoir-scale: (1) basin-slope rise toward shelf near shelf margins, (2) Laramide-generated regional eastward dip, (3) compaction over subjacent sandbodies, and (4) slumping in areas that are updip of reservoirs. Primary production is by solution-gas drive, and recovery efficiency is less than 15 percent in most reservoirs.

Development challenges include delineating productive sandbody geometries, controlling hydrofracture extension to avoid connecting water-bearing with hydrocarbon-productive intervals, preventing formation damage from interactions between acid treatments and Fe-bearing chlorite, and optimizing location of injection wells in continuous-permeability fields with production wells for EOR operations.

INTRODUCTION

The Guadalupian-age Delaware Mountain Group (DMG) of the Delaware Basin consists of as much as 4,500 ft (1,372 m) of stratigraphically cyclic, mixed siliciclastic/carbonate slope, and basin-floor strata (Dutton and others, 2005). The section hosts many economically important hydrocarbon reservoirs. Most of the hydrocarbon production has been from siliciclastic-dominated units in the Brushy Canyon, Cherry Canyon, and Bell Canyon Formations, with secondary production from associated detrital carbonate strata (fig. 1). More than 262.2 million barrels (MMbbl) of 39° gravity (production-weighted average) oil has been produced from approximately 267 reservoirs, within which 65 percent of the 2,103 total wells were producing in 2003. The section has also produced 280,517,264 thousand cubic feet (Mcf) of gas from approximately 95 reservoirs, within which 63 percent of the 183 total wells were producing in 2003. Production depths range from 900 to 9,820 ft (274–2,993 m) (Railroad Commission of Texas, 2003). Despite the economic significance of the DMG, most published technical information regarding its stratigraphy, lithology, and reservoir character is derived from geographically severely limited outcrop exposures and a few field locations.

The Ochoan Series is also present in the Delaware Basin and includes, from older to younger, the Castile, Salado, Rustler, and Dewey Lake Formations. However, only the Castile Formation is restricted to the basin; therefore, stratigraphy and sedimentology of the Salado, Rustler, and Dewey Lake Formations are discussed in the section of this report that deals with the Guadalupian and Ochoan shelf section. The Ochoan in the Delaware Basin hosts a few small reservoirs in the Castile and Rustler intervals. More than 186,403 bbl of 36.26^{o} (production-weighted average) oil has been produced from approximately eight reservoirs, within which no wells were producing in 2003. The section has also produced 429,348 Mcf of gas from approximately six reservoirs. Only three wells were producing from one Rustler reservoir in 2003. Production depths that include all historical reservoirs range from 380 to 3,704 ft (Railroad Commission of Texas, 2003). The importance of the Ochoan to hydrocarbon issues in the Permian Basin is related to its generally low permeability and in its role as a regional top seal for the Delaware Mountain Group in the Delaware Basin. It has also been known to guide hydrocarbon migration from basinal source beds into reservoirs located on the Central Basin Platform and Northwest Shelf (Hills, 1972).

This report summarizes published information on the DMG, whose literature spans nearly 100 years—from initial reconnaissance expeditions early in the 20th century through definitive geologic formational characterizations in the 1940's, development of modern depositional and sequence stratigraphic models in the 1990's and early 2000's, and ongoing investigations of DMG petroleum systems. The DMG, a significant producer of hydrocarbons, still contains abundant resources, although its depositional and diagenetic characteristics are complex. The objective in this report is to provide a basis from which to advance our understanding of the geologic succession and to stimulate continued and more efficient exploitation of the resources of the DMG.

PREVIOUS WORK

The Delaware Mountain Group succession was first described by Richardson (1904), who described it as a formation that included the Bone Spring Limestone. He noted the lateral geometric variability in sandstone strata, which later were recognized as variations among depositional facies. Beede (1924) recognized a lithologic tripartite character in the Delaware Mountain sandstone interval, which formed the basis of its subsequent subdivision into three formations. King (1942) raised the classification of the section to group status and named the Brushy Canyon, Cherry Canyon, and Bell Canyon Formations. King (1942) raised the Bone Spring to formation rank, although its Leonardian age had been recognized previously (King and King, 1929), at which time it was also suggested that the Bone Spring be divided from the Delaware Mountain Formation because the two formations were obviously separated by a pronounced unconformity and were dissimilar lithologically. King (1948) produced several excellent cross sections in the Guadalupe Mountains that are accepted as largely accurate, even after 6 decades of additional investigation by many workers.

Hull (1957) discussed the petrogenesis of the Delaware Mountain sandstones, pointed out the generally finer grained character of the Delaware sands compared with mineralogically similar, coeval sandstones on the surrounding shelves (also recognized by King, 1942), interpreted the carbonate members as including reef detritus, and suggested a turbidite model for Delaware Basin deposition. Jacka and others (1968) summarized previous investigations of Delaware Mountain sedimentation that largely concluded that the section recorded deep-sea fan deposition with submarine-canyon feeder systems, a conclusion reinforced by Meissner (1972). Payne (1976) described and interpreted siliciclastic subfacies from the Bell Canyon and proposed sand-transport directions from shelf areas and estimated relative importance of different source areas. Fischer and Sarnthein (1988) suggested an eolian source on the shelf for Delaware Mountain basinal siliciclastics. Harms and Brady (1996) summarized the several hypotheses historically suggested for deposition of the deep-water succession that, most importantly, contrast turbidite mechanisms with saline density-current mechanisms. Hills (1984) produced west-east cross sections for the Delaware Basin, suggested that the paleogeographically closed character of the Delaware Basin promoted accumulation of organic material that eventually generated hydrocarbons, and that the Castile evaporites overlying the Delaware Mountain effectively preserved hydrocarbons and guided hydrocarbon migration into reservoirs in the surrounding shelves. Facies models were developed from outcrop, core, and well log analyses by Gardner (1992, 1997a), Gardner and Sonnenfeld (1996), Barton (1997), Barton and Dutton (1999), Beaubouef and others (1999), Dutton and others (1999), Carr and Gardner (2000), and Gardner and Borer (2000). Sequence stratigraphic relationships in the Delaware Mountains were investigated and described by Gardner (1992, 1997b) and Kerans and Kempter (2002). Particularly useful discussions of hydrocarbon generation, source rocks, and reservoirs that were developed in Delaware Mountain strata include Payne (1976), Jacka (1979), Hayes and Tieh (1992a), Hamilton and Hunt (1996), May (1996), Gardner (1997b), Dutton and others (1999, 2000, 2003), Montgomery and others (1999, 2000), and Justman and Broadhead (2000). Impact of Delaware Mountain clay authigenesis on reservoir development was discussed by Walling and others (1992). Enhanced oil recovery (EOR) in certain Delaware Mountain Group fields was discussed by Kirkpatrick and others (1985), Pittaway and Rosato (1991), Dutton and others (1999, 2003).

REGIONAL SETTING

The Delaware Basin during deposition of the Delaware Mountain Group was a deep-water basin bounded by carbonate-ramp (San Andres and Grayburg) and carbonate-rim (Goat Seep and Capitan) margins that developed on the western edge of the Central Basin Platform, the Northwest Shelf, and the Diablo Platform. The primary connection between the Delaware Basin intracratonic sea and the open ocean was through the Hovey Channel (fig. 2). Most deposition in the area during sea-level highstands was on the shelves and consisted of the mixed carbonate-siliciclastic San Andres Formation and Artesia Group (Grayburg, Queen, Seven Rivers, Yates, and Tansill Formations). The Delaware Mountain Group shelf-derived siliciclastics and shelf-margin-derived detrital carbonates were deposited during intermittent sea-level lowstands (for example, Silver and Todd, 1969; Meissner, 1972). Basin subsidence outpaced sediment supply such that deep-water conditions were maintained until the close of the Guadalupian, after which Ochoan evaporites filled the basin and eventually blanketed the entire greater Permian Basin area. Onset of basin evaporite accumulation corresponded with demise of the Capitan Reef system and is hypothesized to mark closing of the Hovey Channel, which promoted progressive restriction of the basin from marine influx (King, 1948).

FACIES AND SEDIMENTOLOGY OF THE DELAWARE MOUNTAIN GROUP

Distribution and Age

The Delaware Mountain Group (DMG) is Guadalupian in age, according to fauna described by Girty (1908). The DMG includes the uppermost occurrences of Guadalupian fauna in the Delaware Basin (Lang, 1937) and the three formations of the Delaware Mountain Group were defined to represent the early, middle, and late subdivisions, respectively, of Guadalupian time (King, 1948).

The DMG is formally divided into three formations. From base to top they are the Brushy Canyon, Cherry Canyon, and Bell Canyon Formations. These names, assigned by King (1942), reflect the names of canyons in the Delaware Mountains. The formations are lithologically similar except that the Brushy Canyon contains abundant medium-grained channelized sandstone beds. The other formations are significantly finer grained and dominated by laminated bedding in the outcrop area, although these differences may mark a shifting toward the east and southeast of shelf-edge siliciclastic storage areas that sourced Cherry Canyon and Bell Canyon deposition. The boundary in outcrop between the Brushy Canyon and the Cherry Canyon was placed at the top of the uppermost medium-grained sandstone bed in the Brushy (King, 1942). The contact with the overlying Cherry Canyon is unconformable (fig. 3), and the lower part of the Cherry Canyon composes the Cherry Canyon (sandstone) Tongue. Whereas the Brushy Canyon, most of the Cherry Canyon, and the Bell Canyon are restricted to the Delaware Basin, the Cherry Canyon Tongue extends well onto the shelf and pinches out approximately 6 mi shelfward of the stratigraphically superjacent Goat Seep shelf margin (Kerans and Kempter, 2002). Goat Seep and Capitan shelf-margin carbonates form the updip limits of subsequently deposited Delaware Mountain successions.

The Brushy also lacks the prominent carbonate members that are characteristic of the Cherry Canyon and Bell Canyon intervals. Carbonate members were named by King (1942) for minor geographic features such as small canyons, hills, springs, or houses, where the correspondingly named strata were described. The Hegler (limestone) Member of the Bell Canyon is used to divide the Bell Canyon from the underlying Cherry Canyon. Other carbonate members are used to subdivide the Cherry Canyon (South Wells, Getaway, and Manzanita) and the Bell Canyon (Hegler, Pinery, Rader, McCombs, and Lamar) (fig. 1). South Wells and Getaway members of the Cherry Canyon are lenticular, whereas the Manzanita is more laterally persistent. Hegler, Pinery, Rader, McCombs, and Lamar carbonate members of the Bell Canyon are thinner overall and more laterally persistent than are Cherry Canyon carbonate members. All carbonate members thin basinward from their updip pinch-outs near the shelf margin. All three DMG formations are recognized throughout the Delaware Basin, although they may be more problematic to distinguish in parts of the basin where carbonate interbeds are thin or absent.

It was recognized early (for example, Cartwright, 1930) that the Delaware Mountain Group is a sea-level-lowstand wedge of sedimentary rock that is restricted to the Delaware Basin. Todd (1976) considered the Spraberry basinal sandstones (presumably the upper Spraberry of later usage; for example, Handford, 1981) of the Midland Basin to be Brushy Canyon equivalents and Guadalupian in age. Jeary (1978) and Handford (1981) concluded a Leonardian age for the Spraberry. If Jeary (1978) and Handford (1981) are correct, there may be no deep-water equivalents for the Delaware Mountain Group elsewhere in the Permian Basin. However, Ruppel and Park (2002) demonstrated the existence of Brushy-Canyon-equivalent lowstand-wedge deposits in the Midland Basin, as have other authors.

Facies

The Brushy Canyon was deposited upon an unconformity that developed on Leonardian-age (King, 1942, 1948) Bone Spring carbonates. The unconformity is locally marked on the

Western Escarpment of the Guadalupes, where the Cutoff and Victorio Peak Formations are truncated beneath the Brushy Canyon. On the flanks of the Bone Spring Flexure, an area between El Capitan and Shummard Peak in the Guadalupe Mountains where the top of the Bone Spring rises more than 1,000 ft, the outcropping basal 100 ft of the Brushy Canyon consists of conglomerates as much as 10 ft thick, with interbedded sandstone, limestone, and thinly to thickly bedded sandstone. Conglomerates are composed of gravel, cobbles, and boulders as much as 4 ft in diameter. Conglomerates include limestone material from the Bone Spring and Victorio Peak Formations. Conglomerate bodies are lenticular (channelized) and absent from higher areas of the flexure where Brushy Canyon sandstones onlap (King, 1948). Conglomerates are not reported from Brushy Canyon intervals in the hydrocarbon-productive areas, which are largely located a minimum of several miles from Delaware Basin shelf margins (figs. 2, 4).

Dominant facies in the Delaware Mountain Group are arkosic to subarkosic sandstones and siltstones (for example, Hull, 1957; Kane, 1992; Thomerson and Asquith, 1992) (fig. 5). Sediment texture ranges mainly between coarse silt and very fine grained sand, although fine-grained sand is found in the Brushy Canyon. Shales are rare. Finer grained intervals, even those that contain several percent organic carbon, are properly classified as siltstone (Thomerson and Asquith, 1992). Siltstones compose organic-rich (up to 46 percent total organic content [TOC]; average 2.36 percent TOC) and organic-poor subfacies (average 0.52 percent TOC) (Sageman and others, 1998; Wegner and others, 1998; Dutton and others, 1999) (fig. 6) Clay content is dominantly authigenic illite and chlorite (fig. 5) rather than detrital and is not abundant (for example, 11.6 percent average in the Brushy Canyon, Lea County) (Green and others, 1996).

Siliciclastic sources are updip of and on the surrounding shelves, given the lithologic similarities between the DMG and Guadalupian clastic strata on the shelves (King, 1948; Hull, 1957). Carbonates are volumetrically of secondary importance and increase in prominence shelfward. Limestone is most common; however, some diagenetic dolomite is present. Carbonates are dominantly detrital and derived from the lower San Andres/Victorio Peak ramp margin (Brushy Canyon), Grayburg ramp-margin (lower Cherry Canyon), and Goat Seep (upper Cherry Canyon) and Capitan (Bell Canyon) rimmed shelf-margin complexes (Beaubouef and others, 1999; Kerans and Kempter, 2002).

Depositional Setting and Facies Architecture

DMG facies successions are typical of those found in deep basins in areas relatively proximal to carbonate-shelf margins. Sandstones compose channel, levee, overbank-splay, and lobe subfacies (for example, Galloway and Hobday, 1996; Gardner and Sonnenfeld, 1996; Beaubouef and others, 1999; Dutton and others, 1999, 2003) (figs. 7–10) that were deposited as sea-level-lowstand submarine fans basinward of the shelf-margin break and as lowstand wedges shelfward of ramp margins (Beaubouef and others, 1999). Turbidity flow appears to be the primary transport mechanism for coarser sediment (sand and shelf-margin carbonate debris) (for example, Hull, 1957; Jacka and others, 1968; Silver and Todd, 1969; Meissner, 1972; Zeldt and Rosen, 1995), whereas suspension settling may be an important mechanism for silt-sized sediment, especially the organic content (Payne, 1976). Eolian transport of silt has been proposed as a mechanism for conveyance of silt to the basin margins (for example, Fischer and Sarnthein, 1988; Gardner, 1992). Margins of the Guadalupian platform are well defined by the change from Lower Guadalupian (San Andres Formation) ramp and Upper Guadalupian (Goat Seep/Capitan) reef facies to slope, carbonate-debris-rich facies of the carbonate members of the Delaware Mountain Group (figs. 1, 11). Because of the limited availability of cores through these slope and basin-floor complexes, understanding of their paleoenvironmental setting and facies geometries is greatly facilitated by analyses of the well-exposed Delaware Mountain Group outcrops in the Delaware Mountains (figs. 12, 13).

Facies architecture is controlled by relative sea level and position along the shelf-margin to basin-floor profile. During falling sea level the slope is incised by submarine erosion. Incised channels are (1) barren as long as all throughgoing sediment bypasses the location, (2) containers of laterally discontinuous conglomerates as lag, or (3) blanketed by thin accumulations of silt or sand that mark the waning stages of throughgoing turbidity-current deposition (Beaubouef and others, 1999). Potential for net deposition of sandstone soon following incision increases for basinward locations. Incised channels that are initially bypassed by sediment are eventually back filled.

Channel-levee-complex sandstone deposits are variably sinuous (figs. 14, 15) and asymmetrical in cross section normal to flow direction. Channel sinuosity generally increases downslope, marking decrease in flow velocity attendant upon decreasing topographic gradients.

Channel-facies geometries and stacking patterns systematically vary according to position along the slope-to-basin-floor profile. On the upper slope, which is constructed largely of laminated siltstone intervals that are deposited during sea-level rise, deep incised channels are less numerous than are shallower channels farther down slope. Upper-slope channel deposits are generally isolated and vertically stacked. Channel fills compose multiple, onlapping strata, thus recording backfilling of incised channels. At the toe of slope, avulsion (channel abandonment) promotes development of laterally offset complexes of amalgamated channel deposits (for example, fig. 16a). In progressively downslope locations on the basin floor, avulsion-prone channel systems bifurcate into channel-levee complexes, and overbank sediments (splays) increase in prominence (fig. 8). Along the basin-floor profile, proximal channelized-fan sedimentation transitions to sheet deposition on lobes. Although approximately sheetlike, sandstone packages in distal positions are still deposited in compensatory fashion (Beaubouef and others, 1999) (fig. 8). The overall thickness distribution of individual Delaware sandstone intervals (that is, bounded top and bottom by laterally extensive siltstone sheets) is marked by dominance of channel facies along the axes of maximum thickness (fig. 16b).

Thin, laterally discontinuous siltstones are interlaminated with sandstones in overbank-splay deposits. In many cases siltstones blanket the sandstone deposits that remain after channel abandonment. However, the more important siltstones, in terms of reservoir development, are laterally extensive sheetlike organic-rich and organ-poor accumulations that stratigraphically separate successions of channelized sandstone deposits on the lowstand fan complex. Brushy Canyon correlative siltstone units have been mapped over distances exceeding 50 mi in southern New Mexico (Broadhead and Justman, 2000). In some places, siltstones compose nearly 80 percent of the Delaware Mountain Group (Hayes and Tieh, 1992b). Particularly thick siltstone accumulations (lowstand wedge) occurred during the latest stages of lowstand deposition, when relative sea level rose onto the shelf edge and sand transport to the basin largely ceased (Beaubouef and others, 1999).

DMG carbonate units are constructed largely of allochthonous debris derived from the outer shelf and shelf margins (King, 1948). Rock types range from lutite to boulder conglomerates. Conglomerates from Brushy Canyon carbonate units occur mainly as lag on the bedrock floors of incised channels at the shelf margin and generally do not compose a significant fraction of the formation in more basinward areas (King, 1948; Beaubouef and others, 1999). No carbonate members are formally recognized in the Brushy Canyon or Cherry Canyon sandstone tongue. In the basin-restricted Cherry Canyon and Bell Canyon Formations, however, widespread carbonate-bearing intervals are present and are formally recognized as members (King, 1948). The geometry of carbonate members ranges from lenticular in older units to more sheetlike forms in the younger units (King, 1948). Although conspicuous for their carbonate content, these units comprise cyclic interbeds of carbonate and siliciclastic sandstone and siltstone; carbonate-dominated beds may represent less than half of the thickness of the member (fig. 17).

Diagenesis

The most economically important diagenetic processes in the Delaware Mountain Group are (1) feldspar dissolution, (2) feldspar and quartz authigenesis, (3) clay authigenesis, and (4) calcite cementation. Similar to processes observed in Guadalupian shelf siliciclastics, DMG siliciclastics show evidence of K-feldspar dissolution, which imparts a component of secondary porosity to reservoir facies, although initial porosity enhancement may be destroyed by subsequent collapse of remaining crystal elements. Dissolution of feldspar and quartz (the latter evidenced by sutured contacts between detrital quartz grains) created fluids that resulted in feldspar and quartz overgrowths elsewhere in DMG sandstones, reducing already impoverished permeability (Behnken, 1996). Clay authigenesis (chlorite and illite) probably had the greatest single effect on reservoir quality in DMG sandstones (Green and others, 1996; Thomerson and Asquith, 1992). Whisker- and weblike clays dissect pore space, illite/smectite species may swell when contacted by drilling fluids, and chlorites may decompose in the presence of acidic solutions to form pore-clogging, insoluble, Fe-hydroxide gels if the acids are left in the formation long enough for the pH to rise above 2.2 (Spain, 1992; Behnken, 1996; Green and others, 1996). No stratigraphic or lateral systematic variations in clay mineralogy have been defined in the DMG, although Thompkins (1981, cited in Walling and others, 1992) noted changes in chlorite fabric with depth. Calcite cements occur in thin stratiform accumulations that impart a component vertical porosity and permeability heterogeneity to DMG facies (Dutton and others, 1999) (fig. 18). Calcite cement appears to be most abundant in finer grained siliciclastics that are outside of channel-sandstone subfacies (Spain, 1992; Dutton and others, 1999) (fig. 19).

Hayes and Tieh (1992a) recognized a four-phase sequence of diagenesis in Delaware Mountain sandstones from Reeves and Eddy Counties: (1) early cementation by carbonate, sulfate, and halite that preserved significant intergranular porosity during early burial; (2) dissolution of cements and detrital minerals to produce secondary porosity; (3) chlorite authigenesis that dissected porosity; and (4) authigenesis of dolomite, feldspar, Ti-oxides, and illite. Although Hayes and Tieh (1992a) did not recognize illite/smectite as being as prominent in their studies from Waha field and Big Eddy Unit (Reeves and Eddy Counties), Thomerson and Asquith (1992) in their study of Hat Mesa field (Lea County) and Behnken (1996) in his study of Nash Draw field (Eddy County) did. Walling and others (1992) proposed that chlorite evolved from smectitic precursors and that chlorite may revert to expansive and migratory forms in the presence of some fluids used in well development and completion.

SUBSURFACE RECOGNITION AND CORRELATION

Identification of DMG formation boundaries in the subsurface is based largely on relationships between the formations observed in Guadalupe Mountain outcrops that were described by King (1948). One of the most useful subsurface cross sections based on well log correlations is found in Meissner (1972). Boundary correlations are lithostratigraphic. The Delaware Mountain Group is overlain by the evaporite-dominated Castile Formation, which produces a relatively low gamma-ray response and high acoustic velocity compared with those of the feldspathic siliciclastics of the DMG (Payne, 1976; Dutton and others, 1997, 1999) (fig. 20). The Castile is characterized by bed thickness that is distinctively greater than that of any of the beds in the underlying Delaware Mountain Group (fig. 10).

The base of the Delaware Mountain Group (base of Brushy Canyon Formation) is defined at the base of the lowermost siliciclastic interval that overlies the thick carbonate interval assigned to the Bone Spring limestone. This relationship appears to be basinwide. The Bone Spring typically has a gamma-ray signature that is distinctively lower than that of the siliciclastic-dominated DMG and has comparatively greater resistivity, density, and acoustic velocity. The Bone Spring strata also exhibit greater carbonate-bed thickness than do DMG strata.

The boundary between Cherry and Bell Canyons is extrapolated into the subsurface from relationships observed in the Guadalupe and Delaware Mountain outcrops. The Cherry Canyon/Bell Canyon boundary is between the Manzanita and Hegler Limestone Members in outcrop. These strata have been interpreted into nearby wells (for example King, 1948; Tyrrell and others, 2004) (figs. 17, 21) and form the link between outcrop-defined formation boundaries and the subsurface. In particular, a volcanic ash mapped in the outcropping Manzanita succession by King (1948) has been interpreted as regionally widespread and correlated extensively into the subsurface (BCB marker of Tyrrell and others, 2004) (figs. 17, 21).

The boundary between Brushy and Cherry Canyons was defined by Gardner and Sonnenfeld (1996) to be an organic-rich siltstone (lutite) similar to that observed between the Brushy Canyon and the Bone Spring. Most workers place the boundary at the base of the organic siltstone interval (for example, May, 1996) (fig. 22), which is consistent with King's (1948) original pick at the top of the uppermost sandstone on the Brushy Canyon outcrop. Gamma-ray-log responses for this facies are typically high (fig. 22). These units record transgressive and highstand basin starvation where deposition of windblown silt and marine plankton dominated. The organic-rich siltstones and interbedded carbonate probably record the transgressive leg of late Brushy Canyon deposition and, in light of sequence stratigraphic analysis, might better be placed in the Brushy Canyon Formation.

Most DMG carbonates also have gamma-ray values that are lower than those of most DMG siliciclastics, the exceptions being thinly bedded examples that are interbedded with siliciclastics. A more reliable log for carbonate identification is the density log, however, which indicates much higher densities for the carbonate-dominated strata (figs. 17, 20) than for the more porous siliciclastics. Siltstones have significantly higher gamma-ray values than do sandstones, and organic-rich siltstones (which often include a fraction of volcanic ash) show the highest gamma-ray values of all (for example, fig. 10a).

Sandbodies can be discriminated by their overall lower radioactivity compared with that of the siltstones that envelop them. Widespread siltstones, especially those that are organic rich, are useful for correlation and allow confident mapping of correlative sandstones. Discrimination of DMG sandstone subfacies is more problematic and attempts to define log facies for channel, splay, levee, and lobe deposits that have been largely model driven (for example, Dutton and others, 1999). Interpreted channel subfacies tend to show little gamma-ray variation, such as might be expected in less massive subfacies. Levee deposits have been interpreted where log responses suggest some interbedding of coarser and finer grained siliciclastics, the finer grained of which contain marginally more clay and feldspar and, thus, are slightly more radioactive. Outcrops indicate that levees are most common where sandbodies thin laterally, and this criterion is useful for interpreting the probability of levee development.

The Brushy Canyon/Cherry Canyon boundary in outcrop is picked at the top of the uppermost medium-grained sandstone interpreted to be in the Brushy Canyon (for example, fig. 6). However, the textural fineness of Cherry Canyon compared with that of Brushy Canyon is probably somewhat a function of evolving paleogeography. By Cherry Canyon deposition, sand depocenters had begun to shift toward the east from positions that were prominent during Brushy Canyon deposition (fig. 4). In the north part of the Delaware Basin the Brushy contains no significant carbonate except at the bases of incised channels on the Bone Spring shelf margin. Along the Central Basin Platform margin prominent Brushy Canyon carbonate intervals are evident within the lower part of the section, although they are subordinate in thickness to those in the Cherry Canyon and Bell Canyon.

The Cherry Canyon/Bell Canyon boundary is defined in outcrop at the base of the Hegler limestone member, a pick that King (1948) considered to be correlative to the lowermost part of the Capitan shelf margin. Acceptance of this boundary places the Getaway, South Wells, and Manzanita carbonate members entirely within the Cherry Canyon. Further, the Manzanita was correlated by King (1948) into the Shattuck sandstone member of the Queen. This correlation places the Manzanita stratigraphically between the Goat Seep and Capitan shelf-margin successions. Some subsequent writers agreed with King's correlation (for example, Newell and others, 1953), although some placed the Manzanita at the top of Cherry Canyon (for example, Kerans and Kempter, 2002; Tyrrell and others, 2004) (fig. 11). Others suggested that the Manzanita correlates at least partly into the Capitan (for example, McRae, 1995a; Beaubouef and others, 1999).

There is some uncertainty concerning the stratigraphic equivalence of the Manzanita to either the Goat Seep or Capitan margins. Tyrrell and others (2004) correctly pointed out the potential ambiguities inherent in using only well log criteria for correlations of the Manzanita, which can lead to its correlation into the Capitan in some areas in the north part of the basin, and into the Goat Seep in other areas (fig. 21). The root of the problem may well be that carbonate members and the shelf-margin carbonates are significantly diachronous; thus, lithostratigraphic correlations are not always justified. Carbonate intervals identified as Manzanita may be equivalent to the Goat Seep in some locations and to the Capitan in others.

The top of the DMG (Bell Canyon Formation) is a relatively straightforward pick on the base of the Castile evaporites (anhydrite and calcite), the latter of which is expressed by a regionally extensive, thick interval of very low radioactivity on a gamma-ray log and generally high sonic velocity on an acoustic log (figs. 10, 20).

DEPOSITIONAL MODELS FOR THE DELAWARE MOUNTAIN GROUP

Water Depth

The presence in outcrops of texturally coarse, rippled and cross-laminated, channelized sandstone with current-oriented fossils prompted King (1942, 1948) to interpret the Brushy Canyon as having been deposited under “agitated” conditions and, thus, was an overall shallow-water deposit. King recognized alterations between high-energy and low-energy deposits; however, he did not think that this sedimentary cyclicity indicated significantly varying water depths. He drew similar conclusions for the lower half of the Cherry Canyon, including the carbonate-bearing intervals. However, he interpreted the largely unchannelized upper part of the Cherry Canyon as recording overall deepening of the depositional environment.

It is important to appreciate that King was describing data compiled near the shelf margin of the basin, where water depths were shallower than those anticipated toward the basin center. Even so, King (1948) calculated water depths to be more than 1,000 ft (>305 m) in the area on the basis of the difference in altitudes between updip and downdip extents of the outcropping Lamar limestone member at the top of the Bell Canyon.

Based on differences between updip and downdip altitudes of correlative stratigraphic horizons, King’s cross sections (1948) suggest an overall deepening of the Delaware Basin sea during DMG accumulation. One explanation is that development of shelf-margin barriers over time more efficiently attenuated continental sediment influx while the basin continued to subside at historically comparable rates, such that sediment influx was increasingly unable to match basin subsidence. Alternatively, or concurrently with barrier development, siliciclastic source areas may have become exhausted or buried (King, 1948). Siliciclastic influx into the basin eventually ceased, as evidenced by post-DMG deposition of the virtually clastic-free Castile Formation that filled the basin to its rim.

Sediment Sources and Depositional Processes

Areas to the northwest, north, and northeast of the Delaware Basin were siliciclastic depocenters during sea-level lowstands throughout the Permian and probable sources to the basin for DMG siliciclastics. The Queen and Yates Formations of the Artesia Group (Tait and others, 1962) are especially notable for their abundant siliciclastic content. Broadhead and Justman (2000) interpreted the source of Brushy Canyon sand to be entirely from the Northwest Shelf. This interpretation is supported by the preferred location of Brushy oilfields in the north part of the basin (fig. 4). DMG depocenters shifted toward the east side of the basin during Cherry and Bell Canyon deposition (figs. 4, 23). The dominant original source of DMG siliciclastics was probably granitic rock in the ancestral Front Range in Colorado, given the high feldspar content of siliciclastic facies (Basham, 1996).

Carbonate sediments appear to have been mainly allochthonous and derived from erosion of carbonate shelf margins. Additional carbonate material was swept from outer-shelf back-reef environments, which bounded the Delaware Basin.

Adams (1936) was one of the first to suggest that the very fine siliciclastics found in the Delaware Mountain Group may have been wind borne (see also Fischer and Sarnthein, 1988; Gardner, 1992). Requirements for eolian sedimentation include (1) the presence of winds of adequate power to entrain significant quantities of sediment and (2) proximity to the basin margin of a large sediment reservoir having textural and pedogenic properties amenable to wind transport. Prevailing wind directions during Guadalupian time have been suggested to be northeasterly, northerly, or northwesterly (present azimuths) on the basis of crossbedding measurement across the southwestern U.S. (Peterson, 1988). These directions are mirrored in the orientations of Delaware Mountain submarine-channel systems.

Most depositional models for the Delaware Mountain Group, including and since the early work of Richardson (1904) and King (1934, 1942, 1948), have recognized that patterns of siliciclastic and carbonated sedimentation record the systematic effects of sea-level changes. However, details of this process are debated. For example, sandstones have been interpreted by many to have been transported into the basin during sea-level lowstand from eolian-dominated ergs near the emergent shelf margin. In this mode, sand was transported to the upper slope by wind and then distributed by waves. Upper-slope sand stores grew until a critical mass was reached and sediment began to slump or avalanche into deeper water and eventually be carried farther into the basin by turbidity currents (for example, Gardner, 1992) or saline-density currents (for example, Harms, 1974). By contrast, Loftin (1996) thought that most of the sand that had accumulated during lowstand was "cannibalized" during transgressions and transported into the basin from shelf-margin ergs that had been stabilized by a rising coastal water table.

Similarly, there has been disagreement regarding the timing of carbonate transported to the basin. Some (for example, Gardner, 1992) concluded that carbonates were shed from platforms during highstand when primary carbonate production was optimal. Others (for example, Loftin, 1996) suggested that carbonate was mobilized by erosive wave energy that impinged on an exposed carbonate-shelf margin during the transgressive leg of sea-level change. Both propositions may be correct. During early stages of transgression, shore lines were probably near the shelf margin and wave base probably impinged on parts of the antecedent carbonate margin.

Most carbonate members of the DMG contain gravels, cobbles, and even boulders, with maximum grain size and interval thickness increasing toward the shelves. These deposits are lenticular and have been suggested to be turbidites. Regardless of the sea level, it appears likely that a steepened carbonate margin facilitated carbonate deposition. This conclusion follows from the observation that the carbonate-poor Brushy Canyon and Cherry Canyon tongues lap onto low-angle lower San Andres and Grayburg ramp margins, whereas the carbonate-"rich" Cherry Canyon and Bell Canyon lap onto higher angle forereef deposits of Goat Seep and Capitan rimmed margins.

DMG sandstones have been interpreted by most to compose channel, levee, overbank splay, and lobe subfacies (Galloway and Hobday, 1996; Beaubouef and others, 1999; Dutton and others, 1999, 2003) deposited by turbidity currents (Hull, 1957; Jacka and others, 1968; Silver and Todd, 1969; Meissner, 1972; Zeldt and Rosen, 1995). The alternate theory of hypersaline density current flow proposed by Harms (1974) has recently been challenged by Kerans and Fitchen (1996) and others. These workers contended that the evaporative hypersaline lagoons invoked by Harms (1974) and Harms and Brady (1996) to generate high-density transport fluids could not have existed on the emergent lower San Andres shelf during mid-San Andres time Brushy Canyon sea-level lowstand.

Siltstones include organic-poor and organic-rich subfacies (Sageman and others, 1998) and have been interpreted to occur in three modes: (1) discontinuous drapes and lenses associated with channel sandstones during turbidity-current deposition, (2) laterally continuous intervals deposited by hemipelagic suspension during channel abandonment, and (3) laterally continuous sandstones interbedded with organic-rich siltstones deposited during basin starvation associated with transgressions (Wegner and others, 1998). Organic-rich siltstones are laterally continuous. Organic content varies generally between 0.5- and 4-percent TOC in Brushy Canyon (Sageman and others, 1998) but is as high as 46 percent in uppermost Bell Canyon (Dutton and others, 1999). Organic material, interpreted as being largely hemipelagic, probably accumulated during highstand periods of reduced sand transport to the basin (Gardner, 1992).

Most workers have generally agreed on the sequence of depositional phases that are recorded in DMG successions (fig. 24). During highstand, deposition in the basin consisted of hemipelagic silts that settled from suspension under conditions of basin-sediment starvation (Gardner, 1992; Beaubouef and others, 1999) (figs. 6, 10a, 25a). Organic matter, which is dominantly of algal (Sageman and others, 1998; Wegner and others, 1998) or bacterial (Sageman and others, 1998) origin, occurs in all DMG siltstone. Organic-rich siltstone records relatively high rates of organic production relative to silt deposition and may indicate either an absolute increase in organic productivity or a decrease in silt influx to the basin. High hydrogen-index values, an indicator of marine organic carbon, is correlated approximately with relative organic-carbon abundance in Brushy Canyon siltstones (Sageman and others, 1998). Assuming that organic carbon deposition over the long term occurred at an approximately continuous rate, higher organic-carbon content implies reduced rates of silt deposition. Reduced silt influxes probably occurred when silt sources were at greater distances from the location of deposition. Thus, more organic-rich siltstones were probably deposited during sea-level highstands.

During lowstand, siliciclastics prograde into the basin as channel, levee, splay, and lobe architectural elements of a basin-fan system. Several pulses of deposition are common and show laterally offset (compensatory) depositional axes (figs. 13, 16, 24). Silt deposition commences in areas of channel abandonment. Intermittent splay deposition may also occur in areas near active channels. As sediment supply from the shelf slows, commonly during sea-level rise, sand depocenters backstep onto the slope until widespread silt deposition dominates.

CYCLICITY AND SEQUENCE STRATIGRAPHY OF THE DELAWARE MOUNTAIN GROUP

Cyclicity

Core and outcrop studies demonstrate that the Delaware Mountain Group in the Permian basin is cyclic at several scales. As discussed earlier, DMG successions include alternating sandstone, siltstone, and organic-rich siltstone on the slopes and on the basin floor and interbedding with basinward-thinning, carbonate-debris-bearing intervals along basin slopes. The largest-scale cycles are the three formations that each exhibit overall upward fining that records third-order sea-level rise. Highest frequency cycles consist of channel-levee-splay-lobe complex, sandstone-dominated intervals that alternate with generally widespread sheets of siltstone. These cycles record updip avulsion and channel abandonment (lobe shifting) or shorter term sea-level rises, during which sandstone-depositional environments migrate upslope. Within lobe deposits, sandstone intervals alternate with siltstone intervals, a characteristic that may record episodic deposition of sand and silt under waning current energy or episodes of density-driven sand deposition followed by relatively quiescent periods, when silt entered the basin either by wind or in hypopycnal plumes. Finally, within the siltstone-dominated intervals, organic-rich beds alternate with organic-poor beds—a pattern that records alternating periods of lower and higher siliciclastic sedimentation, respectively (for example, Sageman and others, 1998).

Sequence Stratigraphy

The sequence stratigraphic approach applied to the Guadalupe Mountain DMG succession by recent workers is based essentially on the "Exxon model" (Mitchem and others, 1977). This model was applied to the Guadalupian shelf carbonate succession in the Permian Basin outcrop by Kerans and Kempter (2002) and to the DMG outcrop slope/basin succession by Gardner (1992), Gardner and Sonnenfeld (1996), and Gardner (1997b). The outcrop-based sequence stratigraphic framework was extended into the subsurface of the Delaware Basin by Kerans and Kempter (2002) and Tyrrell and others (2004).

Delaware Mountain Group Sequences in Outcrop

Although the Delaware Mountain Group has historically been subdivided into three formations (Brushy Canyon, Cherry Canyon, and Bell Canyon), it has been interpreted to comprise the basinal components of at least 21 high-frequency depositional sequences recognized on the shelf. Three additional sequences are recognized in the basin that are not present on the shelf. Equivalences between shelf and basin strata are difficult or impossible to establish because shelf-equivalent strata are either not coupled with basinal strata or are so thin as to be below resolution. A possible exception is the Shattuck sandstone of the uppermost Queen Formation, which can be traced convincingly onto a surface that separates the Goat Seep from the Capitan shelf-margin complex, the latter of which can be correlated into the Manzanita Limestone Member of the uppermost Cherry Canyon Formation (King, 1948).

On the basis of studies in the Guadalupe Mountains Kerans and Kempter (2002) defined a sequence stratigraphic framework for the Guadalupian succession that comprised all or part of 6 composite sequences and a total of 28 high-frequency sequences (HFS's). The six composite sequences each record a third-order sea-level cycle. Twenty-five Guadalupian HFS's are recognized on the shelf and in the basin, whereas three HFS's are recognized only in the basin, all of which compose approximately the lower 95 percent of the Brushy Canyon. The Brushy Canyon is interpreted to onlap the upper surface that is developed on the lowermost of the six composite sequences; therefore, the DMG is contained in the younger five of six composite sequences. The DMG includes 24 of the 28 Guadalupian HFS's. Because a complete review of this framework is beyond the scope of this paper, the reader is directed to Kerans and Kempter (2002) for a complete treatment of terminology, concepts, and interpretations. Figure 11 delineates high-frequency and composite sequence boundaries mapped by Kerans, Gardner, and others. However, only composite sequences are labeled. A horizontally extended, more completely labeled version is found in Kerans and Kempter (2002).

RESERVOIR DEVELOPMENT

Delaware Mountain Group reservoirs were assigned to the Delaware Mountain Basinal Sandstone Play by Dutton and others (2003). All of these reservoirs are productive from mainly subarkosic sandstones of the Brushy Canyon, Cherry Canyon, and Bell Canyon Formations.

According to Dutton and others (2005), 78 reservoirs produced more than 1 MMbbl from this play through 2002. Total production from the play, as of 2003, stood at 262.2 MMbbl of oil from 267 reservoirs and 280.5 Mcf of gas from 95 reservoirs (Railroad Commission of Texas, 2003). As of 2003 2,103 oil wells and 183 gas wells were producing.

Controls on Reservoir Distribution

The primary control on reservoir distribution is the geometry of channel-lobe complexes in the context of local structure. A major component of reservoir geometry is the pinch-out of permeable sandstone facies into adjacent low-permeability siltstone. Levee, splay, and lobe subfacies have, to varying degrees, contact with sinuous, depositional-dip-trending channel-sandstone facies. All these stratigraphic elements pinch out laterally into siltstone baffles. However, the overall dip-aligned channel facies provides a potential pathway for fluid migration out of the reservoir system (fig. 26).

Structural elements that affect Delaware Mountain reservoir development are of four types. Regional-scale structures include (1) regional Laramide-induced tilting of the Delaware Basin to the east (figs. 26, 27) and (2) shelfward structural rise near shelf margins that is inherited from original depositional topography (figs. 11, 26). Reservoir-scale structures include (1) local compactional structures developed over subjacent sandstone bodies (fig. 28) and (2) slumps at the updip margin of channel-lobe complexes (fig. 25). Most reservoirs are developed where permeable facies are draped over or pinch out against local structural highs. Highs formed by differential compaction over reservoir-subjacent channel-lobe complexes. A common type of DMG reservoir occurs where a channel meander bend is in an updip position (figs. 26, 27) such that fluids cannot escape into the rest of the channel belt. More regional-scale hydrocarbon migration toward reservoir traps is controlled by the eastward dip imparted to the Delaware Basin by Laramide deformation. Many Bell Canyon reservoirs are located in the basinward extents of channel-lobe complexes rather than toward the Central Basin Platform shelf edge, from which the Bell Canyon feeder channels originate (figs. 4, 26), probably in response to structural tilting to the east. The paucity of basin-margin reservoirs probably reflects the structural rise toward the shelf edge that is inherited from original depositional topography and that may allow hydrocarbons to escape into reservoirs located on the shelf (fig. 26). Although basin and shelf reservoirs are not well connected in the sense that a basin reservoir interval can be traced directly into a shelf reservoir, fluid migration into shelf strata could occur along surfaces where basin strata onlap the slope or through the dip-aligned incised valleys that directed shelf-derived sediment into the basin.

Development of reservoirs in the DMG depends on the location of development of favorable facies, which is a function of the shifting of deep-water sandstone depocenters through the Guadalupian. King (1948) suggested that development of a post-Brushy rimmed margin comprising Goat Seep and Capitan carbonates may have obstructed formerly active clastic-transport fairways across the Guadalupe Mountains region during later DMG deposition. Consequently, early Guadalupian Brushy Canyon reservoirs are most abundant in the northern part of the basin in southeastern New Mexico (Lea and Eddy Counties). Several middle Guadalupian Cherry Canyon reservoirs are also located in the north part of the basin, although some also occur along the margin of the Central Basin Platform in Texas (Loving, Reeves, and Ward Counties) (fig. 4). Late Guadalupian Bell Canyon reservoirs are developed mainly in the northeast and east parts of the basin.

DMG reservoirs are not developed extensively to the west of the basin midline axis (figs. 2, 4), even though channel-lobe complexes occur in the west part of the basin. Channel-lobe complexes are especially evident in the Brushy Canyon outcrops that provide data for the facies models that have been developed (for example, Gardner and Sonnenfeld, 1992; Barton and Dutton, 1999). Absence of reservoirs in the western Delaware Basin partly reflects the absence of a top seal for the Delaware Mountain Group in the west such as the Castile and Salado provide in the subsurface. Channel-lobe complexes on the west side of the basin are sourced from the west and, in the absence of a top seal, dip-aligned channel systems provide a ready conduit for escape to the west of fluids generated in the subsurface.

Porosity and Permeability Development

The present state of DMG reservoir sandstone porosity development reflects the complexities of primary depositional and secondary diagenetic processes. Typical reservoir porosity values range from 10 to 26 percent; permeability values range from 0.1 to 155 md (Spain, 1992; Dutton and others, 1999; Broadhead and Justman, 2000). In spite of overall textural differences between the overall coarser grained Brushy Canyon and very fine grained Bell Canyon intervals, however, productive reservoir intervals from both formations show similar porosity/permeability relationships (fig. 29). Further, there appear to be no significant differences in the porosity/permeability relationships among various sandstone depositional facies (Dutton and others, 1999).

Two of the best single summaries of DMG porosity development and its effects on reservoir performance and well-log-based calculations of fluid saturation come from studies of the Brushy Canyon in Nash Draw field (Eddy County, NM) by Behnken (1996), who used XRD and SEM in his analyses of sidewall cores and cuttings, and by Thomerson and Asquith (1992), who used petrographic analyses coupled with well-log analyses on Brushy core from Mesa Hat field (Lea County, NM). Behnken (1996) recognized that very fine grained texture, grain angularity, and poor sorting caused vertically extended oil/water transition zones and high irreducible oil saturations in subarkosic clastics at Nash Draw. Thomerson and Asquith (1992) interpreted moderate to good sorting of subarkoses in Mesa Hat samples but recognized reduced permeability and enhanced irreducible fluid saturations accompanying very fine grained textures.

Diagenesis in DMG siliciclastics has produced secondary porosity due to feldspar dissolution. Pore throats have been further reduced by pressure solution of quartz grains, which produced a slitlike geometry. Authigenesis of feldspar, quartz, and clay minerals, which occurred in pores, was caused by the presence of organic fluids that were probably sourced from DMG organic-rich siltstones (Hayes and Tieh, 1992 a). However, the most common cements are carbonate (Thomerson and Asquith, 1992; Dutton and others, 1999). Predictably, total cements are the main control on porosity and permeability (Dutton and others, 1999).

Authigenic clay minerals present a particularly troublesome set of complications. Fibrous illite and chlorite, in particular, have developed bridges across pore throats and dissected porosity. Weblike growths of illite/smectite may swell 15 to 20 percent when contacted by drilling fluids, thus occluding even more pore space. Chlorite, as well as other iron-bearing authigenic minerals, can promote precipitation of pore-occluding, insoluble, Fe-hydroxide gels when contacted by acids.

Reservoir Quality Determination from Well Logs

Several critical issues must be dealt with when well log data are used to identify and evaluate DMG reservoirs. First, DMG siliciclastics are subarkosic to arkosic and produce elevated gamma-ray-log responses in shale-free sandstones. Shale is rare in the Delaware

Mountain Group, probably owing to sand storage in an eolian environment prior to basinal deposition.

Second, authigenesis of clays provided abundant microporosity, which is detected by neutron logging because of the presence of bound water. The effect is an overestimate of effective porosity and calculation of high water saturations (Thomerson and Asquith, 1992; Behnkin, 1996). The pessimism generated from calculations of high water saturations may be mitigated by the insight that much of the water bound in the clay fraction is irreducible (Behnken, 1996).

Third, resistivity contrasts between oil- and water-productive intervals are low because of high residual oil saturations in the invaded zone, as well as high irreducible water saturations (Thomerson and Asquith, 1992).

Calculation of effective porosity requires corrections of total porosity for included microporosity. Thus, determination of clay content is required, which cannot be performed using gamma-ray data alone because of the abundance of K-feldspar. In Hat Mesa field (Brushy Canyon), Thomerson and Asquith (1992) used neutron-porosity (ϕ_N) and density-porosity (ϕ_D) data to calculate the clay volume (V_{clay}):

$$V_{clay} = (\phi_N \text{ shaly sand} - \phi_D \text{ shaly sand}) / (\phi_N \text{ shale} - \phi_D \text{ shale}),$$

where all porosities were corrected to a sandstone matrix. Complications arising from borehole rugosity (observed in caliper logs) and gas (observed in gas/oil data) were minimal in Hat Mesa field. Thereafter, Thomerson and Asquith (1992) generated a series of petrophysical crossplots that were interpreted to differentiate permeable water-productive from permeable oil-productive zones.

Integration of the results from crossplot analyses produced cutoff values for productive intervals in Hat Mesa (Brushy Canyon) reservoir: ϕ = 12 percent at 0.1 md. Very similar cutoff values were determined by Dutton and others (1999) for hydrocarbon-productive Ramsey sandstone at Ford Geraldine (Bell Canyon) reservoir in Reeves and Culberson Counties, Texas.

Identification of widespread organic-rich siltstone intervals is important because they act both as local source beds for hydrocarbons and as part of the reservoir seal. Organic-rich beds correspond to some of the most radioactive units observed in gamma-ray logs. Only volcanic-ash deposits show similarly elevated gamma-ray responses.

Older resistivity logs often show an increase in resistivity beginning within the upper part of the Bell Canyon several feet below the contact with the Castile. This effect, called the “Delaware Effect,” is a function of electrode spacing of the resistivity tool (Laterolog). The result can be a misinterpretation that hydrocarbons are trapped below the Castile, when, in reality, the interval may be water bearing. Improvements were eventually made in electrode spacing and tool design (Asquith and others, 1997a).

Traps, Seals, and Sources

DMG reservoirs reflect both stratigraphic and structural controls on hydrocarbon migration and trapping. Stratigraphic controls include lateral pinch-outs of permeable, laterally discontinuous, channel-levee-complex, overbank-splay, and lobe sandstone- and coarse-siltstone facies into much lower permeability, laterally more extensive siltstone facies. Further, the laterally extensive siltstones provide reservoir-scale top seals (for example, Kane, 1992). Gardner (1992) recognized that deposition of regionally extensive fine-grained sediments during third-order sea-level rise recorded progressive basin starvation and produced top seals that genetically and hydraulically separate the three DMG formations. Carbonate strata in DMG carbonate members, which also contain siliciclastics reservoirs, may also form lateral and top seals on siliciclastic reservoirs contained within or below such members (for example, in Avalon reservoir, described by Kane, 1992) (fig. 17). Locally, stratiform calcite-cemented intervals provide additional controls over vertical flow (for example, Dutton and others, 1999) (figs. 18, 19).

Hydrocarbon sources are thought be organic-carbon-bearing siltstone strata that are interbedded with, and laterally adjacent to, reservoir facies (fig. 6). DMG organic carbon in siltstones and in most of the oil accumulations has similar sulfur and carbon isotopic composition (Hayes and Tieh, 1992a). Evolution of organic fluids appears to have controlled much of DMG diagenesis, including development of dissolution-produced secondary porosity and subsequent mineral authigenesis (Hayes and Tieh, 1992a). Some siltstones are remarkably organic rich. Dutton and others (1999) reported a Bell Canyon coarse-grained siltstone (average grain size of 4.94 phi, with an organic-carbon content of 46 percent by weight. Most so-called organic-rich siltstones are not so carboniferous, however, averaging less than 4 percent by weight (Sageman and others, 1998).

Structural controls on reservoir development include a Laramide-induced, regional monoclinal dip down to the east (fig. 26); local compactional antiformal and synformal structures over subjacent sandstone bodies (for example, fig. 28); and syndepositional slumps that bound the up-depositional-dip ends of channel systems (for example, Gardner and Sonnenfeld, 1996) (fig. 25).

Production Characteristics and Completion Challenges

Primary oil production is typically only about 50,000 to 100,000 bbl per well (10 percent of OOIP) in DMG fields. (Montgomery and others, 1999). Production decline rates are initially high as solution gas, the predominant drive mechanism, is depleted. Production characteristics vary significantly over short distances (fig. 30), probably reflecting the laterally restricted extent of productive channel-levee-lobe complex sandbodies.

Porosity and permeability attributes in DMG reservoir facies are modest. Reservoir porosity ranges typically from 12 to 25 percent; permeability ranges from 1 to 5 md, with exceptional occurrences of 200 md in thin, laterally restricted units (Montgomery and others, 1999). Although detrital clay (kaolinite) composes less than 1 percent of the rock, the already impoverished permeability would be further diminished by clogging of pore throats by Fe-hydroxide gels precipitated through the contact of iron-bearing minerals (for example, chlorite) with acidic borehole fluids (Behnken, 1996). Walling and others (1992) warned that chlorites could de-evolve to water-expandable forms in the presence of some anthropogenic borehole fluids and become migratory. Behnken suggested that addition of as little as 2 percent KCl will mitigate potential clay deflocculation and clay-particle migration. Other additives are available to prevent precipitation of Fe-hydroxides, including acetic or citric acid (Green and others, 1996).

Because DMG permeability is marginal, fracture stimulation with sand propping is commonly used in the final stages of well completion. However, reservoirs characteristically comprise numerous thin hydrocarbon-productive intervals that are interbedded with thin water-productive intervals. Further, control of fracture propagation is problematic because of the microlaminated, lithologic variability of reservoir intervals and lack of shaly, stratal, fracture barriers. The danger of connecting water-bearing and hydrocarbon-bearing intervals with induced fractures (“treating out of zone”) is always present, and it can result in excessive water production or “watered-out” hydrocarbon reservoirs (Scott and Carrasco, 1996). Fracture-stimulation jobs are customized for local geologic conditions by varying pump rates, pad-stage volumes (amount of fluid used to create fractures), fluid viscosities, sand concentrations, and fluid-loss additives (Scott and Carrasco, 1996). Success of fracture treatments has traditionally been tested by posttreatment injection of radio tracers (for example, iridium and scandium) and gamma-ray relogging of the well. Posttreatment assessment of the success of the treatment may potentially be performed after formation damage has occurred, a problem whose recognition has prompted the design of real-time fracture-treatment monitoring techniques that allow timely discontinuance of treatments (Scott and Carrasco, 1996). Increased productivity is an obvious indicator of success. Design criteria for fracture stimulation in relatively lower permeability units are different than those for higher permeability units. After successful fracture stimulation, ultimate recoveries in lower permeability units are increased over what might otherwise be expected, whereas they are not increased for higher permeability units (Scott and Carrasco, 1996).

The primary drive for DMG sandstone reservoirs is solution-gas and water drive (Spain, 1992). Per-well initial production may exceed 80 bbl/d (13.25 m^3/d) but will decline to less than 12 bbl/d (<2 m^3/d) after 4 years as solution gas is depleted (fig. 31). Injection of water for pressure maintenance has yielded significant improvement in some cases (for example, Dutton and others, 2005; after Broadhead and others, 1998) (fig. 32). Injection of CO_2 has also proven successful, for example, in Ford Geraldine field (Bell Canyon) (Dutton and others, 2003) (figs. 33, 34).

Limited lateral continuity of productive facies presents a challenge for economic development of DMG reservoirs. The geographic limitation of reservoir continuity is demonstrated by differences in production characteristics in closely spaced wells. Drainage areas for wells at Nash Draw (lower Brushy Canyon) range from 19 to 66 acres, with an average of 34 acres (Montgomery and others, 1999). The effects of limited reservoir are shown by comparing production characteristics in closely spaced wells. Figure 30 shows oil, gas, and water production in three wells that are 0.25 to 0.5 mi (0.4 to 0.8 km) apart. Dutton and others (1999) pointed out that pinch-outs of channel, levee, and lobe sandstone into siltstone are the primary control on lateral reservoir heterogeneity. Additional complications include the pinch-out of splay reservoir sandstone onto topographically elevated levee complexes. Vertical heterogeneities are produced by deposition of both laterally extensive and discontinuous siltstones between stacked channel sandbodies (fig. 8). As discussed earlier, laterally discontinuous distribution of stratiform calcite cements also imparts interwell heterogeneity to reservoirs.

SUMMARY AND CONCLUSIONS

The Guadalupian-age Delaware Mountain Group contains the rock record from deep-water deposition in the Delaware Basin. Rock types include shelf-derived, fine-grained, feldspar-bearing siliciclastics and limestone-dominated carbonates derived from the outer-shelf and shelf margin. Sandstones were deposited mainly by density flow during lowstand and early transgressive sea-level stages, whereas regionally extensive siltstone intervals were deposited from suspension most abundantly during sea-level highstands. Carbonates were probably deposited during periods when the greatest amount of energy was imposed on shelf-margin source areas, which may have been during transgressions or when early highstand shorelines were near the shelf margin. Calcite cement is common and is most often associated with finer grained sandstone and coarse-grained siltstones in areas dominated by overbank deposits. Detrital clay is not abundant, and most clays comprise authigenic chlorite or illite. Clay content decreases sandstone permeability without significantly affecting porosity and increases irreducible water content.

The DMG succession has been formally divided into 3 formations (Brushy Canyon, Cherry Canyon, and Bell Canyon), 5 composite sequences, and 24 high-frequency sequences. The Brushy Canyon, the coarsest grained formation in the outcrop area, contains little carbonate compared with that of the others. Correlations between wells generally depend on recognition of the carbonate members and widespread siltstone intervals. Recognition of the prominence of organic-rich siltstone in the upper parts of the Brushy Canyon and Cherry Canyon facilitates correlations between wells of the Brushy Canyon/Cherry Canyon and Cherry Canyon/Bell Canyon boundaries, respectively. Interpretation of siliciclastic and carbonate end-member rock types from gamma-ray and porosity well logs is relatively straightforward, in most cases. High irreducible water content associated with the clay fraction produces lower-than-expected resistivities in hydrocarbon-productive strata.

Hydrocarbon reservoirs have both stratigraphic and structural elements. Lateral pinch-outs of sandstone porosity into low-permeability siltstones and superposition of siltstones over sandbodies compose the stratigraphic elements. The structural components may include (1) anticline formation caused by differential compaction over and around subjacent sandbodies and (2) regional dip arising either from Laramide deformation or (3) depositional topography on slopes approaching shelf margins. Reservoir traps are preferentially developed where porosity-pinch-out areas are in updip positions. Hydrocarbons may escape to shelf reservoirs where porous and permeable facies are positioned on slopes that rise toward shelf areas.

The DMG is an underexploited reservoir succession; estimated typical primary recovery efficiency is only 10 percent of OOIP. Most enhanced recovery efforts recover an addition of less than 20 percent of OOIP, with some notable exceptions. This modest performance arises largely from laterally restricted distribution of reservoir sandbodies, generally low permeability, and characteristic interbedding of thin hydrocarbon- and water-productive intervals. Economically acceptable production requires fracture stimulation that risks interconnecting water- and hydrocarbon-productive reservoirs and acid stimulation that risks production of formation-damaging Fe-hydroxide gels from decomposing Fe-bearing minerals such as chlorite. Successful application of enhanced recovery techniques depends on accurate knowledge of the interconnectedness of permeable facies between injection and production wells. For example, productive lobe and channel sandbodies may be well connected, whereas productive overbank-splay sandbodies may be isolated from the others. High-resolution 3-D seismic imaging may facilitate mapping of laterally and stratigraphically heterogeneous sandstone distribution. Horizontal drilling may intercept and facilitate production from laterally disconnected sandbodies, although maintaining stratigraphic separation of hydrocarbon- from water-productive intervals may be more complicated than with vertical completions.

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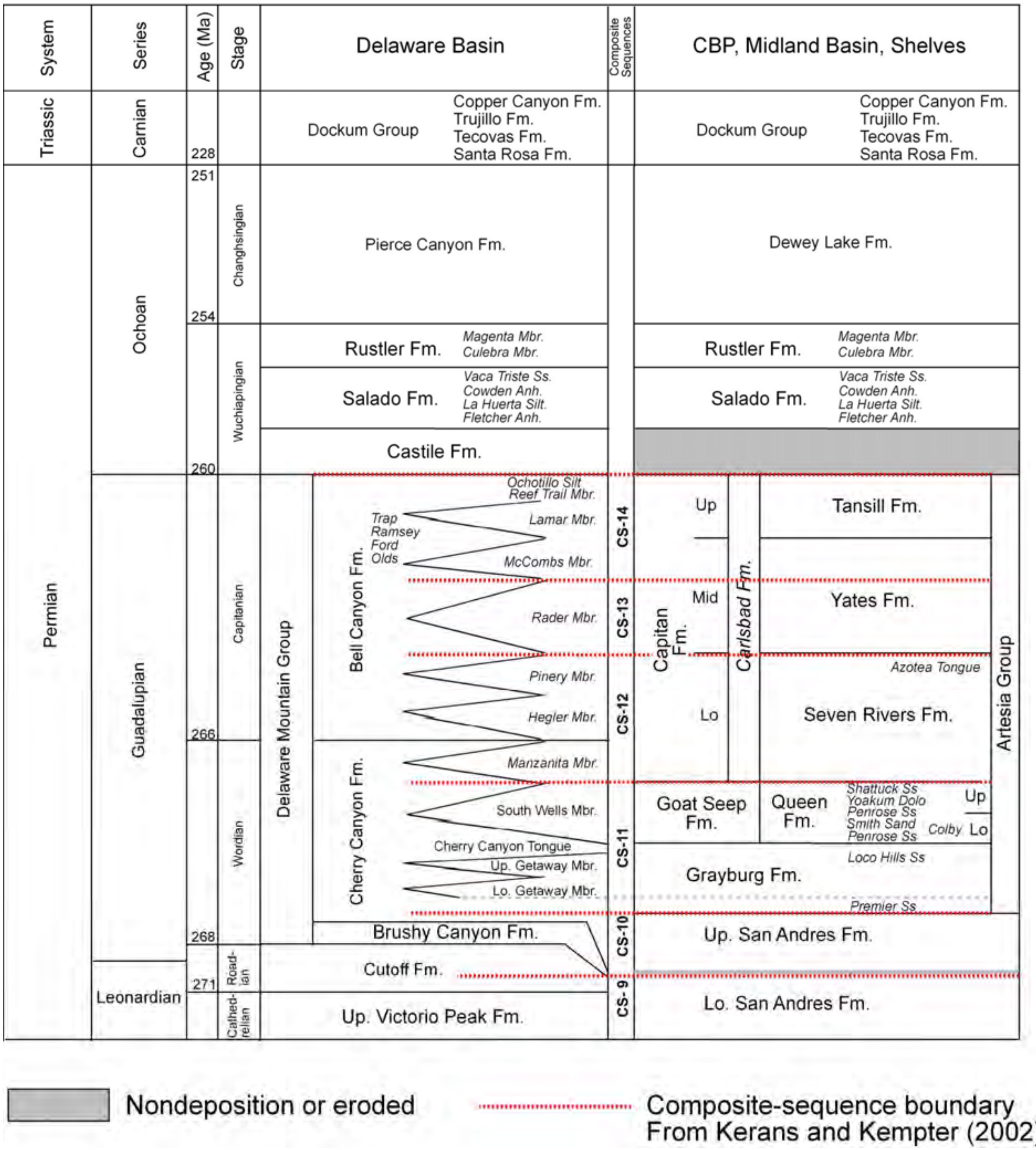


Figure 1. Correlation chart for uppermost Leonardian and Guadalupian strata in the Permian Basin.

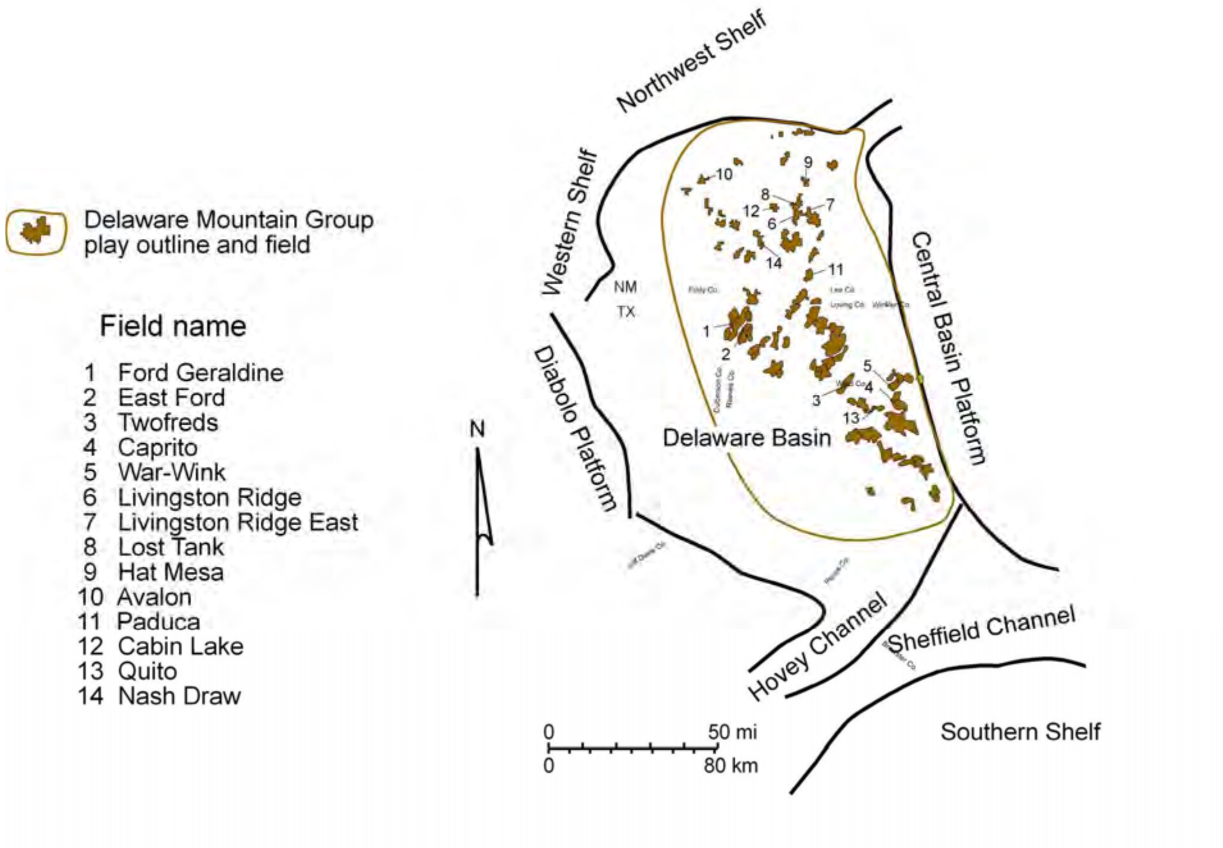


Figure 2. Map showing locations of reservoirs (cumulative production > 1MMbbl) within the Delaware Mountain Group play. Also shown are approximate positions of major tectonic elements and suggested boundaries of plays. Reservoirs specifically discussed in this report are indicated.

Figure 3. Unconformable contact between the Cherry Canyon and underlying Brushy Canyon Formations. Outcrop is on Hwy 62-180, south of Guadalupe Pass and north of El Capitan scenic turnout, Guadalupe Mountains. Strata are composed of subarkosic sandstone and siltstone.

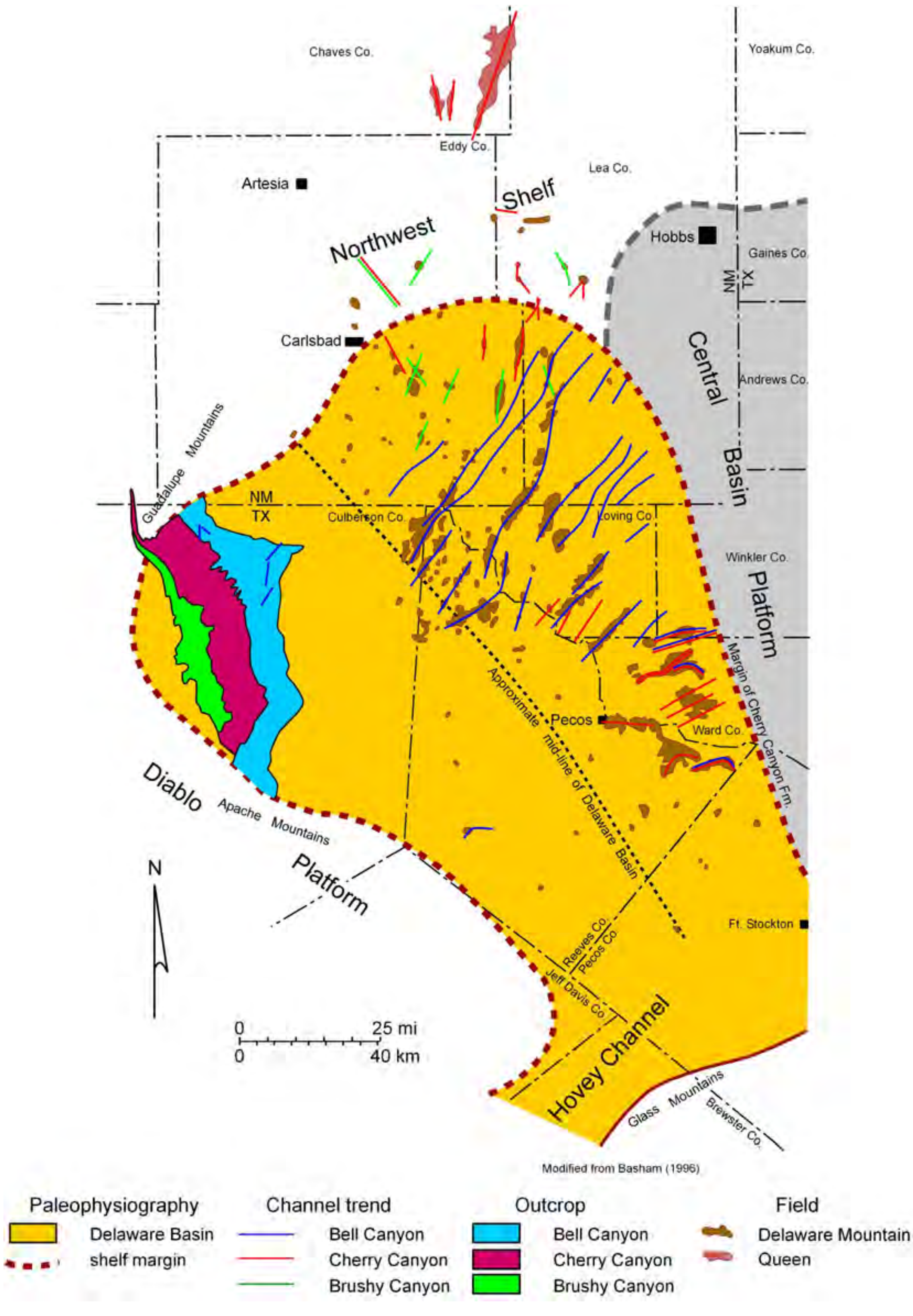


Figure 4. Map of Delaware Mountain Group reservoirs. Also shown are inferred submarine channel trends that are color coded to indicate primary reservoir intervals. Note that Brushy sandstone fairways trend preferentially north to south, Bell Canyon fairways trend northeast to southwest, and Cherry Canyon fairways trend from the north and from the east.

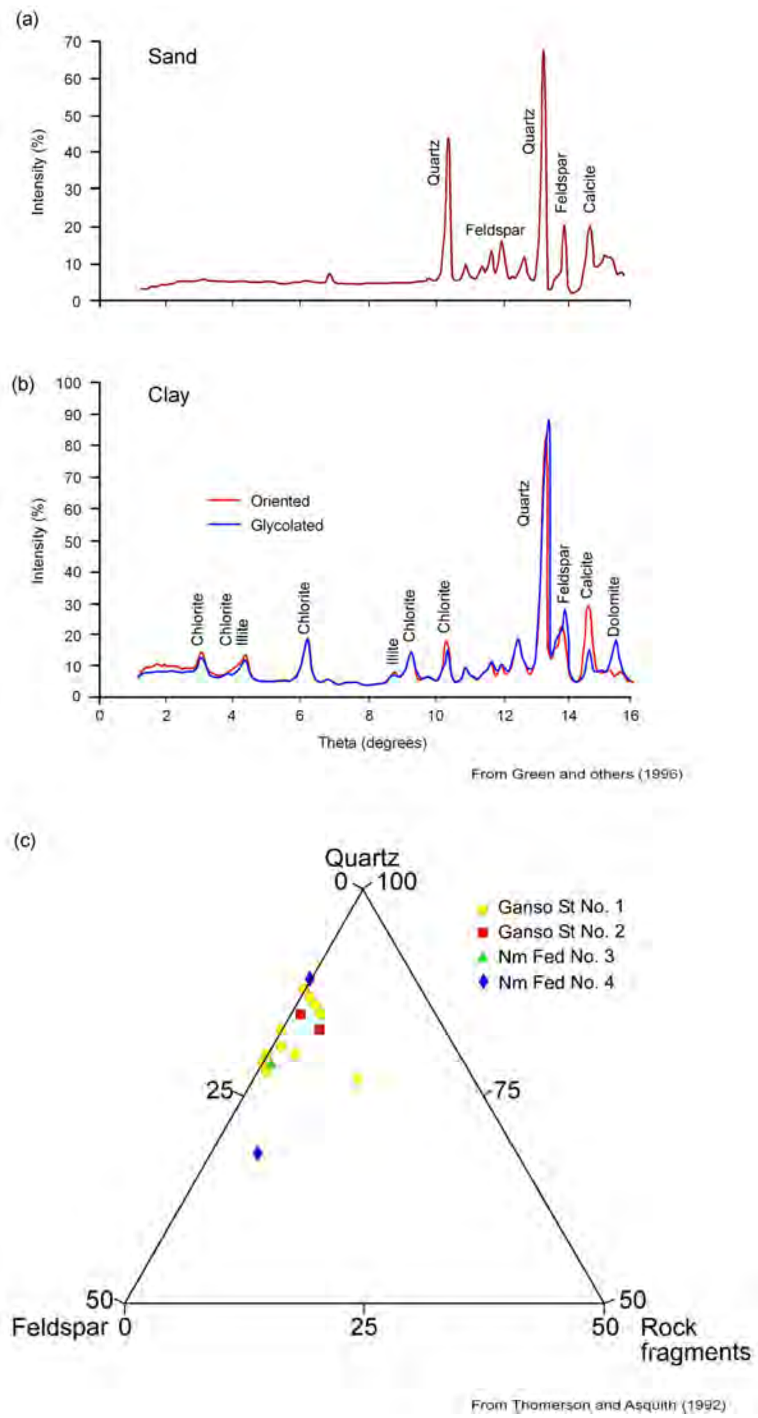


Figure 5. Mineralogy of Delaware Mountain Group siliciclastics: (a) x-radiogram of typical fine- to very fine grained Brushy Canyon sandstone showing prominence of quartz, feldspar, and calcite (cement); (b) x-radiogram of typical, mainly authigenic clay fraction composed of illite, chlorite, feldspar, calcite, and dolomite; (c) ternary compositional diagram of sand fraction from four Brushy Canyon wells showing subarkosic to arkosic character of DMG reservoir facies.

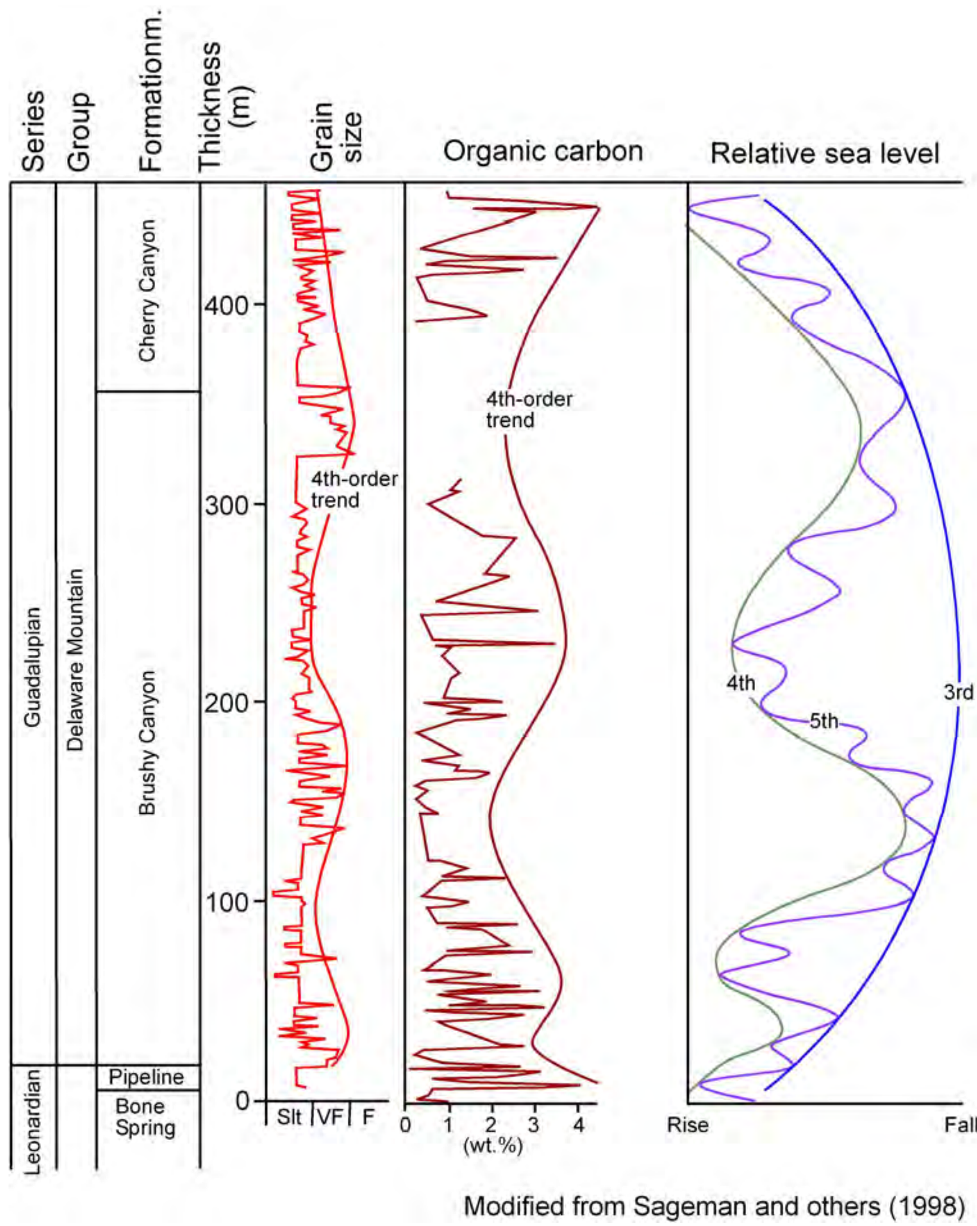


Figure 6. Graphs showing correspondences of grain size, organic carbon content, and interpreted relative sea-level stages for the Brushy Canyon and lowermost Cherry Canyon Formations. Samples are from outcrops in the Guadalupe and Delaware Mountains. Peaks in deposition of silt and organic matter tend to be associated with interpreted rises and highstands of sea level. Modified from Sageman and others (1998).

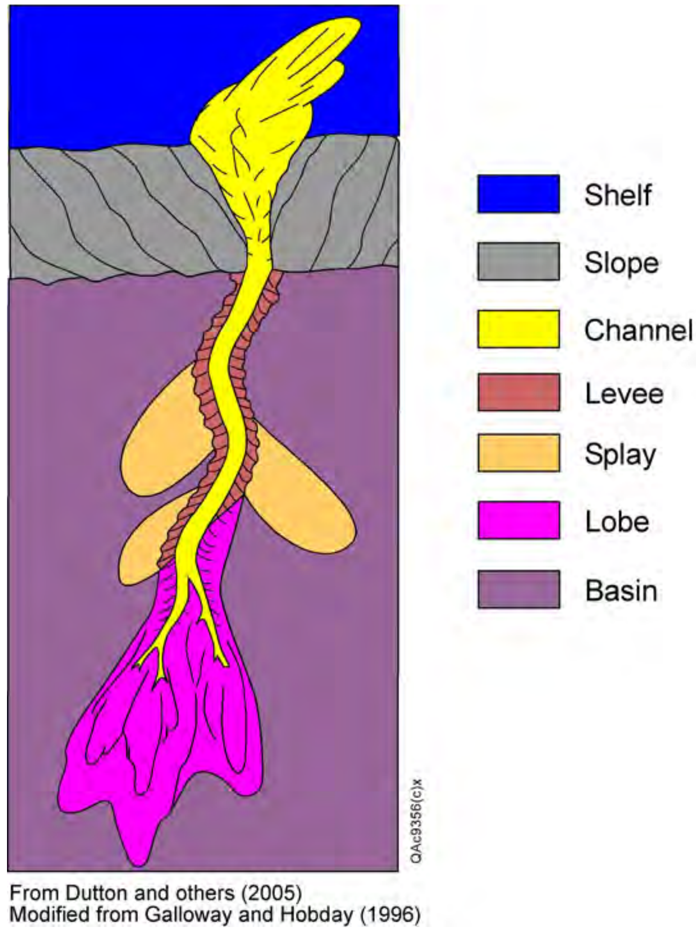


Figure 7. Simplified model of generalized shelf-margin paleogeographic and depositional elements of Delaware Mountain Group deep-water sandstone facies. From Dutton and others (2005); modified from Galloway and Hobday (1996).

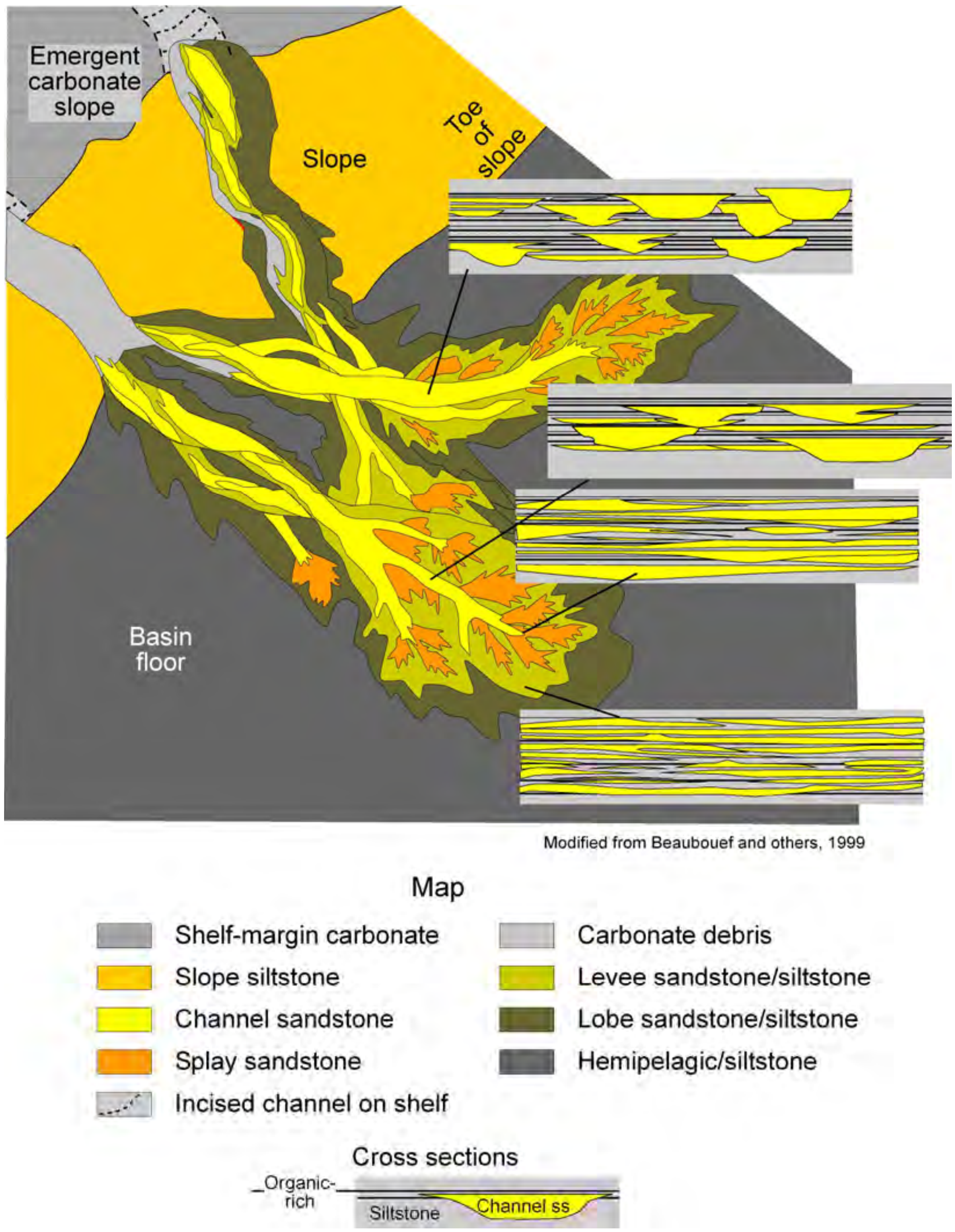


Figure 8. Schematic model of principal reservoir facies of the Delaware Mountain Group showing idealized cross sections of sandbody development along depositional dip. Sandbodies tend to become laterally more extensive with less vertical incision downdip, although compensatory stacking of sandstone units is a characteristic process along the slope profile. Modified from Beaubouef and others (1999).

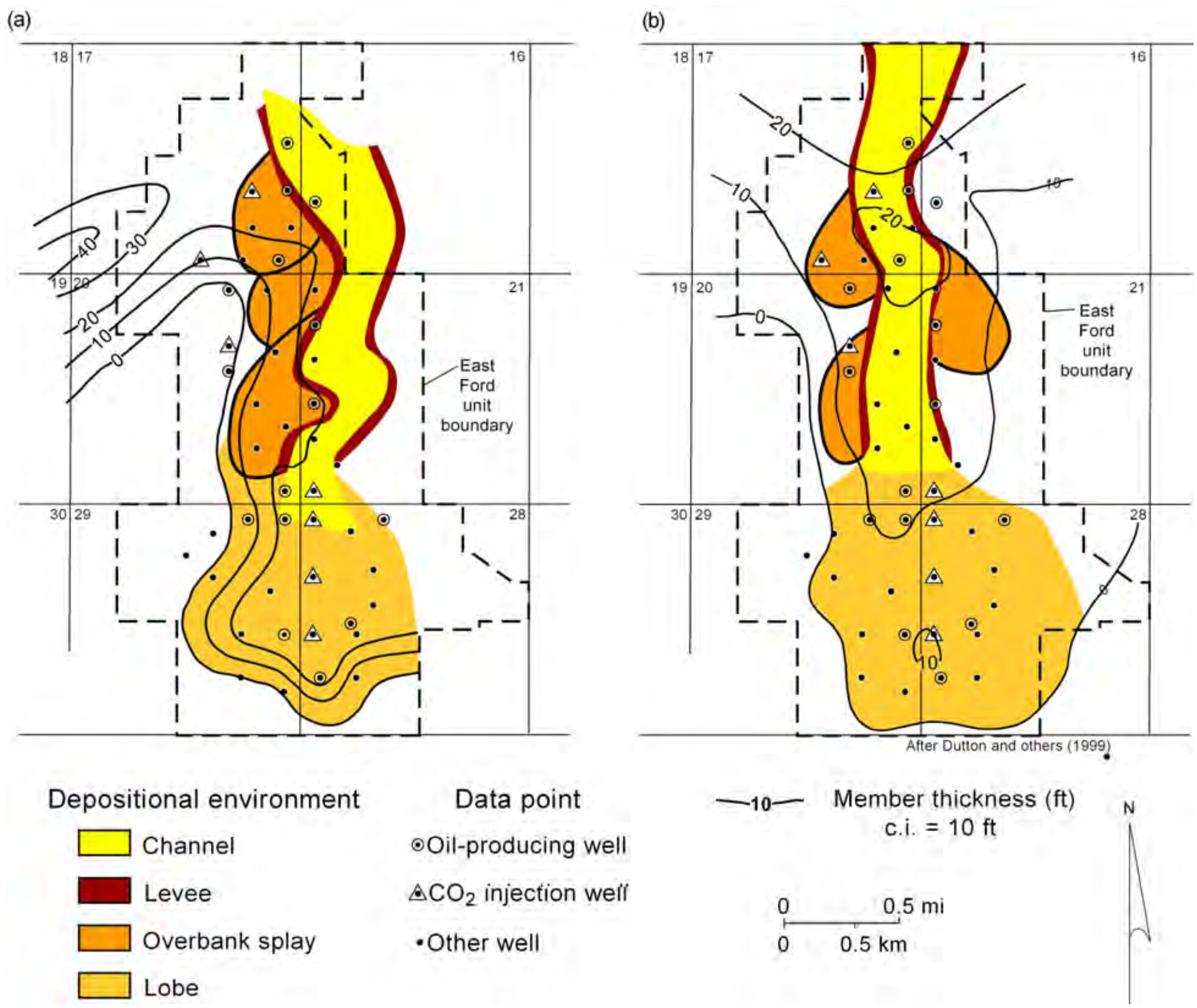


Figure 9. Isopach and interpreted facies maps of (a) Ramsey 1 and (b) Ramsey 2 sandstone, East Ford Unit (Bell Canyon). Facies are based on classification scheme illustrated in figure 7. Field location shown in figure 2.

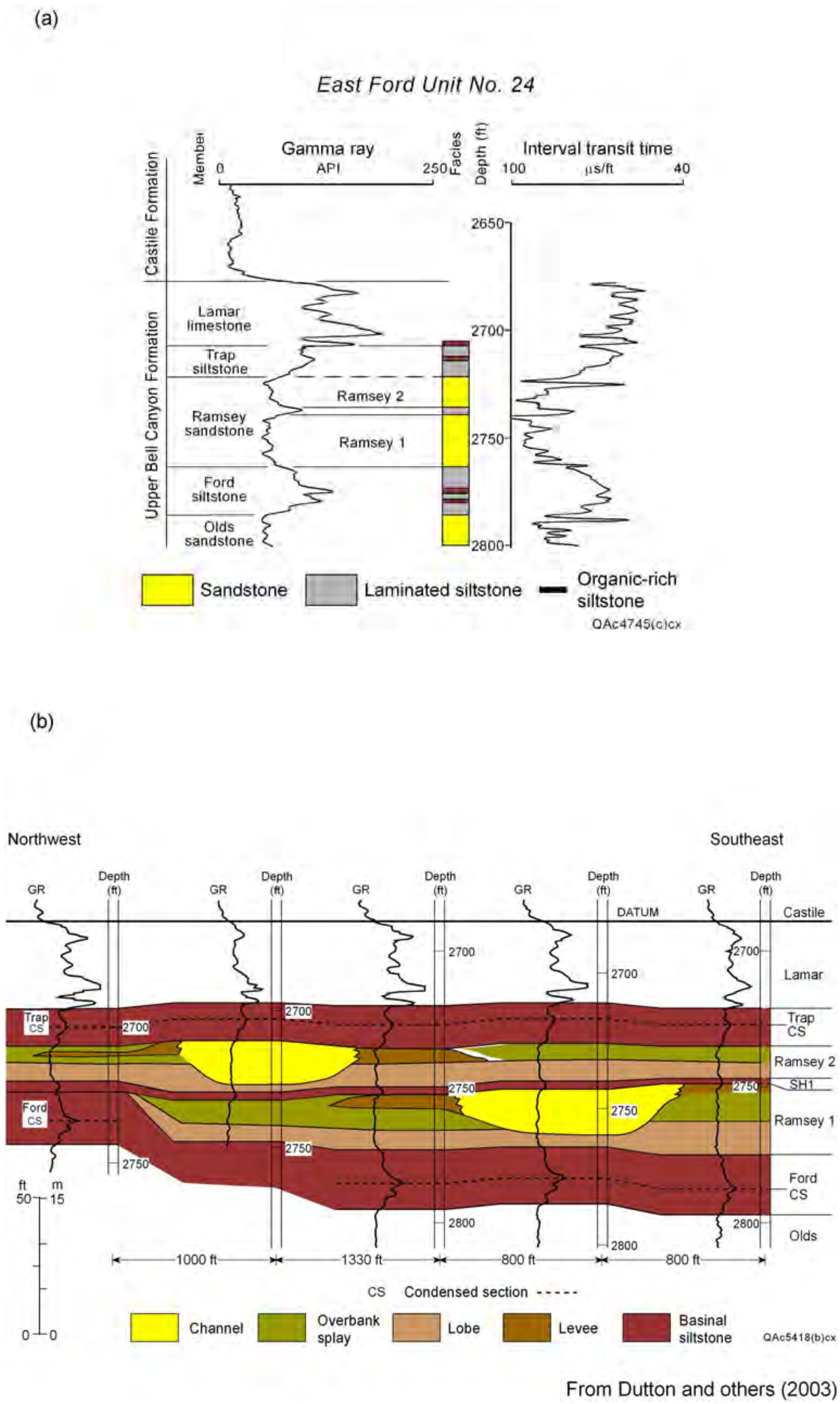


Figure 10. Stratigraphy of Bell Canyon Formation at East Ford unit. (a) Type log showing representative gamma-ray and acoustic logs for the upper part of the formation; Ramsey primary sandstone reservoir intervals are highlighted; (b) Northwest-to-southeast stratigraphic cross section showing compensatory stacking of sandbodies and laterally extensive siltstone seals. Field location shown in figure 2.

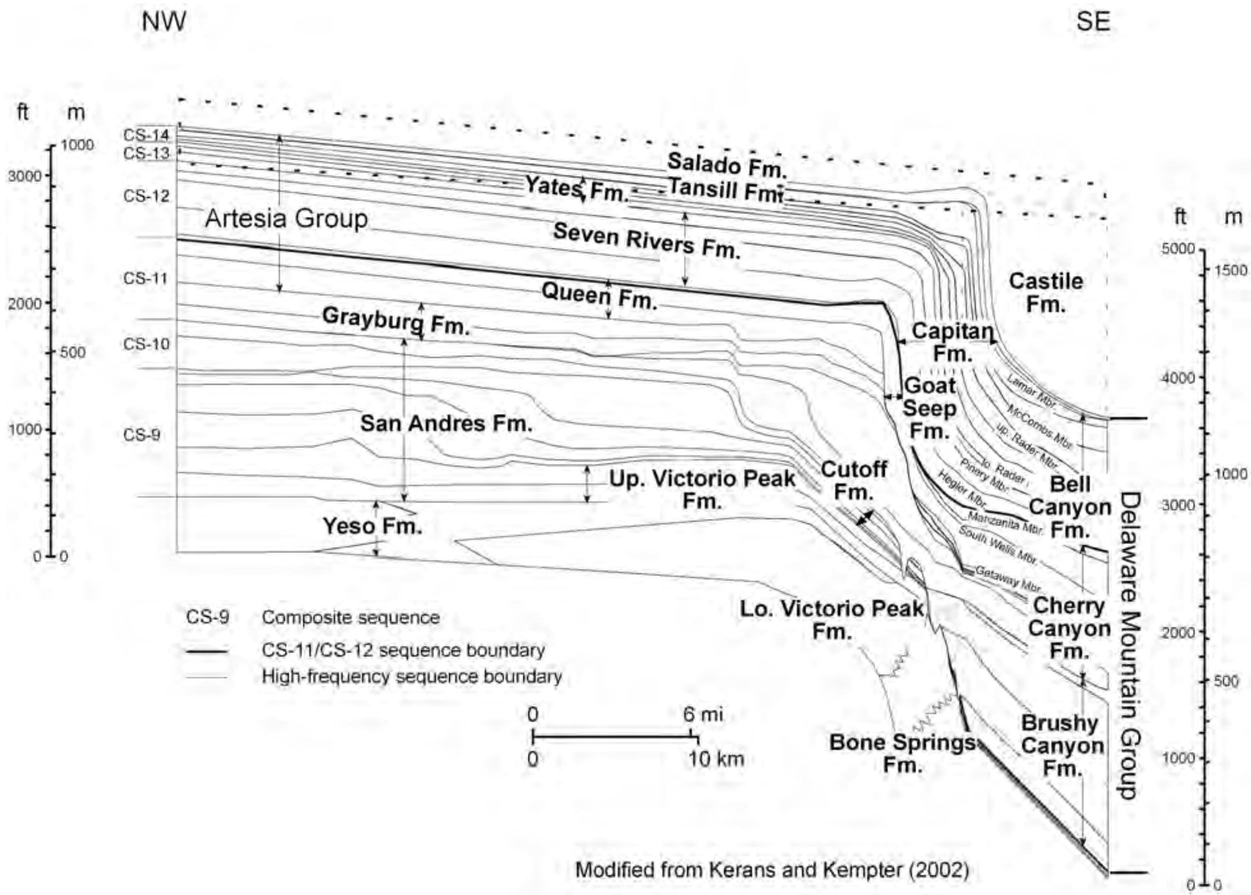
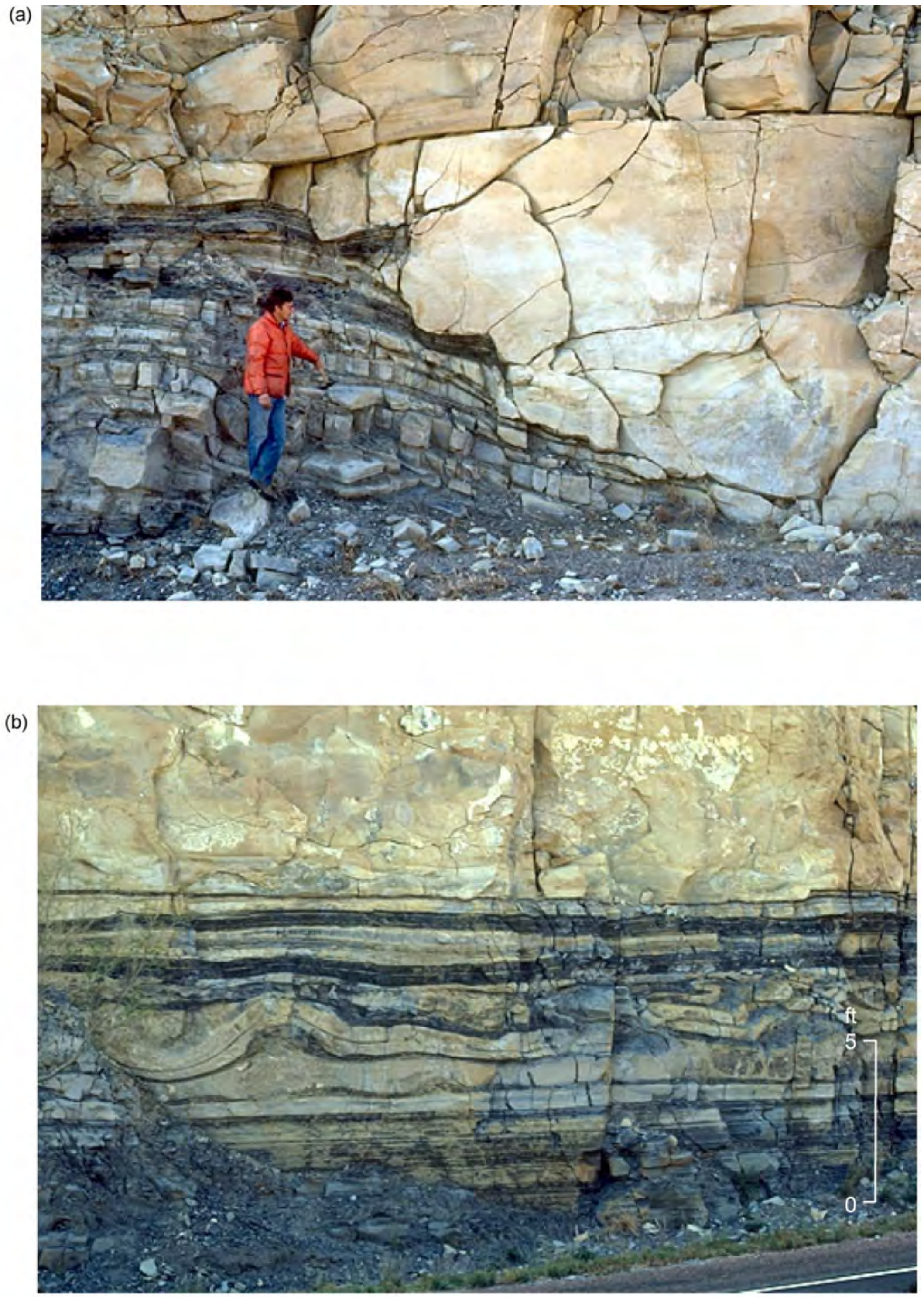


Figure 11. Composite structure dip section of the uppermost Leonardian, Guadalupian, and lower part of the Ochoan in the Guadalupe and Delaware Mountains area showing formation and member names. Also shown are sequence stratigraphic subdivisions, including composite sequences (CS), and high-frequency sequences (not labeled). Sequence boundary that separates the sequences associated with the Capitan shelf margin (Bell Canyon in the basin) from the underlying sequences (Brushy Canyon and Cherry Canyon in the basin) is indicated by the bold line. Modified from Kerans and Kempter (2002).



From Scholle (1999)

Figure 12. Channel and overbank facies, Brushy Canyon Formation, Guadalupe Mountains. (a) Incised valley in overbank deposits with channelized sandstone fill and (b) overbank sandstones and siltstones overlain by channel sandstone. Dark strata are organic-rich siltstones similar to those that act as hydrocarbon source beds for reservoir sandstones. Outcrops are on Hwy 62-180, south of Guadalupe Pass and north of El Capitan scenic turnout, Guadalupe Mountains.

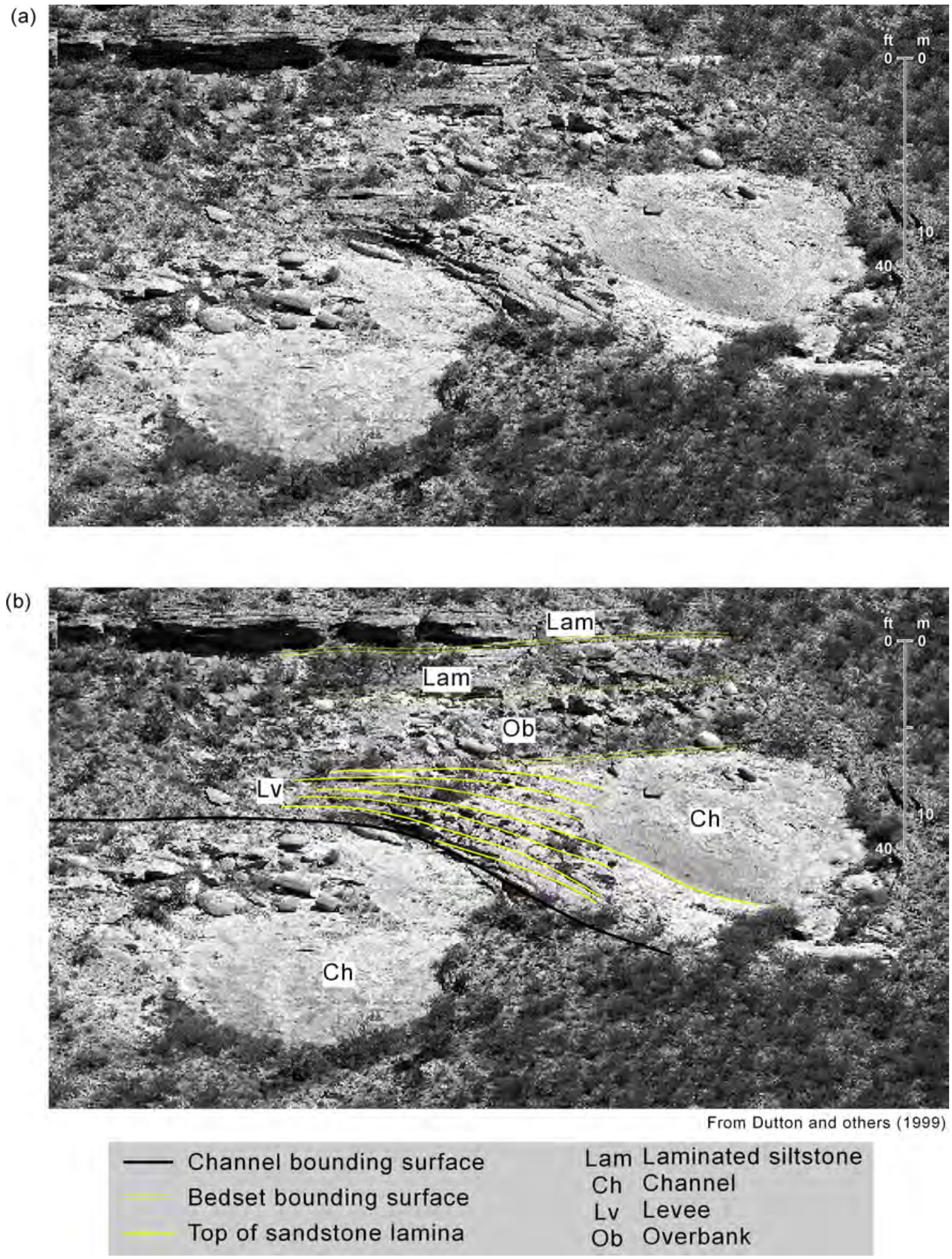


Figure 13. Outcropping channel-levee complexes, overbank deposits, and laminated siltstone deposits at Willow Mountain outcrop area, Delaware Mountains, Bell Canyon Formation: (a) outcrop photo and (b) annotated outcrop photo. Note compensatory stacking of channel sandbodies. From Dutton and others (1999).

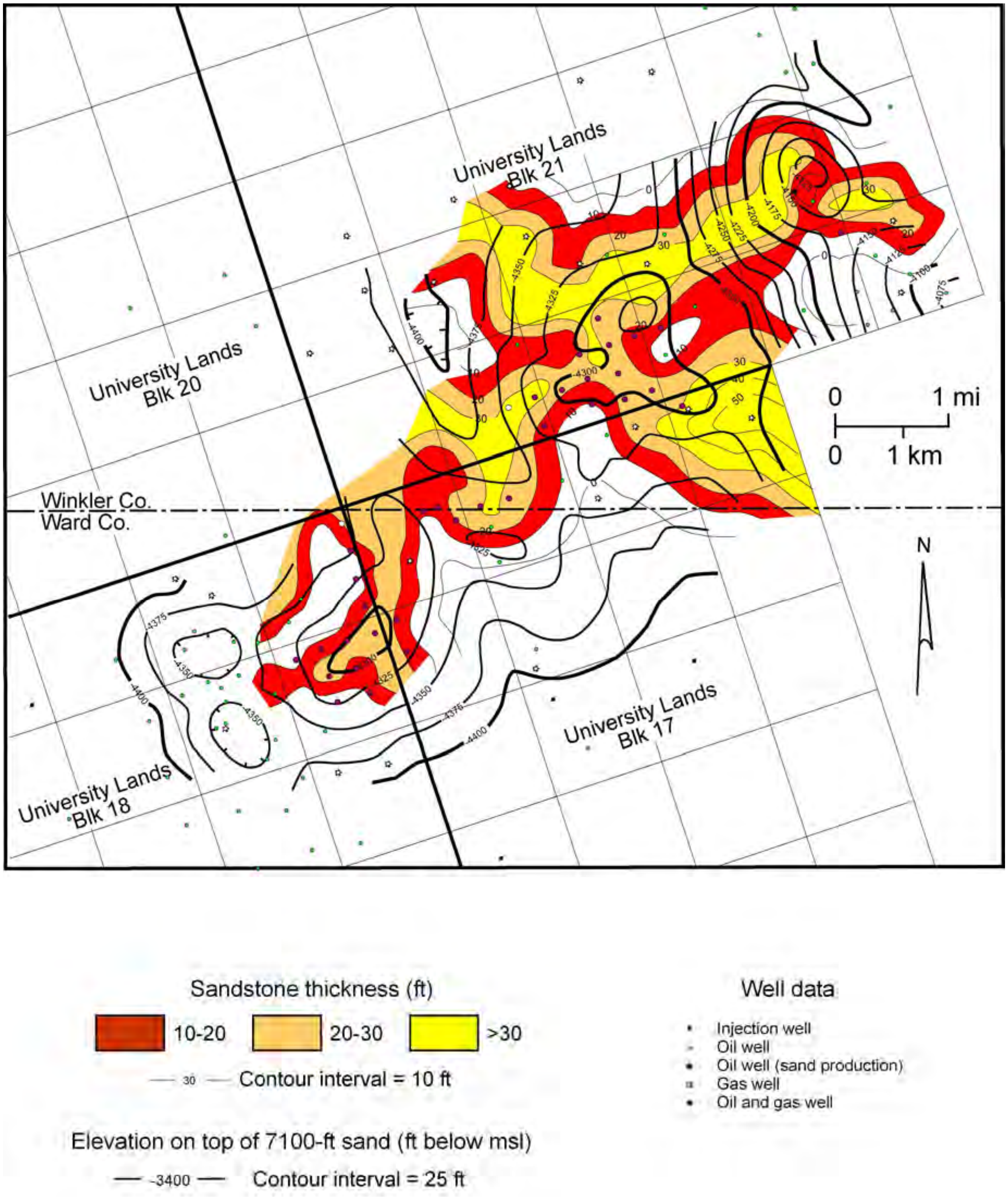


Figure 14. Isopach and structure maps of 7100-ft sand in the War-Wink field area. Porous sandstone facies record deposition in submarine channels. Note that sand-reservoir production is concentrated near anticlinal crests or where sandstone porosity pinches out onto anticline flanks. Field location shown in figure 2.

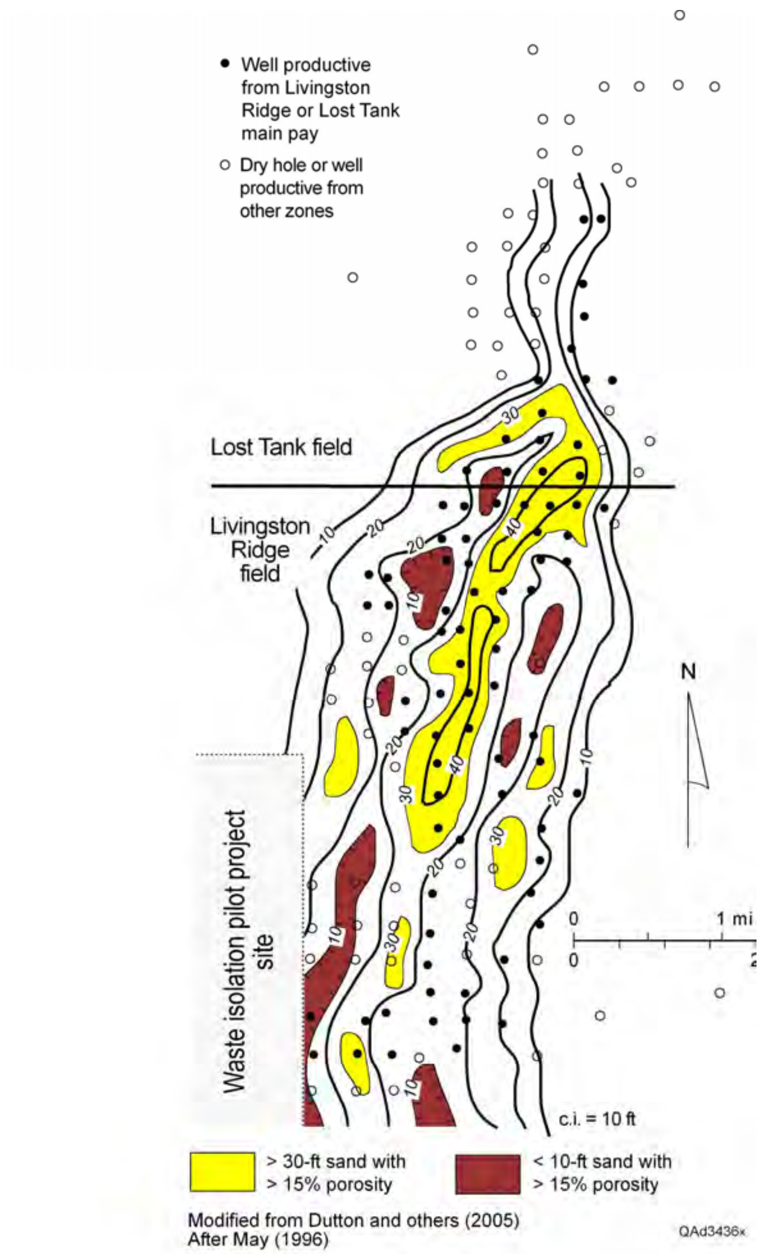


Figure 15. Thickness map of the main pay (porosity >15%) in the Brushy Canyon Formation, Livingston Ridge and Lost Tank fields. Thicknesses greater than 20 ft correspond to main channel complexes. Note that production is not limited to thicker intervals. Field location shown in figure 2.

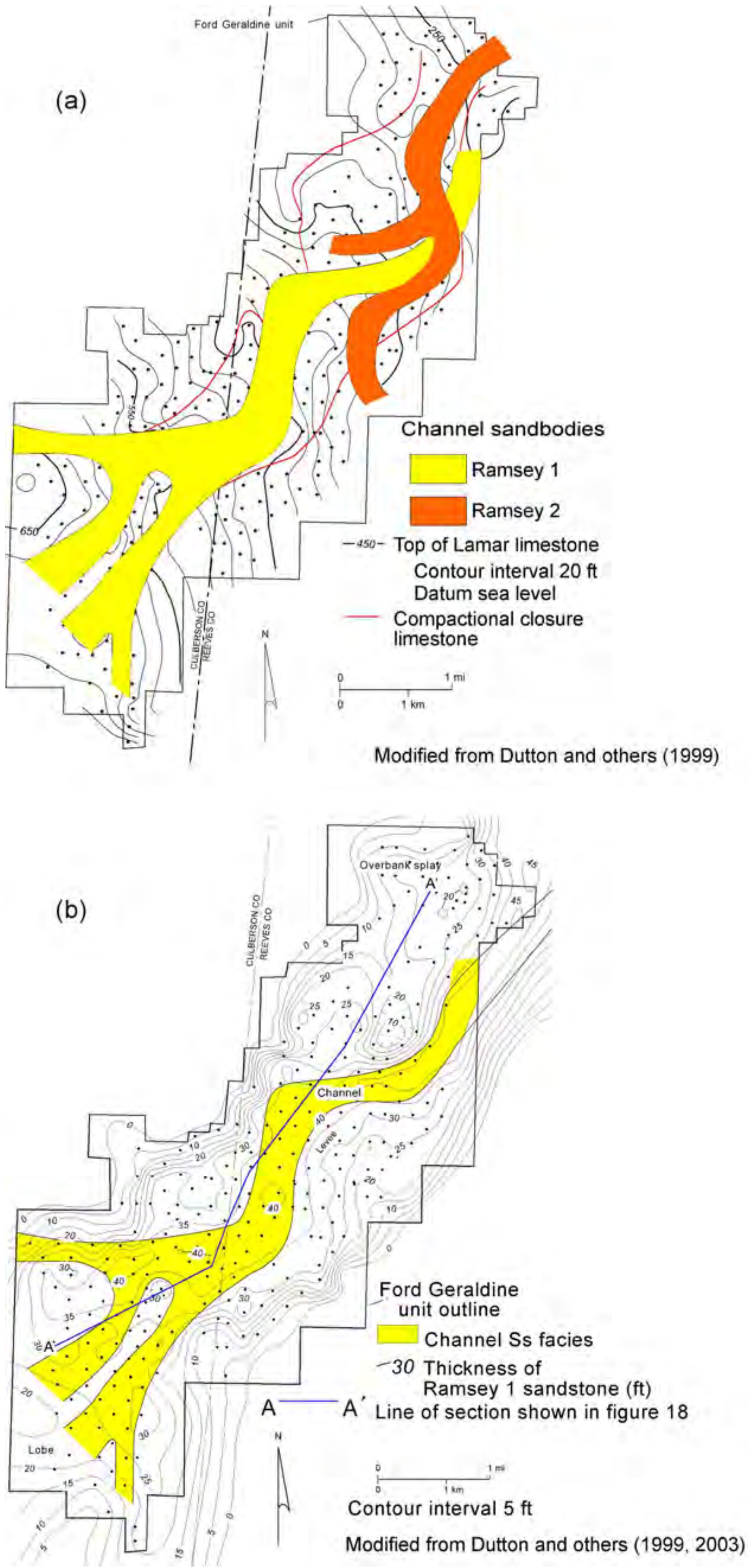


Figure 16. Ramsey Sandstone and Lamar Limestone (Bell Canyon) maps, Ford Geraldine field. (a) Thickness of Ramsey 1 sandstone interval. Thickest accumulations correspond to locations of channel and splay facies development. Note compensatory stacking of channel sandstone facies. (b) Structure on the top of the Lamar Limestone Member of the Bell Canyon Formation showing compactional anticline development over trend of dominant Ramsey Sandstone channel system. Note correspondence with isopach thickness trend shown in a. Field location shown in figure 2.

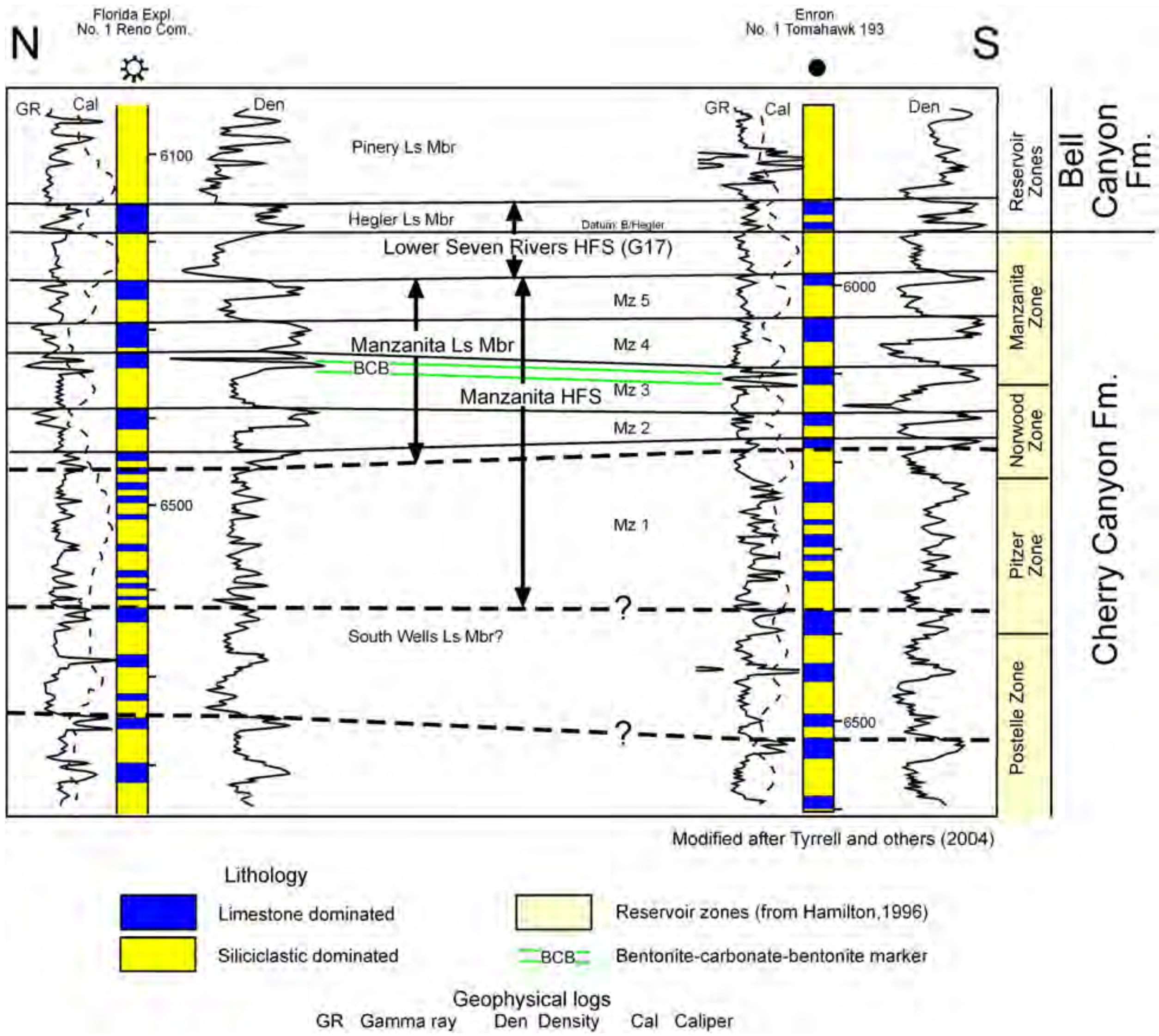


Figure 17. North-south correlation section in Quito field area showing upper Cherry Canyon and lowermost Bell Canyon limestone and siliciclastic intervals and sequence stratigraphy. Reservoir zones designated by Hamilton (1986). Quito field area shown in figure 2.

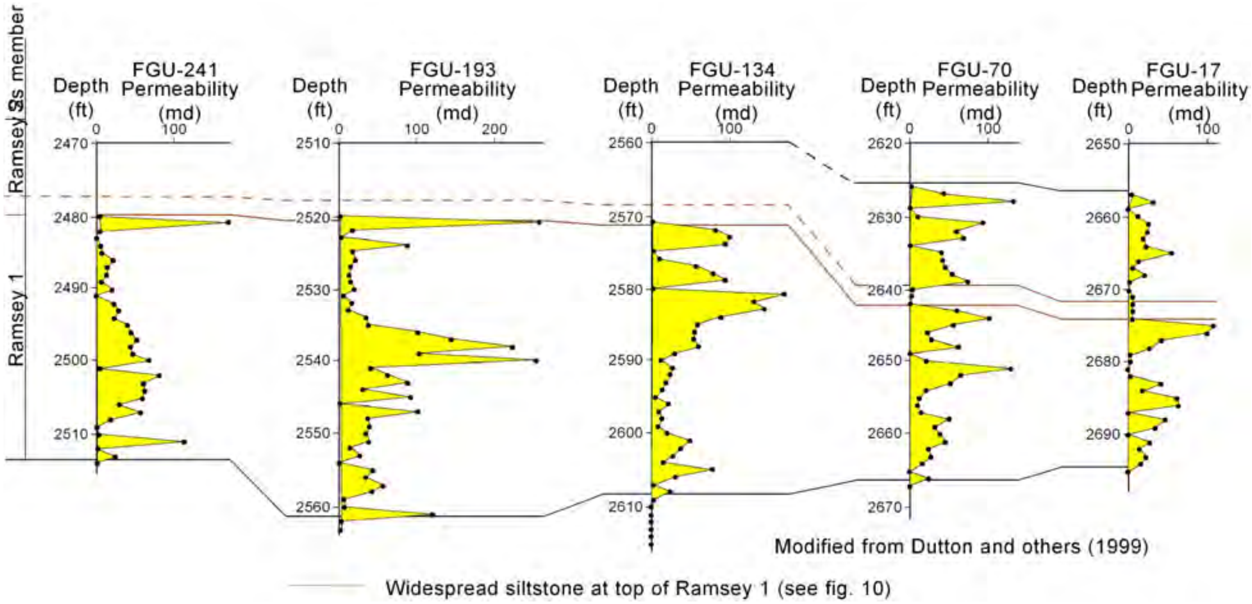


Figure 18. Vertical profiles of permeability distribution for five wells from core analyses. Significant permeability variations are tied more to presence of cement than to grain-size variation. High-permeability zones underlain by calcite-cemented low-permeability zones are common at the top of Ramsey 1 and Ramsey 2 intervals. High permeability at the tops may record calcite dissolution. Location of wells shown in figure 20. Map of calcite cement distribution shown in figure 20. Field location shown in figure 2.

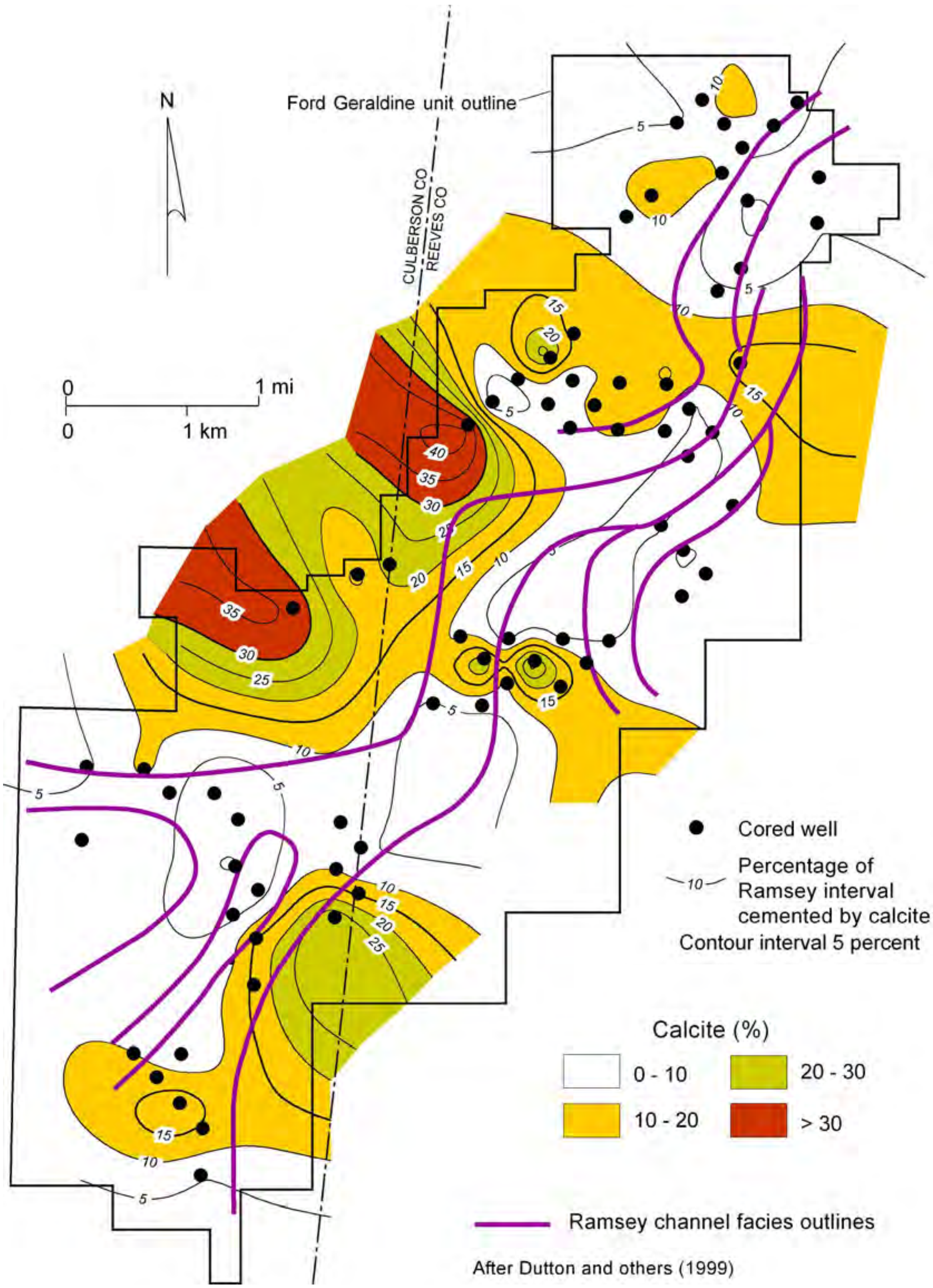


Figure 19. Map of interpreted calcite cement distribution in Ramsey sandstone based on core analyses. Also shown is the outline of combined Ramsey 1 and Ramsey 2 channel sandstone facies. It is possible to recontour the cement map to show a correlation between cement distribution and facies outside the channel complexes. Field location shown in figure 2.

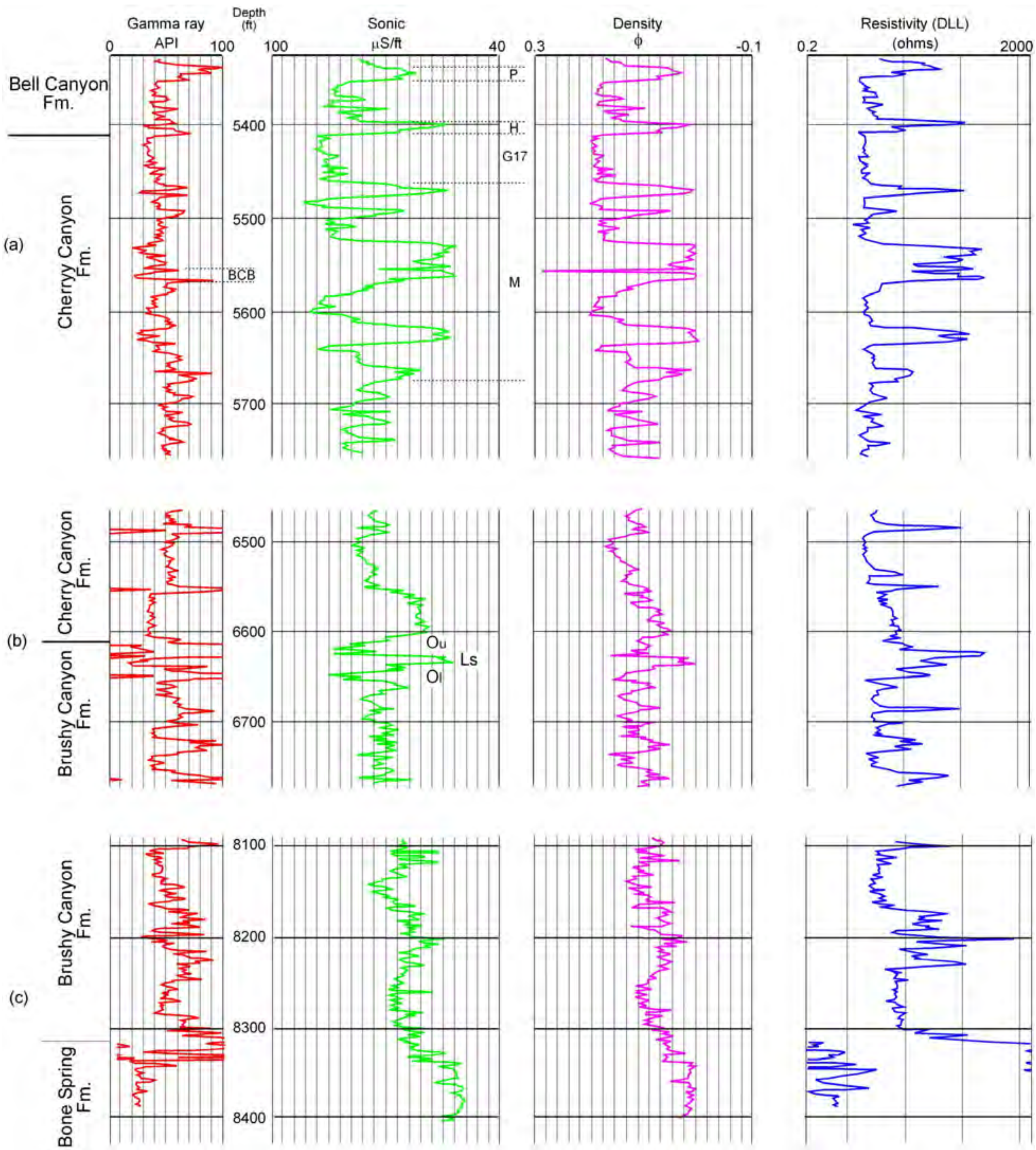


Figure 20. Well log responses in Eddy County Yates Petroleum No. 5 Martha "AK" Federal well (Livingston Ridge field) showing typical stratigraphic boundaries of formations in the Delaware Mountain Group, including (a) top of the Bell Canyon Formation, (c) Cherry Canyon and Brushy Canyon Formations, and (c) base of the Brushy Canyon Formation. Castile and Bone Spring strata at the top and base of the DMG, respectively, are distinguished by distinctively lower gamma-ray values, higher acoustic velocities, lower density porosities, and higher resistivities than those that characterize Delaware Mountain strata. Field location shown in figure 2.

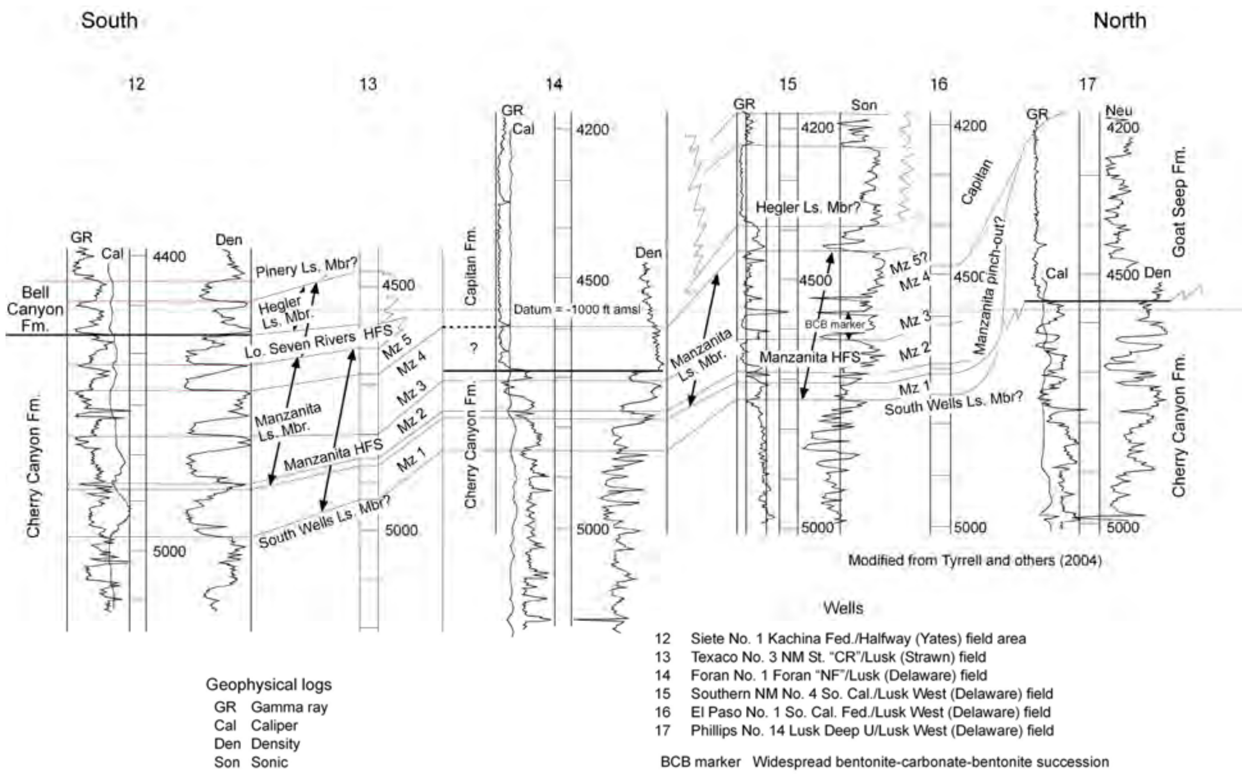


Figure 21. South-north stratigraphic cross section from Halfway field to Lusk West field, northern Delaware Basin, showing correlations within the uppermost Cherry Canyon interval to the Guadalupe shelf margin.

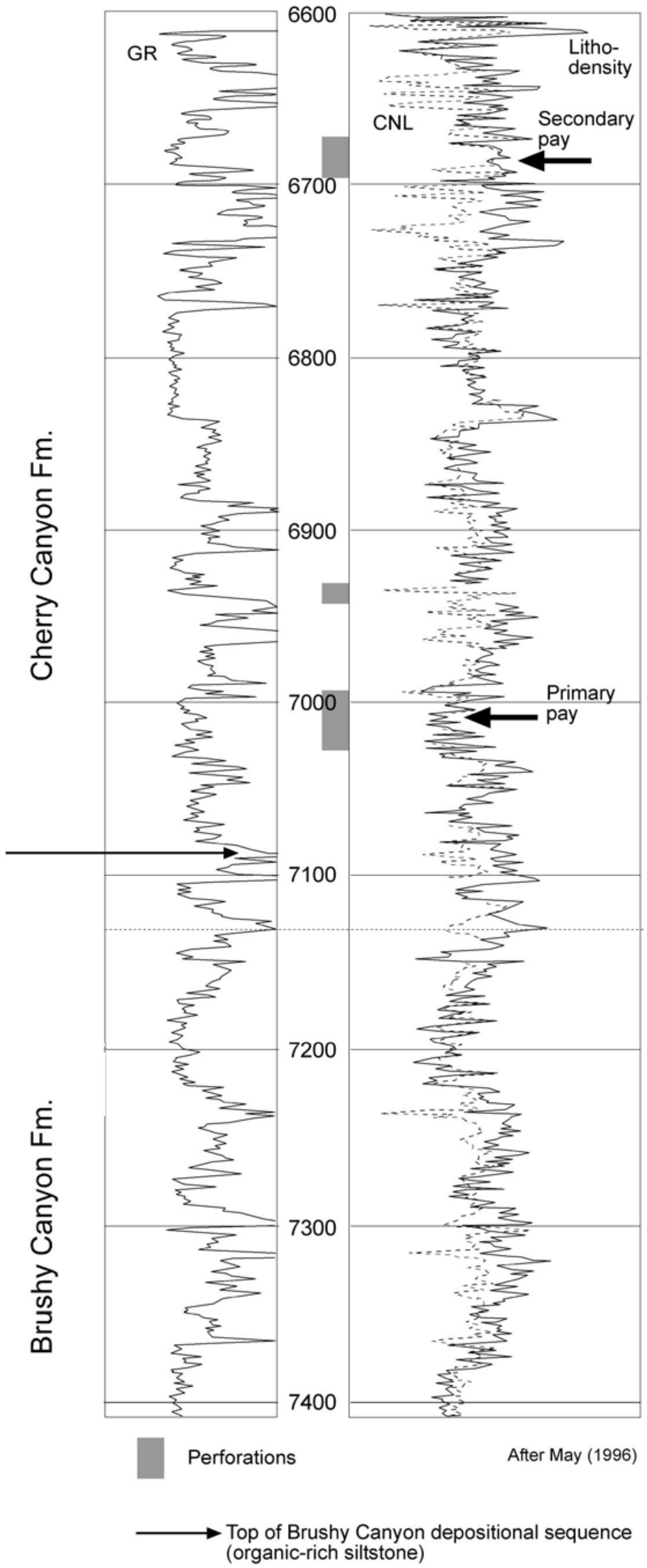


Figure 22. Type log from Livingston Ridge field. Shown are responses for organic-rich siltstone at the Brushy Canyon/Cherry Canyon boundary. The top of the Brushy Canyon depositional sequence is designated to be at the top of the organic-rich siltstone at approximately 7,090 ft, interpreted to record maximum flooding of the shelf. Field location shown in figure 2.

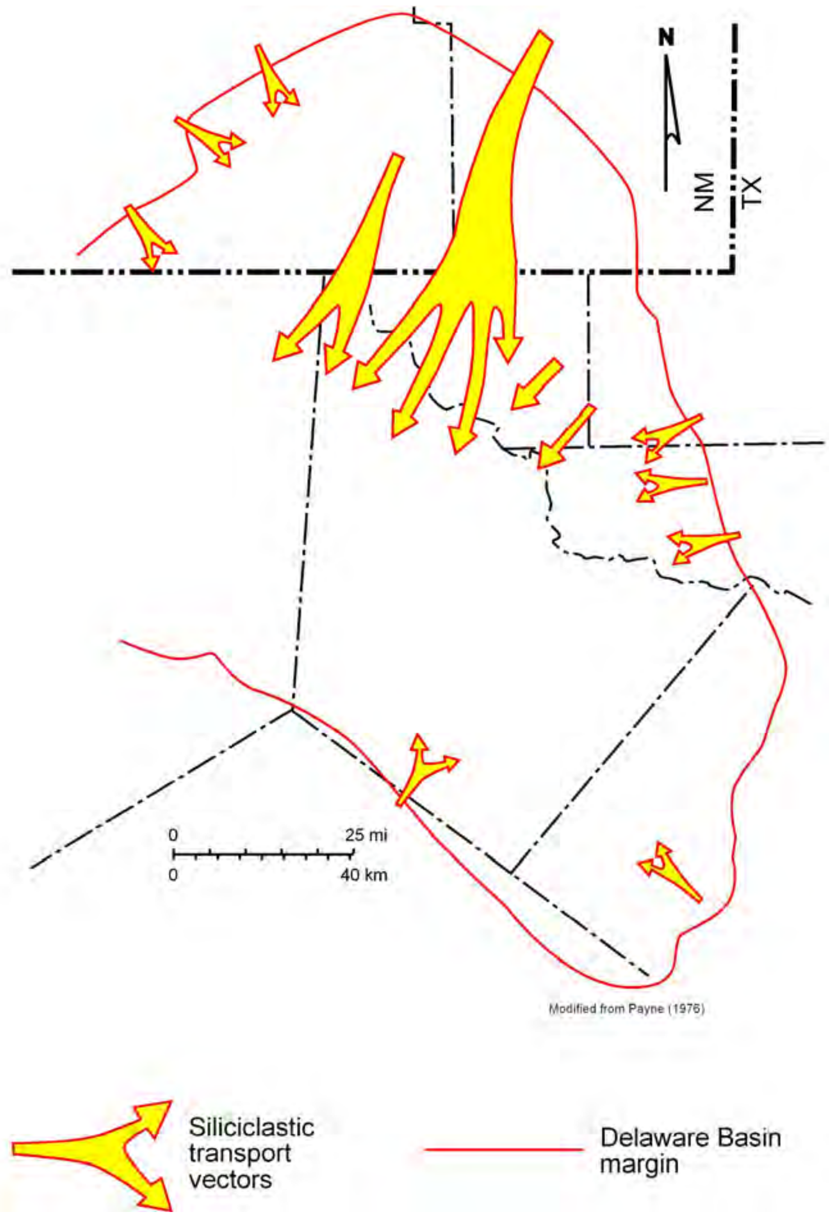


Figure 23. Interpreted Bell Canyon sand depositional fairways based on relative incidence of channel-complex facies. Size of arrows indicates relative importance of fairway.

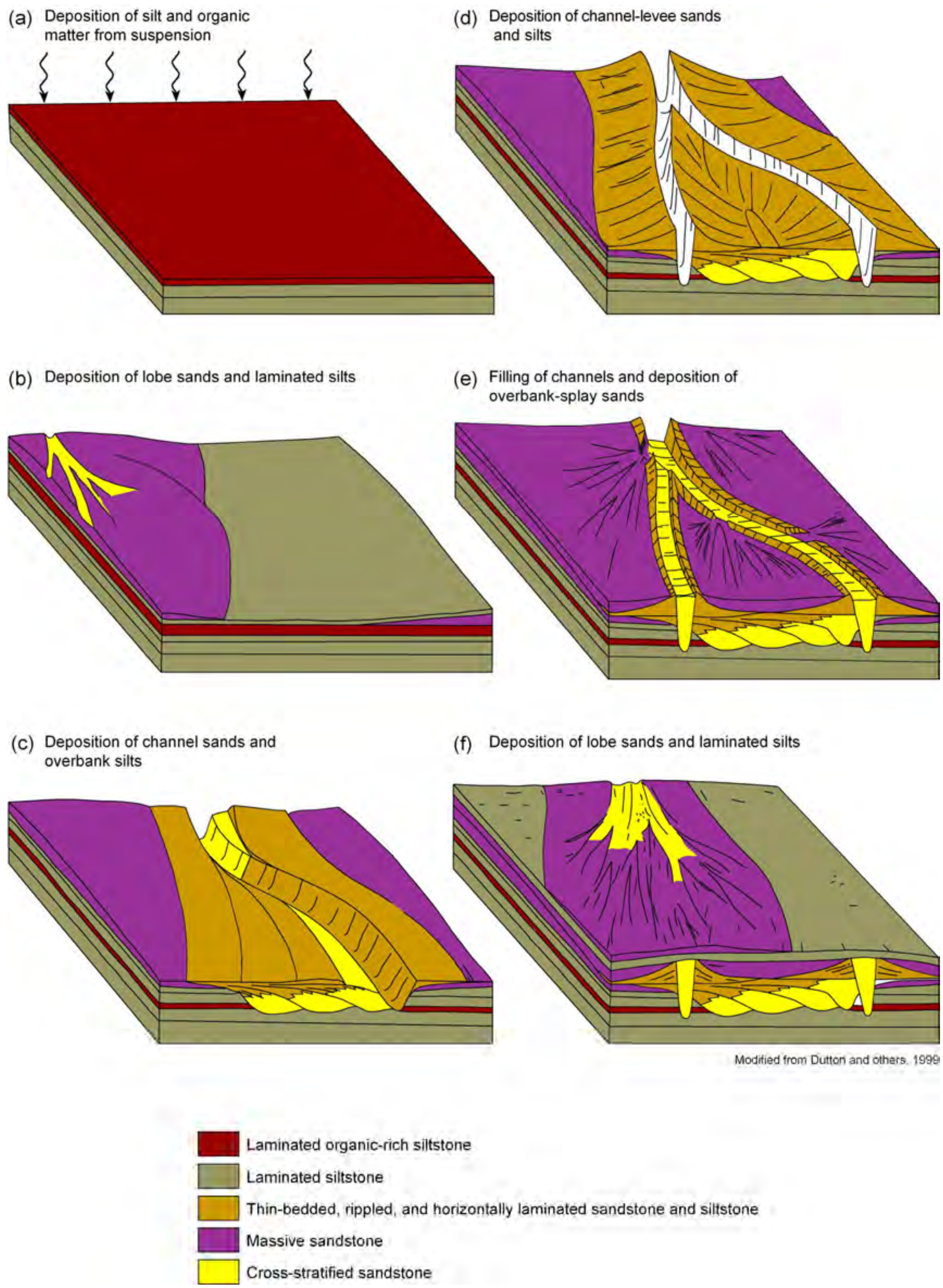


Figure 24. Models of facies development for Delaware Mountain Group depositional units. Organic rich siltstones depicted in a are probable hydrocarbon sources for adjacent sandstone reservoir intervals (see fig. 30). Silt-rich units form top seals. Lateral boundaries for reservoirs are pinch-outs of permeable sandstone facies.

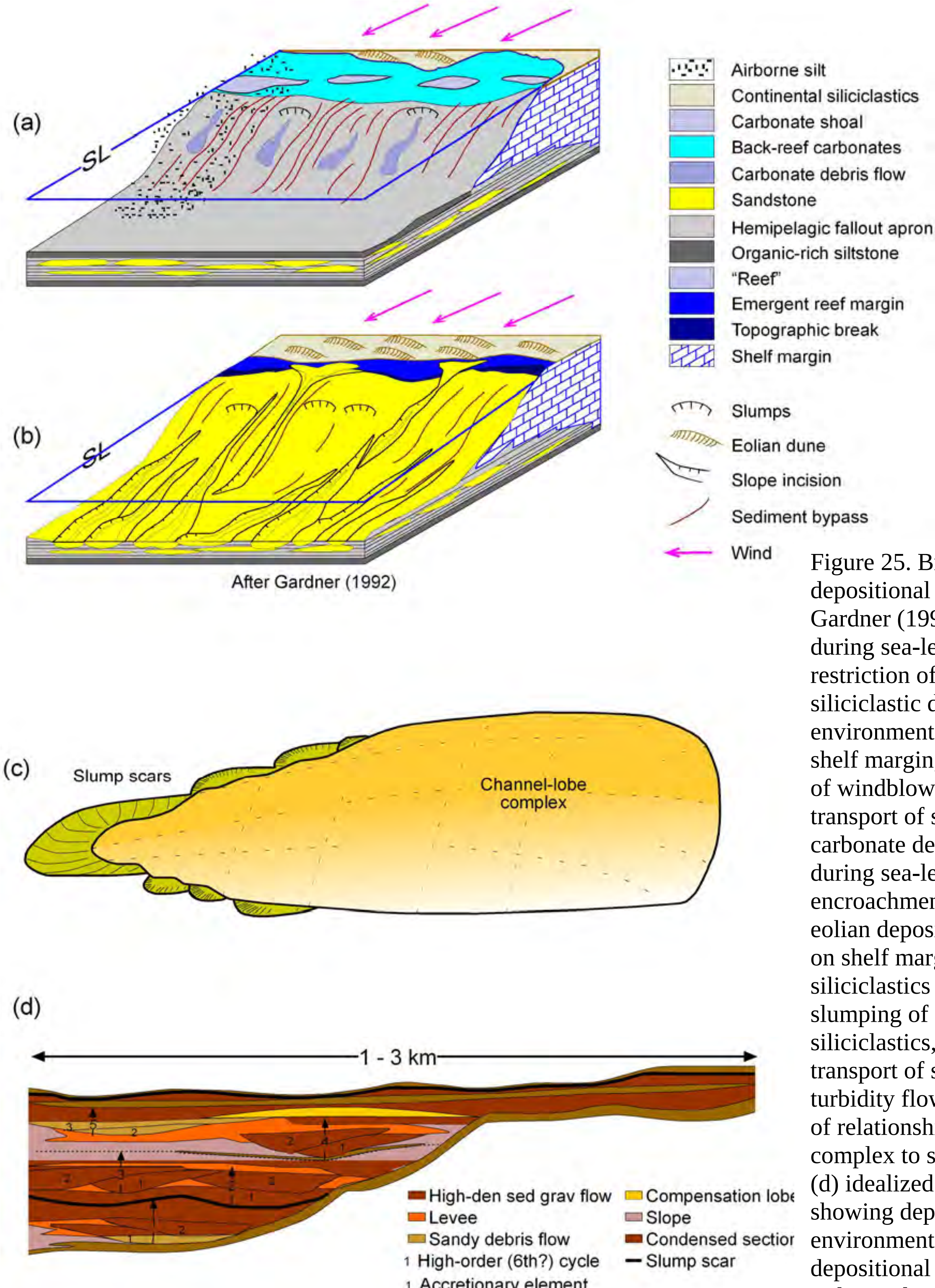


Figure 25. Brushy Canyon depositional cycle models of Gardner (1992): (a) processes during sea-level highstand include restriction of continental siliciclastic depositional environments well shelfward of shelf margin, deposition in basin of windblown silt, and gravity transport of shelf-margin carbonate debris; (b) processes during sea-level lowstand include encroachment of prominently eolian depositional environments on shelf margin, accumulation of siliciclastics on upper slope, slumping of accumulated siliciclastics, and downslope transport of siliciclastics by turbidity flow; (c) idealized model of relationship of channel-lobe complex to slump scar; and (d) idealized strike section showing depositional environments, slump scars, and depositional elements of high-order cycles. Slumping may place updip margins of reservoir facies in contact with low-permeability slope siltstones, thus providing updip lateral seal to some reservoirs.

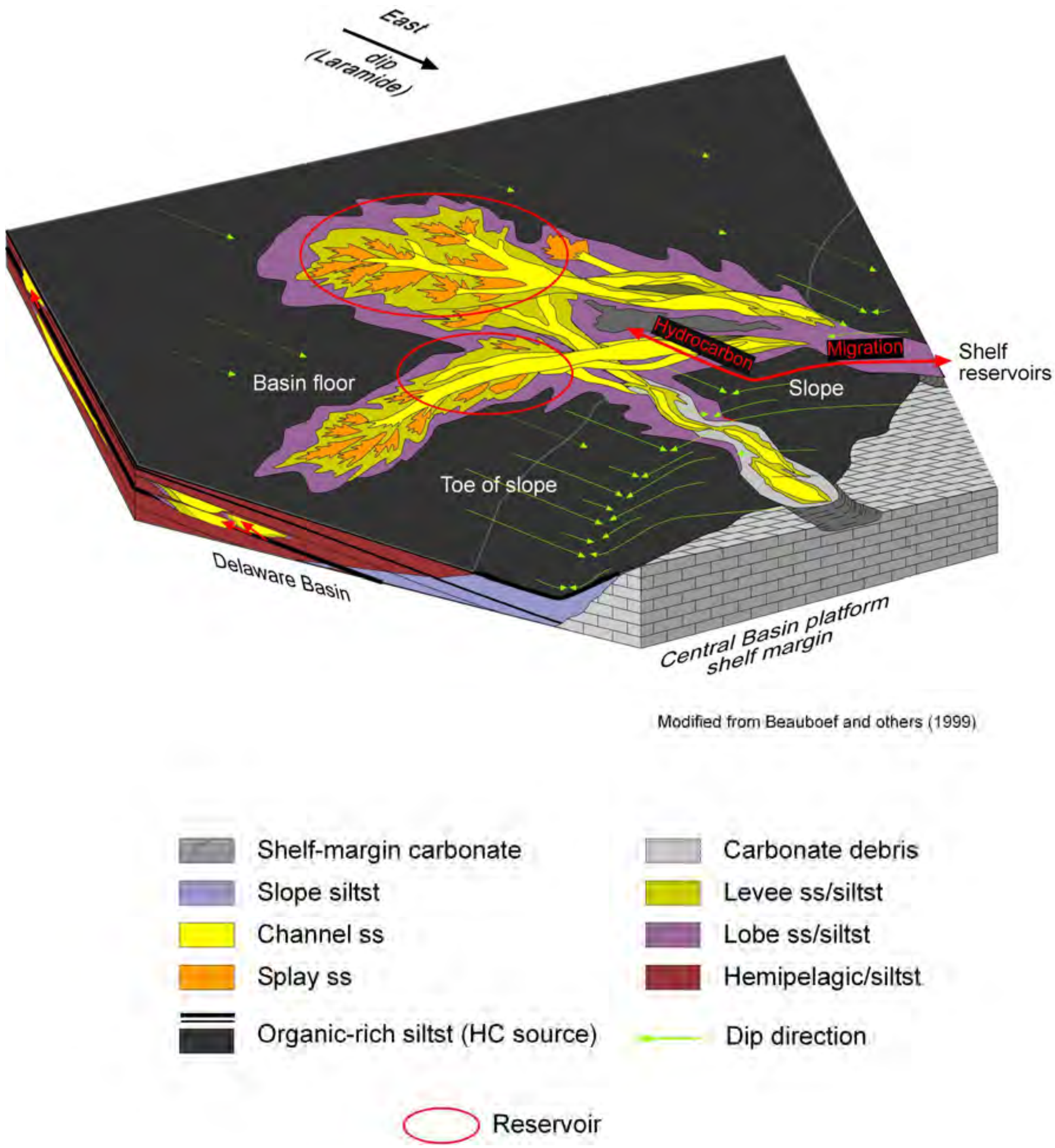


Figure 26. Model of Delaware Mountain Group reservoirs showing paleogeographic elements, principal reservoir and hydrocarbon source facies, regional structural components, and generalized hydrocarbon migration directions. Hydrocarbon reservoirs are preferentially developed in favorable facies, where porous sandstone facies laterally pinch out into low-permeability siltstones. Depending on location, hydrocarbon migration is directed toward the west by easterly dip imparted by Laramide epeirogeny or toward the east into shelf reservoirs by residual, depositionally controlled structural rise on the slope toward the shelf margin.

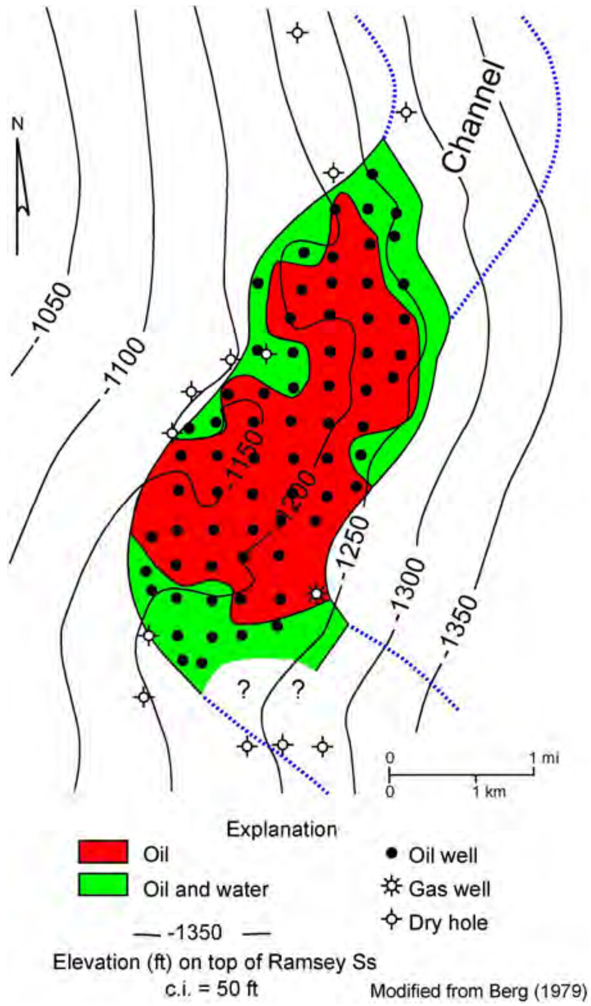


Figure 27. Simplified model of Ramsey sandstone reservoir (Bell Canyon) configuration in Paduca field. Hydrocarbons accumulated in channel-complex meander bend in updip location on regional eastward-dipping structure produced by Laramide epeirogeny. Field location shown in figure 2.

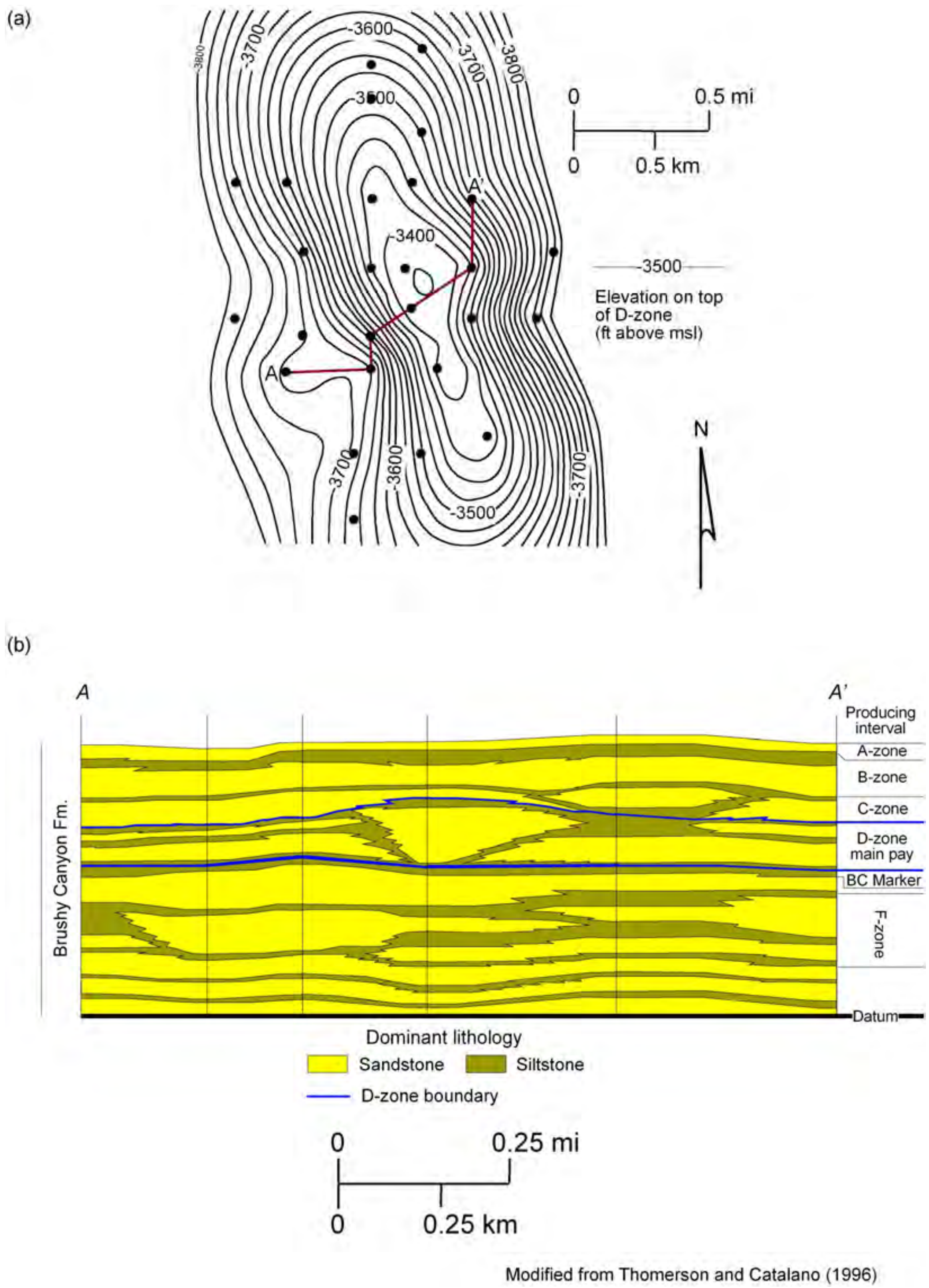
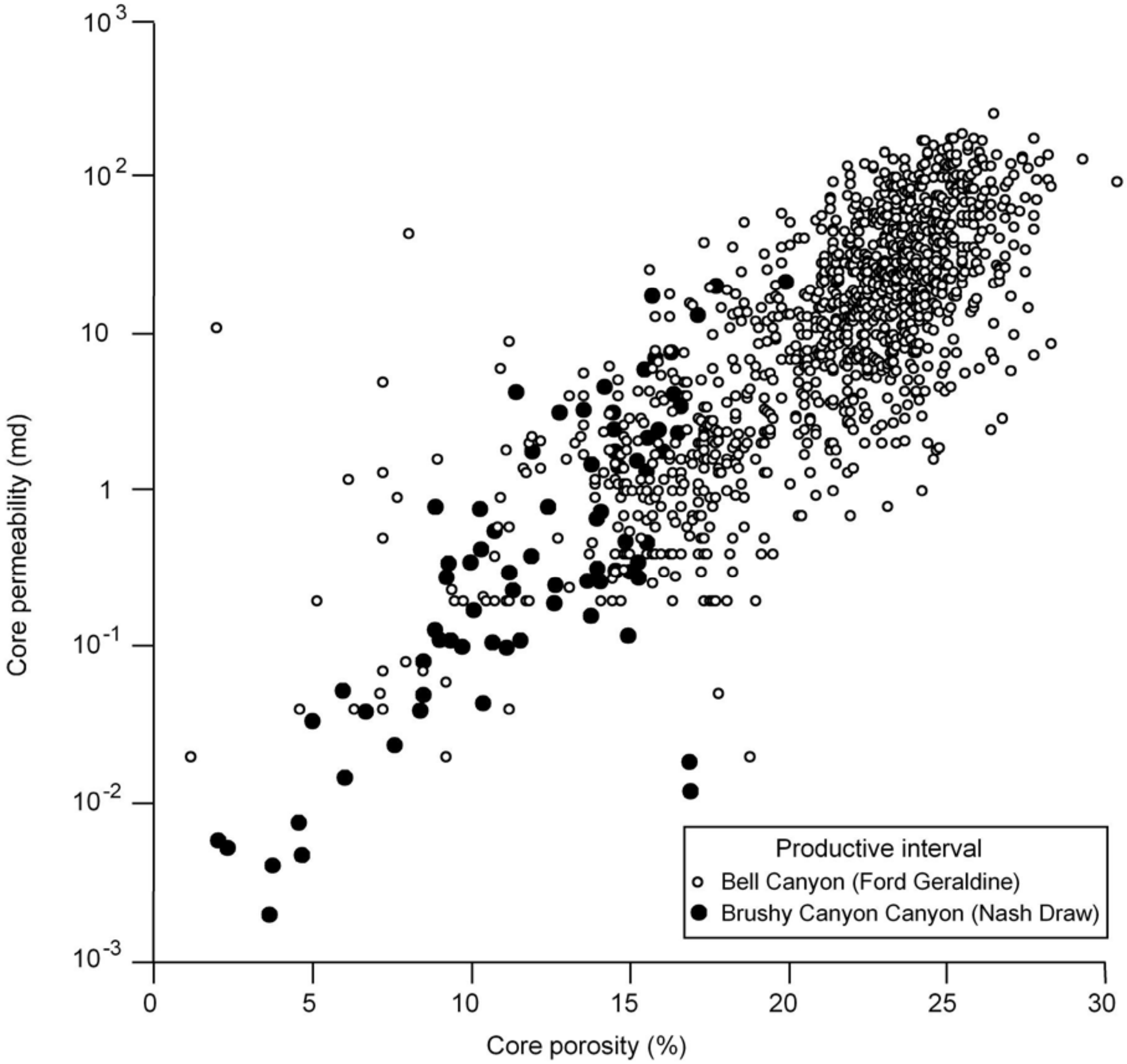


Figure 28. Sandbody architecture, East Livingston Ridge field, Upper Brushy Canyon Formation. (a) Structure map on top of D-zone (primary reservoir) and (b) southwest-northeast stratigraphic cross section of productive intervals. Cross section shows compactional anticlinal structures over thicker parts of sandbodies, especially over D-zone channel sandbody and compensatory offsets of stratigraphically sequential sandbodies. Field location shown in figure 2.



Modified from Thomerson and Asquith (1992)
and Dutton and others (1999)

Figure 29. Plot of core-derived porosity and permeability measurements of productive sandstones from Ford Geraldine (Bell Canyon) and Nash Draw (Brushy Canyon) fields. Although Brushy Canyon porosity and permeability values are overall less than Bell Canyon values, the linear relationship between the parameters is similar in both reservoirs.

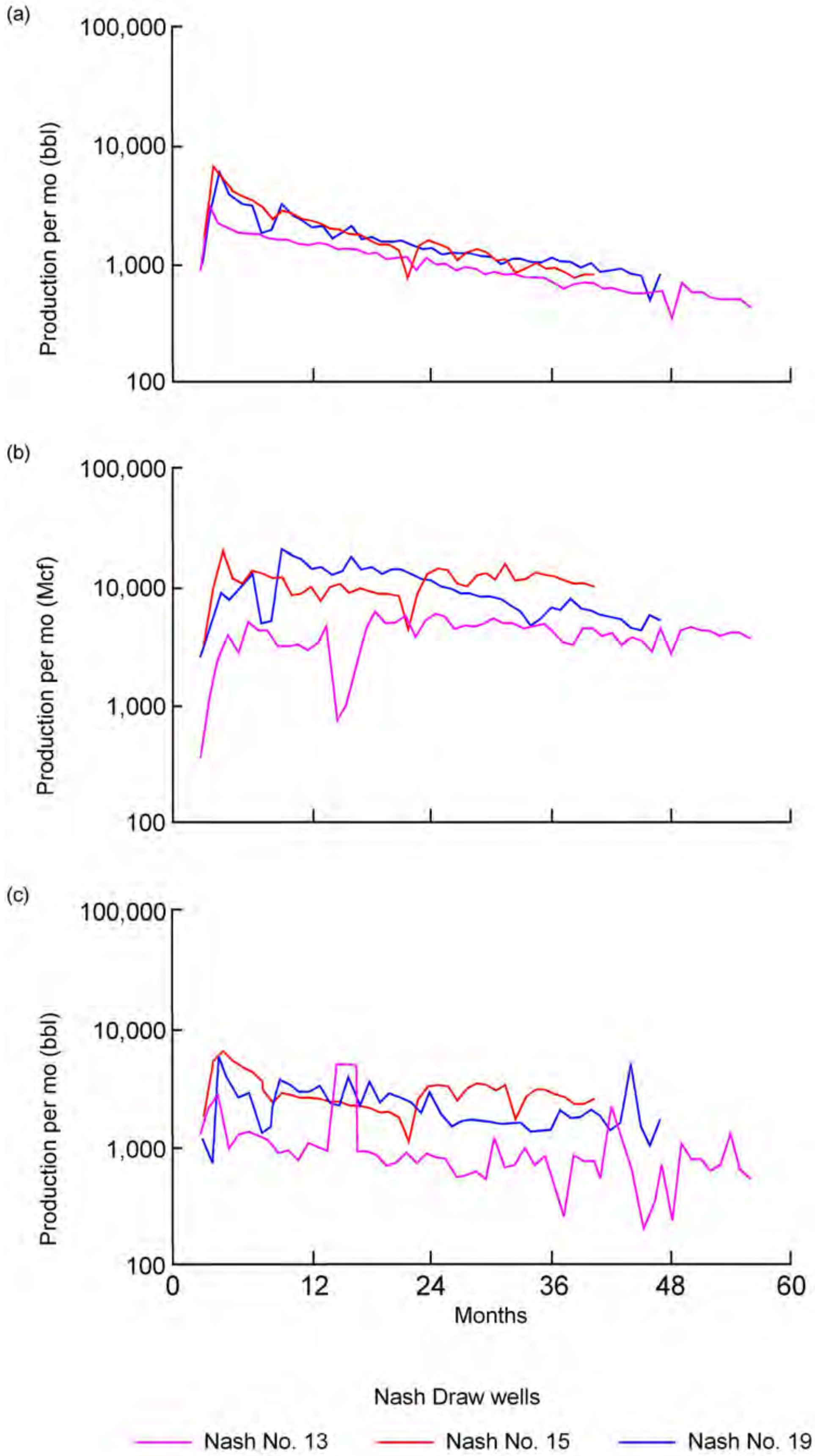


Figure 30. Graphs showing monthly production rates for (a) oil, (b) gas, and (c) water from three closely spaced wells in Nash Draw field. Dissimilarity of production responses in closely spaced (0.25–0.5 mi) may reflect lateral petrophysical variability in channel-levee-lobe complex facies. Note rates of oil-production decline similar to those seen at Livingston Ridge/Lost Tank fields (fig. 31). Field location shown in figure 2. Modified from Montgomery and others (1999).

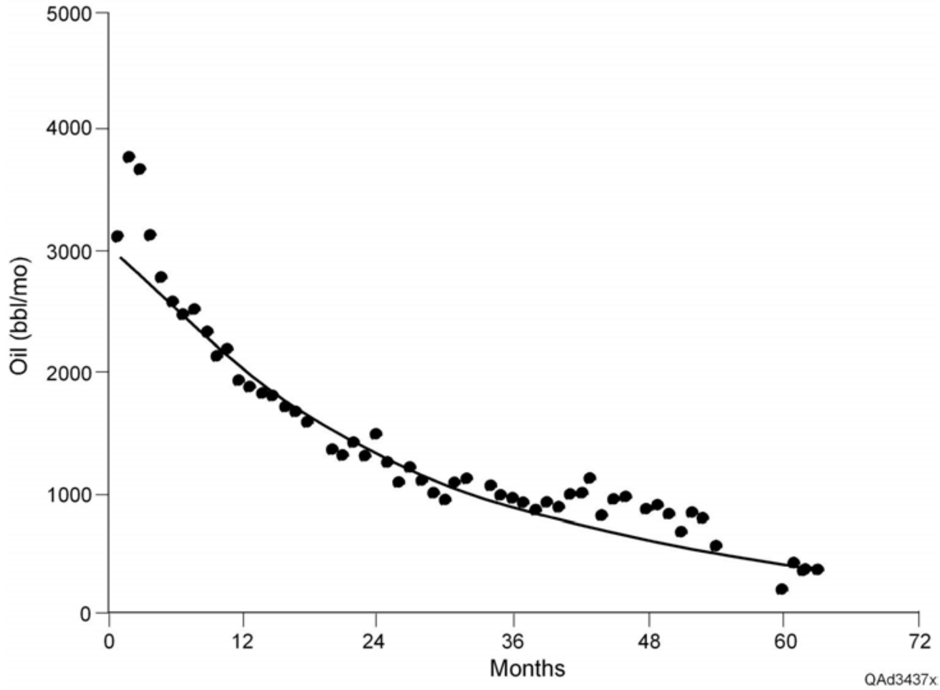


Figure 31. Average production-decline curve for wells in Livingston Ridge/Lost Tank field. Average production is reduced to approximately 10 percent of initial rates after 5 years. Modified from Broadhead and others (1998). Field location shown in figure 2.

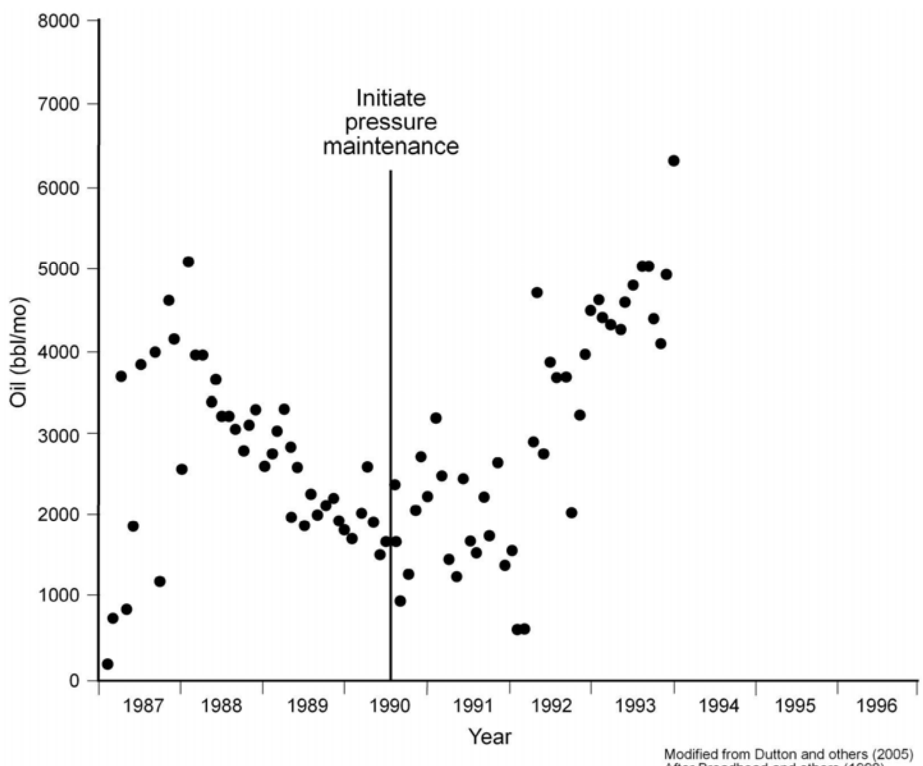


Figure 32. Monthly oil production from Phillips No. 2 James A well, Cabin Lake field, showing production increase after water injection for pressure maintenance. Field location shown in figure 2.

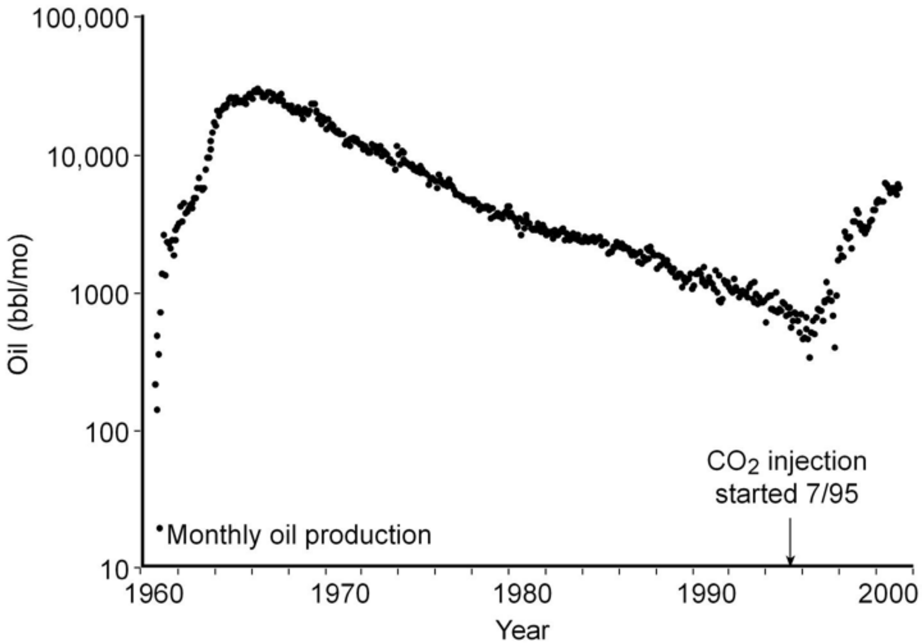


Figure 33. Monthly oil production from East Ford Unit (Bell Canyon), showing production improvement after change from primary to secondary production with initiation of CO_2 injection in 1995. Field location shown in figure 2. From Dutton and others (2003).

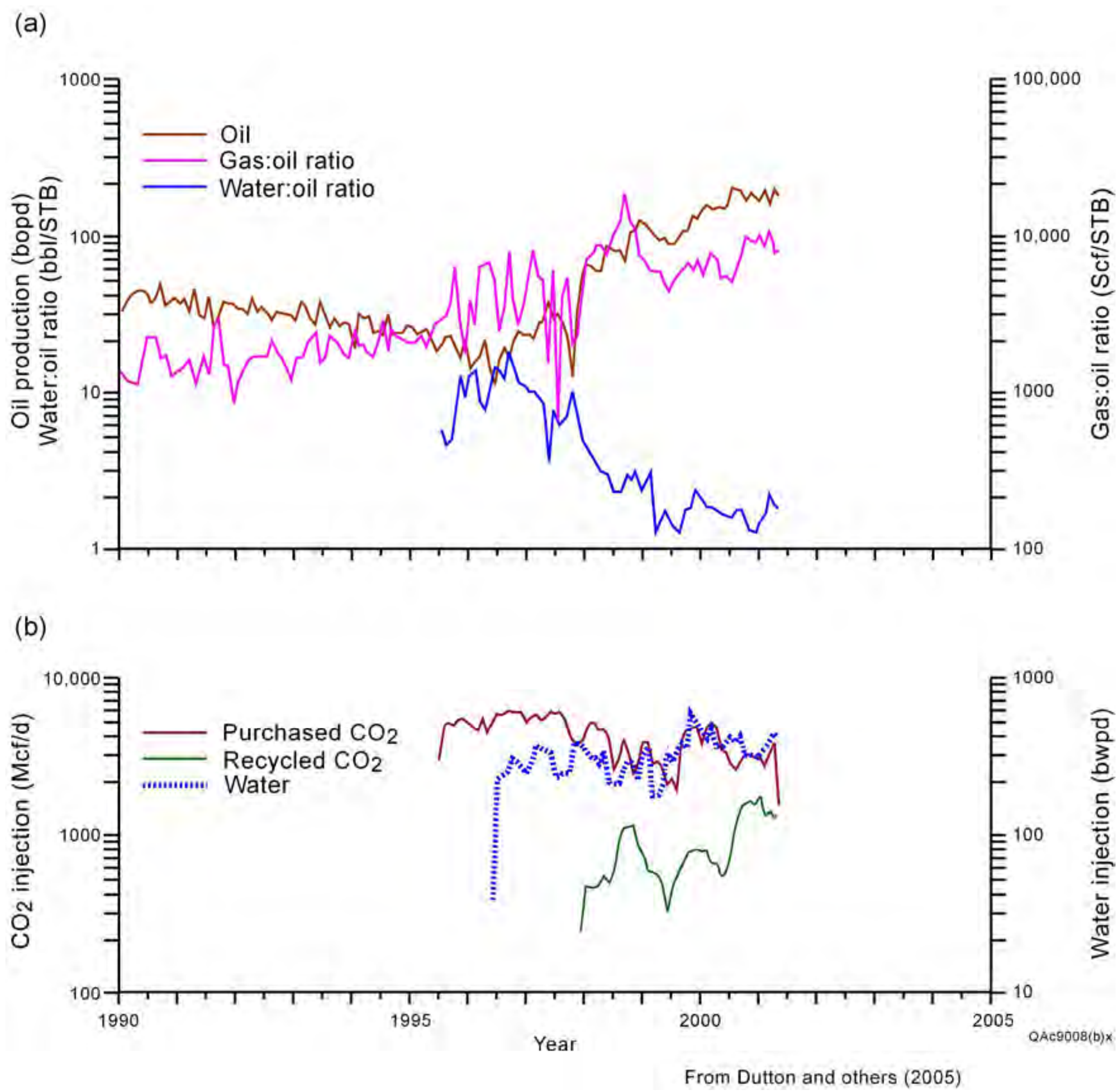
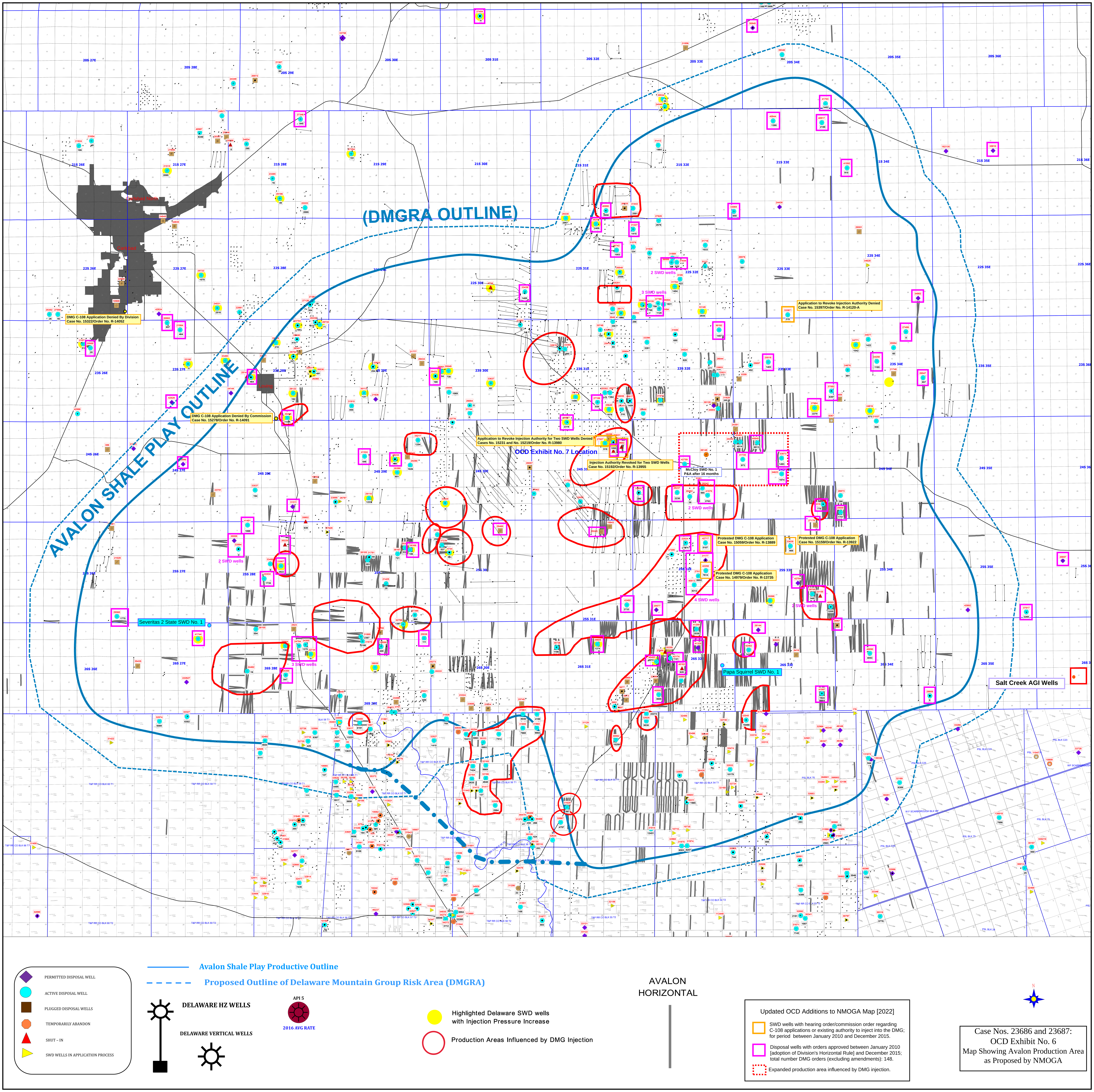


Figure 34. Graphs showing (a) values of oil production, gas/oil, and water/oil for a typical well in the East Ford unit, Reeves County, for 1990 through first half of 2002 and (b) injected volumes of CO_2 and water. Gas injection began in 1995, and water injection began in 1998. Note that production shows an overall increase soon after initiation of water injection. However, water:oil values decrease while gas:oil values increase, suggesting that overall production increases more probably reflect success of CO_2 injection. Field location shown in figure 2.



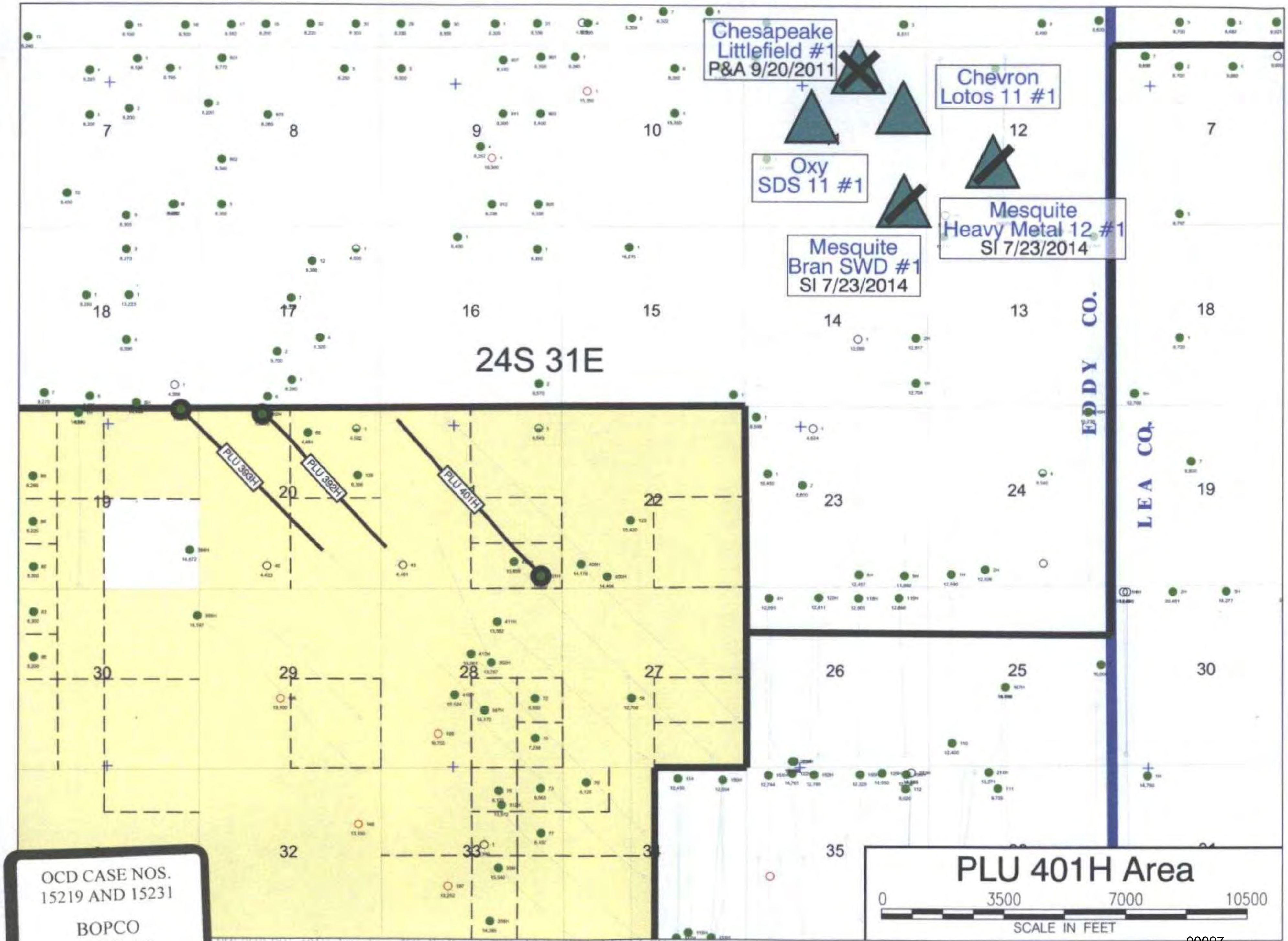
Case Nos. 23686 and 23687:
OCD Exhibit No. 6
Map Showing Avalon Production Area
as Proposed by NMOGA

State of New Mexico
Energy, Minerals and Natural Resources Department
Oil Conservation Division

Case Nos. 23686 and 23687: OCD Exhibit No. 7

Attachments:

- **Copy of BOPCO Exhibit 2; Case Nos. 15219 and 15231**
- **Copy of BOPCO Exhibit 11; Case Nos. 15219 and 15231**
- **Copy of BOPCO Exhibit 12; Case Nos. 15219 and 15231**
- **Copy of BOPCO Exhibit 18; Case Nos. 15219 and 15231**
- **Copy of Hearing Order R-13955; Case No. 15192**
- **Copy of Hearing Order R-13980; Case Nos. 15219 and 15231**



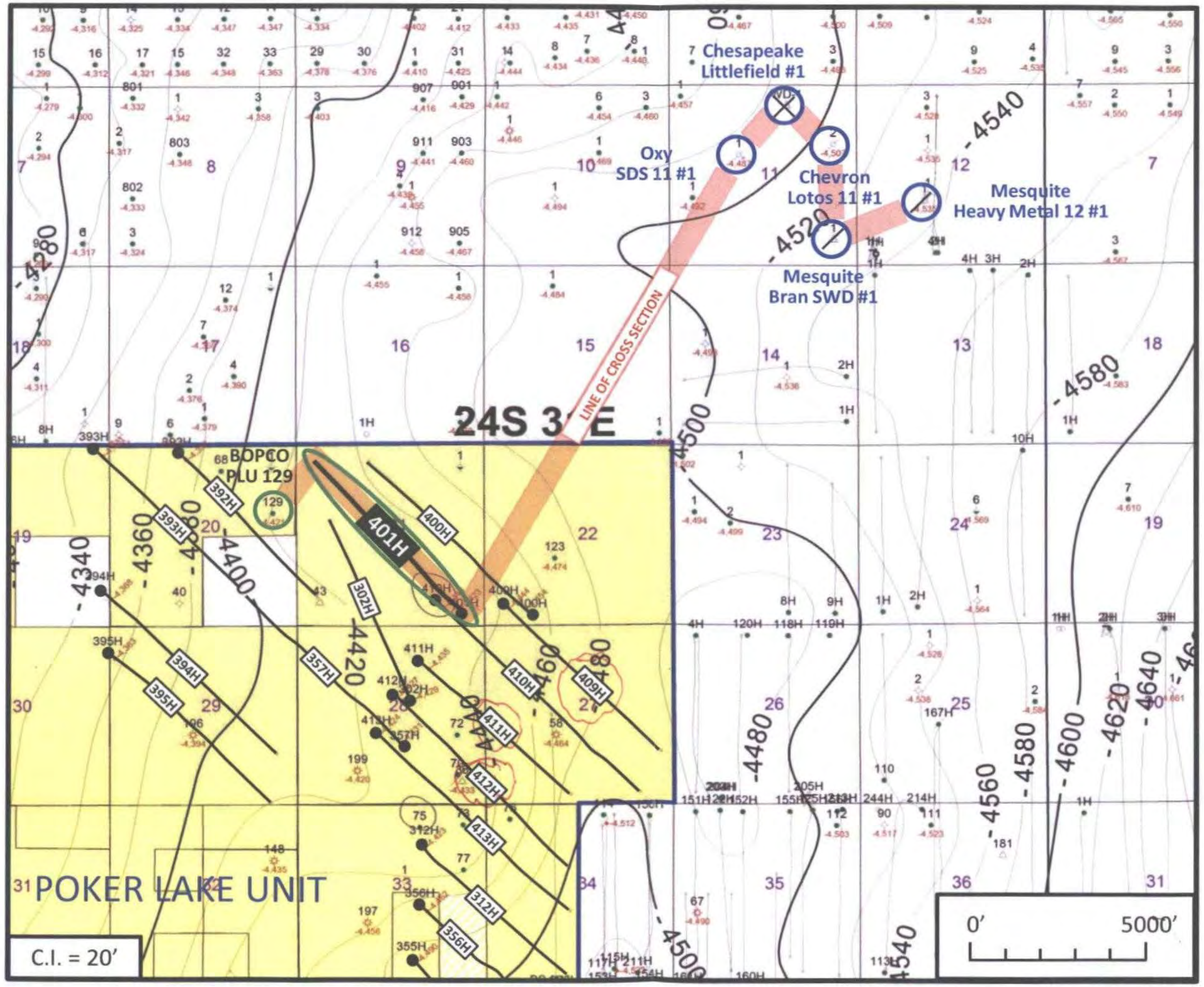
OCD CASE NOS.
15219 AND 15231

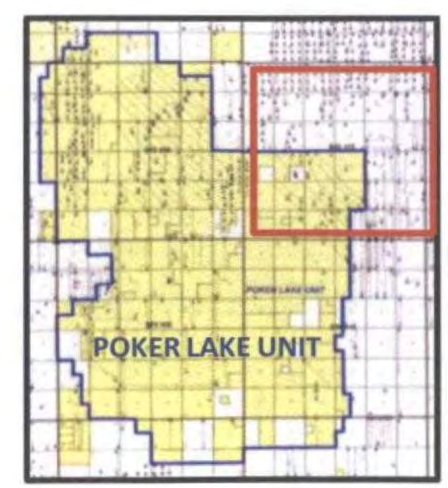
BOPCO
Exhibit # 2

POKER LAKE UNIT 401H - INJECTION AREA LOCATION MAP

Structure Map - Top Delaware Lower Brushy Canyon

Poker Lake Unit, Eddy Co., New Mexico

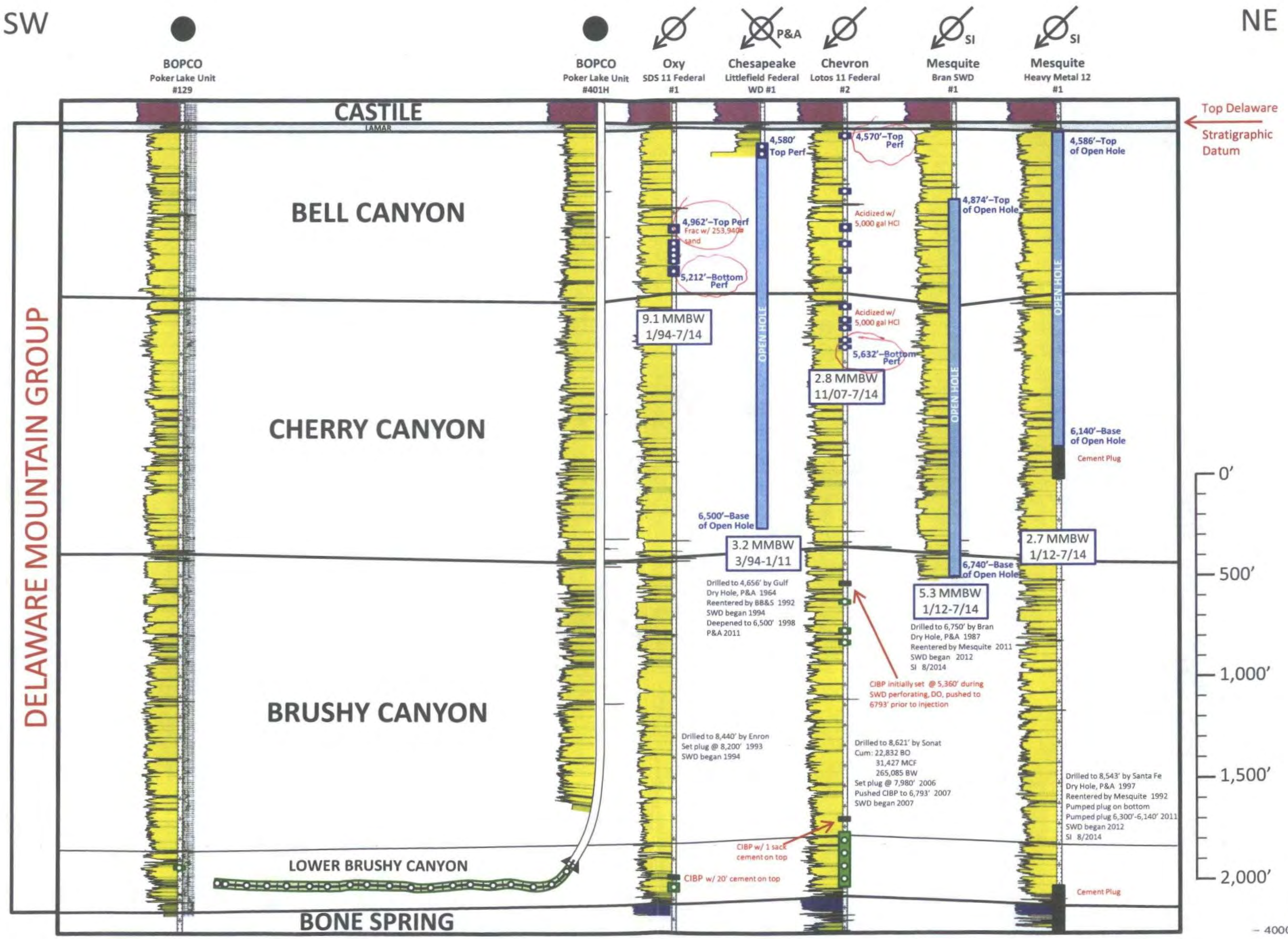




OCD CASE NOS.
15219 AND 15231
BOPCO
Exhibit # 11

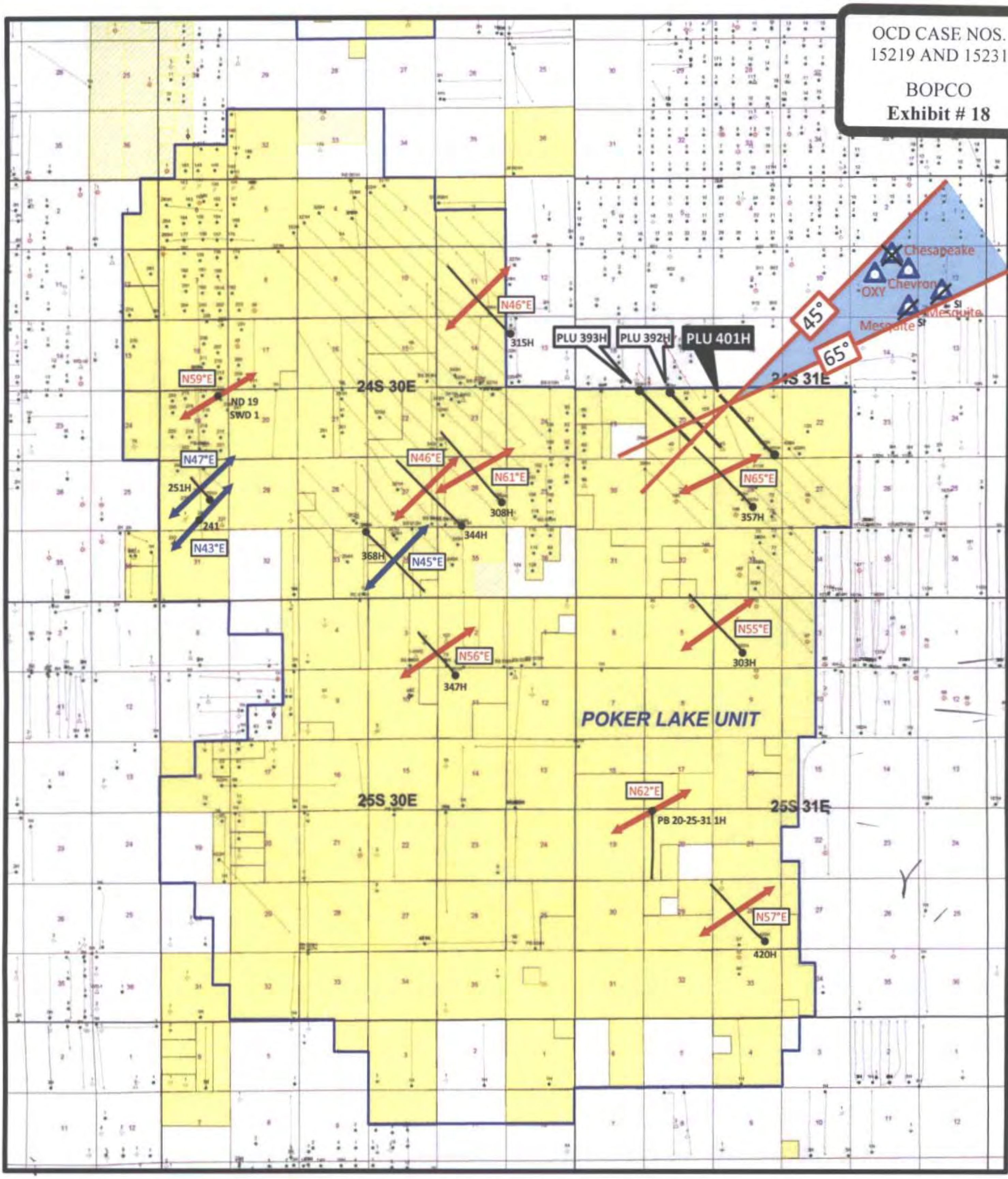
00098

POKER LAKE UNIT 401H STRATIGRAPHIC CROSS SECTION



OCD CASE NOS.
15219 AND 15231
BOPCO
Exhibit # 12

00099



Fracture Propagation Direction

FMI Data	Microseismic Data
Horizontal Well with Fracture Direction Data	

SL

Poker Lake Unit
Eddy County, New Mexico

Delaware Mountain Group Fracture Orientation Map

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:

CASE NO. 15192
ORDER NO. R-13955

APPLICATION OF BOPCO, L. P. FOR THE REVOCATION OF THE INJECTION AUTHORITY UNDER ADMINISTRATIVE ORDERS SWD-1269 AND SWD-649-B, EDDY COUNTY, NEW MEXICO.

ORDER OF THE DIVISION

BY THE DIVISION:

This case came on for hearing at 8:15 a.m. on October 30, 2014, at Santa Fe, New Mexico, before Examiner Phillip R. Goetze and on December 9, 2014, at Santa Fe, New Mexico, before Examiners Phillip R. Goetze and William V. Jones.

NOW, on this 30th day of January, 2015, the Division Director, having considered the testimony, the record, and the recommendations of the Examiners,

FINDS THAT:

(1) Due public notice has been given, and the Division has jurisdiction of this case and its subject matter.

(2) By Administrative Order No. SWD-1269 dated March 29, 2011, the Oil Conservation Division ("Division") authorized Mesquite SWD, Incorporated (Mesquite) to utilize its Heavy Metal 12 Federal Well No. 1 (API No. 30-015-29602) located 1900 feet from the South line and 1900 feet from the West line (Unit letter K) of Section 12, Township 24 South, Range 31 East, Eddy County, New Mexico, as a commercial well for disposal of oil-field produced water into the Bell Canyon and Cherry Canyon formations through an open-hole interval from 4415 feet to 7050 feet.

(3) By Administrative Order No. SWD-649-B dated February 15, 2012, the Division authorized Mesquite to utilize its Bran SWD Well No. 1 (API No. 30-015-25697) located 660 feet from the South line and 660 feet from the East line (Unit letter P) of Section 11, Township 24 South, Range 31 East, Eddy County, New Mexico, as a

commercial well for disposal of oil-field produced water into the Bell Canyon and Cherry Canyon formations through an open-hole interval from 4874 feet to 6740 feet.

(4) By Administrative Order No. IPI-435 dated April 22, 2013, the Division approved an application by Mesquite to increase the maximum surface injection pressure for the Heavy Metal 12 Federal Well No. 1 from 883 pounds per square inch (psi) to 1400 psi based on a step-rate test conducted on February 28, 2013.

(5) By Administrative Order No. IPI-446 dated September 30, 2013, the Division approved an application by Mesquite to increase the maximum surface injection pressure for the Bran SWD Well No. 1 from 975 psi to 1450 psi based on a step-rate test conducted on July 18, 2013.

(6) BOPCO, L.P. ("Applicant" or BOPCO), made application on July 24, 2014, seeking an order revoking the injection authority granted to Mesquite under Administrative Orders SWD-649-B and SWD-1269 and inclusive of the pressure increases granted under Administrative Orders IPI-435 and IPI-446. BOPCO stated that the injection operation of the two disposal wells had impacted production from the Poker Lake Unit Well No. 401H, a horizontal well with a surface location 335 feet from the South line and 570 feet from the East line (Unit letter P) and a bottomhole location 359 feet from the North Line and 544 feet from the West line (Unit letter D) of Section 21, Township 24 South, Range 31 East, Eddy County, New Mexico.

(7) On September 15, 2014, BOPCO submitted to the Division a *Motion For Entry of Order Revoking Injection Authority* (the "*Motion*") that details a negotiated resolution (*Stipulation Regarding Revocation of Injection Authority*) between Applicant and Mesquite. The resolution contained the following stipulated facts:

(a) BOPCO operates producing horizontal wells within the Poker Lake Unit which is southwest of the general location of the Heavy Metal 12 Federal Well No. 1 and Bran SWD Well No. 1 (the "two commercial disposal wells").

(b) The horizontal wells within the Poker Lake Unit ("PLU") are producing from a lower interval in the Brushy Canyon formation which is stratigraphically below the Cherry Canyon formation within the Delaware Mountain group.

(c) In April 2014, BOPCO discovered unusually high bottomhole pressures and an increase in water production for its Poker Lake Unit ("PLU") Well No. 401H (API No. 30-015-39918). This horizontal well has the entire completed interval in the lower Brushy Canyon formation.

(d) Soon after the discovery of the change in well condition of PLU Well No. 401H, additional horizontal wells completed within the

PLU were observed to have similar increases in bottomhole pressures and increases in water production.

(e) BOPCO conducted an investigation of the elevated bottomhole pressures and increased water production for the impacted wells and identified the two commercial disposal wells as the source of impacts to PLU Well No. 401H and the possible source of increased water intrusion for two other PLU horizontal wells.

(f) Applicant notified Mesquite and provided the results of the investigation for review and negotiation.

(g) Following notification, Mesquite voluntarily suspended the injection operations of the two commercial disposal wells on July 24, 2014.

(h) Applicant and Mesquite negotiated a settlement as summarized in Exhibit "A", the *Stipulation Regarding Revocation of Injection Authority* of the *Motion*.

(8) On December 9, 2014, the Applicant appeared through counsel and requested the Division to grant BOPCO's *Motion*.

(9) No other party appeared at the hearing, or otherwise opposed the granting of this application.

The Division concludes as follows:

(10) Applicant has provided sufficient evidence to support a conclusion that the operation of the two commercial disposal wells has impacted hydrocarbon production, thereby causing waste and impairing correlative rights.

(11) Mesquite has reviewed the same evidence provided by Applicant and agreed to issuance of a Division Order revoking the injection authority in the two wells.

(12) The application to revoke the two administrative orders should be approved.

IT IS THEREFORE ORDERED THAT:

(1) Administrative Order No. SWD-1269 issued March 29, 2011, by the Oil Conservation Division ("Division") authorizing Mesquite SWD, Incorporated ("operator" or Mesquite) to utilize its Heavy Metal 12 Federal Well No. 1 (API No. 30-015-29602) located 1900 feet from the South line and 1900 feet from the West line (Unit letter K) of Section 12, Township 24 South, Range 31 East, Eddy County, New Mexico, as a commercial well for disposal of oil-field produced water, is hereby **revoked**.

(2) Administrative Order No. SWD-649-B issued February 15, 2012, by the Division authorizing Mesquite to utilize its Bran SWD Well No. 1 (API No. 30-015-25697) located 660 feet from the South line and 660 feet from the East line (Unit letter P) of Section 11, Township 24 South, Range 31 East, Eddy County, New Mexico, as a commercial well for disposal of oil-field produced water, is hereby **revoked**.

(3) Additional administrative orders associated with disposal operations of the two wells, specifically Administrative Orders Nos. IPI-435 and IPI-446, are terminated as a result of the loss of injection authority.

(4) As a condition of this Order, Mesquite shall notice the United States Bureau of Land Management of: (1) the loss of injection authority for each well and (2) future plans for the beneficial use of each well. A copy of the notice and planned uses for each well shall be supplied to the Division's District II office.

(5) As an additional condition of this Order and prior to any further well activities involving the **Heavy Metal 12 Federal Well No. 1 (API No. 30-015-29602),** Mesquite shall take all the necessary steps to conduct a wireline verification of the cement plug at 6140 feet. The operator shall file the appropriate Sundry Notice of Intent with the United States Bureau of Land Management for approval. Once approval of the Sundry has been obtained, the operator shall notify the Division's District II office 72 hours prior to the verification activity and a representative of the Division's District II office shall be present to witness the wireline verification.

(6) Jurisdiction of this case is retained for the entry of such further orders as the Division may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

David R. Catanach

DAVID R. CATANACH
Director

S E A L

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:

APPLICATION OF BOPCO, L.P. FOR REVOCATION OF THE INJECTION AUTHORITY GRANTED UNDER ADMINISTRATIVE ORDER SWD-542, EDDY COUNTY, NEW MEXICO.

CASE NO. 15231

AND

APPLICATION OF BOPCO, L.P. FOR REVOCATION OF THE INJECTION AUTHORITY GRANTED UNDER ADMINISTRATIVE ORDER SWD-1073, EDDY COUNTY, NEW MEXICO.

CASE NO. 15219
ORDER NO. R-13980

ORDER OF THE DIVISION

BY THE DIVISION:

These cases came on for hearing at 8:15 a.m. on October 30, 2014, at Santa Fe, New Mexico, before Examiner Phillip R. Goetze and on December 9, 2014, at Santa Fe, New Mexico, before Examiners Phillip R. Goetze and William V. Jones.

NOW, on this 23rd day of April, 2015, the Division Director, having considered the testimony, the record, and the recommendations of the Examiners,

FINDS THAT:

(1) Due public notice has been given, and the Division has jurisdiction of these cases and their subject matters.

(2) At the hearings, Cases No. 15231 and No. 15219 were consolidated for the purpose of testimony and one order should be issued for both cases.

(3) In Case No. 15231, BOPCO, L.P. ("Applicant" or BOPCO), made application on September 29, 2014, seeking an order revoking the injection authority

granted to OXY USA, Inc. ("OXY") under Administrative Order SWD-542 and inclusive of the pressure increases granted under Administrative Orders IPI-272 and IPI-451. BOPCO stated that the injection operation of the disposal well had impacted production from the Poker Lake Unit Well No. 401H, a horizontal well with a surface location 335 feet from the South line and 570 feet from the East line (Unit letter P) and a bottomhole location 359 feet from the North Line and 544 feet from the West line (Unit letter D) of Section 21, Township 24 South, Range 31 East, Eddy County, New Mexico.

(4) By Administrative Order No. SWD-542 dated December 20, 1993, the Oil Conservation Division ("Division") authorized Merit Energy Company to utilize its SDS Federal 11 Well No. 1 (API No. 30-015-27627) located 2090 feet from the North line and 1980 feet from the West line (Unit letter F) of Section 11, Township 24 South, Range 31 East, Eddy County, New Mexico, for disposal of oil-field produced water into the Bell Canyon formation through perforations from 4508 feet to 5498 feet. OXY became operator of this disposal well on March 1, 2008.

(5) By Administrative Order No. IPI-272 dated October 24, 2006, the Division approved an application by Pogo Producing Company, the operator before OXY, to increase the maximum surface injection pressure for the SDS Federal 11 Well No. 1 from 902 pounds per square inch (psi) to 2200 psi based on a step-rate test conducted on the well October 6, 2006.

(6) By Administrative Order No. IPI-451 dated October 11, 2013, the Division approved an application by OXY for a second increase of the maximum surface injection pressure for the SDS Federal 11 Well No. 1. This order increased the pressure from 2200 psi to 3170 psi based on a step-rate test conducted on the well July 11, 2013.

(7) In Case No. 15219, BOPCO, L.P. made application on September 8, 2014, seeking an order revoking the injection authority granted to Chevron USA, Inc. ("Chevron") under Administrative Order SWD-1073 and inclusive of the pressure increase granted under Administrative Order IPI-425. BOPCO stated that the injection operation of this disposal well had also impacted production from the above-described Poker Lake Unit Well No. 401H.

(8) By Administrative Order No. SWD-1073 dated February 10, 2007, the Division authorized Chesapeake Operating, Inc. to utilize its Lotos 11 Federal Well No. 2 (API No. 30-015-28821) located 1780 feet from the North line and 660 feet from the East line (Unit letter H) of Section 11, Township 24 South, Range 31 East, Eddy County, New Mexico, as a commercial well for disposal of oil-field produced water into the Bell Canyon and Cherry Canyon formations through perforations from 4570 feet to 5632 feet. Chevron became operator of this disposal well on October 9, 2012.

(9) By Administrative Order No. IPI-425 dated September 24, 2012, the Division approved an application by Chesapeake Operating, Inc. to increase the maximum surface injection pressure for the Lotos 11 Federal Well No. 2 from 914 psi to 1225 psi based on a step-rate test conducted on August 24, 2012.

Applicant appeared at hearing through counsel and presented the following testimony.

(10) BOPCO is currently developing the Permian section within three federal units, all in Eddy County, which include the Poker Lake Unit ("PLU"). The PLU currently contains 138 horizontal wells of which 66 wells were completed in the Brushy Canyon formation.

(11) These horizontal wells are producing from a lower interval in the Brushy Canyon formation which is stratigraphically below the Cherry Canyon formation and the Bell Canyon formation. These three formations comprise the Delaware Mountain group.

(12) In 2014, BOPCO observed an increase in water production for its PLU Well No. 392H (API No. 30-015-40296) PLU Well No. 393H (API No. 30-015-40951) and PLU Well No. 394H (API No. 30-015-41083) and the complete loss of oil production from PLU Well No. 401H (API No. 30-015-39918). All of these horizontal wells are located along the northeast boundary of the Unit and have completed intervals in the lower Brushy Canyon formation.

(13) BOPCO conducted an investigation of the increased water production for the impacted wells and identified four produced-water disposal wells as the source of impacts to PLU Well No. 401H and the possible source of increased water intrusion for the other PLU wells. BOPCO identified the four active wells (collectively referred to as the "four disposal wells") as the SDS Federal 11 Well No. 1, currently operated by OXY; the Lotos 11 Federal Well No. 2, currently operated by Chevron; the Heavy Metal 12 Federal Well No. 1 (API No. 30-015-29602) and the Bran SWD Well No. 1 (API No. 30-015-25697); both operated by Mesquite SWD, Incorporated ("Mesquite").

(14) Applicant contacted Mesquite in July and provided the results of the investigation for review and negotiation. Mesquite voluntarily suspended the injection operations of its two commercial disposal wells on July 24, 2014.

(15) Applicant also notified OXY and Chevron in July 2014, and communicated BOPCO's assertion that their disposal wells were the cause of the water intrusion in the horizontal wells. Subsequently in October, BOPCO met individually with each operator and provided the results of the investigation also submitted to Mesquite.

(16) BOPCO contended that the proximity and the depth of injection by the two remaining active disposal wells continued to impact the horizontal wells in the northeast area of the PLU.

(17) Applicant contended that the disposal injection into the Bell Canyon and Cherry Canyon formations has established communication through fractures between the active disposal wells and the impacted horizontal wells. The horizontal wells in the PLU are drilled in a general southeast to northwest orientation to utilize the natural fracture system in the formation for increased efficiency of oil recovery. BOPCO's witnesses also

testified that there is no effective fracture barrier between the top of the Bell Canyon formations and the lower Brushy Canyon formation.

(18) Applicant presented a historical example of water encroachment between Devon Energy Production Company's ("Devon") North Pure Gold 8 Federal Well No. 11 (API No. 30-015-32619) that was used as a disposal well (Administrative Order SWD-925) in the lower Brushy Canyon formation and BOPCO's James Ranch Unit Well No. 121H (API No. 30-015-38119), a horizontal well completed in the producing portion of the lower Brushy Canyon formation. While drilling the James Ranch Unit Well No. 121H, BOPCO encountered difficulties due to changes in drilling mud properties due to an incursion of salt water. The source of the water was determined to be the North Pure Gold 8 Federal Well No. 11. Devon suspended injection which allowed the horizontal well to be completed without further drilling issues. Devon later resumed injection without impact on the producing well.

(19) Applicant presented a second historical example of water encroachment between BOPCO's PLU Well No. 127 (API No. 30-015-29460) that was used as a disposal well (Administrative Order SWD-1222) and BOPCO's PLU Well No. 347H (API No. 30-015-38668), a horizontal well completed in the producing portion of the lower Brushy Canyon formation. In this example, BOPCO stated the disposal well was injecting into the Cherry Canyon formation which resulted in drilling problems for the PLU Well No. 347H. The water intrusion also impacted the horizontal well by reducing the proposed completion since the impacted portion of the horizontal completion was not perforated.

(20) Applicant presented historical production data for the PLU Well No. 401H for the 16-month period from December 2012 to March 2014 and for comparison, presented oil and produced water decline trends consistent with a depletion-type reservoir. After March 24, 2014, oil production within the PLU Well No. 401H declined to zero and water production increased from 1000 barrels of water per day (BWPD) to 3000 BWPD. Correspondingly, the pump inlet pressure increased with the increase in water production. Applicant was able to identify the portion of the horizontal well being impacted using a production log and isolated the water intrusion to the four final stages (or toe) of the completed interval.

(21) Applicant also noted that the PLU Well No. 401H was returned to production following the removal of the isolation plug and a period of redevelopment began on October 26, 2014. At the time of the hearing, the well was capable of producing approximately 25 barrels of oil per day with 2200 BWPD.

(22) Analytical results for produced water samples obtained during the investigation of the PLU Well No. 401H indicated concentrations and characteristics not consistent with lower Brushy Canyon formation water.

(23) Compilation of formation micro imager (FMI) data, pressure data, microseismic information, and well production logs indicate fractures with an alignment that correlates the water intrusion in PLU Well No. 401H with the four disposal wells.

(24) Applicant summarized injection rates (including corresponding approvals of injection pressure increases) and cumulative volumes for the four disposal wells to demonstrate the capacity for fracture propagation that resulted in the impact of the PLU wells.

(25) Applicant provided analyses of produced water from the impacted PLU horizontal wells that showed a change in water constituents and characteristics representative of an external source and not the properties of produced water typically found in the lower Brushy Canyon formation.

(26) Applicant could not determine from their investigation whether the disposal activities either induced a fracture system or enhanced an existing fracture system. However, Applicant stated that the fracture system is narrow in cross-section; thereby impacting the final completion stages of the PLU Well No. 401H while not impacting other horizontal completion intervals in the same area of the PLU.

(27) Applicant concurred that the two disposal wells operated by Mesquite extended below the upper contact of the Brushy Canyon formation while OXY's and Chevron's disposal wells were isolated by mechanical plugs from the Brushy Canyon formation.

(28) Applicant concurred that the Brushy Canyon formation was a relatively tight formation with permeability less than 0.5 millidarcies (mD) and required fracturing of the target interval in the Brushy Canyon formation for hydrocarbon production to occur.

(29) Applicant agreed that the SDS Federal 11 Well No. 1, OXY's disposal well, was injecting into an interval in the Bell Canyon formation that was approximately 3000 feet above the producing interval of the Brushy Canyon formation.

(30) Applicant agreed that the Lotos 11 Federal Well No. 2, Chevron's disposal well, was injecting into an interval that includes the Bell Canyon and upper Cherry Canyon formations which was approximately 2500 feet above the producing interval of the Brushy Canyon formation.

(31) Applicant acknowledged recent improvement in oil production for the PLU Well No. 401H based on the reporting for November and the beginning of December 2014.

(32) Applicant acknowledged that three producing Brushy Canyon oil wells (Todd 2 State No. 3, API No. 30-015-28906; Sotol A Federal No. 3, API No. 30-015-28626; and Cactus 16 State No. 2, API No. 30-015-28609), located to the northeast

(down-dip) and oriented in a similar trend as the BOPCO's PLU wells with the four disposal wells, did not have any indication of water intrusion. Similarly, a Brushy Canyon oil well (Lotos A Federal No. 1, API No. 30-015-28609), located between BOPCO's PLU wells and the four disposal wells, did not have any indication of water intrusion.

OXY and Chevron (collectively referred to as "Opponent") appeared at hearing through counsel and presented the following testimony.

(33) Current construction (including the fact that both disposal wells were cased and perforated in the approved injection interval) and operation of the wells met Division Rules including specific requirements of the respective Administrative Orders authorizing injection.

(34) Opponent presented evidence that the two Mesquite wells had problematic completions as disposal wells complicated by open-hole injection intervals that extended below the contact between the Cherry Canyon and Brushy Canyon formations. Additionally, Opponent presented data available from the OCD that showed the cumulative injection volume of the two Mesquite wells had exceeded seven million barrels of produced water in less than two years.

(35) Opponent noted that the average surface injection pressure for OXY's SDS Federal 11 Well No. 1 during 2014 was 1250 psi while Chevron's Lotos 11 Federal Well No. 2 had an average surface injection pressure of 1000 psi during 2014. Opponent submitted that Mesquite's reporting to the Division of the surface pressure for their two disposal wells was irregular and not consistent with other injection operations in the area.

(36) Opponent provided interpretation of geophysical logs that indicated a permeability barrier associated with limestone intervals near the contact of the lower Cherry Canyon formation and the Brushy Canyon formation. Opponent contended the two Mesquite disposal wells were injecting below this interval and into the Brushy Canyon formation while the Opponent's disposal wells were separated by this permeability barrier as well as shallower limestone barriers located between the lower Bell Canyon and upper Cherry Canyon formations.

(37) Opponent countered Applicant's claim of significant impact to hydrocarbon production in three of the four horizontal wells, the PLU Well No. 392H, PLU Well No. 393H, and PLU Well No. 394H, with review of their production histories. Opponent stated that the wells exhibited a normal decline trend associated with well development in the lower Brushy Canyon formation combined with the effects created by BOPCO in the effort to isolate the water intrusion in the PLU Well No. 401H.

(38) Opponent presented Hall plot analyses for each of the Opponent's disposal wells using historical injection rates and pressure measurements (surface and downhole measurements). The Hall plot analyses for the SDS Federal 11 Well No. 1 indicated normal injectivity (representing continued stable flooding of pore space in the formation)

without any deflection of the lines that may have indicated fracturing in the immediate vicinity of the wellbore. The Hall plot analyses for the Lotos 11 Federal Well No. 2 also demonstrated normal injectivity without any deflection of the lines indicating fracturing in the immediate vicinity of the wellbore.

(39) Opponent presented injectivity indices calculated based on the results of the downhole Hall plot analyses and used to estimate an injection interval permeability for each of the disposal wells. The injection interval permeability for the SDS Federal 11 Well No. 1 was estimated to be 2.29 mD and the permeability for the Lotos 11 Federal Well No. 2 was 2.40 mD. Each estimated injection interval permeability was comparable with data obtained by reservoir tests of the Bell Canyon formation and significantly less than 150 mD, a representative fracture permeability for a fractured reservoir in the Delaware Mountain group.

(40) Opponent's witnesses testified that Opponent's water analyses of produced water did parallel the results of the Applicant's analyses but disputed Applicant's claim the intrusion water was from Opponent's disposal wells since the analytical results were more characteristic of the commercial disposal operation with multiple sources of produced water.

The Division concludes as follows:

(41) The typical production decline from a well with a depletion drive reservoir is either exponential or hyperbolic depending on the reservoir characteristics. It appears from evidence presented by Applicant that some of its wells producing in the lower Brushy Canyon formation in the PLU area are affected by water influx from somewhere in the formation.

(42) The Division is responsible for the orderly development and production of hydrocarbon resources in the state. It is obligated to the prevention of waste, the protection of correlative rights, and providing for the protection of human health and the environment.

(43) Applicant could not provide adequate evidence to determine the individual influences of each disposal well to either the establishment or the enhancement of the fracture system which provided the pathway for the water intrusion. The summary of water analyses and the mapping of the fracture systems did not support Applicant's contention the Opponent's two disposal wells continued to be a source of the water intrusion.

(44) Opponent's presentation of stratigraphy, well construction differences, and Hall plot analyses supported Opponent's contentions that the Mesquite disposal wells had greater potential for impacting BOPCO's horizontal wells. However, the Hall plot analyses were inconclusive in addressing the potential effect of communication existing fractures within formation and vertical migration of injected produced water.

(45) Review of the production reports for the PLU Well No. 401H submitted to Division indicated a steady improvement of hydrocarbon production for the period starting in November and ending with January 2015 reporting.

(46) Based on the testimony and evidence submitted in hearing, the applications to revoke the two administrative orders authorizing injection should not be approved. However, Division should acquire original data that better characterizes the operation of the individual disposal wells for consideration under Division Rules and the conditions of the administrative orders that authorize injection.

IT IS THEREFORE ORDERED THAT:

(1) In Case No. 15231, BOPCO, L.P. application to revoke Administrative Order No. SWD-542, dated December 20, 1993, authorizing OXY USA, Inc. to utilize its SDS Federal 11 Well No. 1 (API No. 30-015-27627) located 2090 feet from the North line and 1980 feet from the West line (Unit letter F) of Section 11, Township 24 South, Range 31 East, Eddy County, New Mexico, as a disposal well for oil-field produced water, is hereby **denied**.

(2) In Case No. 15219, BOPCO, L.P. application to revoke Administrative Order No. SWD-1073, dated February 10, 2007, authorizing Chevron USA, Inc. to utilize its Lotos 11 Federal Well No. 2 (API No. 30-015-28821) located 1780 feet from the North line and 660 feet from the East line (Unit letter H) of Section 11, Township 24 South, Range 31 East, Eddy County, New Mexico, as a disposal well for oil-field produced water, is hereby **denied**.

(3) Administrative Order No. IPI-425 shall remain in full force and effect with respect to Administrative Order No. SWD-1073.

(4) Administrative Order No. IPI-451 shall be suspended with respect to Administrative Order No. SWD-542 until a new step-rate test (SRT) is conducted to verify the results of the SRT submitted for Order No. IPI-451. Until the new SRT results are reviewed by Division, OXY USA, Inc. shall operate the SDS Federal 11 Well No. 1 (API No. 30-015-27627) following the maximum surface pressure of 2200 psi approved under Administrative Order No. IPI-272. The Director of the Division may, upon the review of the new SRT results, authorize an amendment of the maximum surface tubing pressure approved under Administrative Order No. IPI-451.

(5) In order to continue to operate its SDS Federal 11 Well No. 1 (API No. 30-015-27627), OXY USA, Inc. shall complete the following requirements:

(a) Provide a report that includes copies of all documentation (sundry notices, workover reports, a current completion diagram, etc.) that support the current completion of the well with the retrievable bridge plug (RBP) at 4923 feet and perforations from 4510 feet to 4822 feet. This report is to be submitted to the Santa Fe

Engineering Bureau office within 60 days of the issuance of this Order.

(b) If OXY USA, Inc. is not capable of demonstrating the installation of the RBP through documentation, then the operator shall take all the necessary steps to conduct a wireline verification of the plug at 4923 feet. The operator shall file the appropriate Sundry Notice of Intent with the United States Bureau of Land Management for approval. Once approval of the Sundry has been obtained, the operator shall notify the Division's District II office 72 hours prior to the verification activity and a representative of the Division's District II office shall be present to witness the wireline verification. If the operator is not capable of demonstrating the placement of RBP, the Division Director shall require the installation of a cast-iron bridge plug (CIBP) with cement cap no greater than 200 feet below the current deepest perforation at 4822 feet.

(c) Within three (3) months following confirmation of the RBP, the operator shall conduct tracer injection and temperature surveys over the entire injection interval using representative disposal rates.

(d) Within six (6) months following confirmation of the RBP, the operator shall conduct a proper fall-off test to determine condition of the injection including skin factor, current characteristics of the injection interval, and assessment of flow parameters. The test shall be completed following, at a minimum, the *New Mexico Oil Conservation UIC Class I Well Fall-Off Test Guidance (December 3, 2007).*

(e) Within 60 days of completing the fall-off test, the operator shall provide a report detailing the results of the tracer injection and temperature surveys and the results of the fall-off test along with all supporting data. The report shall be provided to the Division's District II office, Santa Fe Engineering Bureau office, and the Applicant, BOPCO, L.P. The report shall be placed in the case file and reviewed by Division.

(6) In order to continue to operate its Lotos 11 Federal Well No. 2 (API No. 30-015-28821), Chevron USA, Inc. shall complete the following requirements:

(a) Install a cast-iron bridge plug (CIBP or equivalent) with cement cap within 200 feet of the deepest perforation (no greater than 5832 feet). Chevron USA, Inc. shall submit a sundry notice to the Bureau of Land Management for approval of installation of the plug. Installation of the plug shall be completed within three (3) months subsequent to the issuance date of this Order; however, the Division Director, upon written request, mailed by the operator prior to the expiration of the six-month period, may grant an extension thereof for good cause.

(b) Within three (3) months after installation of the CIBP, the operator shall conduct tracer injection and temperature surveys over the entire injection interval using representative disposal rates.

(c) Within six (6) months after installation of the CIBP, the operator shall conduct a proper fall-off test to determine condition of the injection including skin factor, current characteristics of the injection interval, and assessment of flow parameters. The test shall be completed following, at a minimum, the *New Mexico Oil Conservation UIC Class I Well Fall-Off Test Guidance (December 3, 2007).*

(d) Within 60 days of completing the fall-off test, the operator shall provide a report detailing the results of the tracer injection and temperature surveys and the results of the fall-off test along with all supporting data. The report shall be provided to the Division's District II office, Santa Fe Engineering Bureau office, and the Applicant, BOPCO, L.P. The report shall be placed in the case file and reviewed by Division.

(7) In the event that the additional engineering data, required to be submitted by Chevron USA, Inc. and OXY USA, Inc. subsequent to the entry of this order, indicates that continued injection within the Lotos 11 Federal Well No. 2 and/or the SDS Federal 11 Well No. 1 may be affecting production in the lower Brushy Canyon formation of the Delaware Mountain group, the Division shall re-open this case to consider further action as may be necessary to prevent waste and protect correlative rights.

(8) Jurisdiction of this case is retained for the entry of such further orders as the Division may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

DAVID R. CATANACH
Director

S E A L

Case Nos. 23686 and 23687; OCD Exhibit No. 8

Avalon Shale Production Interference

Observations of Impact Caused by Delaware Disposal Water Injection

July 2016

Summary:

In late 2008, early 2009, the Avalon Shale became a popular, productive, horizontal drilling target for operators in the Southern portion of the New Mexico Delaware Basin in Eddy County from T23S to the state line and 10-15 miles into Texas. At the time, the wells were predominantly gas producers with high (10,000+) gas-oil ratios and high water-cuts (80-90%). Towards the early part of 2011, a lot of the focus in the play had shifted to an oilier window of the play again from T23S to the state line, but in Lea County from R32E to R34E. The wells drilled into this formation have seen significant advances in completion stimulation efforts and the play is now a premier target for operators in these areas, generating high initial rates and sustained production rates across 2-3 different benches within the overall Avalon Shale formation. As of the beginning of 2016, we have identified over 650 horizontal wells that have targeted the Avalon Shale across the aforementioned area based on our interpretation of permits/completions/directional surveys and our regional mapping of the zone.

It has come to our attention that across the productive area of the Avalon Shale in the basin, there appears to be a correlation to interference in producing and in some cases active drilling horizontal Avalon Shale wells and multiple salt water disposal wells injecting into the Delaware formation. We believe this is leading to the waste of the oil and gas resource in place. Being an unconventional, shale play, there is limited rock matrix permeability. This leads us to believe the increased overall productivity from water must be a result of a fracture. After further investigation, we attribute the cause of this interference to an anomalously low frac gradient in the Delaware formation, specifically the Cherry and Brushy Canyon, and into the Avalon Shale which actually promotes the downward migration of the injected water and in the absence of a strong frac barrier leads to the watering out of the Avalon Shale producers. Based on the standard state allowable maximum surface injection pressure of a "0.2 psi/ft gradient" from surface to the top of the injection interval, many wells are injecting above the frac gradient of the Delaware and Avalon Shale (0.58-0.65 psi/ft) at the maximum allowable pressure (0.69 psi/ft). Our research found that this interference happens at multiple levels of magnitude. In some instances, the producing well sees an increase in total fluid and the water-oil ratio gradually increases overtime until the well effectively waters out. In more drastic cases, water breakthrough causes water flows that render the producing well non-productive.

Undoubtedly, disposal applications within the Delaware interval need to face more scrutiny. One immediate recommendation is for the New Mexico Oil Conservation Division to require more monitoring of the surface injection pressures and not allow for injection pressure increases based on step rate tests. Furthermore, operators should not perform hydraulic fracturing in an attempt to improve injectability. These two steps should help confine injection fluids into what needs to be a diligently selected and limited interval within the Delaware formation. Any disposal wells injecting into the Delaware at anomalously high rates need to be revisited in order to protect the correlative rights of the offset owners, even beyond the ½ mile radius currently provided. A transition away from any salt water disposal into the Delaware formation within the productive limits of the Avalon fairway needs to be considered to protect the future of the play.

All interest owners in prospective Avalon Shale acreage should have a common interest in protecting the present and future of the play.

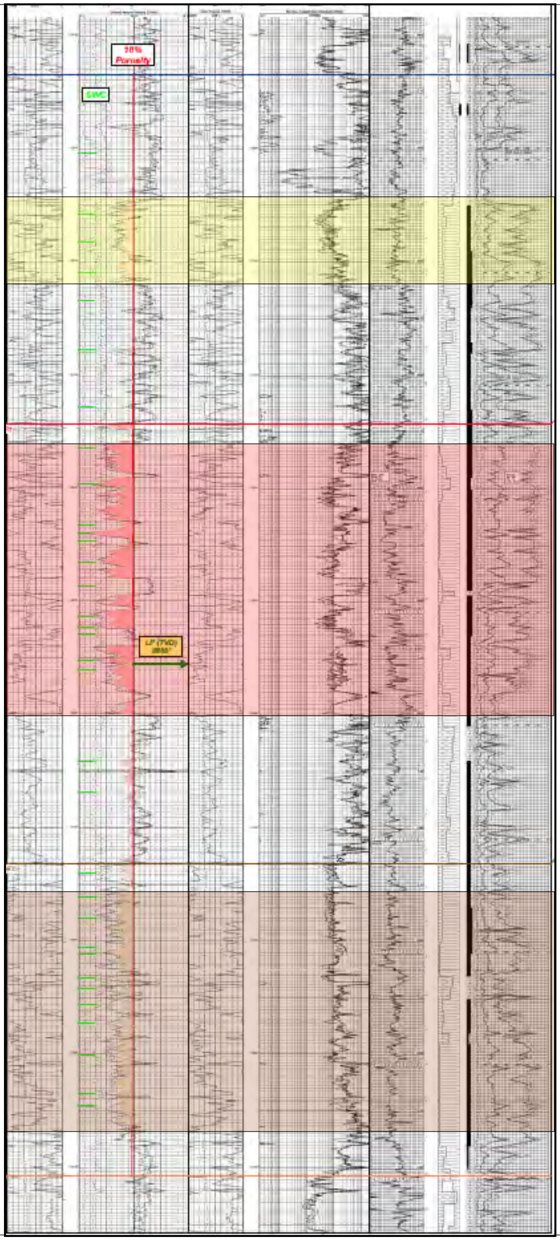
Avalon Shale Type Log
Pilot Hole Drilled in:
Unit P Section 8 T26S R32E

- To the right is a triple combo log (gamma ray, density-neutron porosity, resistivity) and corresponding mudlog. Note the good oil and gas shows throughout the section

- The three main "targets" have been broken out as a representative type log of the Avalon Shale, particularly for this area. The Avalon Shale is situated within the top ~ 1000 ft of the Bone Spring.

- The section varies depending on the location throughout the basin, with variations in the specific targets and overall section becoming thicker/thinner with more/less limestone stringers or overall facies changes feeding in.

- This will be a useful tool as we focus in on the Avalon Shale throughout this presentation for our interpretation of targets correlated from directional surveys.



BS Lime →

Low Porosity →

Limey Section →

Bone Spring Top

Upper Avalon

Middle Avalon

Lower Avalon

1st BS Sand

Avalon Shale Prospectus
New Mexico

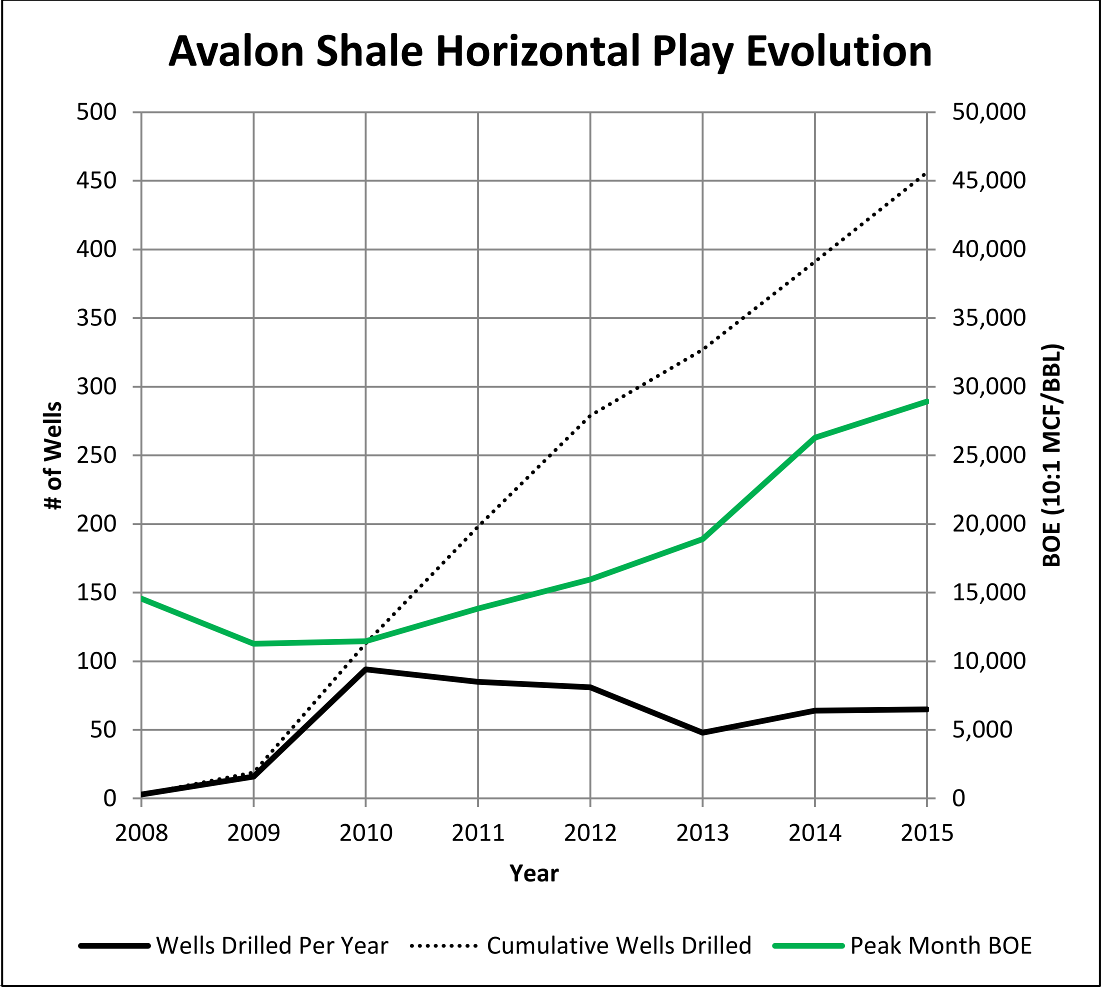
- Since 2008, we estimate approximately 450 horizontal Avalon Shale wells have been drilled in SE New Mexico alone.

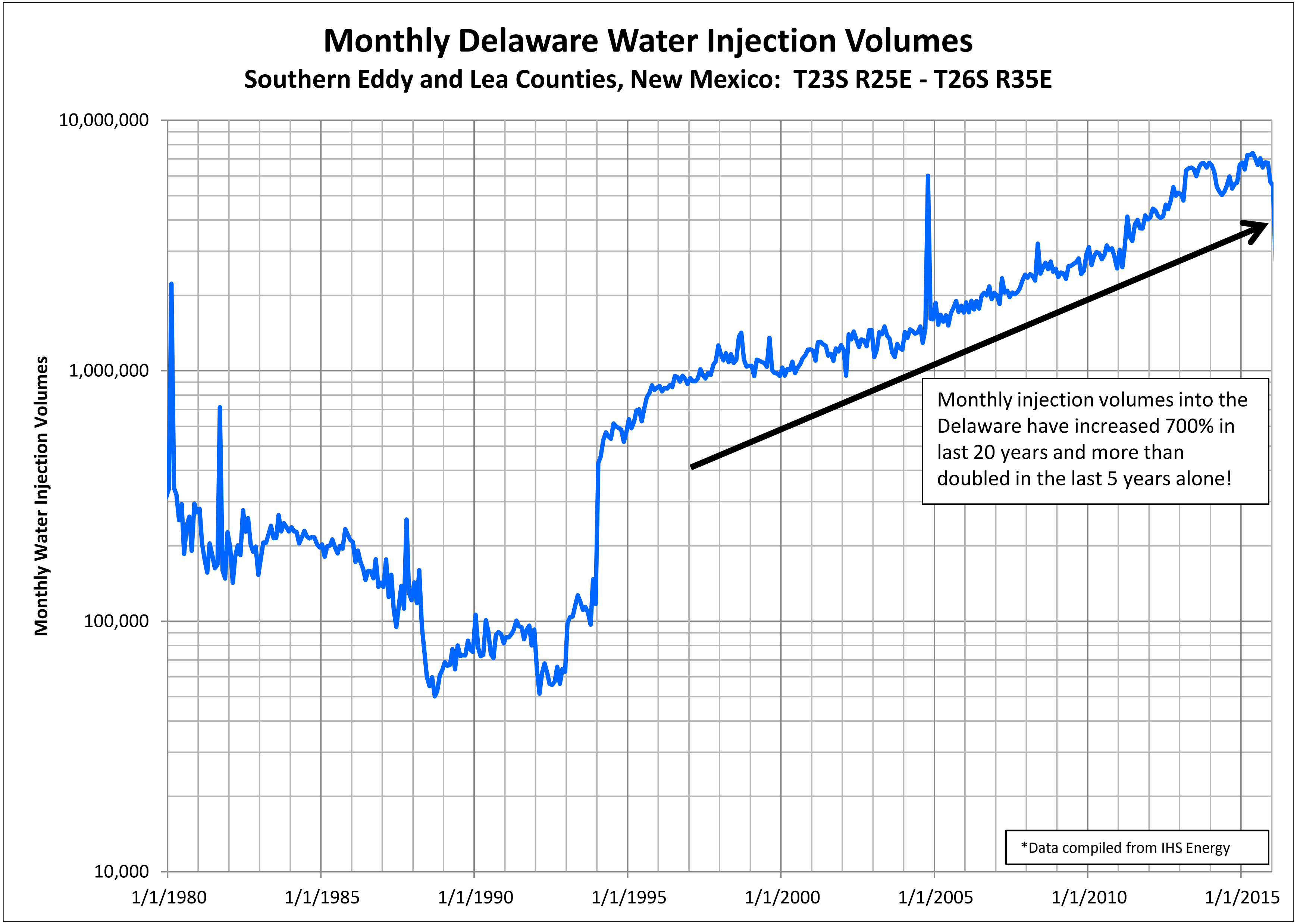
- In that time, the average peak 30 day initial rates have nearly doubled from 14,600 to 28,900 BOE as operators have focused on optimizing hydraulic fracturing completions. Today, most active operators project average EUR's for a 1 mile lateral at approximately 500,000 BOE.

- Operators have tested down spacing and are planning development of 4 to 16 wells per section (160 acre spacing in one target to 80 acre spacing in two targets), between 2 and 8 million BOE.

- The Avalon Shale has been targeted in 43 townships in New Mexico, and proven productive in at least 25. That equates to a range of at least 3,600 to 14,400 proven locations with recoverable reserves currently between 1.8 to 7.2 billion barrels of oil equivalent.

- With approximately 8% of the proven locations already drilled, the play has just scratched the surface and the protection of the future reserves warrants addressing for every interest owner.

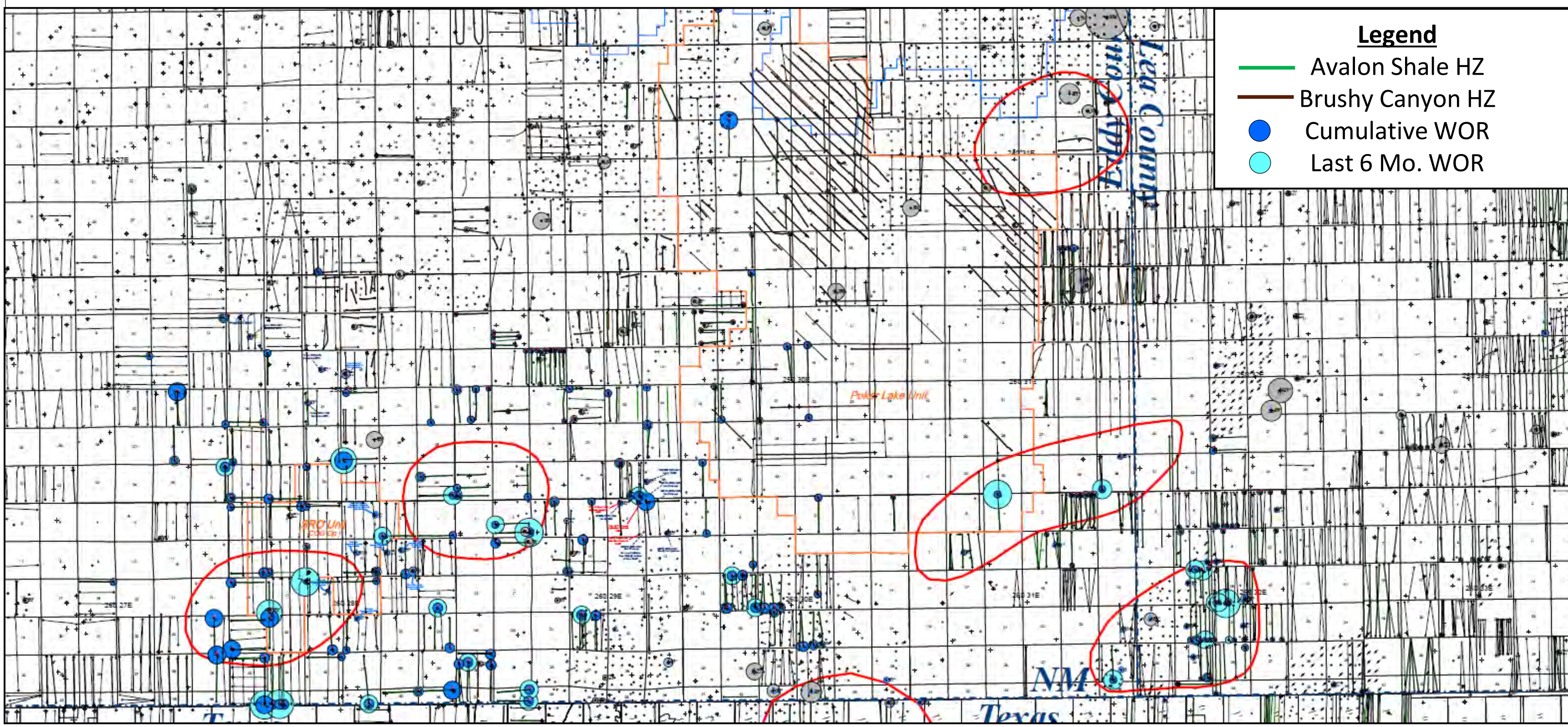



Monthly Delaware Water Injection Volumes
Southern Eddy and Lea Counties, New Mexico: T23S R25E - T26S R35E
Monthly Water Injection Volumes
10,000,000
1,000,000
100,000
10,000
1/1/1980
1/1/1985
1/1/1990
1/1/1995
1/1/2000
1/1/2005
1/1/2010
1/1/2015
Monthly injection volumes into the Delaware have increased 700% in last 20 years and more than doubled in the last 5 years alone!
*Data compiled from IHS Energy

00119

S. Eddy & Lea Counties, NM
Avalon Shale Horizontals

- The Avalon Shale play covers over 25 townships within the Southern portion of the basin in New Mexico and extends down into Texas as well. The map below shows that the correlation between Delaware disposals and abnormally high or increasingly high water cut Avalon Shale wells isn't limited to the examples outlined, but rather, occurs over a broad area.



Loving County, TX
Block 56 T-1S
(Approximately South of 26S-30E Eddy County, New Mexico)

- In 2009, Chaparral (Now WPX, formally RKI) operates Delaware Bell Canyon Fields.

- Begin injecting into two wells (Δ)located in the NW/4 Section 8 and the NE/4 Section 9 formerly completed in the Wolfcamp plugged back to the Bell and Cherry Canyon (3400'-5300'). Maximum allowable surface pressure 1700# and 2423#, respectively.

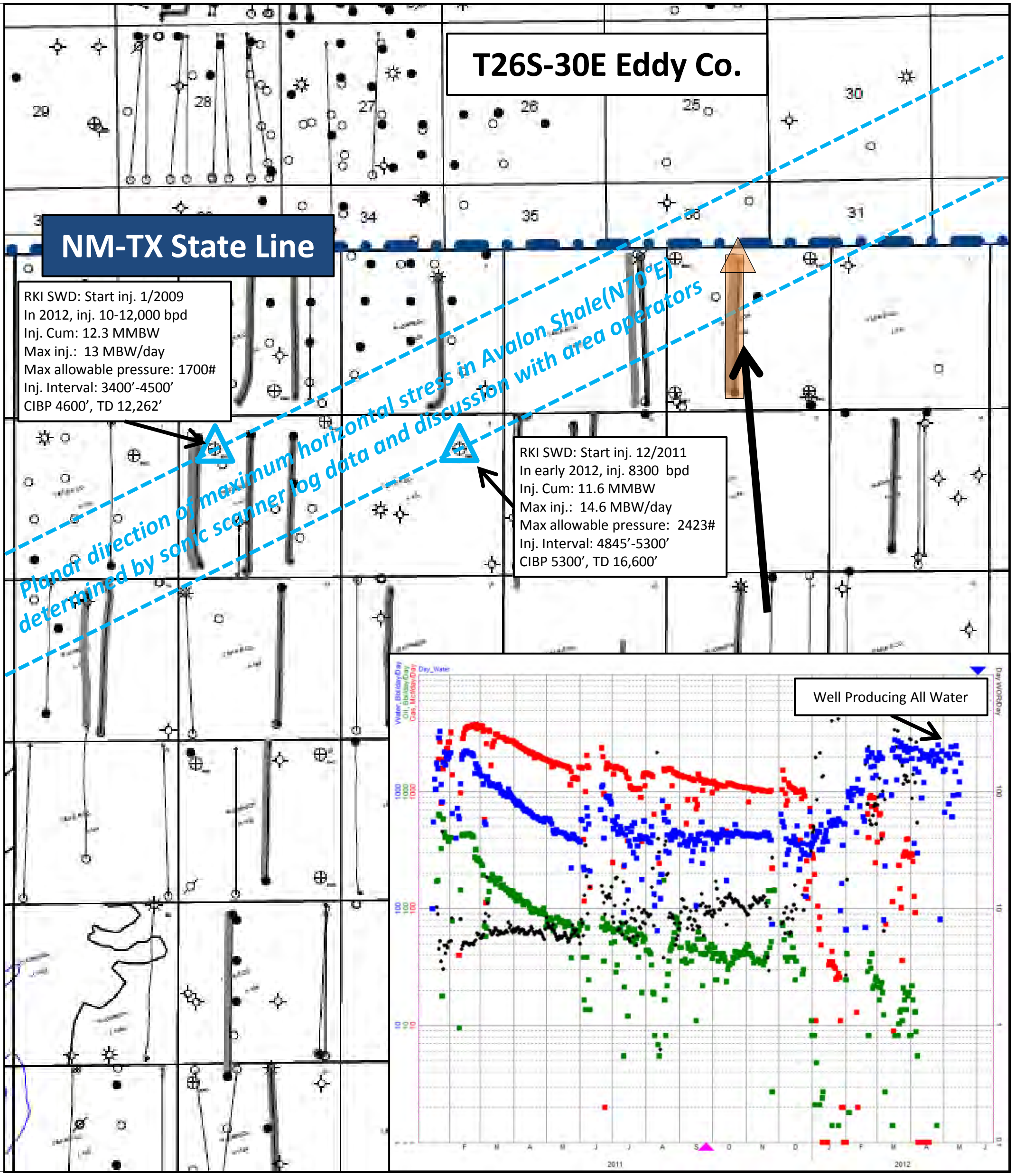
- 8/2010, Chaparral drills Avalon Shale hz (Δ) in the E/2 W/2 Section 2. First production 1/2011. IP 425 BO, 3600 MCF, 2150 BW.

- By early 2012, salt water disposal injection volume is averaging 8,000-12,000 BW per day, per well. Combined, the two wells have injected nearly 24 million barrels of water since 2009.

- The producing well was put into production on submersible pump and continued to produce on ESP. In December 2011 and into 2012, the oil and gas volumes fell off from 1000 MCF/d and 35 BO/d. Meanwhile, the water volume increased from 375 to over 2000 BW/d by the end of February 2012.

- The well was shut-in in May 2012 after continuing to make all water.

- We estimate the well had approximately 70,000 BBLs oil and 1.75 BCF gas remaining when the well was shut-in.

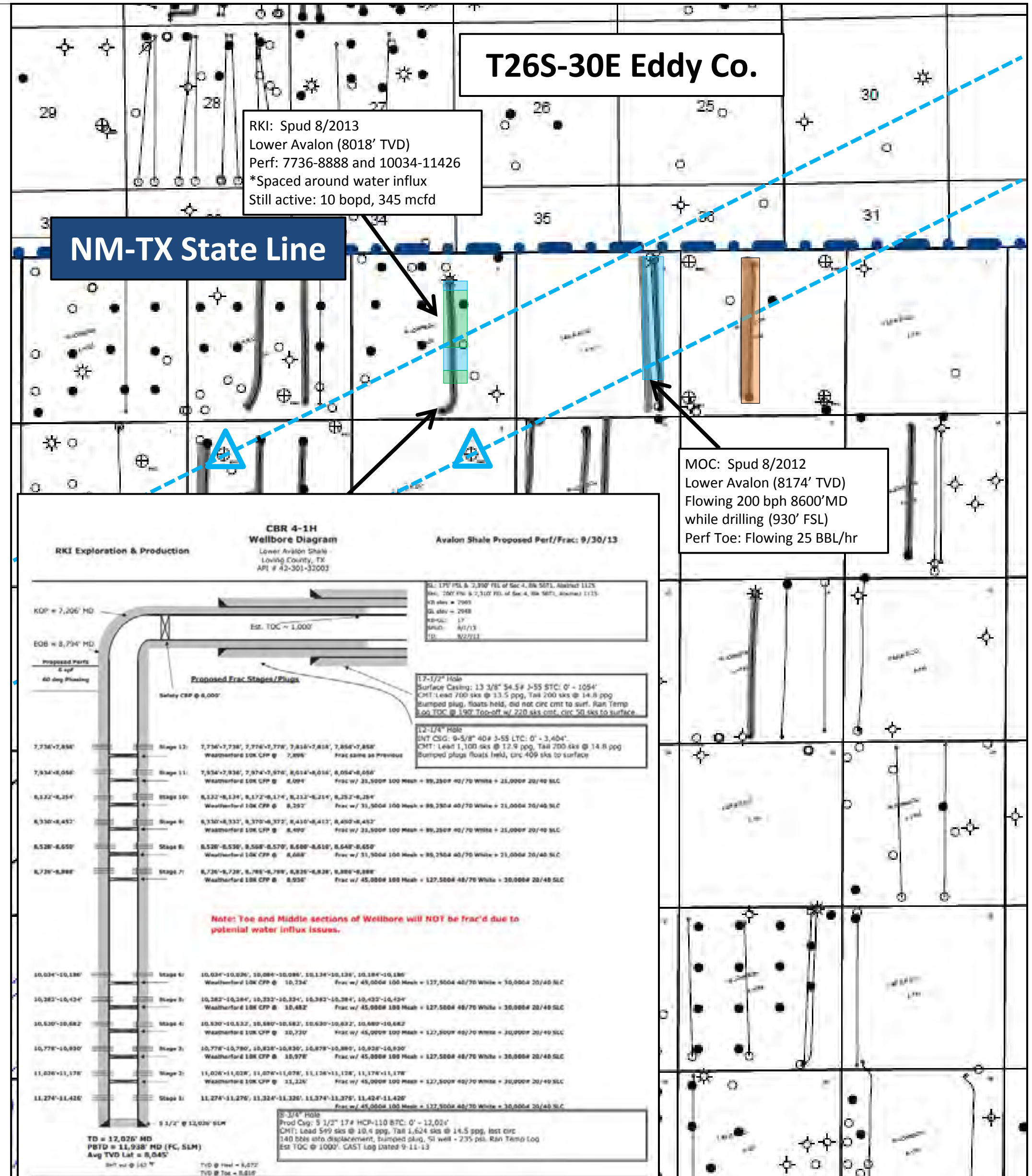


Loving County, TX
Block 56 T-1S
(Approximately South of 26S-30E Eddy County, New Mexico)

- Mewbourne Oil company spud Avalon Shale horizontal offset to Chaparral well in section 3 in 8/2012.

- After setting intermediate 7" csg string at the hz landing point, encountered 200 barrel per hour water flow 200' into lateral section. Drilled well to TD and ran and cemented liner. Perforated toe and well began flowing 25 BW/hr naturally. Set plug part-way through lateral and perforated 1000' from TD. Well still flowing naturally. Possible bad cement job. Temporarily abandoned well.

- RKI drills Avalon Shale hz Avalon Shale in section 4 in 8/2013. Does not complete ~1150' of the horizontal section due to "potential water influx issues." Well is still active at 10 BO/day and 345 MCF/day. We estimate spacing around the water influx decreased the ultimate recovery by 30-35% based on results in the area.



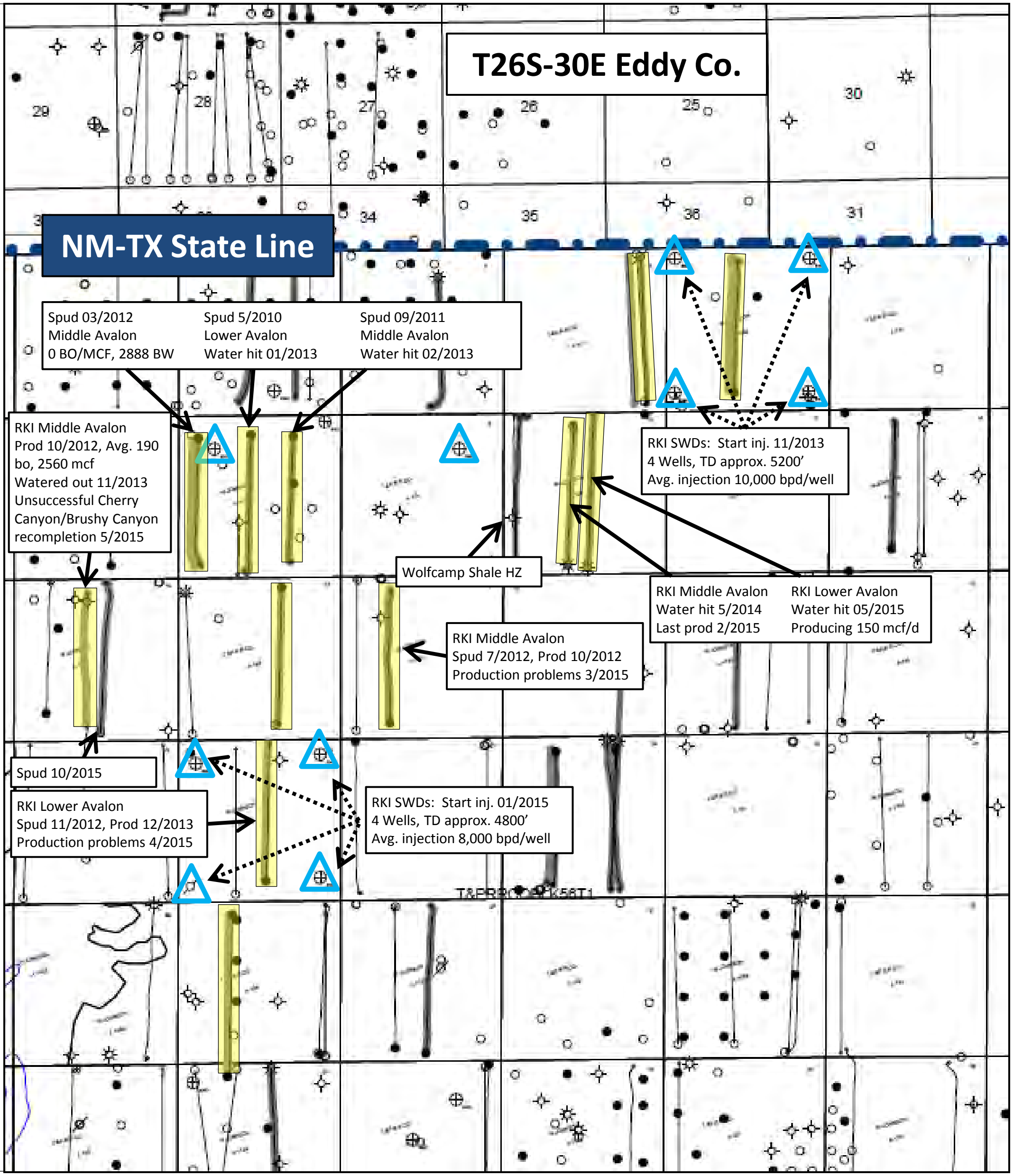
00122

Loving County, TX
Block 56 T-1S
(Approximately South of 26S-30E Eddy County, New Mexico)

- RKI continued drilling Avalon Shale Horizontals (indicated by grey highlight) and Bell/Cherry Canyon salt water disposal wells (Δ) in Blk 56 T1-S.

- Highlighted in yellow ( ) are 10 additional wells in the immediate area that have either stopped producing or exhibit production disturbances that resemble an effect attributable to an influx of water from an outside source.

- A predictable, systematic timeline develops along the "anticipated frac planes" from when water injection starts to when production complications in the Avalon Shale producers commence. While the initial wells were promising, we believe it would be unthinkable to drill an Avalon Shale well in this field in the future due to the high risk associated.



00123

Loving County, TX
Block 56 T-1S
(Approximately South of 26S-30E Eddy County, New Mexico)

<u>Additional Decline Examples:</u>

A: W/2 E/2 Section 4

Lower Avalon Shale

* Completed interval originally spaced around potential water influx. Well exhibits a typical hyperbolic decline

B:E/2 W/2 Section 10

Lower Avalon Shale

Interference appears to occur 5/2014

C: E/2 W/2 Section 18

Middle Avalon Shale

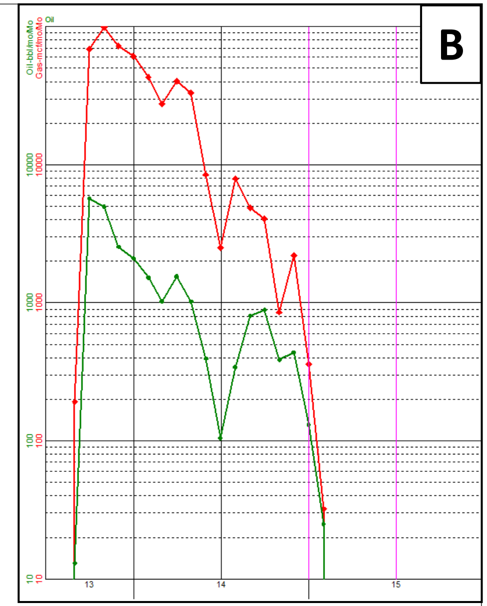
Interference appears to occur 11/2013

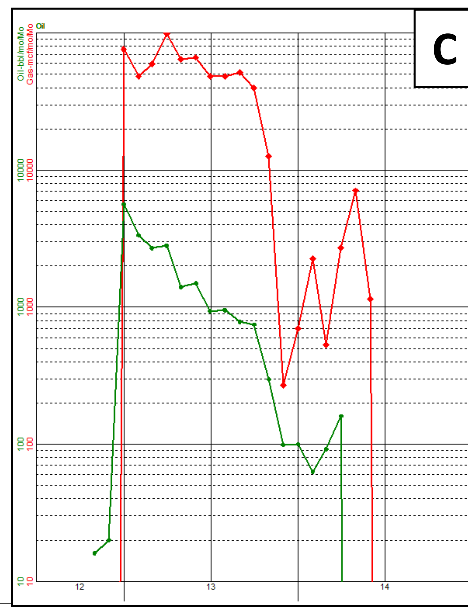
D: W/2 E/2 Section 20

Lower Avalon Shale

Interference appears to occur 4/2015

*Note: Water production is not reported in Texas





Eddy/Lea County, NM
T25S R31E → T26S R32E

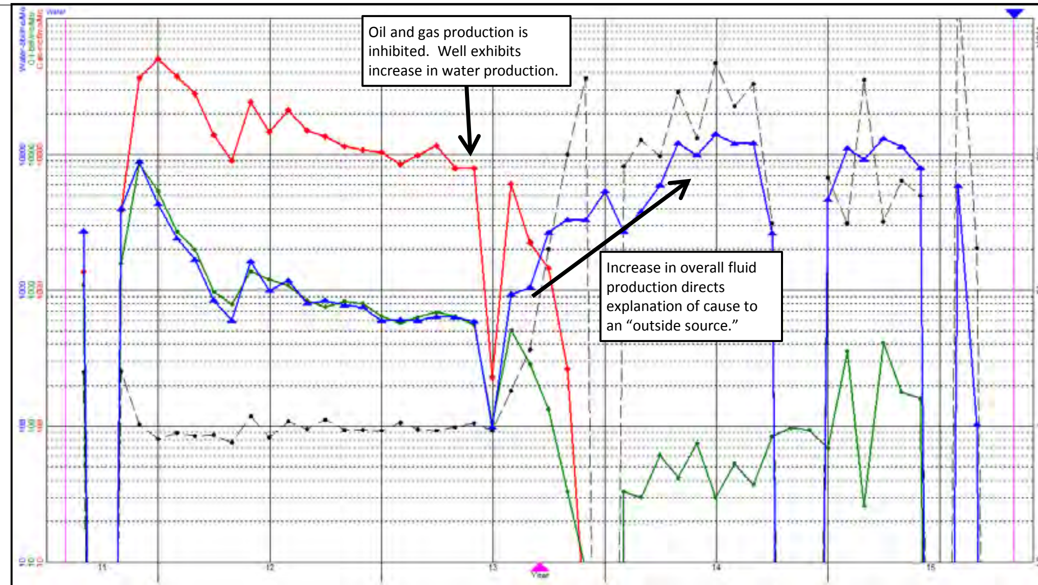
● Began looking into this area based on Mewbourne's (formerly Yates) Bebop BPE State 1H in the W/2 W/2 Section 36 T25S R31E ( ).

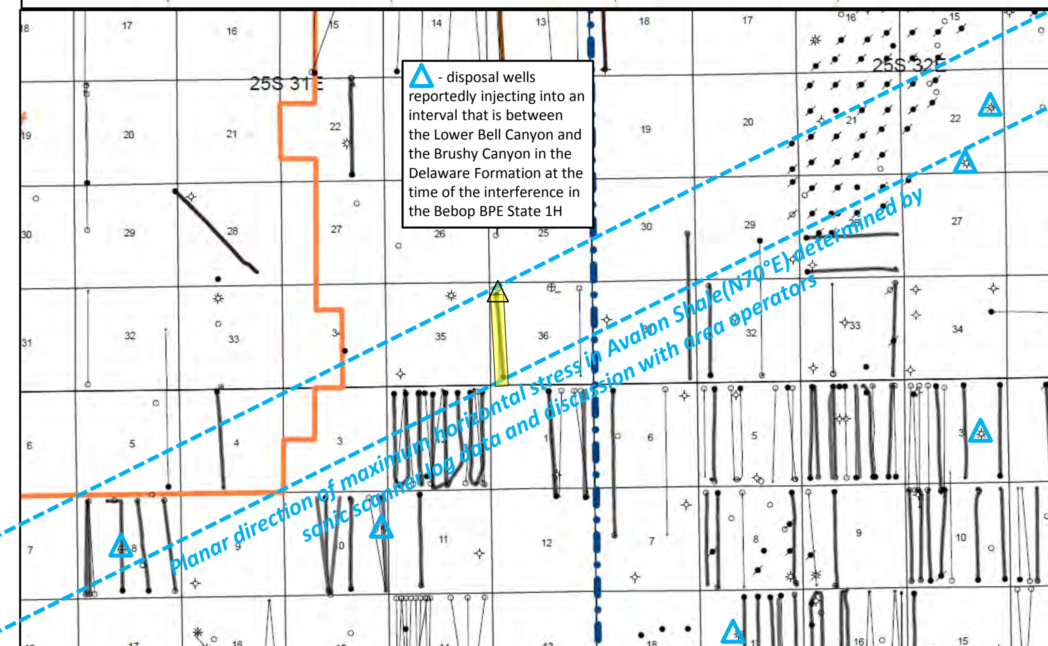
● Well went from producing 20 BO, 270 MCF and 20 BW per day to 100 BW per day at effectively a 100% water cut in the second half of 2013. The problem appeared to be a textbook example of a casing leak.

● The intermediate casing was tested and held 1000#, showing no signs of a casing leak. Hard scale was encountered, not typical of other Avalon producers we are aware of.

● Well was put on rod pump and produces nearly 100% water. The well does not pump off and holds a fluid level near the surface.

● The increase in overall fluid productivity does not support a "watering out" of the matrix model. The outside source must be tied to the reservoir.





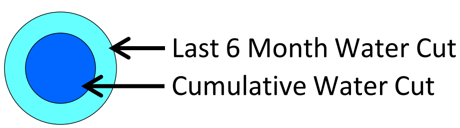
Eddy/Lea County, NM
T25S R31E → T26S R32E

● The graph to the right shows a rate-time plot of monthly Delaware SWD rates gathered from IHS. The average disposal volume is around 30,000 BBL/month or 1,000 BBL/day.

● Two of the most active Delaware disposals are located in section 22 T25S R32E at an average of 300,000 BBL/month or 10,000 BBL/day, a full order of magnitude higher than the average.

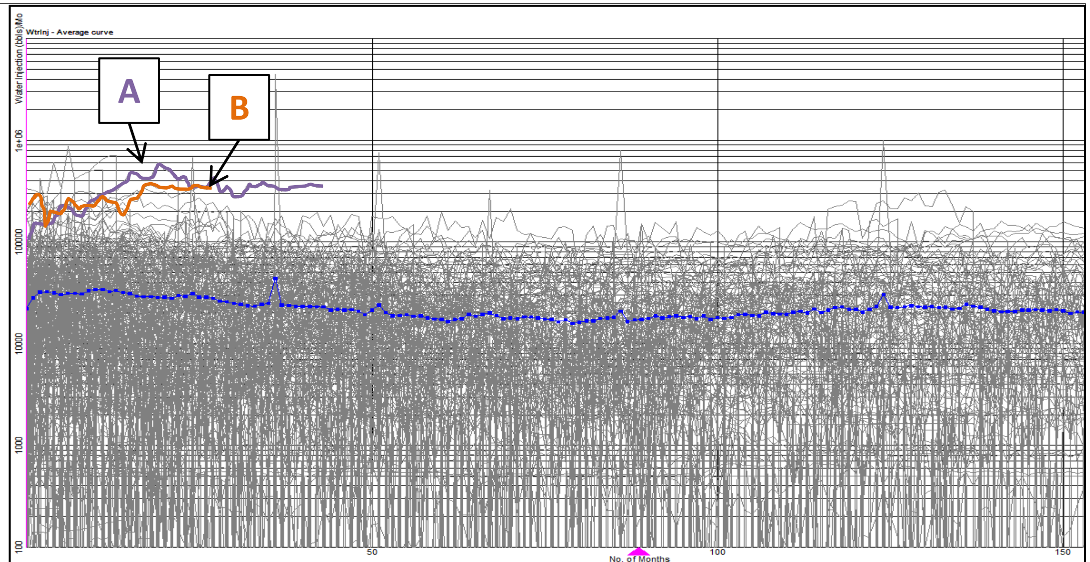
● The map shows to the right shows the relative amount of water injected into the Delaware SWD's based on the grey bubble size.

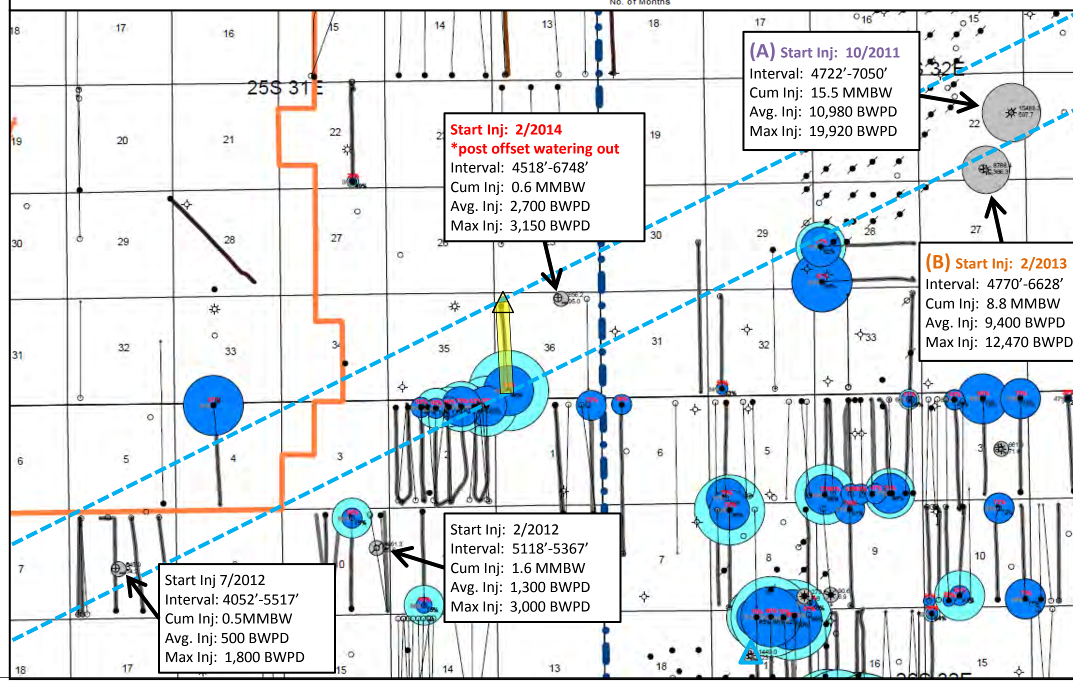
● Additionally, a historical comparison of the water cut is presented as follows:



● A light blue halo forming around the cumulative water cut shows the water cut is increasing over the last six months compared to the average water cut over the life of the well.

● The size of the bubble is representative of the water cut as compared to 100% at 36 T25S R31E.





Eddy/Lea County, NM
T25S R31E → T26S R32E

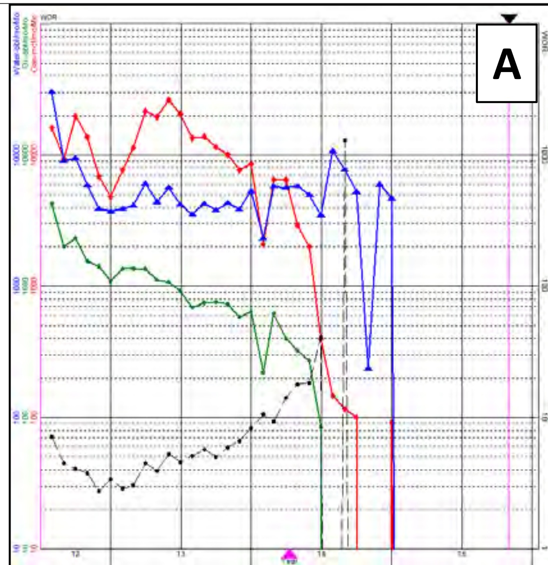
- In either direction along the plane of maximum horizontal stress (frac plane) from the Bebop BPE State 1H, there are additional occurrences of anomalous water volumes.

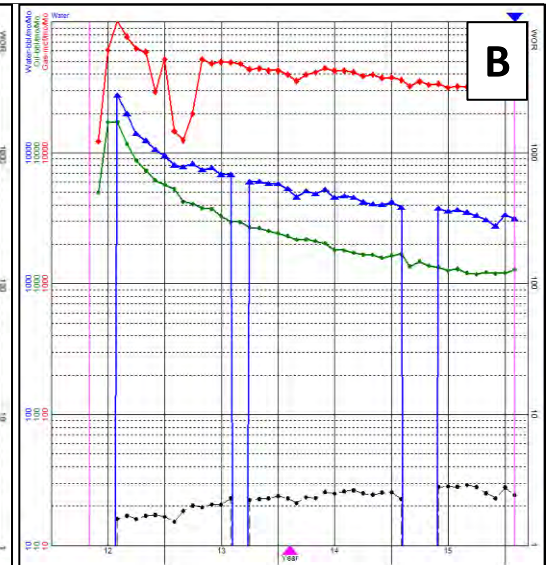
- East of section 36, EOG spud a Middle Avalon Shale well in section 31 T25S 32E drilling North into section 30. Approximately 2000’ FNL (according to plans filed), it was communicated that EOG encountered a 600 BW/hour water flow (~14,400 BW/day) while drilling in the lateral.

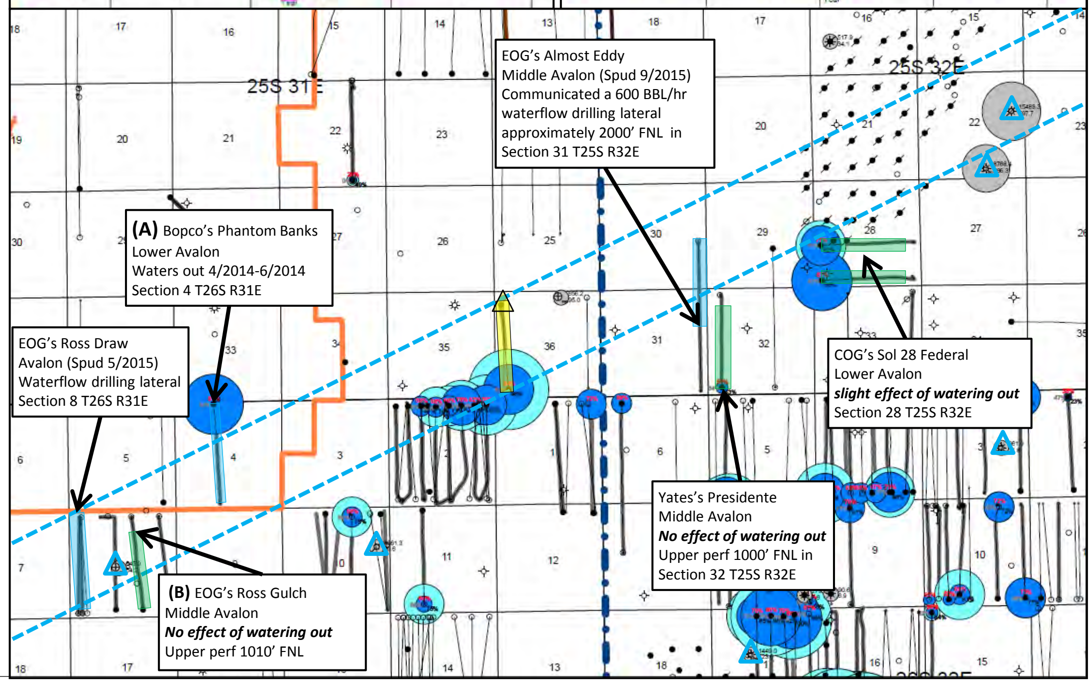
- West of section 36, BOPCO had a producing well in the Lower Avalon Shale in section 4 T26S R31E which watered out in the middle of 2014 as shown in production plot (**A**).

- In section 8 of T25S R 31E, EOG drilled and completed a Middle Avalon Shale well in the W/2 E/2. It subsequently put in a Delaware SWD in Unit K of the same section. To date, the producing well has shown little to no sign of watering out as shown in production plot (**B**).

- In the same section, EOG encountered a waterflow while drilling the lateral of an Avalon Shale horizontal spud in 5/2015 in the W/2 W/2. The waterflow occurrence in this wellbore but not in the well in the E/2 of the section instills doubt that the origination of the problem is the result of the disposal well in the section.







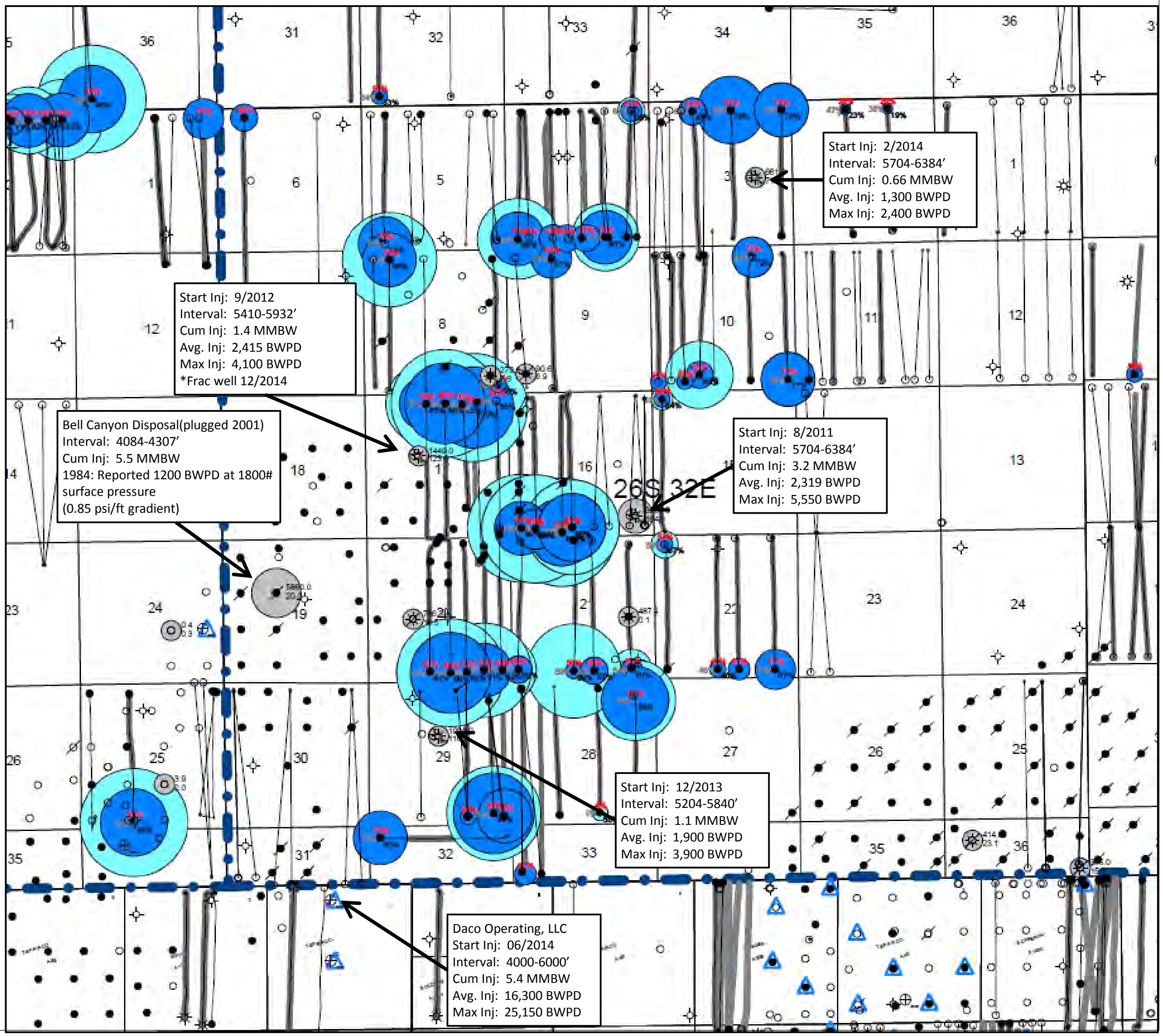
Lea County, NM
T26S R31E/32E

- Another area that has become cause for concern is T26S R31E & R32E.

- Historically, a number of vertical wells were drilled into the Upper Bell Canyon as part of the Mason East Field. Recently, there has been heavy development in the Avalon Shale with horizontal drilling.

- The map to the right highlights the location of the five main disposal wells in the Lower Bell/Upper-Middle Cherry Canyon.

- Notice that the disposal wells in New Mexico all average under 2,500 BWPD. However, directly across the state line an injector is averaging over 16,000 BWPD with a reported maximum over 25,000 BWPD since the middle of 2014.



Lea County, NM
T26S R31E/R32E

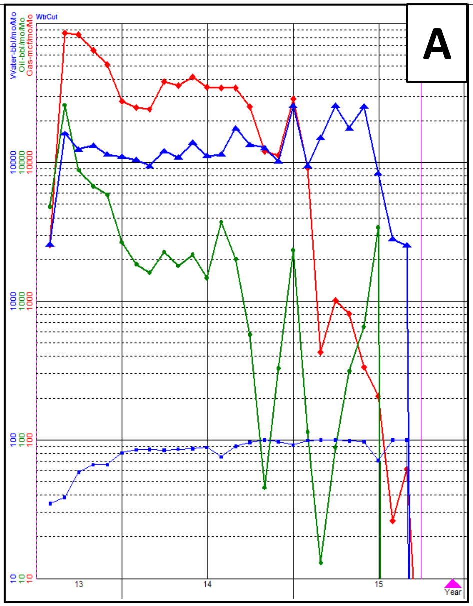
<u>Decline Examples from COP production data:</u>

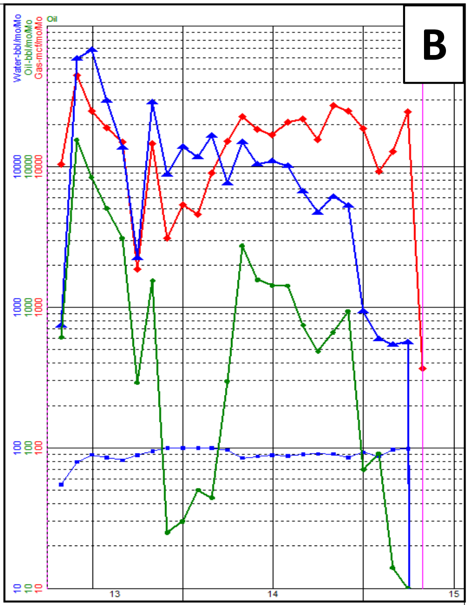
A: W/2 W/2 Section 16, T26S R32E
Middle Avalon Shale

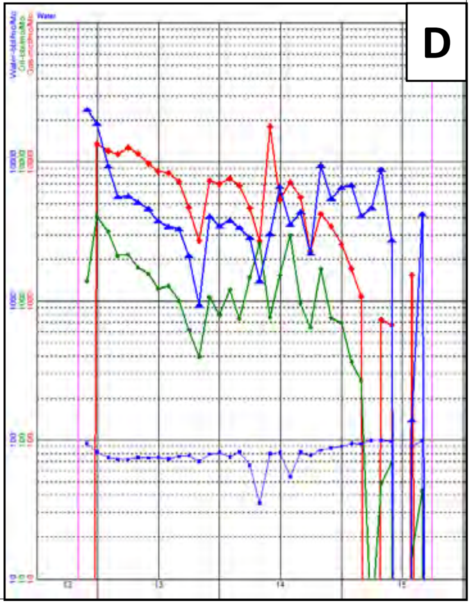
B: E/2 E/2 Section 17, T26S R32E
Middle Avalon Shale

C: W/2 E/2 Section 20, T26S R32E
Middle Avalon Shale

D: E/2 W/2 Section 25, T26S R31E
Lower Avalon Shale







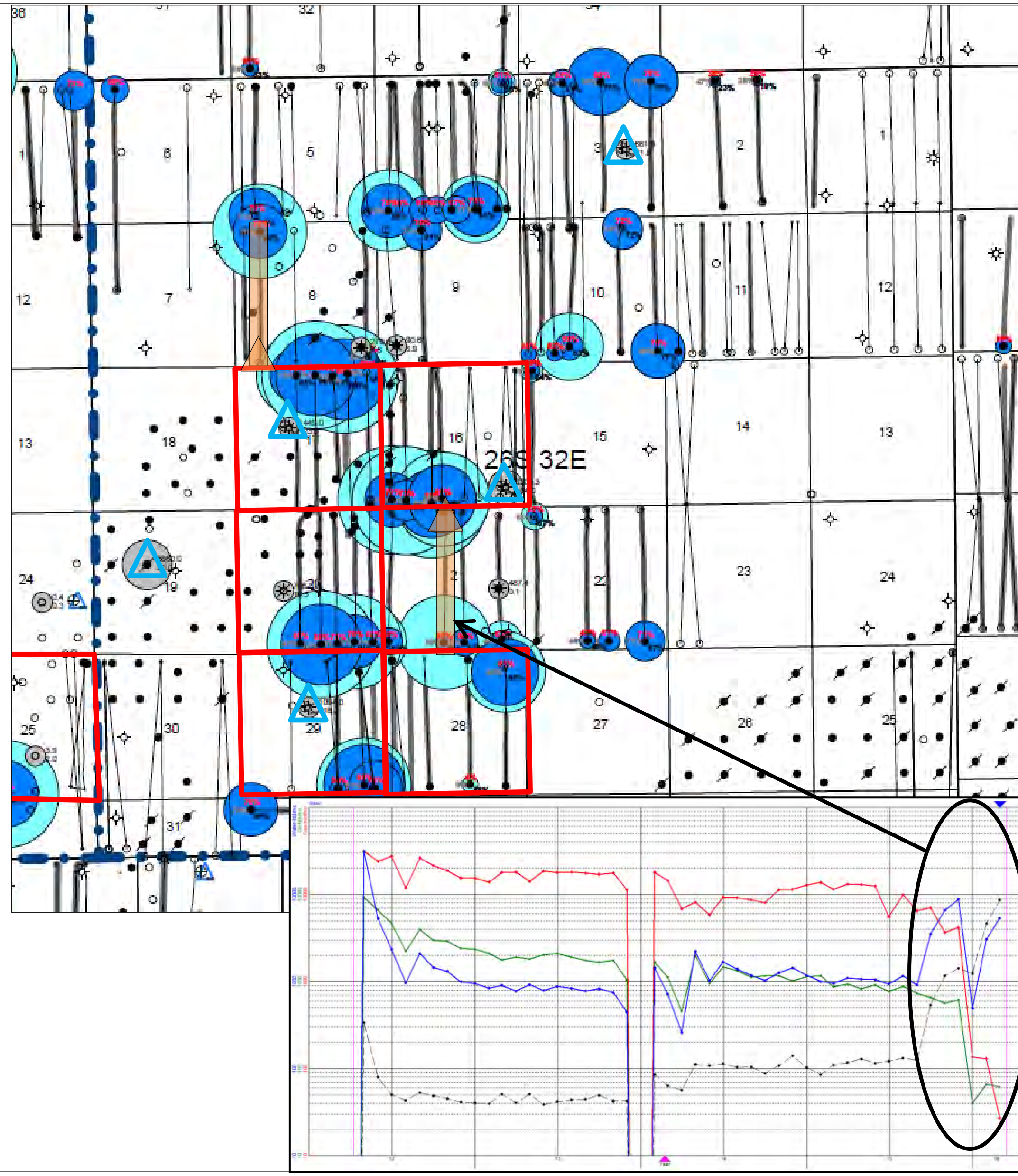
00129

Lea County, NM
T26S R31E

● ConocoPhillips operates Avalon Shale wells in the sections highlighted in red in T26S R31E and R32E. They have drilled what we would characterize as both “Middle” and “Lower” targets within the formation.

● Compared to wells operated by offset operators, their wells drilled in the Middle Avalon Shale target have exhibited higher initial water cuts which have nearly increased to 95-100%, as shown in the graphic to the right.

● Mewbourne operates a well in the E/2 W/2 of section 21 T26S R31E that has increased from a 50% water cut to over 90% in the last 3 months. The intermediate casing was tested to 700# and confirmed there was no leak. The well was producing 30 BW/day and has increased to nearly 300 BW/day, a 10 fold increase that is likely capped due to capacity restraints on rod pump.



Frac Gradient Data
Pilot Hole Drilled in:
Unit P Section 8 T26S R32E

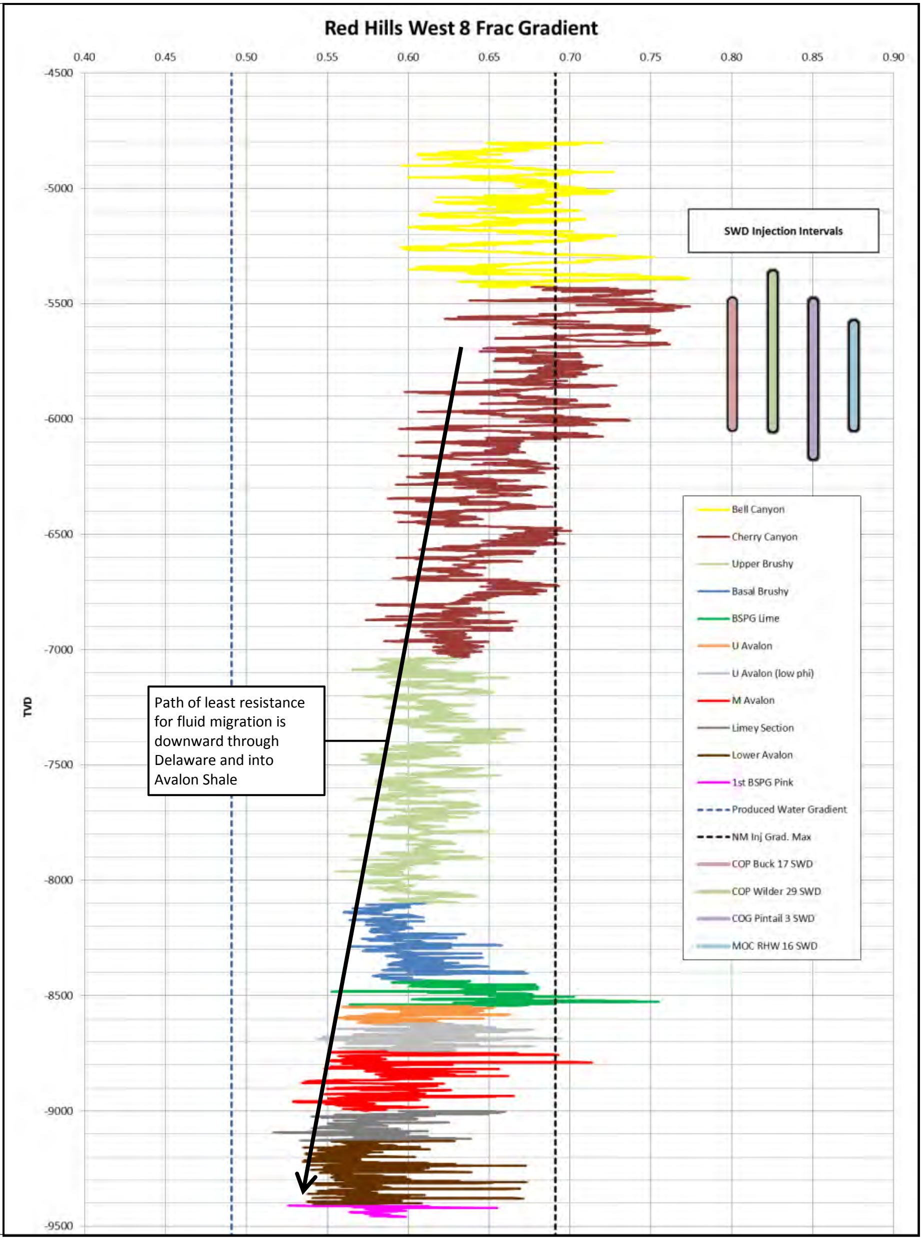
● For answers to why these wells across the basin are seeing these incremental increases in water production, especially in areas surrounded by Delaware disposals, we looked at a comparison of the gradient of injected produced water compared to a data set of the frac gradient through the Delaware and into the Avalon Shale as calculated from the data provided by a sonic scanner log.

● Plotted to the right are the following:

- frac gradient of the formation, broken out by zone
- produced water average gradient .49 (see appendix)
- maximum allowable injection pressure gradient (0.2) determined by the OCD before an SRT approved IPI
- correlated disposal intervals of four highlighted SWD wells in the township

● With an injection interval in the Cherry Canyon, the path of least resistance is downward through the Brushy Canyon and into the Avalon Shale with very few true “frac barriers”.

● As shown by the injection gradient, even at the current allowable operating conditions, Delaware disposals can pose a serious threat to the potential reserves in the Avalon Shale and even Brushy Canyon. This threat become exaggerated if disposal operators frac their well as part of the completion or apply for an injection pressure increase based on the results of a step rate test. It is possible and even likely in some cases that a step rate test is inconclusive or even misleading as the formation may already be fractured.



00131

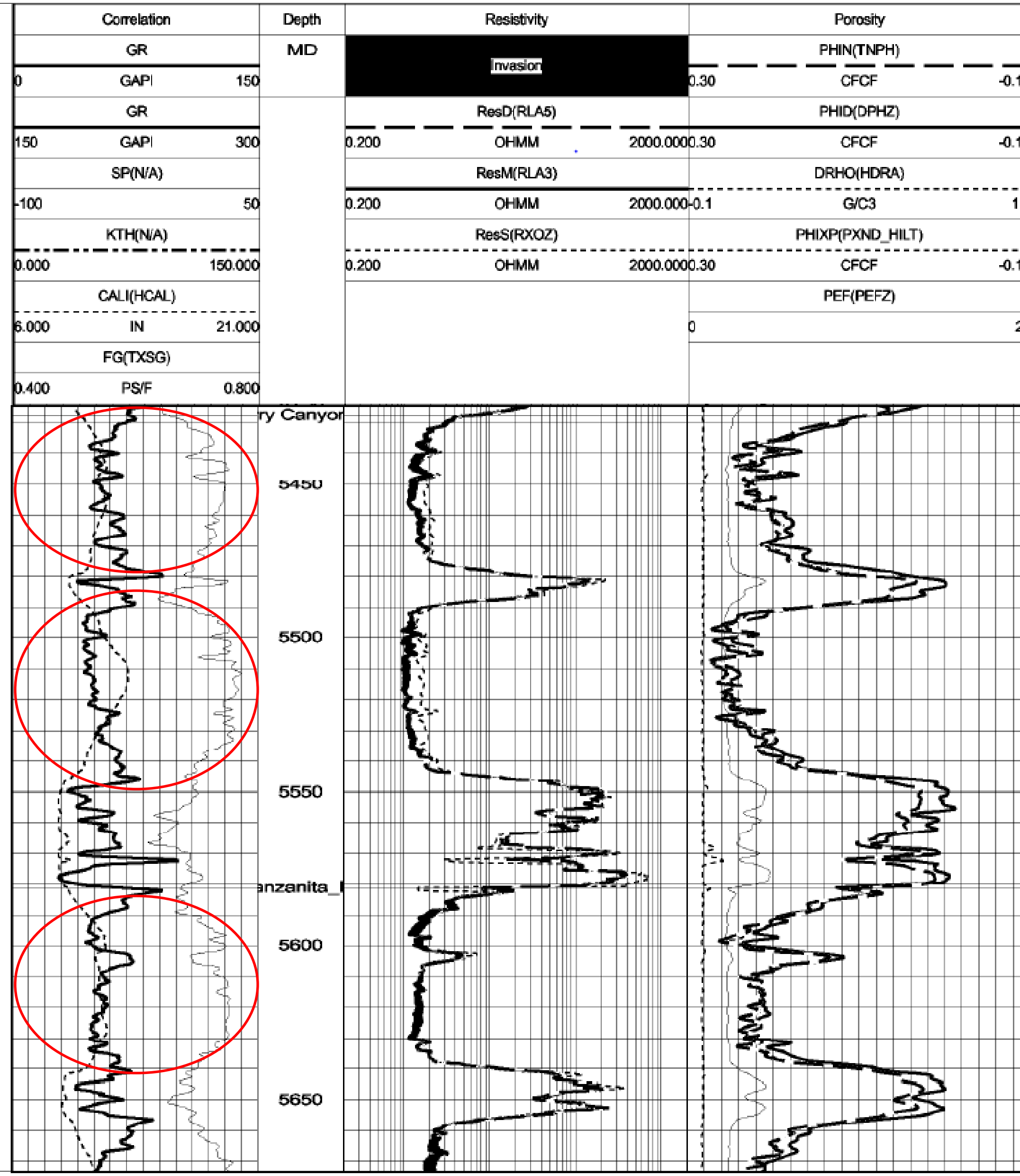
Frac Gradient Data
Pilot Hole Drilled in:
Unit P Section 8 T26S R32E

- Shown to the right is a overlay of the calculated frac gradient on the Gamma Ray/Caliper curves in Track 1. Also shown are the Dual-Laterolog Resistivity in Track 2 and Density-Neutron Porosity in Track 3.

- This portion of the log is taken over the top of the Cherry Canyon where some of the highest "frac gradient" values occur, approximately .75 psi/ft.

- These high intervals correspond to some of the highest porosity values over sands exhibiting considerable washout, circled in red.

- While these calculate as some of the highest frac gradient intervals, we know they don't provide any form of barrier due to their high porosity and permeability.

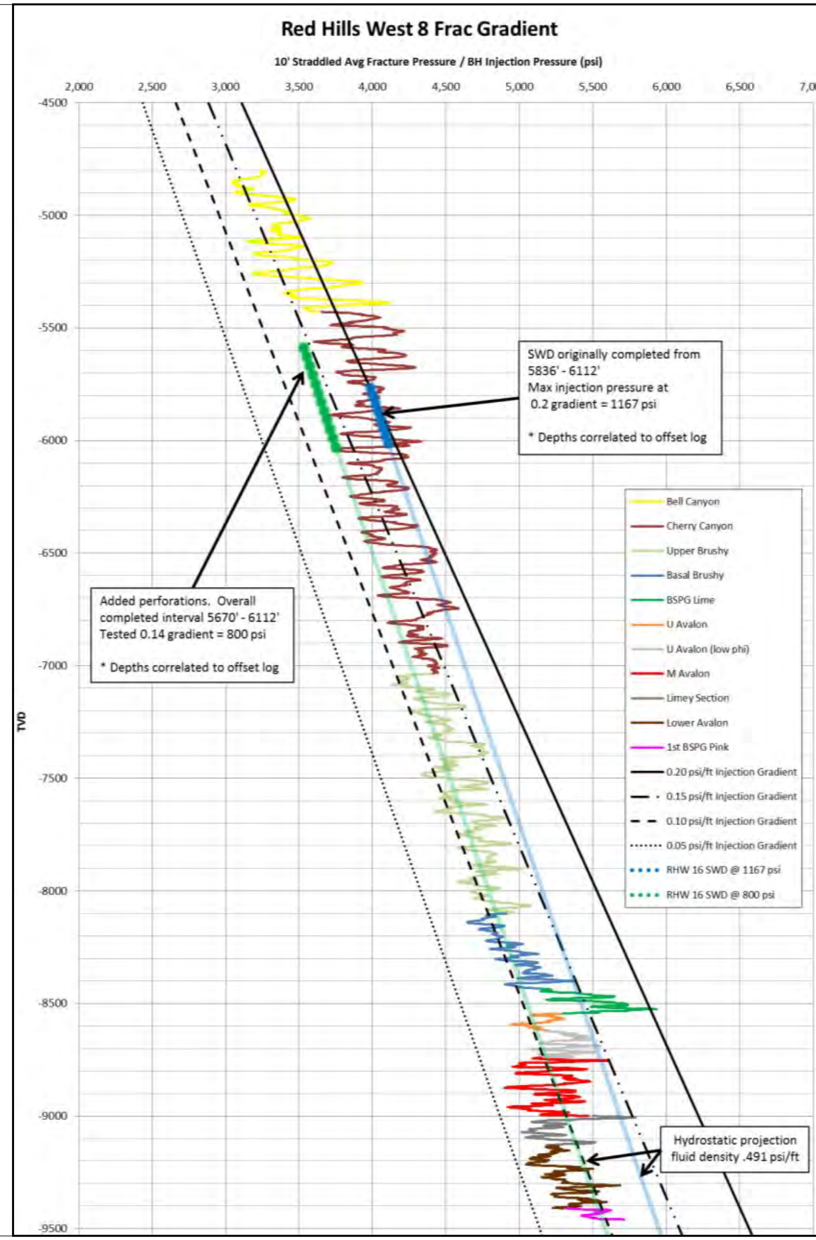


Injection Pressure Testing
Sec. 16 T26S R32E

- Fracture pressure plotted with depth along with 0.20, 0.15, 0.10, and 0.05 psi/ft gradient fracture pressures.

- The original completed interval of Mewbourne's RHW 16 SWD is plotted in blue. At the maximum allowable surface injection pressure of 1167 psi, the BHP is exceeding the frac gradient of not only the majority of the Bell Canyon, but also the entirety of the Brushy Canyon and Avalon Shale.

- Mewbourne added perforations up-hole in the Cherry Canyon and attempted to inject at 800 psi surface pressure (0.14 psi/ft gradient). Mewbourne still observed communication in offset Avalon Shale producers. SWD was shut-in.

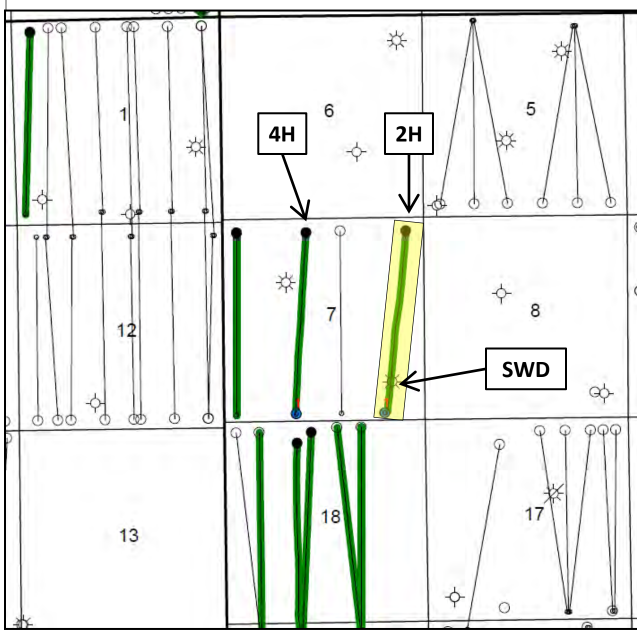


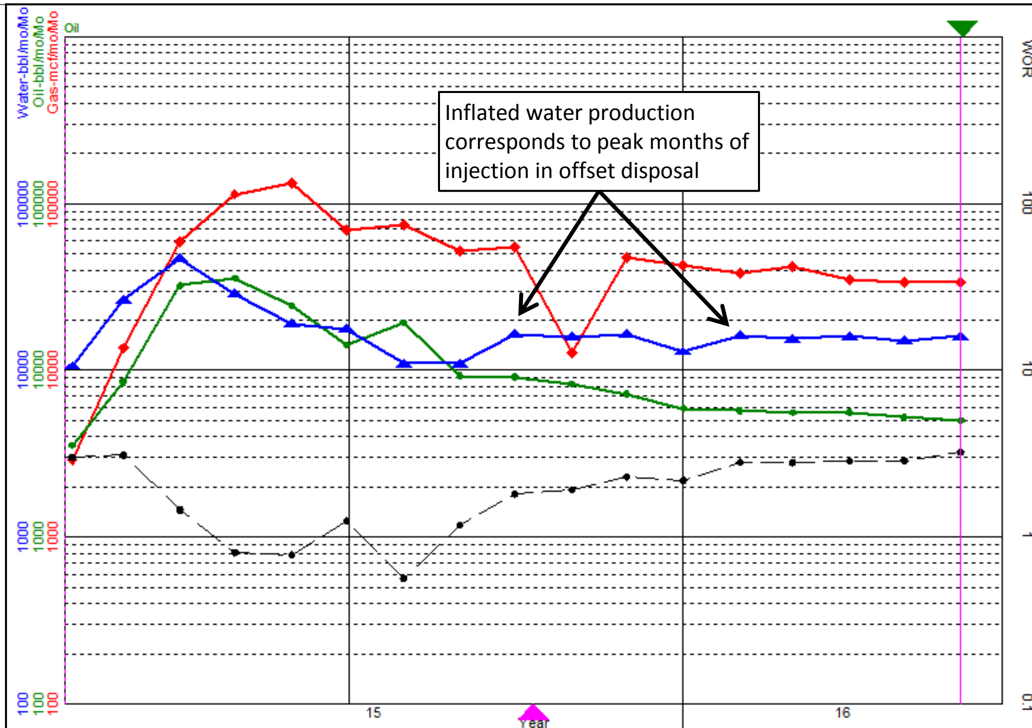
00133

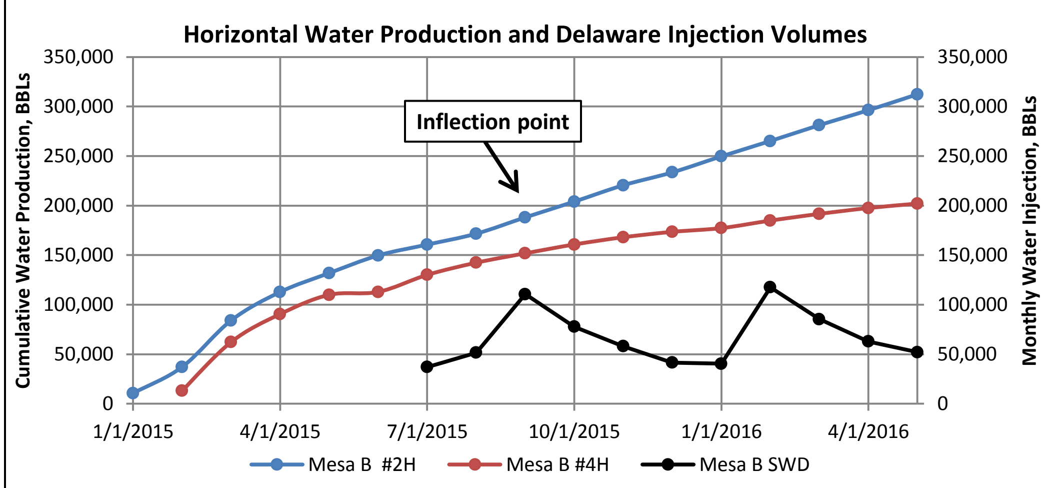
Lea County, NM
Sec. 7 T26S R33E

- Communication seen between disposal well and offset horizontal producer after 3 months of injection below .2 psi/ft surface pressure

- Disposal well completed in the Bell and Cherry Canyon formation. There is over 2000' vertical separation from the base of the disposal interval to the TVD of the horizontal.







00134

Eddy County, NM
T26S R29E

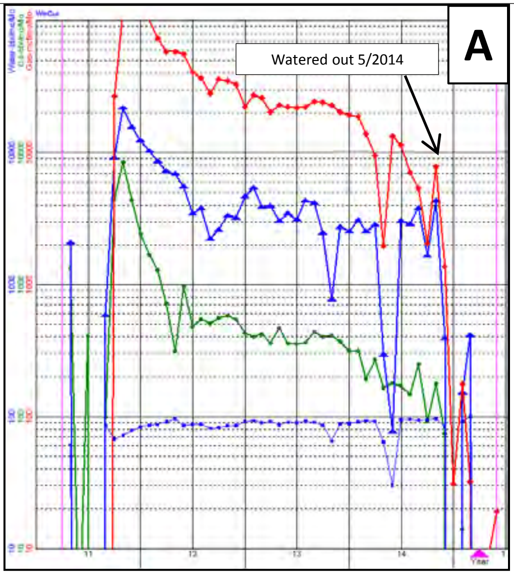
● Marbob/COG drilled and completed a Lower Avalon Shale well in early 2010 in the N/2 N/2 section 8.

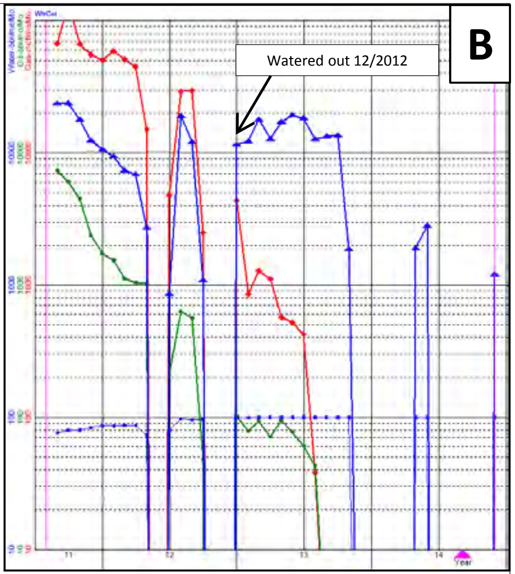
● They subsequently drilled and completed two disposal wells with an injection interval over the Cherry and Brushy Canyon.

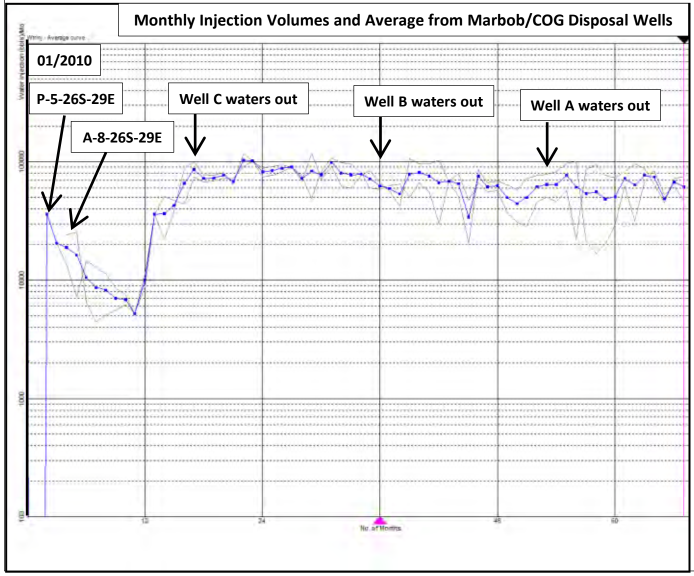
● Two additional Avalon Shale wells are drilled and completed in the S/2 of section 5 in 2011.

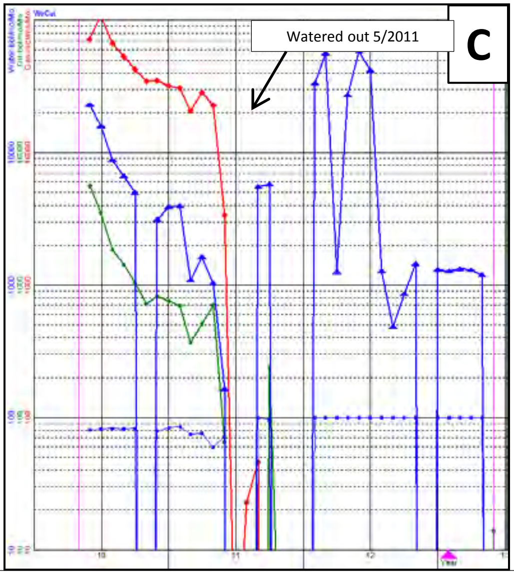
● As the injection volume in the two wells ramps up, the original producer in section 8 waters out in 5/2011.

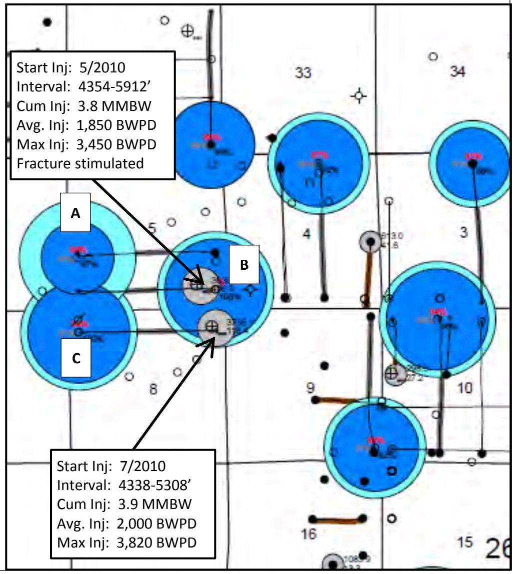
● Subsequently, the producer in the S/2 S/2 followed by the well in the N/2 S/2 of section 5 water out. All three wells have been plugged.











Precedent

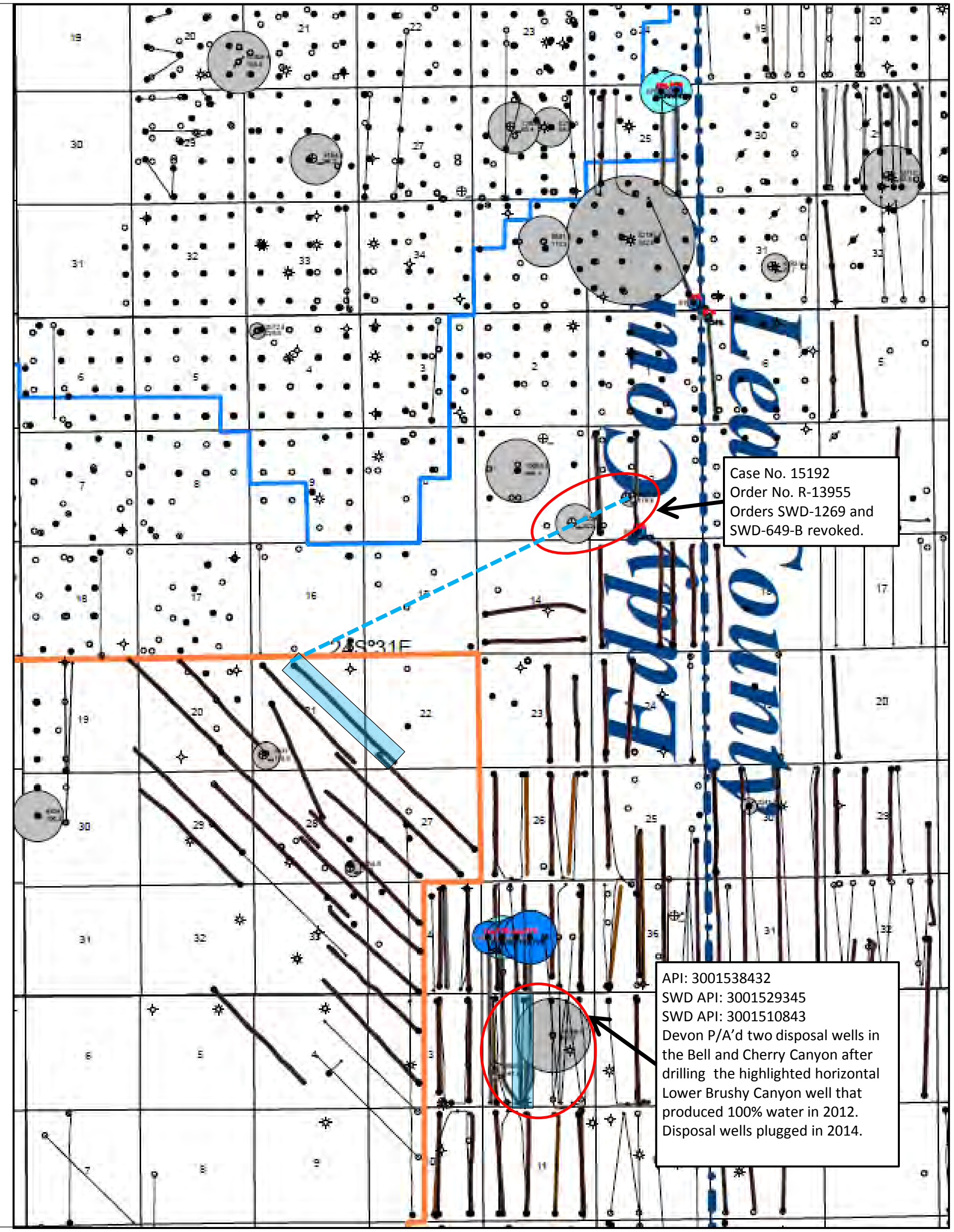
Delaware Disposal Wells Have Communicated with Brushy Canyon Horizontal Producers

● The industry and OCD have acknowledged that disposal in the Bell Canyon and Cherry Canyon can pose a threat to the Brushy Canyon.

● Devon P&A'd two Bell/Cherry Canyon disposal wells in section 2 T25S R31E after drilling a horizontal Brushy Canyon well that produced 100% water. The producing zone was over 2000 feet deeper than the lowest open injection perf.

● Division order R-13955(Case Nos. 15231 & 15219) recognized the ability of injected water to migrate vertically as least 1000 feet through the Delaware formation(whether from the Cherry Canyon to the base of the Brushy Canyon or through the different sands of the Brushy Canyon. Additionally, the order acknowledged the ability of a disposal well to impact producing wells more than 2 miles away, outside of the standard ½ mile radius area of notice.

● Mention was made in the testimony for the above cases that after the injection wells were shut down, production began to recover in the Delaware horizontal producers. A similar result would be less likely and effective in the Avalon Shale producers as the permeabilities are orders of magnitude lower in the shale as compared to the sand. Competition from an induced fracture with high relative conductivity would impede contribution from the formation.



Next Steps Forward?

- Further study the issue of communication between Delaware disposals and Delaware/Avalon producers.

- Suspend step rate tests for “Injection Pressure Increase” orders in Delaware disposals.

- Ban the use of hydraulic fracturing in the completion of Delaware disposals.

- Suspend new “Authorization for Injection” orders within the fairway the Avalon Shale is productive for disposals in the Delaware formation.

- Require more intensive measurement, monitoring, and/or reporting of surface injection pressures.

- Work with disposal operators to transition out of the Delaware formation; especially operators injecting “commercial disposal volumes” and/or above the 0.2 psi/ft surface injection pressure gradient.

- Work with Texas RRC to minimize injection along the State Line.

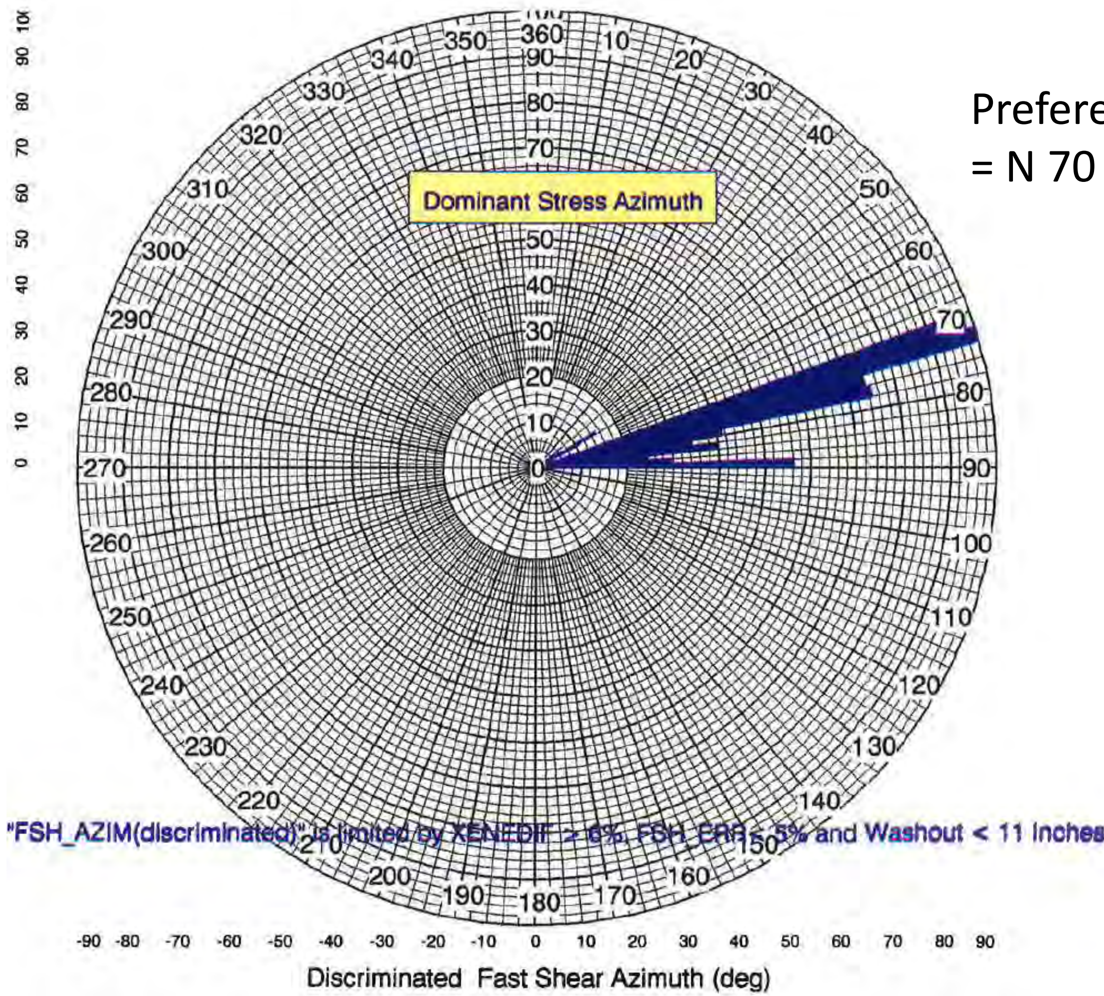
Mewbourne has been actively involved in working through these issues caused by both commercial and non-commercial Delaware SWD's with:

BLM
BOPCO
BTA
Chevron
Cimarex
Concho
ConocoPhillips
Devon
EOG
Mesquite SWD
NMOCD
Oilfield Water Logistics
WPX Energy

Appendix

New Mexico Delaware Basin
Produced Water Fluid Gradient

Producing Formation	Well Name	Section	Township	Range	County	Measured Specific Gravity	psi/ft
Delaware (Brushy)	Layla 35 MD 1H	35	23S	28E	Eddy	1.2	0.520
Delaware (Cherry)	Pierce Crossing 36 St 2H	36	24S	29E	Eddy	1.2	0.520
Delaware	**Average**						**0.520**
Avalon Shale	Cooksey 36 State Com 1H	36	26S	27E	Eddy	1.18	0.509
Avalon Shale	Delaware Ranch 11 Fed Com 2H	11	26S	28E	Eddy	1.14	0.494
Avalon Shale	Brushy Draw 1 Fed 1H	1	26S	29E	Eddy	1.17	0.507
Avalon Shale	Red Hills West Unit 001H	8	26S	32E	Lea	1.10	0.476
Avalon Shale	Red Hills 22 CN Fed Com 1H	22	26S	32E	Lea	1.10	0.476
Avalon Shale	Salado Draw 10 Fed Com 1H	10	26S	33E	Lea	1.13	0.487
Avalon Shale	**Average**						**0.491**
2nd BSS	Layla 35 OB	35	23S	28E	Eddy	1.12	0.485
2nd BSS	Bison Wallow 34 Fed 2H	34	25S	29E	Eddy	1.15	0.496
2nd BSS	Owl Draw 23 DM Fed Com 2H	23	26S	27E	Eddy	1.13	0.489
2nd BSS	Cooksey 36 PA State Com 1H	36	26S	27E	Eddy	1.14	0.491
2nd BSS	Delaware Ranch 13 EH Fed Com 1H	13	26S	28E	Eddy	1.14	0.491
2nd BSS	**Average**						**0.491**



Preferential frac direction = N 70 deg E

Mewbourne Oil Company
Sonic Scanner Shear Anisotrophy Analysis – For Maximum Stress Direction
Red Hills West 8 Federal #1H (3002539902)
Sec 8, Twp 26S, Rge 32E
Logged 10/24/2010.

Injection/Disposal Permit Restrictions by Geography and Geology

Statewide

Deep Disposal

- UIC Staff will not administratively grant a permit for disposal into a formation immediately overlying basement rocks (e.g. Cambrian or Hickory sand) without a substantial demonstration that the proposed disposal well will not cause seismicity.
- Therefore, any deep disposal well (typically considered to be disposal into Devonian-age and older in the Permian Basin) are required to plugback at least 150 feet from the base of the formation overlying Cambrian-age strata or any formation that immediately overlies the basement. In the Midland basin, this is often the base of the Ellenburger group. A well log or mud log annotated with formation tops must be submitted to demonstrate compliance with this permit condition.

Districts 01, 02, 04

Austin Chalk

- UIC Staff will administratively deny any commercial disposal permit application.
- UIC staff will consider non-commercial low-volume applications on a case-by-case basis.

Districts 02/03/04

Gulf Coast Counties – Shallow Injection

- Applicable to Texas counties that border the Gulf of Mexico: Jefferson, Galveston, Matagorda, Calhoun, Aransas, Nueces, Kleberg, Kenedy, Willacy, Cameron counties.
- Maximum surface injection pressure will be limited to 0.25 psi/ft for wells injecting with shallow injection intervals less than 2000 feet.

Districts 05/6E/7B/09

Formations overlying the Newark East Barnett Shale (NEBS) Field in North Central Texas

- For applications for commercial disposal or high-volume non-commercial disposal.
- Expanded area of review (AOR) from ¼ to ½ mile, within which the applicant must demonstrate whether all wells are plugged or cased and cemented in a manner that insures they do not represent a conduit for non-confinement of fluid to the proposed injection interval.
- Reduce the maximum surface injection pressure by 50%.
    - Limit the maximum injection rate to 5000 barrels per day.
    - Submit pressure influence calculations prepared by a registered professional engineer in Texas to show that the zone of endangering influence (ZEI – the distance from the proposed injection well to where the pressure increase due to injection will not be sufficient to raise a column of oil field brine to the base of the useable quality groundwater) is less than ½ mile.
    - If ZEI is greater than ½ mile, demonstrate that all wells within ZEI are plugged or completed in a manner sufficient to prevent non-confinement.
    - Core Counties: Denton, Johnson, Tarrant, Wise
    - Permit applications in non-core counties will be evaluated on a well-by-well basis.
    - Non-Core Counties: Archer, Bosque, Clay, Comanche, Cooke, Coryell, Dallas, Eastland, Ellis, Erath, Hamilton, Hill, Hood, Jack, Montague, Palo Pinto, Parker, Shackelford, Somervell, Stephens

Ellenburger Formation underlying Newark East Barnett Shale (NEBS) Field in North Central Texas

- Top of the injection interval must be at least 250 feet below the top of the Ellenburger.
- Injection volumes are limited to no more than 25,000 Barrels per Day (BPD).
- Core Counties: Denton, Johnson, Tarrant, Wise
- Permit applications in non-core counties will be evaluated on a well-by-well basis.
- Non-Core Counties: Archer, Bosque, Clay, Comanche, Cooke, Coryell, Dallas, Eastland, Ellis, Erath, Hamilton, Hill, Hood, Jack, Montague, palo Pinto, Parker, Shackelford, Somervell, Stephens

Districts 05, 06

Nacatoch Sand

- UIC Staff will administratively deny any injection permit application.

District 7B, 7C

Coleman Junction

- All applications in District 7B & 7C to dispose into the Coleman Junction formation must undergo further review, such as:
    - Approval from the District Office.
    - Approval from UIC manager and Chief Geologist.
    - Monitoring conditions such as annual H-5, weekly tubing casing monitoring, and bottom hole pressure testing may be requested.
- The Coleman Junction is a highly corrosive and over pressured formation that has caused multiple casing leaks across both districts.
- In 2012, commercial disposal permits were administratively denied due to public complaints of salinization of cropland.
- The applicant must differentiate the Coleman Junction across the Eastern Shelf and the Permian Basin.

Districts 7C, 08

San Andres

- Disposal applications in the San Andres formation in Irion, Reagan, and Upton counties require an accounting of any known bradenhead pressure concerns or well plugging concerns within a quarter-mile radius around the subject well location.
- The UIC review requests the district office to identify any known concerns. The reviewer will consult with the district office to determine whether to administratively grant the permit and what permit conditions are appropriate if granted.

Districts 7B, 08, 8A

Santa Rosa

Disposal applications in 8A must have detailed area of review and district approval. The reviewer will consult with the district office to determine whether to administratively grant the permit and what permit conditions are appropriate if granted.

District 01

Deep Maverick Aquifer, Glen Rose Formation

- UIC Staff will administratively deny any injection permit application. Investigation is on-going into this newly recognized freshwater source.

District 03

Sour Lake Salt Dome

- Special order requirements for all injection/disposal permits.
- Applications may be subject to additional monitoring conditions as Fluid Source Limit (FSL) and annual Radioactive Tracer Survey.

District 06

East Texas

- Harrison, Panola and Shelby Counties:
  - Any disposal application will undergo a formation over-pressurization review.
  - This applies to all formations and is not limited to the Rodessa formation.
  - Operator is required to submit ½ mile top of cement table showing that all wells in AOR have cement across injection interval.
  - Required to submit porosity and permeability data for the disposal formation.
  - Must submit annotated log including formation tops.
  - Submit historical H-10 data for any injection/disposal well within a 2-mile radius going back for at least 2 years in both pdf and excel.
  - All wells undergoing an over-pressurization review will require bottom hole pressure monitoring. The frequency of the monitoring will be determined by the UIC staff using available information on the pressure hazard. The operator should be advised that volume and/or pressure limitations may be required in areas with elevated bottom hole pressure.
  - Additional conditions such as cement bond logs, injection tracer surveys, pressure front calculations and step-rate tests may be requested during the over-pressurization review.

District 7B

Flippen formation

- Formation fracture pressure may be relatively low. Applicant must submit documentation of the formation fracture gradient with any disposal permit application.

District 08

Capitan Reef

- Capitan Reef is a minor aquifer as described by the Texas Water Development Board and contains freshwater (TWDB/Daniel B. Stephens: Capitan Reef Complex Report).
- UIC staff will use the recommendations of the Groundwater Protection Determination, Form GW-2, to protect the Capitan Reef aquifer.

Delaware Mountain Group

- Geologic group name for the Brushy Canyon, Cherry Canyon, and Bell Canyon formations.
- ¼ psi/ft maximum surface injection pressure in areas of seismic activity.

District 10

Brown Dolomite

- Disposal applications in the Brown Dolomite formation in counties bordering Oklahoma may require bottom-hole pressure tests when MITs are performed, a maximum daily injection volume of no greater than 10,000 bbl/day and a maximum surface injection pressure cap no greater than 1,000 psig. The reviewer will consult with the district office to determine whether to administratively grant the permit and what permit conditions are appropriate if granted.

Case Nos. 23686 and 23687;
OCD Exhibit No. 10

The Seismic Record
A journal of the Seismological Society of America

Stability of the Fault Systems That Host-Induced Earthquakes in the Delaware Basin of West Texas and Southeast New Mexico

Peter Hennings*[1], Noam Dvory[2], Elizabeth Horne[1], Peng Li[1], Alexandros Savvaidis[1], and Mark Zoback[2]

Abstract

The Delaware basin of west Texas and southeast New Mexico has experienced elevated earthquake rates linked spatiotemporally to unconventional petroleum operations. Limited knowledge of subsurface faults, the in situ geomechanical state, and the exact way in which petroleum operations have affected pore pressure (Pp) and stress state at depth makes causative assessment difficult, and the actions required for mitigation uncertain. To advance both goals, we integrate comprehensive regional fault interpretations, deterministic fault-slip potential (DFSP), and multiple earthquake catalogs to assess specifically how faults of two systems—deeper basement-rooted (BR) and shallow normal (SN)—can be made to slip as Pp is elevated. In their natural state, the overall population faults in both the systems have relatively stable DFSP, which explains the low earthquake rate prior to human inducement. BR faults with naturally unstable DFSP and associated earthquake sequences are few but include the Culberson–Mentone earthquake zone, which is near areas of wastewater injection into strata above basement. As a system, the SN faults in the southcentral Delaware basin are uniformly susceptible to slip with small increases in Pp. Many earthquakes sequences have occurred along these shallow faults in association with elevated Pp from shallow wastewater injection and hydraulic fracturing. Our new maps and methods can be used to better plan and regulate petroleum operations to avoid fault rupture.

Cite this article as Hennings, P., Dvory, N., Horne, E., Li, P., Savvaidis, A., and Zoback, M. (2021). Stability of the Fault Systems That Host-Induced Earthquakes in the Delaware Basin of West Texas and Southeast New Mexico. *The Seismic Record*. **1**(**2**), 96–106, doi: 10.1785/0320210020.

Introduction

The Delaware basin of West Texas and Southeast New Mexico is one of the world's most productive petroleum basins (Fig. 1). Approximately 16,000 horizontal wells have been drilled and hydraulically fractured in Permian, shale-dominated reservoirs (IHS Markit, 2021). In 2020, the basin produced >700 million bbls of oil and >3.1 trillion cubic feet of natural gas (IHS Markit, 2021; Energy Information Administration [EIA], 2021). Since 2010, this unconventional development has required the subsurface disposal of 8.6 billion bbls of wastewater (saltwater disposal [SWD]) into strata both above and below petroleum-producing intervals (Lemons *et al.*, 2019), and there are currently ~1200 active SWD wells in the basin (IHS Markit, 2021; Fig. 1). The basin has also experienced a significant number of earthquakes that are spatiotemporally linked to unconventional oil and gas development. Frohlich *et al.* (2016) discussed the history of induced seismicity in the region, and Frohlich *et al.* (2020) demonstrated that induced seismicity in the Delaware basin initiated in 2009 and accelerated significantly in 2016. From January 2017 through June 2021, the TexNet Earthquake Catalog

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*Corresponding author: peter.hennings@beg.utexas.edu

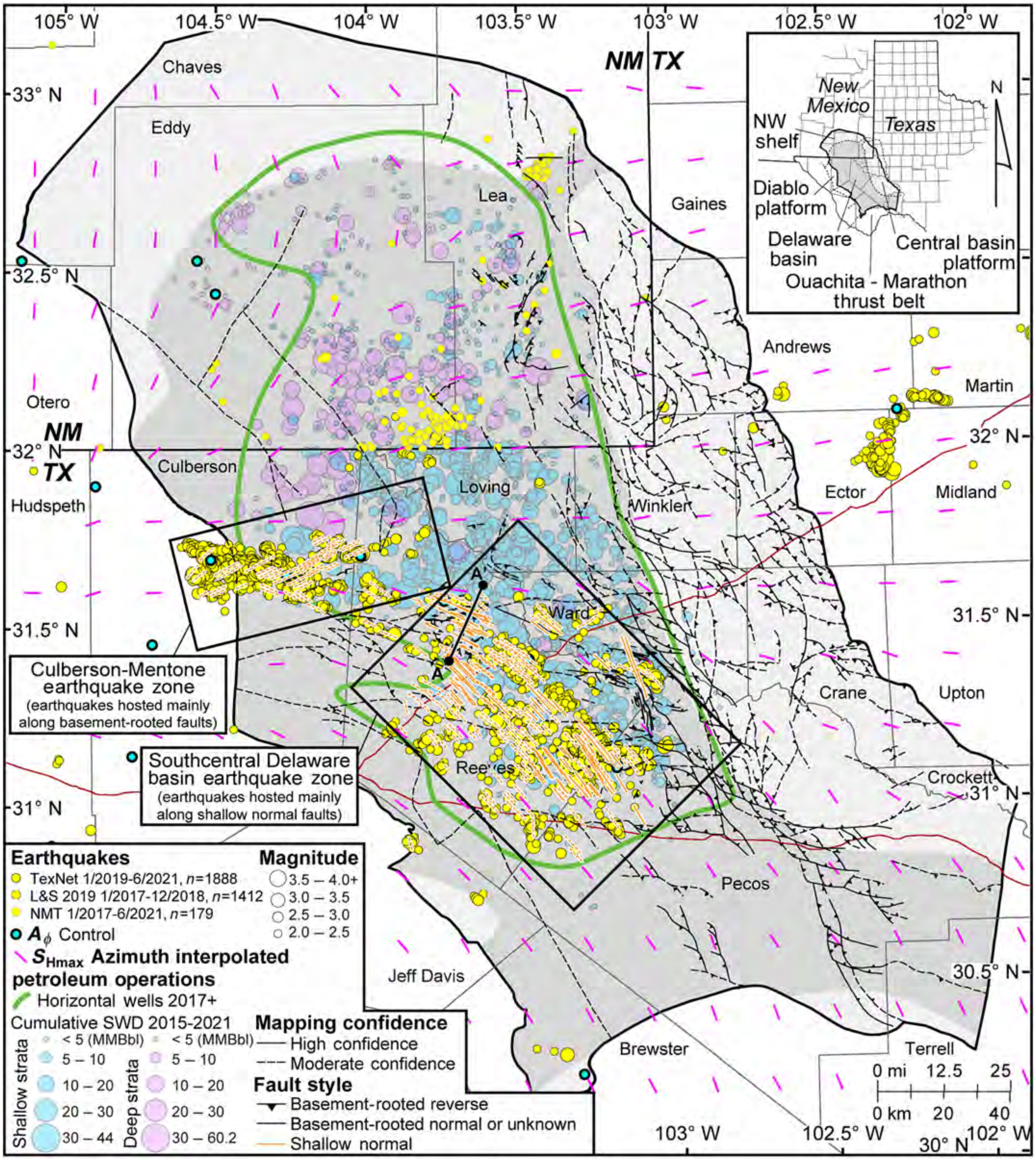

Figure 1. Map of the Delaware basin and surrounding structural highs in West Texas and southeastern New Mexico showing fault interpretation from Horne *et al.* (2021), the data sources used for the new interpretation of the shallow normal (SN) faults, and the data from Lund Snee and Zoback (2018, 2020) used for the interpolation of $S_{H\,max}$ azimuth and for control of A_ϕ. NMT, New Mexico Tech Seismological Observatory; SWD, saltwater disposal. Inset map shows the location of the Delaware Basin in west Texas and northeast New Mexico and the geologic elements that bound it.

(Savvaidis *et al.*, 2019) and New Mexico Tech Seismological Observatory (NMT) have cataloged >3500 M_L 2.0+ earthquakes in the basin. Lomax and Savvaidis (2019), Savvaidis *et al.* (2020), and Skoumal *et al.* (2020) provided spatiotemporal causal assessments, each proposing complex linkages of earthquakes to both hydraulic fracturing and SWD. Skoumal *et al.* (2020), Tung *et al.* (2020), and Gao *et al.* (2020) provided analyses linking new earthquake sequences in the northern Delaware basin to SWD in deep strata regionally. Dvory and Zoback (2021a) show that pressure depletion from prior production from the Delaware Mountain Group and Bone Spring Formation limits the likelihood of shallow seismicity in some areas of the basin. Zhai *et al.* (2021) use geomechanical modeling to propose that shallow SWD is the primary driver of earthquake inducement in the basin. Skoumal and Trugman (2021) expand the earthquake analysis of Frohlich *et al.* (2020) and conclude that shallow SWD in the southcentral Delaware is the primary driver of earthquake inducement.

Human influence leading to earthquake inducement occurs within a complex geomechanical system. With stratified pore pressure (Pp) regimes, multiple faults systems, regionally heterogeneous tectonic stressing, and highly complex operational history, the Delaware basin is the most challenging region impacted by induced seismicity that has been studied to date. Given the accelerating earthquake rate in the basin, it is vital to develop causal assessments that are grounded within the complex geological architecture of the basin so that mitigation strategies can be implemented that target specific agents of causation. To advance this objective, we present comprehensive new fault interpretations, deterministic analysis of fault-slip potential (DFSP), and the association to earthquake sequences. Our DFSP maps of multiple extant fault systems extend throughout the region of the Delaware basin and Central basin platform. They provide a resource not only for the understanding of induced seismicity but also for assessments of fault stability in application to landform evolution, for hazard assessment for sequestration, and for hydrocarbon production mechanics.

Geology of the Delaware basin and its flanks

The Delaware basin is a subbasin of the Permian basin province of West Texas and Southeast New Mexico. The Delaware basin and Central basin platform are defined structurally by a complex network of BR faults (Fig. 1). The basin and its flanks have been affected by several extensional and contractional tectonic events cumulatively leading to the present-day tectonic fabric (Horne *et al.*, 2021 and references therein). The basin formed in Mississippian through Permian time in the autochthon of the Ouachita–Marathon orogeny and was defined structurally as a foreland basin, as it became downthrown to the west-vergent, BR, contractile Central basin platform that formed as a prominent constituent of the Ancestral Rocky Mountains.

Earthquake data

For this analysis, we refer to the following earthquake catalogs to cover the entirety of the Delaware basin (Fig. 1). For New Mexico, we use NMT. For Texas, we use TexNet for 2019 through June 2021 (Savvaidis *et al.*, 2019) and Lomax and Savvaidis (2019), who provided advanced relocation of TexNet for 2017–2018 (L&S). The TexNet and L&S catalogs have an $M_c = 1.5$ (Lomax and Savvaidis, 2019; Savvaidis *et al.*, 2019). There are no duplicate earthquakes from these combined catalogs. To assist with fault mapping and earthquake-to-fault association, we use P. Li, and A. Savvaidis (unpublished manuscript, see Data and Resources) who provide relative relocations for TexNet and L&S (TNr, Fig. 2a).

In situ stress

Dvory and Zoback (2021a) show from both direct measurements and calculations that are based on Mohr–Coulomb criteria that the crust is in critically stress state in the seismically active area of the Delaware basin. Lund Snee and Zoback (2018, 2020) compiled various types of data in the region to define the maximum principal horizontal stress azimuth ($S_{H\,max}$ Az) and stress ratio (A_ϕ). They show that $S_{H\,max}$ Az varies systematically across the region, smoothly transitioning from northwest–southeast in the southern Delaware basin to east–west in the center of the basin to almost north–south in its northern areas. The interpretation of A_ϕ varies from about 0.6 (normal faulting) in the western boundary of the basin to ~0.85 in the Central basin platform and to ~1.0 in the Midland basin to the east, indicating a transition to combined strike-slip and normal faulting. Fault-plane solutions for earthquakes in the Delaware basin indicate normal faulting (TexNet) with planes striking parallel to the local direction of $S_{H\,max}$, as expected. Dvory and Zoback (2021b) provide a smoothed and interpolated stress field (Fig. 1) that closely fits the discrete stress observations. We use this interpolation for our DFSP analysis and assume an intermediate A_ϕ value between the Delaware basin and the Central basin platform of 0.7.

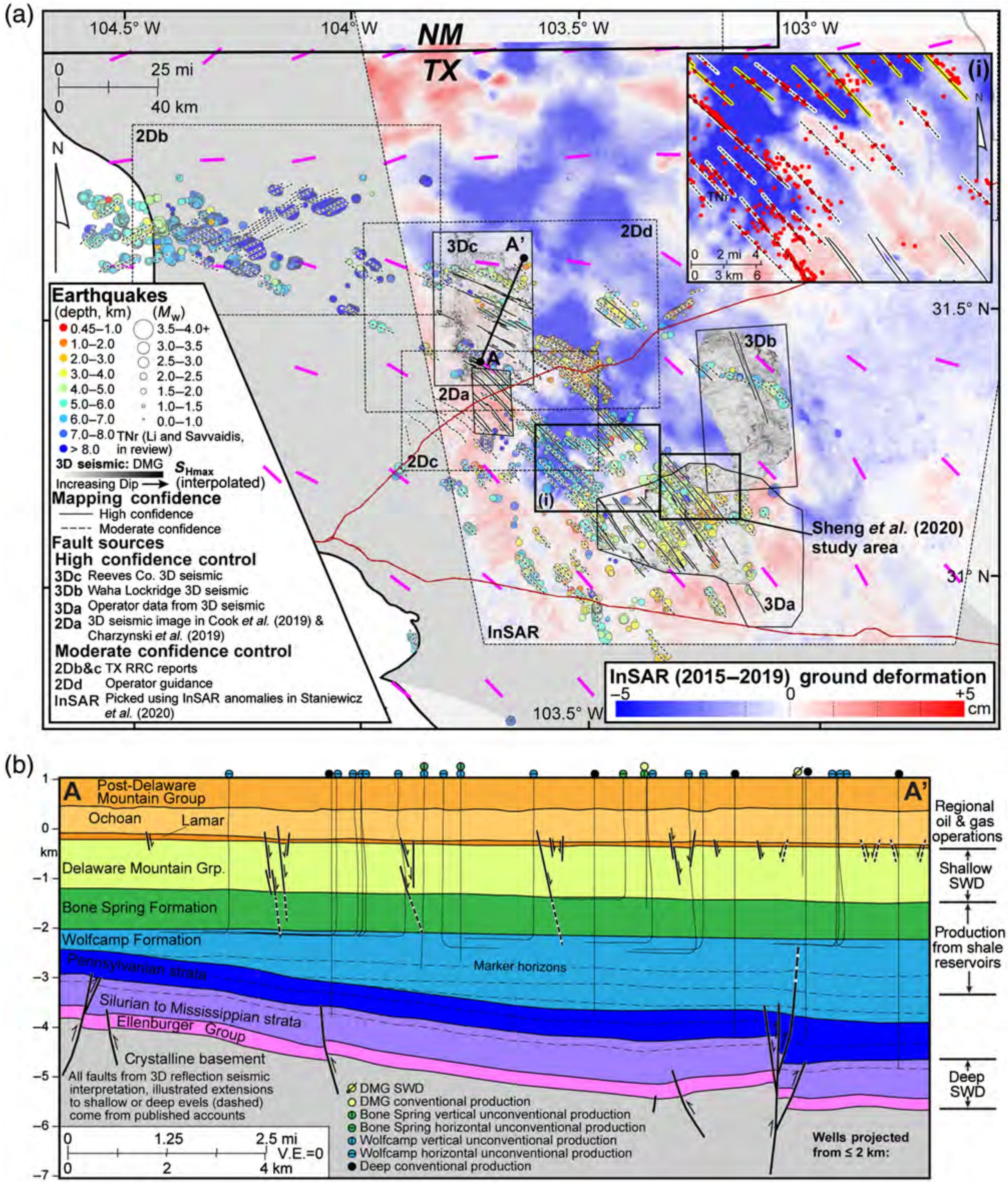

Figure 2. (a) Map of the central Delaware basin showing examples of the data used for interpretation of the SN faults including horizons from 3D reflection seismic data newly presented here and from Charzynski *et al.* (2019) and Cook *et al.* (2019), Interferometric Synthetic Aperture Radar (InSAR) from Staniewicz *et al.* (2020), and earthquake relative relocations from P. Li and A. Savvaidis (unpublished manuscript, see Data and Resources). See Figure 1 for map location. The traces of SN faults delineated using both relative relocation for TexNet (TNr) and InSAR ground deformation anomalies are considered to be high-confidence interpretations. (b) Cross section in Reeves Co. illustrating the nature of the basement-rooted (BR) faults and SN faults that we use for the deterministic fault-slip potential (DFSP) analysis. DMG, Delaware Mountain Group.

Faults

Basement-rooted faults. Many faults deform the Delaware basin and the Central basin platform; the most significant are the BR reverse faults that formed in late Paleozoic time and control its primary structural architecture (Fig. 1). Modern rupture along these faults must, therefore, represent normal slip reactivation. Horne *et al.* (2021) provided a new and comprehensive 3D interpretation of these faults from well-based framework mapping, 3D seismic data, and prior publications. Horne *et al.* (2021) classify their faults in terms of mapping confidence, and we use these faults for our DFSP analysis.

The primary BR fault fabric strikes north-northwest, is dominantly reverse, and forms the first-order structural relief in the region. This primary fabric is most intensely developed along the western margin of the Central basin platform. A secondary fault fabric strikes west-southwest to west-northwest and is dominantly associated with reverse and strike-slip offset. This secondary fabric occurs in concentrated zones that are distributed from south to north along the overall strike of the basin (e.g., Grisham fault zone, Culberson-Mentone earthquake zone). Complex deformation occurs at the points of convergence between the primary and secondary fault fabrics. The BR faults cut up section from basement to levels as shallow as the Wolfcamp Formation (Fig. 2b). The total fault-trace length (length) of BR faults is ~6500 km, with individual segments ranging in length from 5 to >100 km. The BR faults have throws from 50 to >1000 m and a mean throw to length ratio of ~1 : 25. In the regional-scale 3D fault framework in Horne *et al.* (2021); the mean surface area of the BR faults is 58 km^2 with $n = 638$. This is an underestimate, because the interpreted faults are not interpreted deeply into basement.

Shallow normal faults. The great majority of recent earthquakes do not occur on BR faults, but on northwest-trending shallower normal (SN) faults in the central Delaware basin that do not extend to the depth of the BR faults. Our interpretation of these seismogenic faults is newly presented here and based on integrating 3D reflection seismic data (extending the work of Charzynski *et al.* 2019; Cook *et al.*, 2019), unpublished records from Railroad Commission of Texas, and as directly reported to us by petroleum operators (Fig. 2a). Many of the SN faults follow linear patterns of Interferometric Synthetic Aperture Radar (InSAR) surface deformation (Staniewicz *et al.*, 2020), and the TNr earthquakes closely follow many of the mapped SN faults. Therefore, both the InSAR lineations and TNr earthquakes inform our SN fault interpretation. We are confident in combining these data to map SN faults, because all these indicators come together in areas where we can independently confirm the interpretation using 3D reflection seismic data (e.g., data region 3Dc, Fig. 2a). We employ the same high- and moderate-confidence mapping criteria for the SN faults as Horne *et al.* (2020).

Throughout the seismically active area, the SN faults strike parallel to $S_{H\,max}$ azimuth, varying smoothly from northwest-striking in the south to west-northwest-striking in the north. The faults often occur in pairs forming narrow graben bounded by steeply dipping faults and have a mean throw to length ratio of ~1 : 100. They appear stratigraphically and mechanically bound to the Delaware Mountain Group, Bone Spring Formation, and uppermost Wolfcamp Formation. The SN faults occur primarily in Reeves County but extend into adjacent Texas counties including Pecos, Ward, and Culberson. Where we have 3D seismic control, the SN faults have a mean surface area of 4.2 km^2 with $n = 41$. The total fault-trace length of SN faults is ~1450 km, with individual segments ranging in length from 0.5 to 20 km. Of the ~1450 km of mapped SN faults, ~550 km (38%) of fault length is considered to be high-confidence interpretations; the remaining 900 km (62%) of segment length is interpreted as moderately confident. The estimated ~1450 km of SN fault-trace length is a minimum, as there is strong anecdotal evidence of many more SN faults within Delaware basin to the northwest and south of the distribution we show (Fig. 2a) but where data control for mapping is not available to us.

There was no previously recognized surface expression of these faults until the observation of recent InSAR displacements (Staniewicz *et al.*, 2020). Anderson (1981) found that some SN faults in the region resulted from organized flowage and dissolution of evaporite-dominated strata above the Delaware Mountain Group. Cook *et al.* (2019) used analysis of 3D seismic anisotropy to map the fault zones from the Delaware Mountain Group into the Wolfcamp Formation. Charzynski *et al.* (2019) concluded that in some areas, the SN faults extend downward as permeable fracture zones that cause wells targeting the Wolfcamp Formation to have diminished hydrocarbon productivity, and produce anomalous volumes of H_2S and water.

Assessment of Fault-Slip Potential

Fault-slip potential method

We assess the slip potential of the BR and SN faults in our interpretations using a deterministic approach (DFSP), which assumes that the Coulomb failure criterion is applicable and describes the Pp increase (ΔPp) needed to achieve criticality. Critical ΔPp is the perturbation in Pp from ambient, therefore low values of ΔPp or DFSP indicate a greater sensitivity (Zoback, 2007). Other similar works assessing the slip potential of induced earthquakes include Walsh and Zoback (2016) and Lund Snee and Zoback (2018). These works employed probabilistic approaches (PFSP) to investigate the slip potential of fault systems assuming hypothetical yet plausible global increases in ΔPp. The PFSP analysis of Hennings *et al.* (2019) compared unperturbed versus hypothetical yet plausible global increases in ΔPp. Hennings *et al.* (2021) assessed the evolution in PFSP using a deterministic regional model of temporally varying ΔPp. Morris *et al.* (2021) also employed a deterministic assessment of slip potential for 3D fault surfaces in the Delaware basin region using the Horne *et al.* (2021) interpretation but focused exclusively on the BR faults.

The DFSP analysis uses fault strike and dip, the depth of the trace that samples the fault surface, the in situ stress tensor, and scalar geomechanical parameters such as Pp and the coefficient of fault friction. Based on the work of Luo *et al.* (1994), we employ a hydrostatic condition of 0.01 MPa/m, which is representative of the native pressure state of the Delaware Mountain and Ellenburger Groups prior to widespread petroleum operations. Following Dvory and Zoback (2021a), we assume acritical fault friction of $\mu = 0.7$. The strike and dip of the BR faults come from the upthrown intersection of the faults and the Ellenburger Group in Horne *et al.* (2021). Thus, our DFSP calculations represent the slip potential of BR faults that cut from basement through to levels as shallow as the Wolfcamp Formation, the uppermost of which is the current primary target for petroleum production using hydraulic fracturing. The strike and dip of the SN faults come from the intersection of the faults and the Delaware Mountain Group. Fault dip was determined explicitly for the faults constrained by 3D seismic data. We use the mean of the explicit dip (72°) for SN faults that lack 3D seismic control. The traces for both BR and SN fault systems are sampled at 1 km increments laterally for the DFSP analysis.

Fault-slip potential results

The DFSP results are shown in the map in Figure 3 and as distributions in Figure 4. About 62% of BR fault length have a very high DFSP of >5.0 MPa (implying stability). Only 18% are considerably less stable with DFSP ≤2 MPa. The most sensitive BR faults occur primarily along the southwest flank of the Central basin platform, the southeast axis of the Delaware basin, and along segments of the secondary fault fabric in the central Delaware basin (Fig. 3). The DFSP for the SN faults is *very* different—71% (~1030 km) have a DFSP of ≤2.5 MPa indicating that they are prone to reactivation in response to modest ΔPp. Nearly all of the SN faults are inherently sensitive to slip.

Earthquake sequences and fault-slip potential

Only a few of the earthquake sequences potentially coincide spatially with BR faults (Fig. 3). The most noble of these is the Culberson–Mentone earthquake zone, where there are numerous highly unstable BR faults associated with recent earthquake sequences. Other areas include in Lea County, New Mexico; along the Texas/New Mexico border; and in the Waha area. The SN faults, which are uniformly unstable, spatially correlate to many earthquake sequences in the central Delaware basin.

Discussion

Combining the interpretation of both the fault systems—the DFSP and the earthquake epicenters—we conclude that rupture has occurred in distinct geographic groupings. The majority of the earthquakes that have occurred along deeper BR faults are concentrated in the western part of the basin, especially in the Culberson–Mentone earthquake zone. We concur with the previous works of Gao *et al.* (2020), Savvaidis *et al.* (2020), Skoumal *et al.* (2020), Tung *et al.* (2020), and Zhai *et al.* (2021) that the most plausible causal agent for earthquake inducement in this area is from ΔPp from SWD into strata above basement—principally units of Devonian. Our DFSP analysis indicates that rupture of many faults in this area can occur with very small ΔPp.

We show here that induced earthquakes in the southcentral part of the basin have occurred mainly along the SN faults, which, as a system, have uniformly low DFSP and are highly sensitive, requiring ≤2.5 MPa ΔPp to achieve criticality. The faults closely follow the azimuth of $S_{H\,max}$ (Fig. 1). Ge *et al.* (2020) show that SWD into the Delaware Mountain Group has caused ΔPp ≥ 2 MPa in the same areas as these active faults. We, therefore, concur with Skoumal and Trugman (2021) that ΔPp from SWD into the Delaware Mountain Group is a primary causative agent for fault rupture and seismicity in this area. Savvaidis *et al.* (2020) demonstrate that hydraulic fracturing is an additional causative agent for more isolated earthquake sequences in this area. With SWD into the Delaware Mountain Group and hydraulic fracturing of the

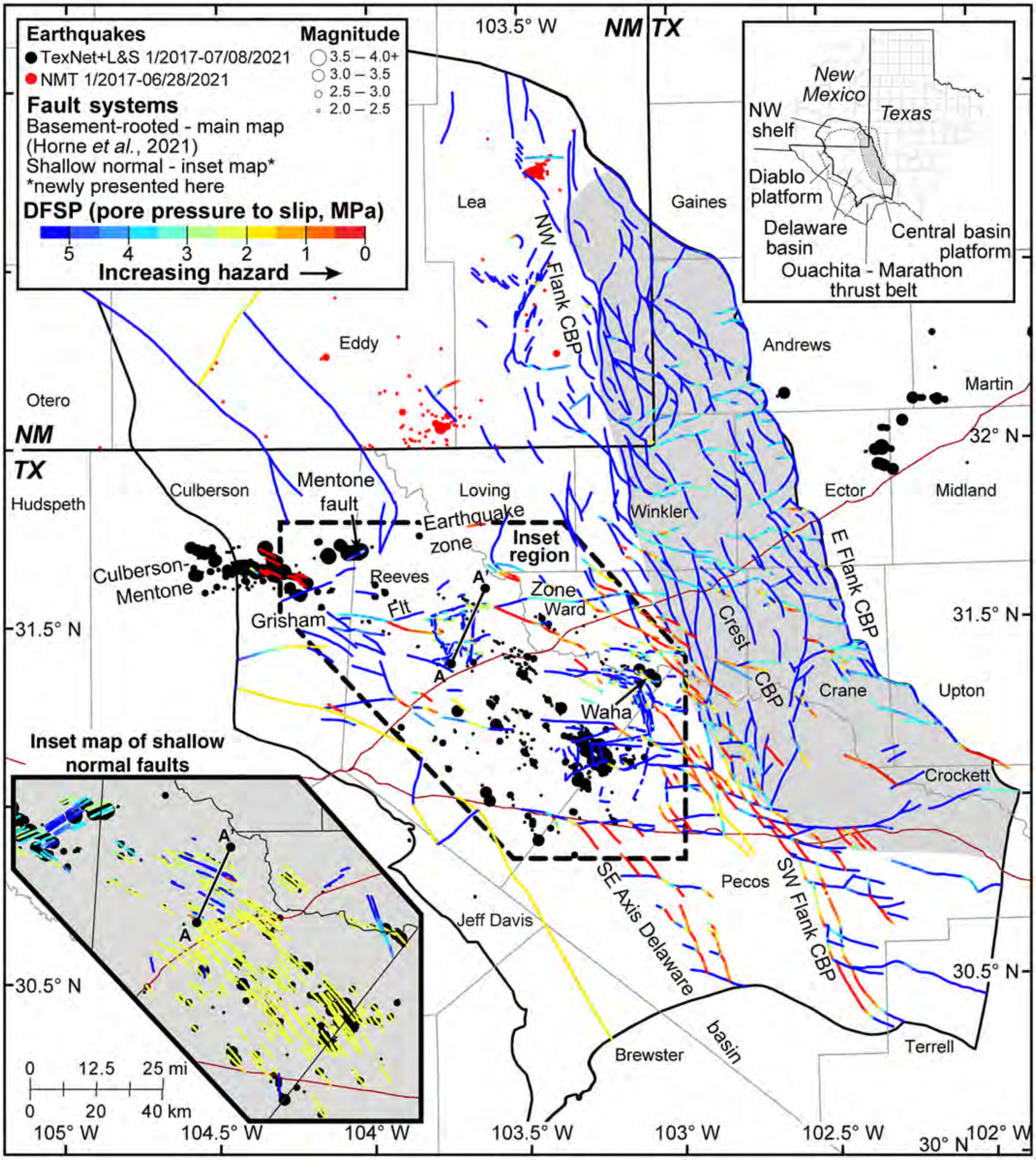

Figure 3. Map of DFSP for the BR faults in the main map and for the SN faults in the inset map. Both maps are to the same scale.

underlying shale intervals, it is, therefore, likely that the induced seismogenic ruptures are occurring at depths shallower than basement or the strata immediately above.

Although the velocity structure of the Delaware basin is highly

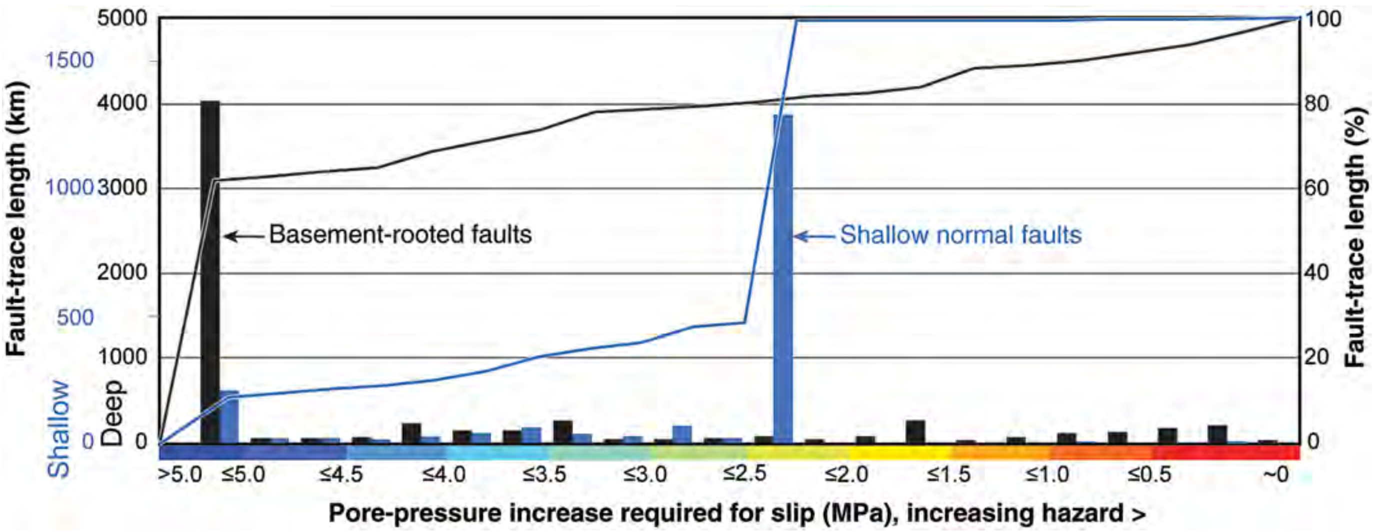

Figure 4. Histogram of DFSP showing the distribution in the Figure 3 maps.

complex, TexNet has relatively sparse station spacing and uses a coarse, regional-scale, 1D velocity model for locating hypocenters. Therefore, the reported uncertainty (e.g., one standard deviation [st. dev.]) in depth provided by TexNet should be used to identify the comprehensive uncertainty that is much larger (three st. dev. accounts for 99.7% of the depth estimates for each earthquake). The hypothesis of shallow rather than deep earthquakes in the central Delaware basin is supported by the high-resolution earthquake depth mapping by Sheng *et al.* (2020). They show that earthquakes in their study area (see Fig. 2a) are principally concentrated in deeper levels of the Delaware Mountain Group and upper levels of the Bone Spring Formation rather than in units under the Wolfcamp Formation and downward into basement. Combining these factors, along with their inherent instability, we conclude that most of the earthquakes in the central Delaware basin occur along the SN faults as we have mapped them. Many of these faults are *now* neotectonic. We concur with Zhai *et al.* (2021) that SWD into the Delaware Mountain Group provides the causative stress change required for fault rupture but, rather than stress being transmitted downward 3–4 km causing rupture of exclusively deep faults, it is the SN faults in direct communication with ΔPp that host most of the earthquakes in the central Delaware basin.

In Figure 5, we show the magnitude histories of earthquakes from the Culberson–Mentone earthquake zone, which has an increasing maximum magnitude with time, and the southcentral Delaware basin earthquake zone, which has a steady maximum magnitude with time. Since 1 January 2018, the Culberson–Mentone earthquake zone, where the earthquakes are occurring along BR faults, has had >1300 earthquakes of $M_L \geq 2$ and 19 with $M_L \geq 3.5$, including the 26 March 2020 M_L 4.6. Conversely, in the entire footprint of the SN faults since 1 January 2017, there have been >1000 earthquakes with $M_L \geq 2$ and only one $M_L \geq 3.5$, the 22 December 2018 M_L 3.8. As described previously, only a few earthquake sequences have occurred on the BR faults. This may be beneficial, given that BR faults can have large surface areas and cut relatively stiff country rock (e.g., basement and platform carbonates), which implies the potential for larger seismic moments during slip (Zoback and Gorelick, 2012). In contrast, the SN faults are strata-bound, have smaller surface areas, and cut rocks with a relatively lower stiffness (e.g., sandstones and shales), implying a reduced potential for larger seismic moments during slip. The earthquake history in Figure 5 reinforces this hypothesis. With this hypothesis as a prompt, we encourage additional quantitative study comparing the earthquake data from these two regions.

The DFSP map we provide should be used to assess the fault-slip hazard related to petroleum operations in the Delaware basin region and as a general guide for mitigation. It can also be used for hazard assessment associated with sequestration. However, our characterization is based on the strength of the available data, and our fault interpretations should be considered as inherently incomplete. Hazard assessment and mitigation at the local scale should be performed using the best data available for fault and geomechanical parameterization.

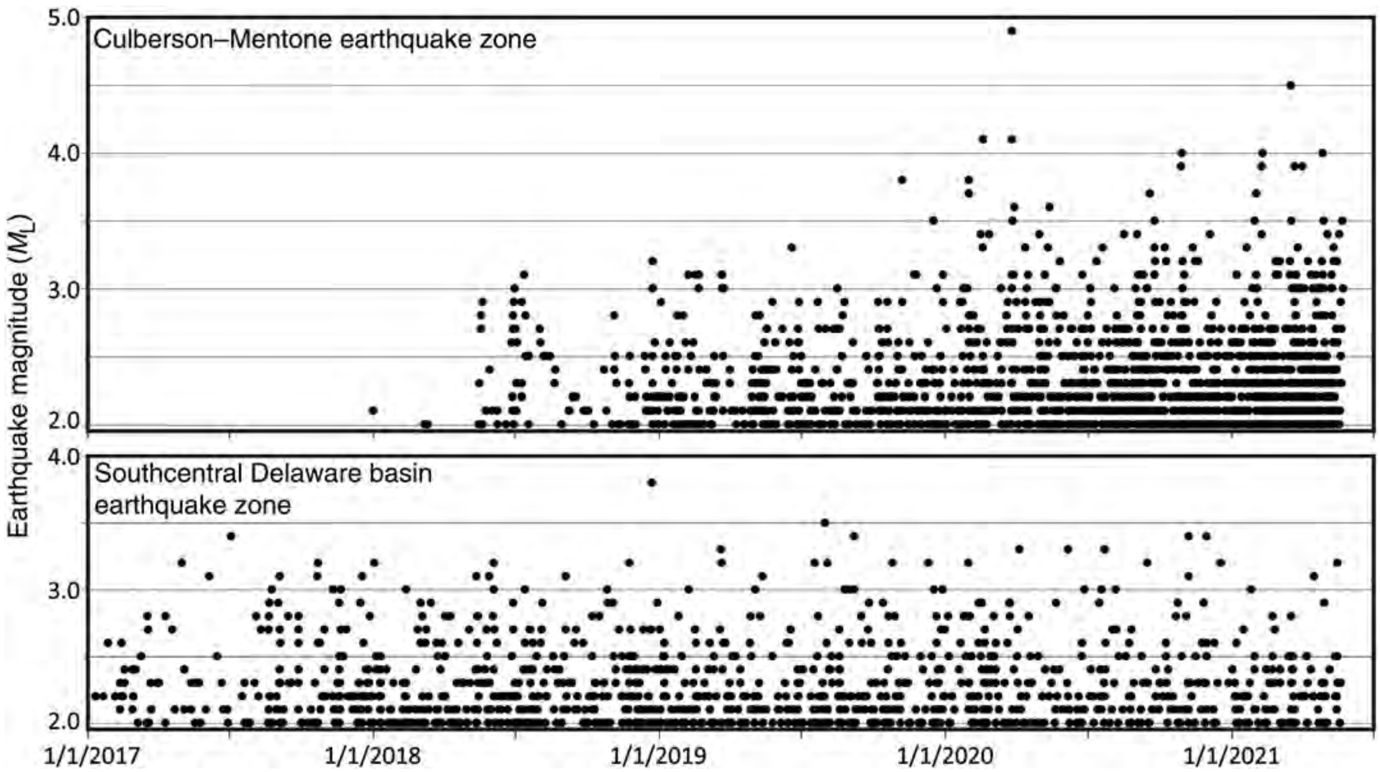

Figure 5. History of earthquake magnitude in the Culberson–Mentone earthquake zone and the southcentral Delaware basin earthquake zone from TexNet. The areas are indicated in Figure 1.

Conclusions

In their natural state, the faults in both the systems are relatively stable, which explains why the earthquake rate was low prior to the initiation of unconventional petroleum operations.

BR faults that are potentially unstable exist throughout the Delaware basin region, but only a few earthquake sequences are associated with these faults, most prominently the Culberson–Mentone earthquake zone. These faults typically have large surface areas and cut relatively stiff strata; therefore, their maximum earthquake moment can be large.

SN faults are numerous in the central Delaware basin; they are highly sensitive to reactivation, they spatially correlate with many recent earthquake sequences, and they have recently become neotectonically active. About 71% of their length becomes unstable at Pp changes of ≥2.5 MPa—a level of ΔPp that has been shown to have been created in the region due to SWD into strata cut by these faults. Perturbance from hydraulic fracturing operations is also implicated in causing earthquakes along these faults. Given the mechanically stratified architecture of these faults and the stiffness of the rocks they cut, maximum earthquake moment may have an upper limit, perhaps to what has been observed thus far.

Data and Resources

All existing data we use can be accessed at the respective journal cited. The data on faults and fault-slip potential we discuss are available for download at the Texas Data Repository at doi: 10.18738/T8/TBTRXM. FSP software can be accessed at https://scits.stanford.edu/software (last accessed June 2021). The unpublished manuscript by P. Li, and A. Savvaidis (in revision), "Cross-correlation relocation to identify active faults in the Permian Basin," submitted to *Seismol. Res. Lett.*

Declaration of Competing Interests

The authors acknowledge that none have conflict of interest

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State of New Mexico
Energy, Minerals and Natural Resources Department
Oil Conservation Division

Case Nos. 23686 and 23687: OCD Exhibit No. 11

OCD Recommendations for Administrative Approval of UIC Disposal Wells in the Delaware Mountain Group

1. C-108 Application: Criteria for selection of new location for proposed disposal well to be approved through the administrative review process*
    a. Approve locations outside of the identified Avalon production as delineated by NMOGA and provided in Exhibit 6.
    b. Exclude locations for proposed wells previously denied at hearing.
    c. Exclude locations that have demonstrated waterflows/interference problems or have issues for the proper completion of the proposed well.
    d. Uniform distance between wells with Delaware Mountain Group ("DMG") disposal intervals: OCD is recommending the use of the current area of review ("AOR") radius of one-half mile as an initial buffer around the individual wells. When applied to the technical review process, this would result in a distance of one mile between the surface locations of new DMG wells. For this criteria OCD would exclude DMG disposal wells that are plugged and active DMG disposal wells that are restricted by volume or source of disposal fluids.
    e. Exclude surface locations within three (3) miles of a gas processing facility that are currently approved by the Commission for disposal of treated acid gas in the DMG.

2. C-108 Application: Criteria for selection of injection interval
    a. Exclude the Lamar Limestone from inclusion in the permitted interval.
    b. Exclude the lower Brushy Canyon formation of the DMG from permitted interval and provide sufficient information in the application to demonstrate a lower confining layer to prevent vertical migration of injection fluid.
    c. Application should include a review of the AOR and assessment for evidence of natural fracture systems or faults. The proposed well would not be subjected to the requirements of a Seismic Response Area unless shallow disposal is indicated as a contributing source to the induced seismicity.

3. UIC Permit: Conditions of Approval: Well Design and Construction
    a. Only new well construction to be approved administratively: injection is through perforated casing; all casing to be cemented to surface; dedicated string of casing for isolation of the Capitan Reef; and dedicated string of casing for isolation of the Salado formation.
    b. Limit the outside diameter for injection tubing to 5.5 inches.
    c. Prohibit well stimulation that induces new fracture systems or propagates existing fracture and any use of proppants in stimulation.

Case Nos. 23686 and 23687: OCD Exhibit No. 11

4. UIC Permit: Additional Testing and Monitoring:
   a. Permittee is required to conduct a cement bond log ("CBL") for each casing string in addition to observing the circulation of cement to surface.
   b. Permittee is required to conduct, at a minimum, a suite of open-hole logs over the approved injection interval and submit this information to the OCD.
   c. Permittee to conduct a successful step-rate test ("SRT") before injection commences. The OCD may reduce the maximum surface injection pressure of the UIC permit should the results of the SRT show that the permitted pressure (as calculated using a gradient of 0.2 PSI per foot of depth to the top perforation) exceeds the formation parting pressure.
   d. Every two years after commencement of injection: permittee shall obtain a static bottomhole pressure and permittee shall review and provide a summary on the performance of the disposal well including analysis by Hall's plot method.
   e. If warranted, permittee may be required to establish a public seismic monitoring station where the new well location is not covered by the current public array.
   f. OCD should establish a process to allow the use of existing DMG disposal wells as observation wells including pressure monitoring.

*These criteria would incorporate current practices used in the review process such as the proximity of new locations with oil and gas production in the DMG.

Case Nos. 23686 and 23687; OCD Exhibit No. 12

State of New Mexico
Energy, Minerals and Natural Resources Department
Oil Conservation Division
UIC Program Guidance

Application Process for Injection Pressure Increases

If an operator has decided to request an increase of the maximum surface injection pressure for a well above the administrative gradient of 0.2 pounds per square per foot (psi/ft), then the operator must conduct a step-rate test (SRT) to establish the fracture parting pressure (or formation parting pressure) for the injection interval.

Subject to OCD approval, an estimated baseline fracture gradient may be applied to determine maximum allowable wellhead injection pressure for all injections within a certain area of same geological characteristics (lithology and stratigraphy). An estimated baseline fracture gradient shall be supported by representative mini-frac, step rate test, other geological tests demonstrating to the OCD that the estimated baseline fracture gradient is lower than the real fracture gradient found anywhere in the injection zone where the estimated baseline fractur gradient will be applied.

(a) In absence of an injection well within the area and there is no estimated baseline fracture gradient, or if the operator opted to establish a well-specific fracture gradient, then the operator must conduct step-rate test on an injection well. A step rate test conducted after a hydraulic fracture stimulation may be inconclusive and may not be acceptable for determining fracture gradient pressure.

(b) After determining the fracture gradient by subsections (a) and (b), a calculated maximum allowable wellhead injection pressure equals to the true vertical of depth of the shallowest portion of the well open the injection zone multiplied by the difference between the injection gradient and the injection fluid gradient: MAWIP= ((Fracture Gradient X 0.9) - P fluid) * TVD. The injection gradient is the fracture gradient determined by subsections (a) and (b) multiplied by a safety factor of 0.90 or other safety factor multiplier subject to OCD's approval on well-specific basis that is more appropriately accounts for more stringent allowance of friction loss.

The process for conducting the SRT begins with the Oil Conservation Division (OCD) District office (or the Bureau of Land Management (BLM)) and finishes with the Engineering Bureau of OCD in Santa Fe.

OCD DISTRICT OFFICE - BLM FIELD OFFICE

Submit Sundry Notice of Intent with SRT information to appropriate OCD District Office and the BLM Field Office (if necessary).

Approval of Sundry for the SRT is by the OCD District Office or the BLM Field Office.

CONDUCT STEP RATE TEST

PREPARE APPLICATION FOR IPI ORDER

EGS BUREAU, OCD SANTA FE OFFICE

Submit application with cover letter and required information to Santa Fe Office.

Review of the application will be completed by the Bureau and either submitted to the Director for approval of the IPI order or rejected.

IPI ORDER ISSUED BY SANTA FE; COPIES TO WELL FILE AND OCD ONLINE IMAGING FILE FOR THE ORDER

Where the injection well is located on federal surface, the Sundry Notice of Intent describing the proposed SRT operation will be submitted and approved by the BLM Field Office. The operator will supply a copy of the same sundry to the OCD District Office. The BLM may require supplementary testing not related to the SRT and may not require the pre-SRT testing requested by OCD. OCD has the authority for approval of any injection pressure increase for wells operated with orders (permits) issued under Division rule 19.15.26 NMAC.

State of New Mexico
Energy, Minerals and Natural Resources Department
Oil Conservation Division
UIC Program Guidance

Guidance for Conducting a Step-Rate Test

1. The operator must submit Division Form C-103 to the OCD District office with the description of the procedure for the SRT. The procedure will include the following information:

- ☐ A description of the equipment for measurement and data recording (manufacturer and model) Note: the pressure gauge and recorder must have an appropriate range for use during the test.
- ☐ Updated well-bore diagram,Christmas tree and wellhead specifications and pressure ratings
- ☐ Summary of injection volumes for last five years with average injection pressure.
- ☐ Summary of well treatments and pressures especially any historical Instantaneous Shut-in Pressure (ISIP).

2. Once the operator has an approved Sundry Notice, the operator shall notify the appropriate OCD District office at least 72 hours prior to the scheduled SRT so that OCD personnel may be present to witness the test.

3. A bradenhead test (if required by the District) and mechanical integrity test (MIT)-simulating SRT conditions i.e., at proposed higher pressure - will be performed before the SRT. If the subject well fails either test, then the SRT will be suspended until the mechanical integrity issue(s) has been remediated. The mechanical integrity testing may be modified at the discretion of the District Supervisor.

4. The casing and bradenhead pressures will be monitored during the test. All wellhead equipment must be rated for the anticipated pressures.

5. . Bottomhole pressure measurements will be required for wells deeper than 1000 feet (ft) and injection rates greater than one (1) barrel per minute (BPM). In the event of installing a bottomhole pressure gauge becomes to be operationally unattainable, direct surface pressure measurement while injecting fluid of same density and viscosity to that of proposed fluid to be injected in normal operation can be applied towards determining maximum allowable surface injection pressure. Where the density and viscosity of fluid used for testing is significantly different to that of the proposed fluid to be injected, then the results must be adjusted for difference in hydrostatic and friction pressures.

6. Wells currently injecting must be shut-in at least 48 hours before the test unless the shut-in pressures indicate that the well has not adequately stabilized and a longer time is required for the permitted interval to approximate pre-injection conditions. The wellbore effect must be clearly overcome, and radial flow condition (bottomhole pressure is equivalent to shut-in formation pressure) must be achieved before each step's time interval is determined depending on the permeability of the well. OCD might require submission of fall-off test to make sure that wellbore storage has been overcome before step rate time interval for subsequent stages is determined.

7. Selection of rates for the SRT will be developed by the operator based on the proposed operation and the historical information of the well. Suggested rates for the test are 5%, 10%, 20%, 40%, 60%, 80% and 100% of the proposed maximum daily injection rate at the corresponding pressure. The intent is to complete SRT with at least three (3) steps below the 0.5 psi/ft gradient and three (3) steps above the fracture parting pressure (breakdown pressure). Starting pump rates and pressures must be lower than the current rates and pressures if the well is currently injecting. It may be necessary to backflow the well to reduce initial SRT pressures.

8. Each step shall be at least 30 minutes in duration unless otherwise determined by the OCD. Longer step intervals of 60 minutes shall be required for low permeability injection intervals (less than 0.5 millidarcies) and for open-hole intervals greater than 500 feet in length. The operator may request, in the submission of the Sundry Notice of Intent, a modification of the time length for the step intervals with an explanation for the modification. Appropriate time interval determined by the operator to conduct the step rate test must be same amount of time and result in a stabilized pressure value in each step. If steps are carried out in different length of time, if steps don't result in a stabilized pressure value, or a formation parting or fracture is not clearly indicated then OCD my consider the step rate test inconclusive. The goal is for increments with equal time and rate and allow for down hole stabilization of pressure for each step.
In the event no fracture of the formation is noticed, the operator shall not apply surface pressure that would result in higher than the initial reservoir pressure of the reservoir.

Intent, a modification of the time length for the step intervals with an explanation for the modification. The goal is for increments with equal time and rate and allow for downhole stabilization of pressure for each step.

9. The duration of the step intervals for the SRT must not change during the test or the test results will not be deemed adequate for determining an accurate fracture parting pressure.

10. Pumping equipment must be able to pump at the rates and pressures needed for the test. Rate changes will be 0.5 BPM or smaller unless the OCD witness determines that bigger rate changes are necessary due to small incremental increases in pressure.

11. The operator shall ensure that there is enough water to conduct the entire test.

12. The completed SRT results are to be submitted to the Engineering Bureau in Santa Fe and should include the following information:
    - ☐ Administrative application checklist (available on OCD website under Unnumbered Forms on Form webpage).
    - ☐ Cover letter with contact information, general description of test and pressure increase being proposed.
    - ☐ Complete data summary including injection rates, duration of each step, pressure measurements (surface and bottom hole) and the ISIP.
    - ☐ SRT-specific information: location of pressure gauges (depth); initial bottomhole pressure; injection fluid type and specific gravity.
    - ☐ Graph summary of pressure versus injection rate with interpretation.
    - ☐ Current well completion diagram.
    - ☐ Copy of the order authorizing the injection into the well.

13. If a pressure increase is granted, it shall be limited for use in the well with the same tubing, size, length, and type of interior coating as present for the SRT. If these components are changed, the operator must ask the Engineering Bureau to re- calculate the surface pressure limit, which may require another SRT.

Additional Sources:

Martin Felsenthal, ***Step-rate Test Determine Safe Injection Pressures in Floods*** in The Oil and Gas Journal, October 28, 1974.

US Environmental Protection Agency, ***Step-Rate Test Procedure***, Region VIII; January 12, 1999.