Letter Report—December 2006

Historical and 2006-2025 Estimation of Ground Water Use for Gas Production in the Barnett Shale, North Texas

Prepared for:
R.W. Harden & Associates, Austin, TX
and
Texas Water Development Board, Austin, TX

by

Jean-Philippe Nicot, P.E., P.G., and Eric Potter, P.G.

Bureau of Economic Geology
John A. and Katherine G. Jackson School of Geosciences
The University of Texas at Austin
Austin, Texas 78713-8924

Historical and 2006-2025 Estimation of Ground Water Use for Gas Production in the Barnett Shale, North Texas

Prepared by:
Jean-Philippe Nicot, P.E., P.G., and Eric Potter, P.G.

Bureau of Economic Geology
John A. and Katherine G. Jackson School of Geosciences
The University of Texas at Austin
Austin, Texas 78713-8924

Summary

The Barnett Shale play, currently the most prolific onshore gas play in the country, has seen a quick growth in the past decade with the development of new “frac” (a.k.a. fracture stimulation) technologies needed to create pathways to produce gas in the very low permeability mudstones. This technology uses large amounts of water in a short period of time to develop a gas well. There are currently over 5,600 wells producing gas from the Barnett Shale, with thousands more likely to be drilled in the next couple of decades as the play expands out of its core area. A typical vertical completion consumes approximately 1.2 million gallons, and a typical horizontal well completion 3.0 to 3.5 million gallons of fresh water. Almost 8,000 acre-feet of water (from all sources) was used in 2005, mostly in an area equivalent to a Texas county. This usage has raised some concerns among local communities and other groundwater stakeholders, especially in the footprint of the Trinity aquifer.

In this study, we present projections of groundwater use by the oil and gas industry through 2025. Total water use is highly uncertain, being dependent on the price of gas above all. We approach this uncertainty by developing high, medium, and low scenarios that can be somewhat understood as cases with decreasing gas prices. Other important factors include geologic risk factors in the Barnett (maturity of the shale, thickness of the formation, presence of features limiting or hampering well completion), technological factors (horizontal vs. vertical wells, water recycling), operational factors (number of well completions that can be done in a year, proximity of a fresh-water source), and regulatory factors. The high scenario cumulates most of the high-end water use of the previous parameters, whereas the low scenario uses the low values of their range.

The low scenario utilizes 29,000 AF of groundwater to the 2025 horizon (1,500 AF/yr on average), a clear retreat from current annual rate of water use by the industry, corresponding to a large drop in gas price. The high scenario calls for a total water use between 2007 and 2025 of 417,000 AF of groundwater (~22,000 AF/yr on average). It corresponds to sustained high gas prices allowing operators to expand to all economically viable areas and produce most of the accessible resource but also includes the assumption that water use is not limiting. All scenarios assume that operators continue using water at a per-well rate similar to that of today and that no technological breakthrough will bring it down. The medium scenario assumes a groundwater use of 183,000 AF (~10,000 AF/yr on average). In the high scenario, groundwater use steadily climbs from ~5,000 AF/yr in 2005 to 20,000 AF/yr in 2010 and then slowly increases to a maximum of ~25,000 AF/yr in 2025. The medium scenario follows a similar path, climbing to a maximum of ~13,000 AF/yr in 2010 and then slowly decreasing to ~7,500 AF/yr in 2025. The medium case is not necessarily the most likely. Because the Barnett Shale play is dependent on gas prices, a more accurate statement would be to formulate that the medium case is the most likely under the condition that gas prices stay at their current level.

Table of Contents

Summary i
Table of Contents iii
Figures iv
Tables v
Acknowledgments vi
I. Introduction 1
II. What is the Barnett Shale? 4
III. Data Sources and Processing 11
III-1. Well Completion and Water Use 11
III-2. Fresh-Water Consumption 11
IV. Current and Past Practices 12
IV-1. History of Production Technology in the Barnett Shale 12
IV-2. Historical Water Use 17
IV-3. A Few Relevant Numbers: Amount of Water Used per Well 19
IV-3-1 Literature Review 19
IV-3-2 Statistical Analysis of the RRC Database 19
V. Water-Use Projections 24
V-1. Impact of Geologic Features 24
V-1-1 Regional Features 24
V-1-2 Sags Over Cave-Collapse “Karst” Features 30
V-1-3 Development in Overlying Formations 31
V-2. Technological and Cultural Controls 34
V-2-1 Horizontal/Vertical Technology and Rural/Urban Environment 34
V-2-2 Restimulation 35
V-2-3 Recycling 36
V-2-4 Water Use Intensity 36
V-2-5 Well Spacing—Infilling 36
V-3. Operational Controls 38
V-4. Numerical Projections 38
V-4-1 Hypothetical Maximum Water Use 40
V-4-2 Derivation of Activity-Weighting Curve 43
V-4-3 Year of Peak Activity and Quality of the Resource in County Polygons 45
V-4-4 Uncorrected Annual Water Use 47
V-4-5 Correction due to Maximum Number of Completions Constraint 50
V-4-6 Correction due to Recompletions and Recycling and Final Projections for Frac Job Annual Water Use 50
VI. Groundwater Pumpage for GAM Input 53
VI-1. Groundwater/Surface Water Split 53
VI-2. Final Projections for Groundwater Use 57
VII. Conclusions 64
VIII. References 64
IX Appendix: Responses to Comments 67

Figures

Figure 1. Barnett Shale extent and TWDB major aquifers. 3
Figure 2. Yearly Barnett gas production. 4
Figure 3. Relevant geologic features associated with the Barnett Shale. 7
Figure 4. Top of the Barnett Shale (northeastern area of full Barnett Shale extent). 8
Figure 5. Barnett Shale isopachs (northeastern area of full Barnett Shale extent). 9
Figure 6. Barnett Shale well location. 10
Figure 7. Wells drilled (a) up to 1997 (included), (b) up to 2000 (included), and (c) up to 2002 (included). 14
Figure 8. Spatial and temporal distribution of horizontal wells. 16
Figure 9. Historical annual and monthly completions in the Barnett Shale. 20
Figure 10. Distribution of water use for vertical-well frac jobs. 23
Figure 11. Distribution of water use for horizontal-well frac jobs. 23
Figure 12. Distribution of water use intensity for horizontal-well frac jobs. 23
Figure 13. Spatial definition of high, medium, and low scenarios. 27
Figure 14. Spatial definition of high, medium, and low scenarios (combined). 28
Figure 15. Bar plot of counties in the high (a), medium (b), and low (c) scenarios. 29
Figure 16. Example of collapse features in the Ellenburger Fm. on the Wise-Jack county line as seen from a seismic survey. The picture may or may not be representative of the Ellenburger as a whole. 31
Figure 17. Water use in a six-county area in the Atoka/Bend Formations (2001–2006). 32
Figure 18. Distribution of water use in the six-county area in the Atoka /Bend Formations (2001–2006). 32
Figure 19. Recent (2001–2006) well completion in the Atoka/Bend Conglomerate of the Fort Worth Basin. 33
Figure 20. County polygons for water-use projections. 34
Figure 21. Schematics of pilot test results of lateral spacing in Johnson County (map view). 37
Figure 22. Annual completions projections up to 2015 (constant rate from 2012 to 2025). 38
Figure 23. Annual well completion in selected county polygons. 43
Figure 24. Annual well completion in selected county polygons per well type. 44
Figure 25. Basic model of time distribution of number of completions/water use. 44
Figure 26. Column chart illustrating calibration of county activity. 46
Figure 27. Uncorrected annual water use and completion (high scenario). 47
Figure 28. Uncorrected annual water use for high, medium, and low scenarios. 47
Figure 29. Corrected annual water use for high, medium, and low scenarios. 50
Figure 30. Rivers and reservoirs in the study area. 55
Figure 31. Selected water-supply wells in the study area. 56
Figure 32. Groundwater annual water use for high, medium, and low scenarios. 57
Figure 33. Groundwater annual water use per county polygon for the high scenario. 58
Figure 34. Groundwater annual water use per county polygon for the medium scenario. 59
Figure 35. Groundwater annual water use per county polygon for the low scenario. 60

Tables

Table 1. 2000-2005 historical water use in the Barnett Shale 17
Table 2. 2000-2005 estimated historical ground water use in the Barnett Shale..........................18
Table 3. Annual completion statistics in the Barnett Shale 20
Table 4. Barnett Shale well statistics by county 21
Table 5. Summary description of parameters used in the water-use projections..........................26
Table 6. Historical water use (all sources combined) in 2005 per county polygon......................39
Table 7. Derivation of hypothetical maximum water use by county polygon..............................41
Table 8. Start year and prospectivity/risk factor for county polygons..45
Table 9. Uncorrected annual water use per county polygon for the high scenario (1000’s AF). ..48
Table 10. Corrected annual water use per county polygon for the high scenario (1000’s AF). 51
Table 11. Groundwater use as a fraction of total water use (county level). 54
Table 12. Groundwater annual water use per county polygon for the high scenario (1000’s AF). 61
Table 13. Groundwater annual water use per county polygon for the medium scenario (1000’s AF). 62
Table 14. Groundwater annual water use per county polygon for the low scenario (1000’s AF). 63

Acknowledgments

Many people/organizations were involved in the production of this document. We acknowledge the help of Bob Harden at R.W. Harden & Associates and Cindy Ridgeway, Robert Mace, Ali Chowdhury, project manager, at the TWDB in helping collect data, contacting numerous individuals, and funneling the information to us.

We thank Peter Galusky from Texerra and the Barnett Shale Water Conservation and Management Committee for sharing with us data directly collected from operators. Several Bureau of Economic Geology (BEG) researchers helped by sharing their Barnett Shale knowledge. Romulo Briceno and Ramón Treviño, also from BEG, helped in processing of the data and in providing useful comments on the report, respectively. Lana Dieterich edited the report.

Last, we are grateful to **drilling.info.com** and **IHS Energy** for giving us free access to their extensive well and production databases, and Landmark Graphics Corporation for access to their software through the Landmark University Grant Program..

Introduction

The Barnett Shale play, located in North Texas and currently the most prolific onshore gas play in the country, has seen a quick growth in the past decade with the development of new “frac” (a.k.a. fracture stimulation) technologies needed to create pathways to produce gas in the very low permeability shales. Approximately 150 operators are active in the play. Devon Energy, a Barnett Shale pioneer, is still by far the most important player in terms of production. This technology uses a large amount of water in a short period of time (up to 5 million gallons of water within a day, followed by a few days of flowback) to develop a gas well. There are currently more than 5,000 wells tapping the Barnett Shale, with thousands more likely to be drilled in the next few years and possibly decades. The so-called core area, also officially described as Newark East field and which has seen the initial production in the 1990’s, includes part of Denton, Wise, and Tarrant Counties (Figure 1). The production area is now expanding to the southwest, into Parker and Johnson Counties, and may eventually include more than 20 of the 44 counties of the Fort Worth Basin covered in all or partly by the Barnett Shale footprint. This growth concerns local communities and other stakeholders because this part of the state does not have any Groundwater Conservation District (GCD) (it generally relies mainly on surface water), except in Erath and Comanche Counties (Middle Trinity GCD). Contrary to the surface water case, where usage rights are well appropriated and water use is tracked, no state or local rule governs the legitimate use of groundwater outside of a GCD, potentially leading to overdraft.

This work was performed to provide input to an updated version of the Trinity Groundwater Availability (GAM) model (R.W. Harden & Associates, 2004). Although the Trinity Aquifer GAM and Barnett Shale extents only partly overlap (Figure 1), it was felt that the whole Barnett play should be studied because experience shows that water sources can be located far from their point of use. A compounding factor is that the TWDB has not defined any major or minor aquifer on the western half of the Barnett Shale extent, suggesting low yield in the local aquifers and that water could still come from the Trinity and be transported to these areas.

One may wonder why operators would need to use fresh water instead of the abundant saline water produced in the basin. Produced saline water has been the bane of oil operators since hydrocarbon production started, and any reuse option would certainly be welcome. Unfortunately, Barnett Shale operators prefer using fresh water (Margaret Allen, RRC, written communication, April 2006) for technological and operational reasons. Saltwater significantly increases the potential for scale deposition in the formation, tubing, casing, and surface equipment, therefore inhibiting gas production. Saltwater also significantly increases the potential for corrosion on the tubing, casing, and surface equipment, potentially shortening the life of a well. In addition, chemicals needed to carry out a good frac job do not perform as well with saltwater. Friction reducers are not as effective and are more costly when used in saltwater. Depending on the composition of the saltwater, it can be altogether incompatible with friction reducers. Saltwater is not compatible with x-linked gels that were commonly used in fracs (see later section). Economic factors may be important as well. Produced water of acceptable quality may not be available in close proximity.

The Barnett Shale play is rapidly expanding, and new information is released at a fast pace. However, this report will try to capture our understanding of the play as it relates to water resources as of summer 2006. This document presents historical information about the play, as well as tentative projections. It will expand on the following points:

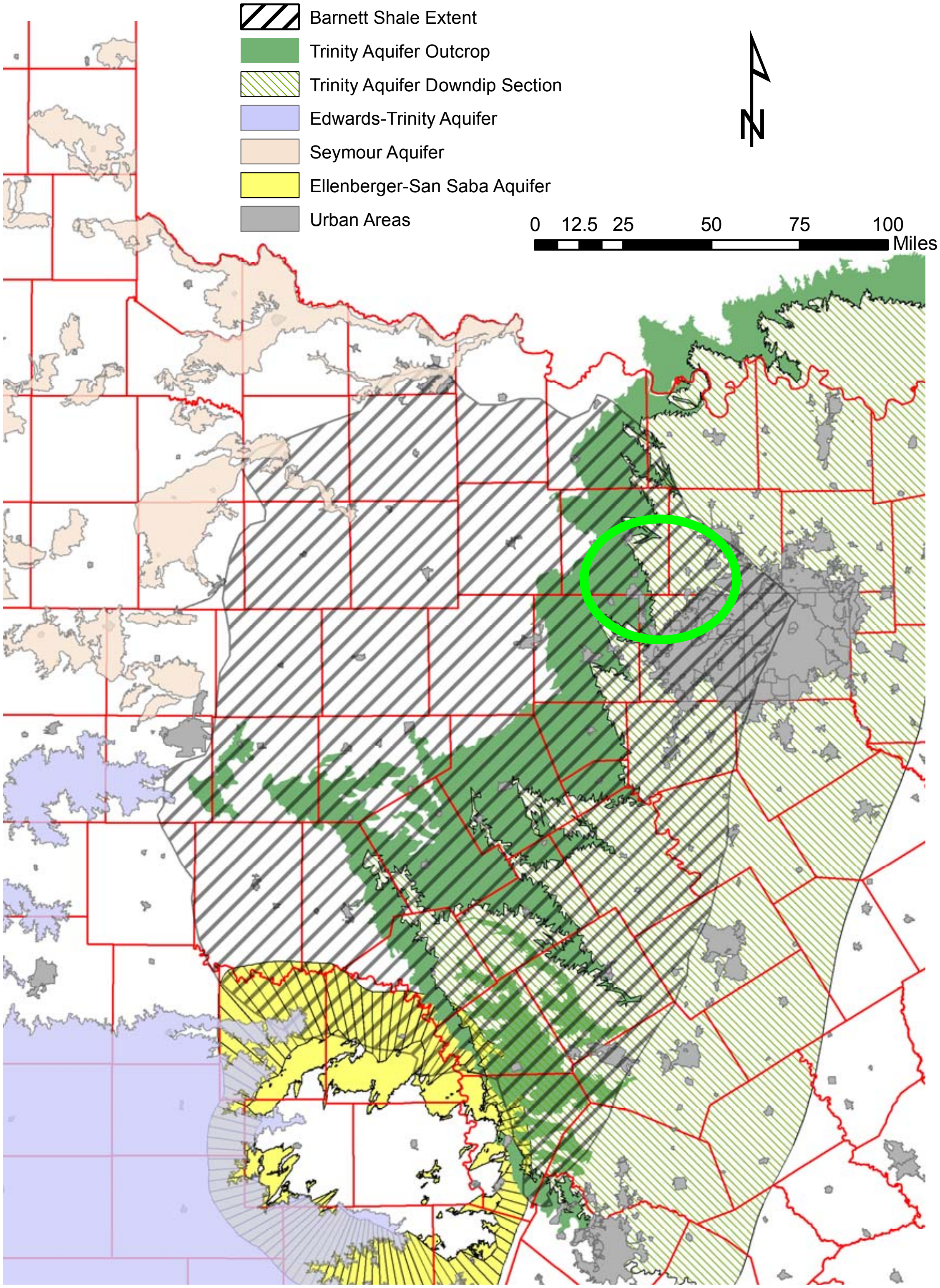
(1) Understanding spatial and temporal trends: the exploration boom started in Wise and Denton Counties but is expanding mainly southward and westward. Using geologic insight, our knowledge of the play, and discussions with operators, we forecast the likely geographic evolution of the play. Operators may also turn their interest to parts of the overlying Bend Conglomerate, increasing the number of frac jobs in a given area.

(2) Understanding the future of the technology: a few questions need to be answered. Will the water consumption per frac job decrease? How often can a given well be frac'ed? What percentage of the wells would be directional horizontal wells. Will multiple frac jobs in horizontal wells result in the same number of forecast fracs, compared with development by vertical wells?

(3) Understanding the impact of recycling: there is currently some recycling of the frac water and strong incentives to increase the recycled fraction because the used frac water ("flowback") has to be hauled away and disposed of generally in commercial disposal wells not necessarily located in close proximity to the drilling area.

We tried to keep the model simple. There might be arguments to make a supposedly more accurate and/or more complicated model, but there are currently no data to build additional or more sophisticated parameter distributions.

A word of caution on terminology: in the oil and gas industry m or M means thousands (as in Mcf—thousand cubic feet), whereas in the water resources field M means million (as in MGD—million gallons a day); in the oil and gas field, million is denoted by MM. Because this report is geared mainly toward water-resources issues, we have adopted "M" to mean millions when water is involved. We also use acre-feet (AF), the standard water resources unit: 1 AF is equivalent to 325,851 gallons, or 7,758 barrels.



Note: Barnett extent is approximate and will change with new studies. Llano uplift is outlined by the Ellenburger Aquifer. The lower downdip limit of the aquifers is set when salinity reaches 3,000 ppm. Green circle represents the core area.

Figure 1. Barnett Shale extent and TWDB major aquifers.

I. What is the Barnett Shale?

The Barnett Shale can be defined as an unconventional play. A significant part of US gas production (over 30%) comes from unconventional plays. They are characterized by marginal-quality reservoirs requiring artificial stimulation, usually fracture treatments ("frac jobs"). They are also "continuous" (similar to coalbed methane), that is, the resource is distributed across large geographic areas and there may be few dry wells. It follows that the play is currently more driven by technology than by geology. The U.S. Geological Survey (USGS) estimated the mean of the gas resources at 26.7 Tcf of gas (USGS, 2004), whereas Montgomery et al. (2005) put proven reserves (in the core area) at 2.7 Tcf, at the time the paper was written, and ultimate producible resources between 3 and 40 Tcf. The Railroad Commission of Texas (RCC) puts forward a value of 250 Tcf for total gas in place (not all of it recoverable). Montgomery et al. (2005) cited >200 Tcf. In a quickly evolving play, reserve values are also varying (in general increasing) as geologic understanding and technology progress. The play is currently producing gas at a rate ~0.5 Tcf/year (Figure 2). Per-well reserves are relatively low, compared to conventional gas plays. Reserves are often discussed on a unit surface area basis, although this is an oversimplified approach. Because of stimulation and drilling cost, play success is sensitive to gas price. A large drop in gas price will stop the viability of the play. There seems to be some agreement that the gas price needs to stay above $4/Mcf for the play to stay viable in the long term (e.g., Rach, 2005).

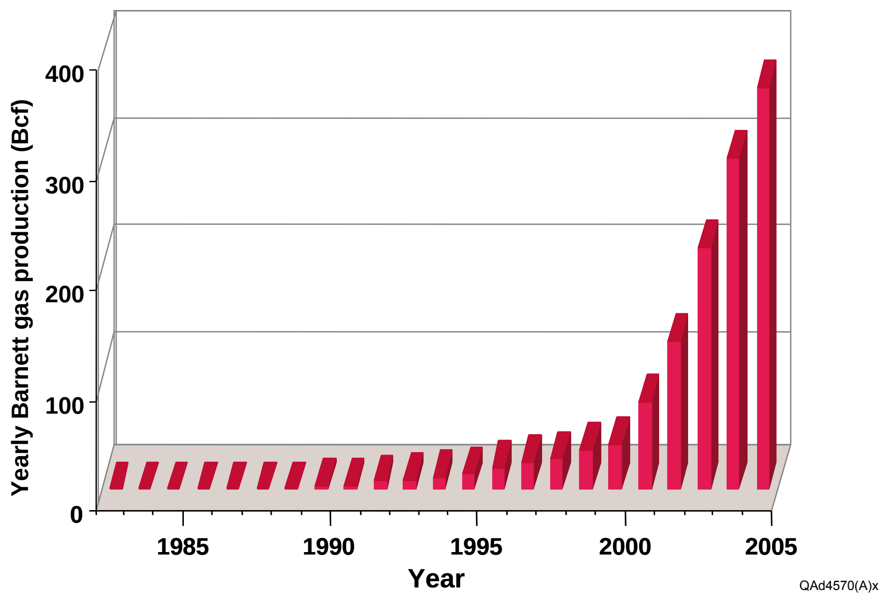


Figure 2. Yearly Barnett gas production.

The Barnett Shale has been described as a black organic shale and is a fine-grained rock formation. It is considered the source rock for numerous oil and/or gas conventional reservoirs in the Fort Worth Basin (Pollastro et al., 2003), including the Pennsylvanian-age Bend Conglomerate Formation, that have produced gas starting in the 1950's. However, the Barnett Shale is at the same time, source, reservoir, and trap, with a natural permeability in the microdarcy to nanodarcy range and porosity in the 0.5 to 6% range. Water saturation is below 50% (25% in places, Montgomery et al., 2005). In reality, in geologic parlance, the word *shale* is a misnomer, or at least misleading by some definitions. The Barnett strata, although very fine grained, are not composed of shales, but of siliceous mudstones, argillaceous lime mudstones (marls), and phosphatic argillaceous skeletal packstones (R. Loucks, BEG, oral communication, 2006). Mineralogically, clays (mainly non-swelling illite) account volumetrically for about 25% of the formation, the remainder being dolomite, calcite, feldspars, and quartz, as well as metal oxides and pyrite (Montgomery et al., 2005, p.162).

The Barnett Shale formation exists under wide areas in Texas and crops out on the flanks of the Llano Uplift 150 miles to the south of the core area (Figure 3). Most current boundaries of the formation are due to erosion. The Fort Worth Basin is bounded by tectonic features to the east by the Ouachita thrust foldbelt (old, eroded, and buried mountain range) and to the north by the uplifted Muenster and Red River Arches. The Barnett Shale is also limited by erosional limits on its western boundaries. A depositional equivalent is present farther west in the Delaware Basin. Equivalents are also present in the Texas Panhandle in the Hardeman and Palo Duro Basins (Pollastro et al., 2003).

The Barnett Shale dips gently toward the core area and the Muenster Arch from the south where it crops out and west where it thins considerably and its base reaches a maximum depth of ~8,500 ft (subsea) in the NE confines of its extent. The depth to the top of the Barnett ranges from about ~4,500 ft in northwestern Jack County to about ~2,500 ft in southwest Palo Pinto County to about ~3,500 ft in northern Hamilton County to about ~6,000 ft in western McLennan County to about 7,000 to 8,000 ft in the Dallas-Fort Worth area (Figure 4). Further west in Throckmorton, Shackelford, and Callahan Counties the depth to the Barnett varies between ~4,000 to 2,000 ft.

Formation thickness is in the 30-to 50-ft range on the Llano Uplift and increases to almost 1,000 ft farther north in the core area, when the whole Barnett section, including interspersed limestones, is counted. Toward the west, Barnett Shale thickness is impacted by the presence of the Chapel Limestone and decreases to almost zero in southwestern Jack County (Figure 5). In the northeasternmost part of the Barnett extent, in eastern Jack County and continuing in Young, Throckmorton, and Baylor Counties, the Barnett thickness decreases to ~50 ft because of the presence of the Chappel carbonate shelf, which contains paleo reefs with oil accumulations (Montgomery et al., 2005).

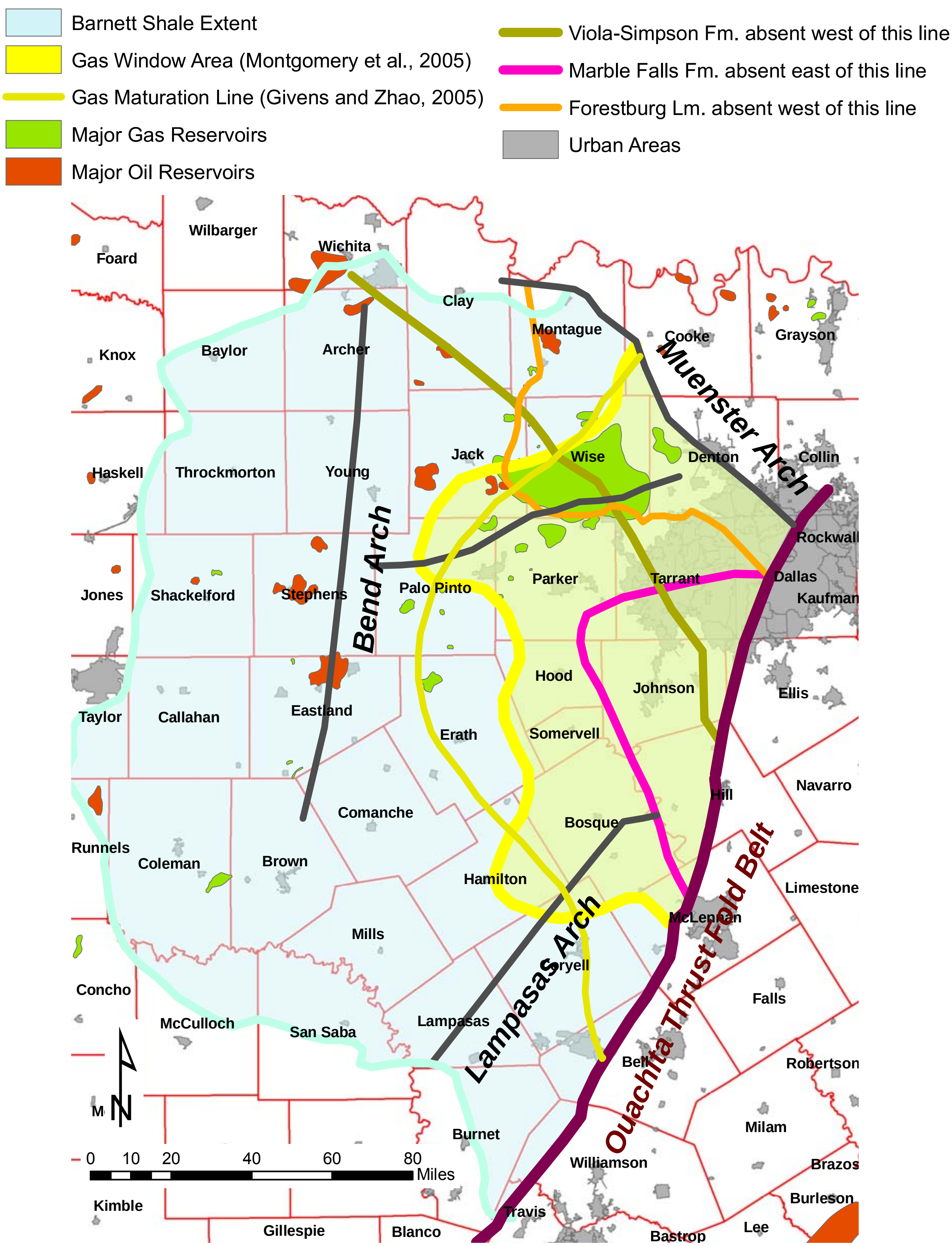
The Barnett Shale is a marine basinal deposit of Mississippian age, deposited under mostly anoxic conditions in a calm back-arc basin just before the formation of the Ouachita thrust foldbelt. It lies unconformably on the Ordovician limestones of the Viola-Simpson formations and dolomites of the Ellenburger Group and is overlain by the carbonates and shales of the Pennsylvanian-age Marble Falls Group. In the core area, the Barnett Shale is divided by a middle muddy limestone (Forestburg Limestone) into lower and upper intervals. The thickest and most productive section is the Lower Barnett. The so-called Forestburg Limestone, not a single individual unit, contains shale intervals (W. Wright, BEG, personal communication, 2006). The Forestburg Limestone and other limestone formations are better developed in Montague County (Figure 3). The marked gross Barnett increase in thickness close to the Muenster Arch is due mostly to limestones. Lower and upper Barnett sections vary from ~260 to 715 ft and ~20 to 210 ft in thickness, respectively. The Marble Falls Formation is also absent locally, in the west half of Hill County, the south half of Tarrant County, and all of Johnson County (Figure 3). Important to the history and technological evolution of the play, the Viola-Simpson Formation, present in the core area, pinches out toward the SW (Figure 3). Where it is present, the Viola-Simpson

Formation acts as a buffer between the Ellenburger Formation and the Barnett Shale. It is important to keep the frac job within the Barnett Shale and the dense Viola Limestone is able to achieve this purpose. According to the current operational model, frac jobs penetrating into the Ellenburger generally mean trouble for the operator because of the excess water drawn from the Ellenburger owing to its high permeability. The Viola Limestone covers eastern Wise County, the southwest half of Denton County, and most of Tarrant County, as well as Montague and most of Clay Counties. To a lesser extent, the Marble Falls Limestone plays a similar role helping to confine frac jobs within the upper Barnett.

As most formations, the Barnett Shale is naturally fractured. In Newark East field, the core area, fractures trend NW-SE. They are generally closed by calcite but it is speculated that they can be reactivated during a frac job. Induced fractures have a NE-SW strike (mean of 60^{o}) (Schmoker et al., 1996, p. 3).

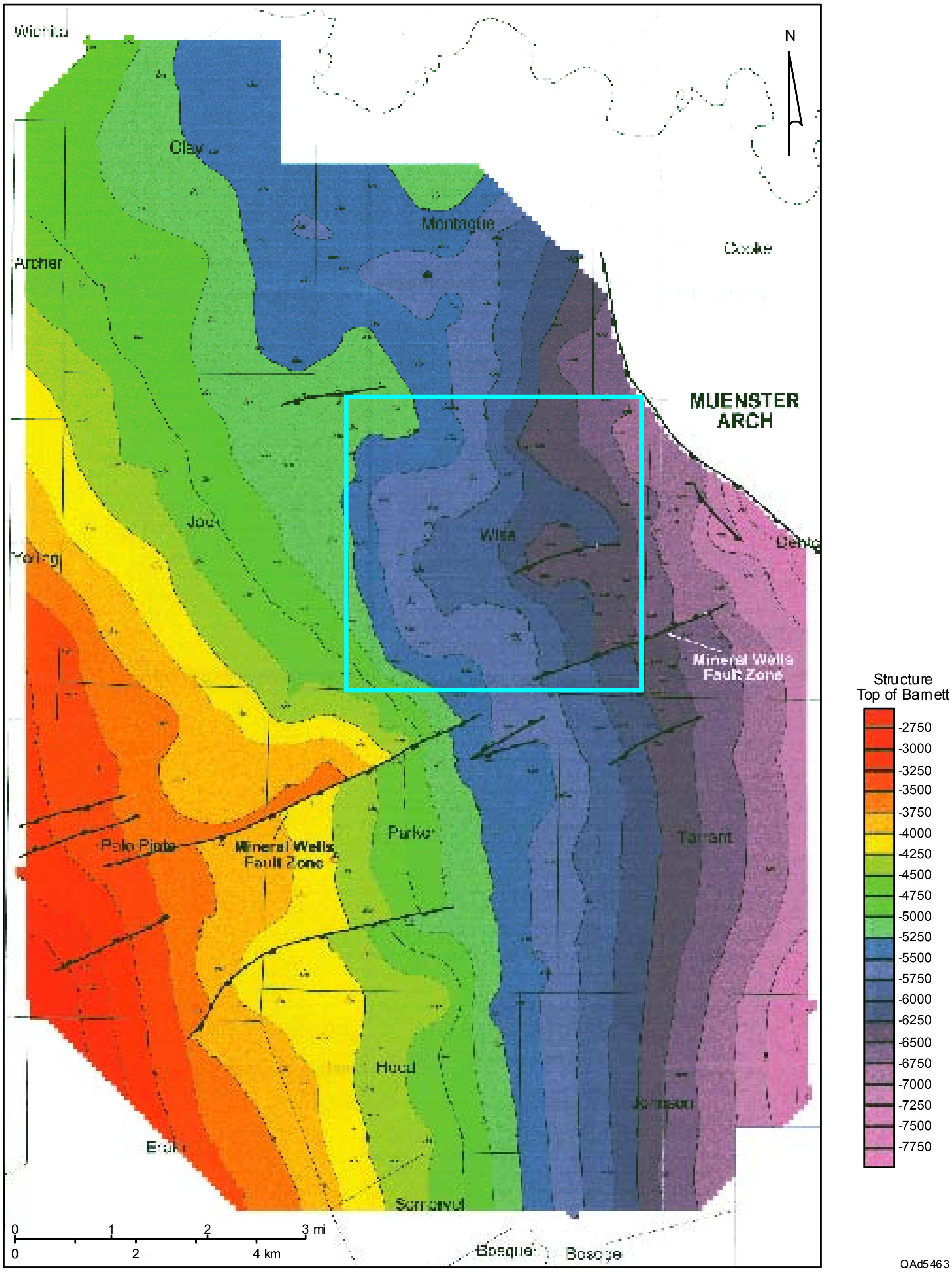
The gas maturity area is another important geologic feature presented in Figure 3. Organic matter and/or oil needs to be subjected to a specific range of temperature for a long enough period of time to produce gas. That threshold occurred in the Mesozoic period for the Barnett Shale (Montgomery et al., 2005, Fig. 7). It is generally thought that some gas subsequently migrated upward to accumulate in stratigraphic traps of the Bend Conglomerate / Atoka Formation, where it has been produced since the 1950's (Figure 3). West and north of the area where the Barnett is in the gas window, the Barnett has been producing both gas and oil (Figure 3). Oil also accumulated in conventional traps above or below the Barnett. Figure 3 displays a few of the major oil and gas reservoirs and is not comprehensive in that matter. The map boundaries of the gas maturation area are open to geologic interpretation and, as demonstrated In Figure 3, different authors have come up with slightly different boundaries (e.g., Givens and Zhao, 2005; Montgomery et al., 2005; note that Givens and Zhao had less confidence in the southern half of their gas-maturation line). Gas-oil ratio decreases systematically toward the west. The gas maturation area as defined is more of a commercial fairway boundary. It is best defined in Wise County, but there is considerable scope for redefinition in other areas. Gas operators undoubtedly have a better handle on it, as compared with what is available in the open literature, but for understandable reasons, they do not advertise their findings. This is one example of the uncertain and evolving, or "soft" data used in this report.

The impact of these geologic features is clearly visible on the map showing all wells drilled in the Barnett (Figure 6). The core area is constrained (1) on its northeast boundary by the Muenster Arch, immediately beyond which no Barnett has been found; (2) on its southwest boundary by the Viola Limestone pinch-out; (3) on its northwest boundary by the northern limit of the dry gas window; and (4) on its southeast boundary by the presence of the urbanized areas of Fort Worth and its suburbs, and ultimately by the Ouachita fold and thrust system, east of which there is little chance of Barnett presence.. Within the core area, the impact of NE-SW-trending faults is also visible through the lack of wells drilled close to them.



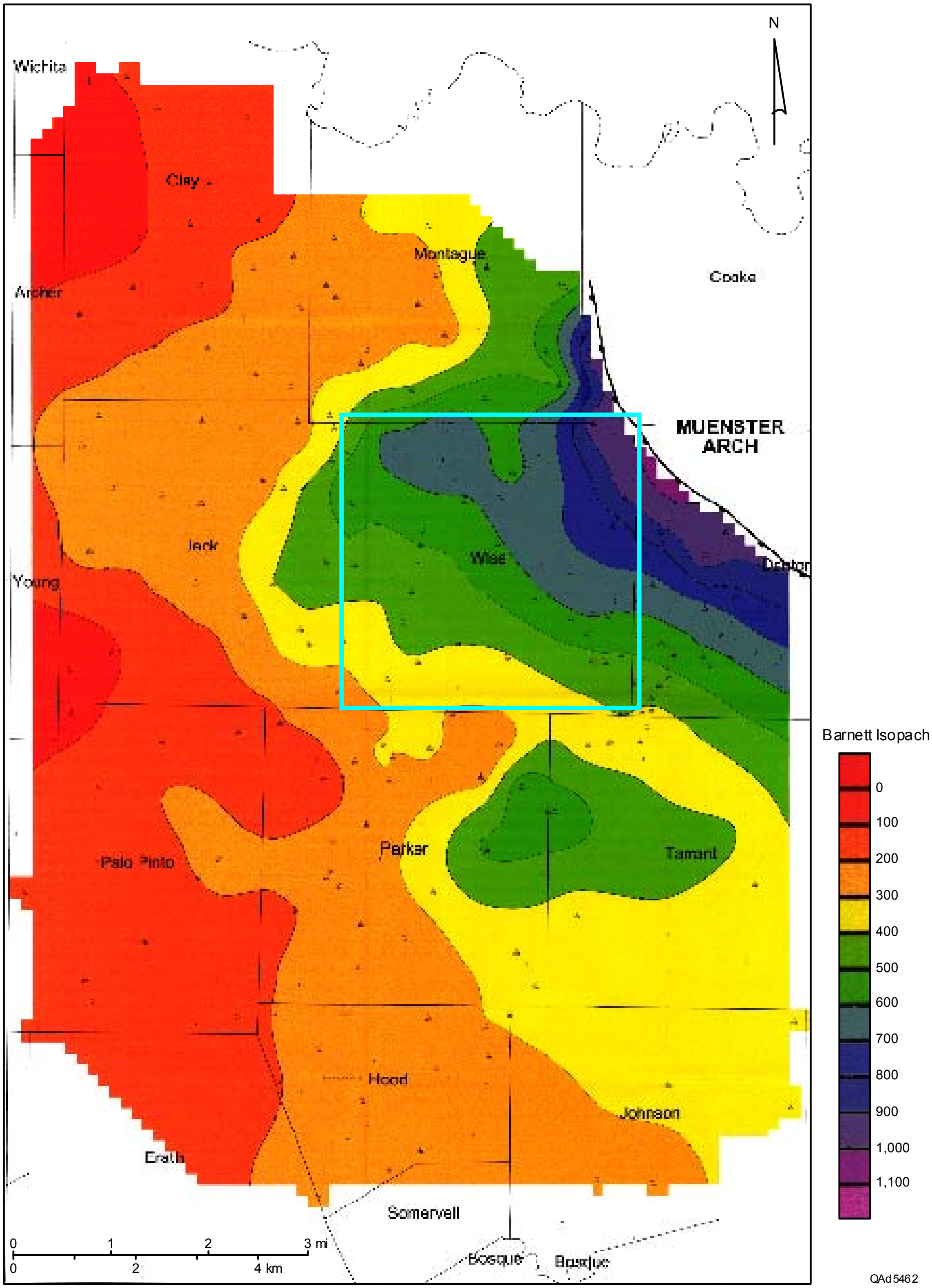
Forestburg limit modified from Givens and Zhao (2005); all others modified from Montgomery et al. (2005); major oil and gas reservoirs from Galloway et al. (1983) and Kosters et al. (1989). The Major Gas and Oil Reservoirs refer to non-Barnett production.

Figure 3. Relevant geologic features associated with the Barnett Shale.



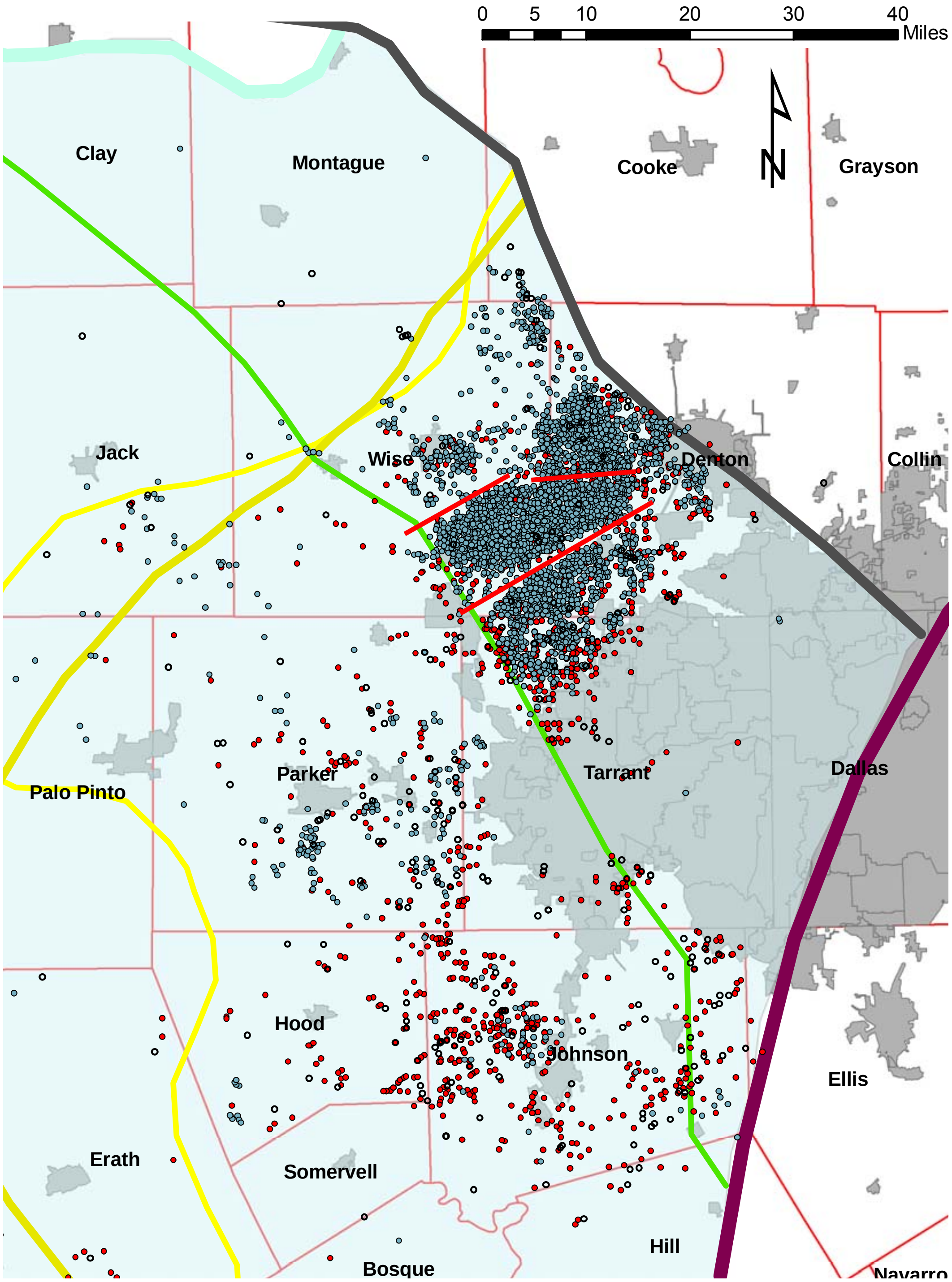
Courtesy of T. Hentz, BEG; Units are subsea feet; blue square represents Wise County

Figure 4. Top of the Barnett Shale (northeastern area of full Barnett Shale extent).



Courtesy of T. Hentz, BEG; Units are feet; blue square represents Wise County

Figure 5. Barnett Shale isopachs (northeastern area of full Barnett Shale extent).



Core area is clearly delimited between the Muenster Arch and the Viola Simpson pinch-out (green line). The vast majority of the wells drilled to date are within the gas window (2 versions shown with yellow lines) and in rural areas. Blue dots represent vertical wells whereas red dots represent horizontal wells. Non-colored dots represent those wells where directional information is not available. Known faults are shown by red lines. Well locations courtesy of drillinginfo.

Figure 6. Barnett Shale well location.

II. Data Sources and Processing

II-1. Well Completion and Water Use

Hard data on oil and gas production wells ultimately come from the RRC W2 and G1 (completion) forms. Vendors may handle raw data faster than the RRC and have it processed in a searchable and user-friendly fashion. We turned to both drillinginfo.com and IHS Energy to obtain completion information on all Barnett Shale wells present in their respective databases. We obtained well-location information from drillinginfo.com, as well as a data dump on completion data on all Barnett wells. We were not successful in finding location information for a small percentage of wells. Our lack of success has, however, a negligible impact on the water-use projections. We also obtained full completion information by using Enerdeq IHS software. In both databases, we searched for all Texas wells that included “Barnett” in their profile.

We also gained useful insight by talking to operators in meetings and conferences, including those held by the Barnett Shale Water Conservation and Management Committee (BSWCMC). The BSWCMC was conducting a thorough operator survey, headed by Peter Galusky, at the same time that our work was performed. Although not finalized at the time of submission of this report, those preliminary results from a non-RRC source were consistent with our findings and were integrated into this report.

II-2. Fresh-Water Consumption

Even perfect knowledge of water use for frac jobs is not sufficient for the task at hand. There is no legal requirement to declare the source of frac makeup water to the RRC. However, input to a groundwater numerical model in order to understand the impact of water retrieval for frac jobs requires being able to recognize the source of the water (surface-water bodies or subsurface) and its original location. In Texas, water flowing in Texas creeks, rivers, and bays is owned and managed by the State. Therefore, a person who withdraws surface waters for mining, construction, and oil or gas activities must obtain a water rights permit from the Texas Commission on Environmental Quality (TCEQ).

The most useful source of information on groundwater-surface water split in water use was provided by the BSWCMC survey (Galusky, 2006). Galusky (2006) provided groundwater use estimates by operators of historical data for year 2005 and projections for 2006 and 2007. TWDB efforts to get information on Trinity aquifer water wells did not come to fruition except for workers gaining an understanding that groundwater usage for frac jobs is widespread. All water well drillers must complete a Texas Department of Licensing and Regulation (TDLR)’s State of Texas Well Report for any and all groundwater wells. TWDB has maintained the online report database since 2003 and also had access to hard copies for the past 2 years (Ridgeway, 2006). However, water supply wells used for frac jobs can fall into many categories, including, for instance, domestic wells that might be drilled by an operator but later used by the landowner.

Another avenue pursued by R.W. Harden and Associates (R. Harden, 2006, written communication) was to contact river authorities. Brazos River Authority (BRA) has been selling water to Barnett operators. However, that water belongs to the “mining category,” which includes quarries, road construction, oil and gas activities, and other activities. BRA provided its mining water use values from ~2000, but we were not able to discriminate between the different mining usages. Although it was not done, a visit to the “Central Records” of the TCEQ, where permits are filed, might not have helped because a specification of “oil and gas” is not required.

III. Current and Past Practices

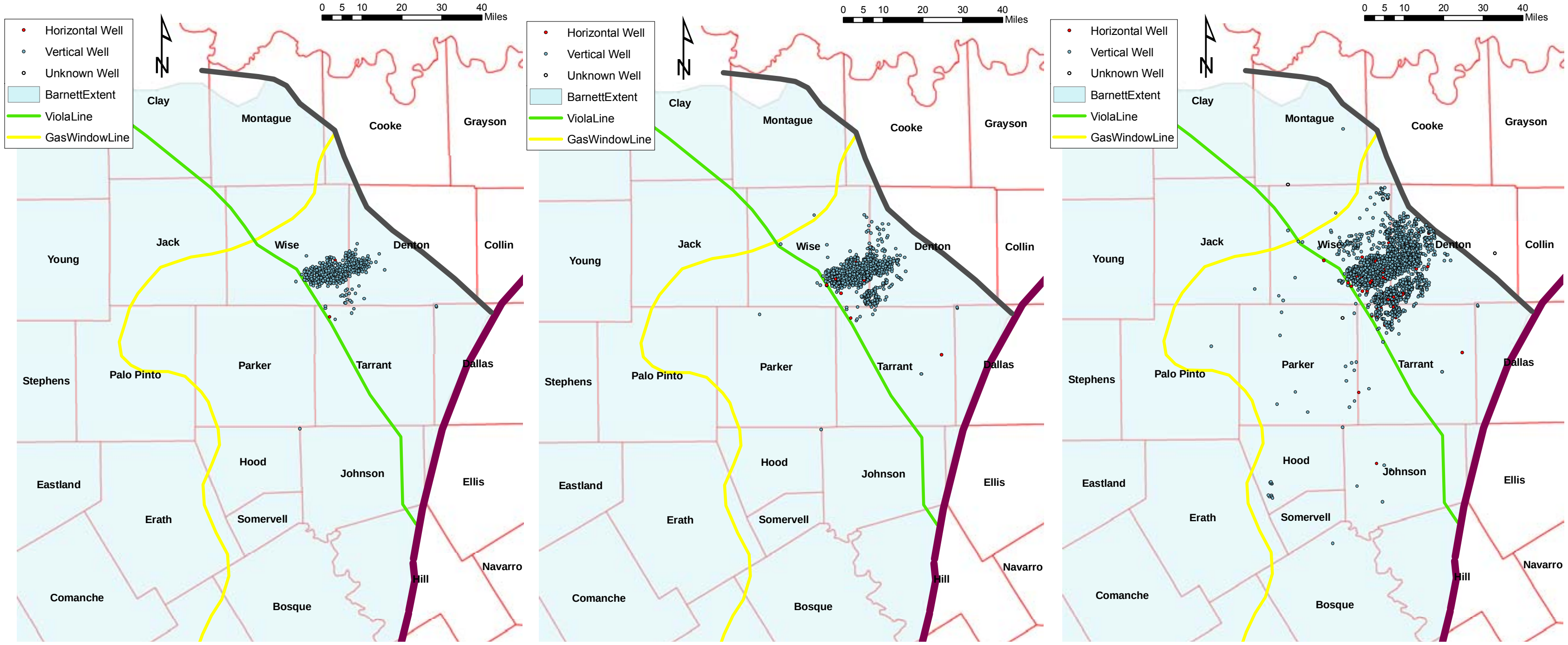
III-1. History of Production Technology in the Barnett Shale

Given the extremely low permeability of the Barnett Shale (even naturally fractured), hydraulic fracturing seemed a logical solution. Hydraulic fracturing, initially developed by Halliburton in the 1940’s, has been practiced and improved on since then (e.g., Martinez et al., 1987). Early treatments injected only a few thousand gallons of fluids into a few select wells. The technique was expanded to treat many more wells, not necessarily at initial completion, and to use a much larger volume of fluid. The initial impetus was to remove formation damage (scaling, oily deposits, porethroat occlusion by drilling fluids) in the vicinity of the well to renew the good communication between the reservoir and the well bore. Hydraulic fracturing quickly included treatment of low-permeability formations to improve production and is now also applied to medium-permeability formations. The concept is to prop natural or induced fractures open by injecting fluids in order to raise the pressure beyond the point at which it can be sustained by the rock, creating artificial fractures. Addition of a proppant to the fluid is needed to keep the induced fracture open once the fluid has been removed and the pressure has subsided. Sand is usually used as a propping agent, but many more sophisticated materials are also available from vendors and service companies. In the past, oil-based fluids were used as carrying fluids, but nowadays frac jobs use water-based fluids or, more rarely, mix-based fluids (oil-water emulsions). Hydraulic fracturing technology has evolved essentially by changing the nature and amount of the chemicals added to the water and by the accumulated knowledge of what works and what does not.

Starting in the early1980’s to just before 1997, operators tried several design approaches to produce gas economically from the Barnett Shale. Initially, massive hydraulic fracture treatments with high-polymer crosslinked gel fluids and large amounts of proppant at moderate concentration were used (e.g., Ketter et al., 2006; Moore and Ramakrishnan, 2006), as it was generally done in the U.S. at the time. Polymer concentrations were progressively reduced to zero and, subsequently, trials with nitrogen foam to improve flowback were used. Those practices were discontinued for the most part by the mid-1990’s. The breakthrough came in 1997, when Mitchell Energy (subsequently bought out by Devon Energy in early 2002) realized that much less expensive slickwater completions with small amounts of sand proppant would produce as much gas as the extremely expensive gel frac jobs. These frac jobs are called “slick water frac” or “light sand frac.” Very large amounts of fresh water are injected in a short time period (~1 day). Water is injected at a high rate of 60 to 80 bbl/min (2,520–3,360 gpm) (e.g., Ketter et al., 2006) in a 5.5-inch casing, or possibly even higher 140 bbl/min (5,880 gpm) (Lohoefer et al., 2006) in a larger casing (7 inches). In essence, a high flow rate of fresh water has replaced the higher viscosity of previous fluids to keep proppant particles moving with the fluid. Slickwater completion does not generate gel damage (such damage limits gas diffusion from the fracture walls) or limit proppant banking (leaving unopened some sections of the fractures). Fresh water could also generate formation damage if water-sensitive clays were present (e.g., Mace et al., 2006), which is not the case in the Barnett Shale.

Since 2002, when the play started to expand out of the core area, horizontal well technology has become more widespread. Horizontal wells are more expensive to drill and develop but have better performance and larger production. The need for horizontal wells derives from the local geology. Operators' interest is to frac as much of a vertical section of the Barnett Shale as possible because production is clearly related the length of the frac'ed material. A frac job in the Lower Barnett section of the core area can be highly successful, even if it cracks into the underlying Viola-Simpson Formation. However, this formation acts as a barrier between the Ellenburger and the Barnett but pinches out SW of the core area. A frac job with a too-large rate or volume will frac into the Ellenburger Formation where the Viola buffer is absent. The permeability of the Ellenburger is relatively high and the less-than-successful frac job will put in direct communication the well bore and the Ellenburger water, leading to gas production problems and an unacceptable water cut. The solution put forward by operators is to use horizontal wells and multiple carefully sized frac stages. Those consequences also explain the general reluctance of operators to drill next to a fault. The frac job could access the fault and potentially connect the water-rich Ellenburger Formation to the newly drilled well bore through the intersected fault and the induced fracture. Such is apparently the case of the NE-SW-trending Mineral Wells Fault across the core area, where few wells have been drilled (Figure 7). Another geologic feature has also emerged of interest (details in Section V-1-2). Dolomites of the Ellenburger Formation are, at least in large areas underneath the Barnett Shale, paleokarsts—that is, cave-collapse cavities are common. Many of the resulting sags do impact the Barnett Shale, as well as other overlying formations (e.g., Hardage et al., 1996). Barnett Shale horizontal wells drilled through the faults of these collapse features could again encounter weakness zones prone to water flow and directly link the Ellenburger to the borehole. These features are common, and many early well failures could possibly be explained by them. Vertical wells are less likely to encounter a fault, even when they are drilled in the middle of a collapse structure, and are not as affected as horizontal wells.

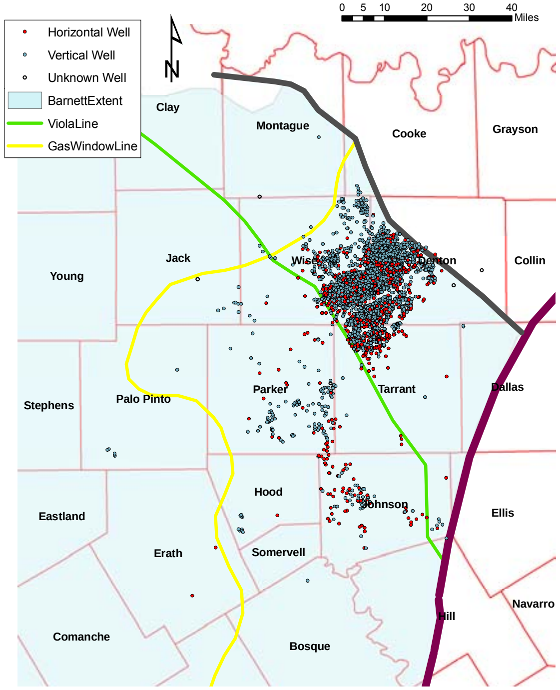
Figure 7a displays well spatial distribution at the onset of the slickwater frac technology in 1997. Following years (Figure 7b) do not show much spatial expansion because operators were busy refrac'ing wells completed using gel technology in the Lower Barnett, frac'ing the Upper Barnett, and doing some infill drilling. In 2001 and 2002 (Figure 7c), the play started to expand as horizontal well technology in the Barnett developed, but it was still confined mostly within the Viola Limestone footprint. Starting in 2002, but most obvious in 2003 and following years (Figure 7d and e), horizontal well technology allowed operators to jump over the Viola pinch-out and start producing from other areas in the gas window, mainly toward the south in Parker and Johnson Counties. On the other hand, the urbanized areas of Fort Worth in Tarrant County, although now technologically accessible by either vertical (because of the Viola footprint) or horizontal wells have been much slower to develop because of administrative issues (local ordinances limiting drilling, mineral rights more time-consuming to determine, access difficulties owing to buildings, resistance of local residents, etc.).



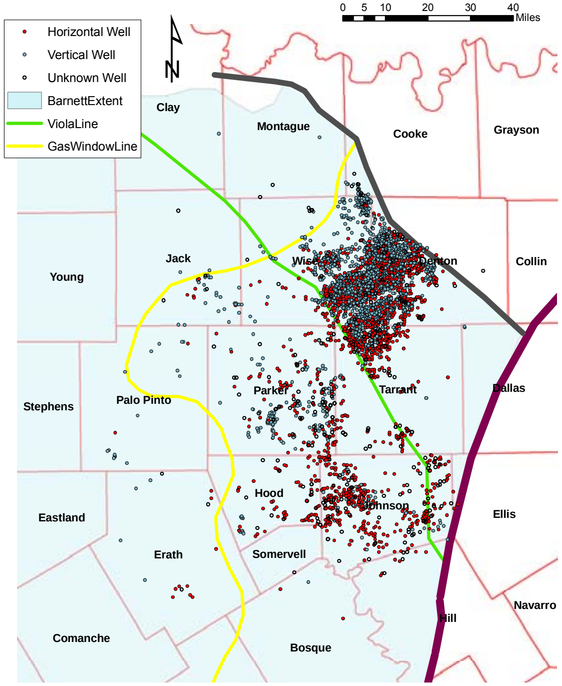
(a) (b) (c)

Data from drilling info.com

Figure 7. Wells drilled (a) up to 1997 (included), (b) up to 2000 (included), and (c) up to 2002 (included).



(d)



(e)

Data from drillinginfo.com

Figure 7 (continued). Wells drilled (d) up to 2004 (included) and (e) up to summer 2006.

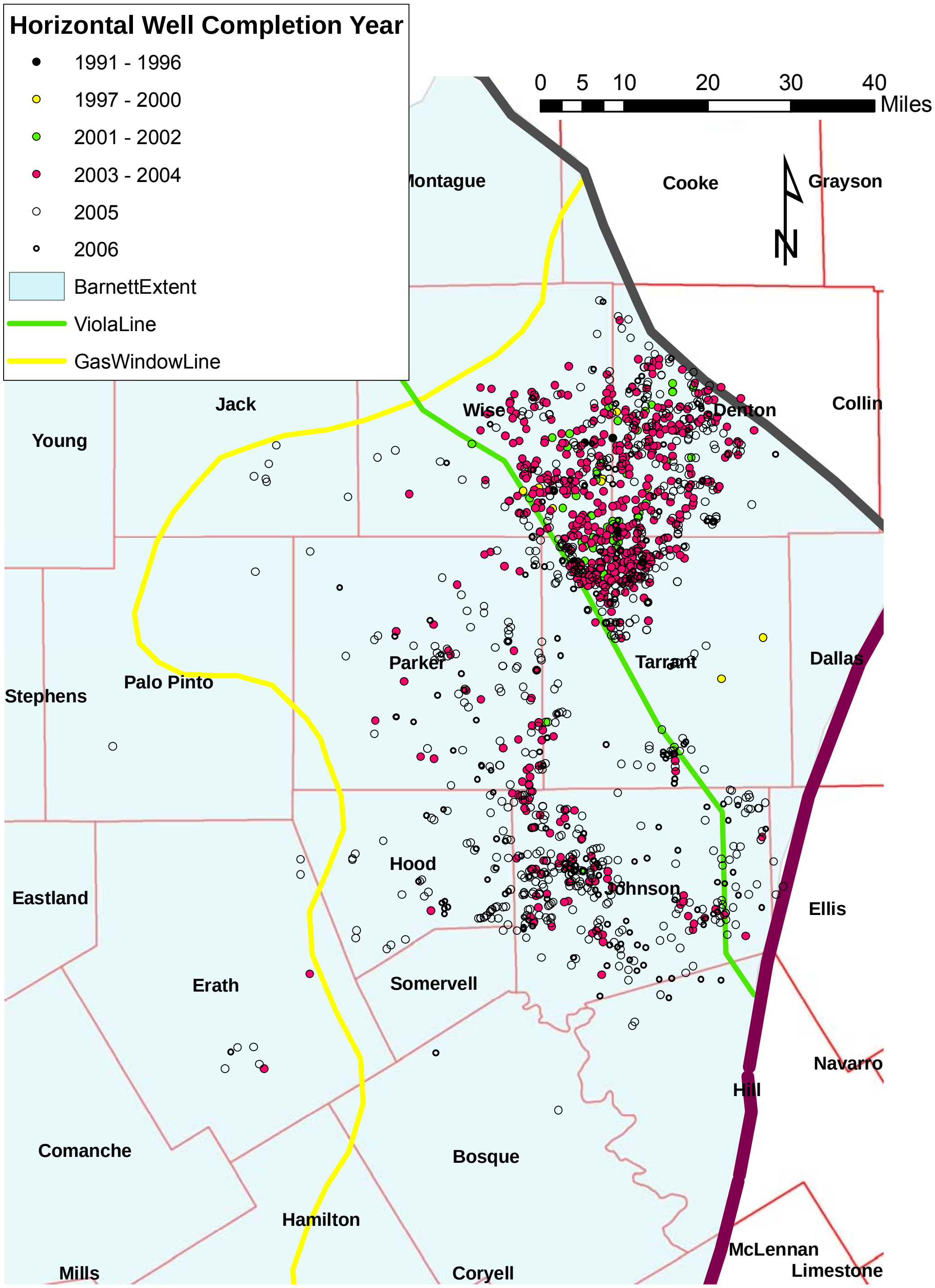


Figure 8. Spatial and temporal distribution of horizontal wells.

III-2. Historical Water Use

Water use information is derived from drillinginfo.com and IHS Energy (Table 1) from which ground water use can be estimated (Table 2). Water use has quickly increased from ~700 AF in 2000 to more than 7,000 AF in 2005. The trend and partial numbers suggest an even higher water use in 2006.

Table 1. 2000-2005 historical water use in the Barnett Shale (all sources, AF/yr)

County Polygon	2000	2001	2002	2003	2004	2005
Bosque	0.0	0.0	0.0	0.0	0.0	3.3
ClayH	0.0	0.0	0.0	0.0	0.0	0
ClayV	0.0	10.7	0.7	0.0	0.0	0
Comanche	0.0	0.0	0.0	0.0	0.0	0
Cooke	0.0	0.0	0.0	9.6	22.9	47.5
Coryell	0.0	0.0	0.0	0.0	0.0	0
Dallas	0.0	0.0	0.0	0.0	0.0	0
DentonR	371.8	1,191.5	1,837.2	1,966.2	1,700.6	1,784.0
DentonU	0.0	0.0	4.4	3.2	6.8	210.2
Ellis	0.0	0.0	0.0	0.0	0.0	18.3
Erath	0.0	0.0	0.0	0.0	1.6	22.7
Hamilton	0.0	0.0	0.0	0.0	0.0	0
Hill	0.0	0.0	0.0	0.0	0.0	0
Hood	0.0	2.3	4.3	0.0	11.4	316.6
Jack	0.0	6.0	2.6	8.7	15.9	38.1
JohnsonH	0.0	0.0	109.0	57.9	508.9	1,626.8
JohnsonV	0.0	0.0	0.0	4.4	0.0	189.0
McLennan	0.0	0.0	0.0	0.0	0.0	0
Montague	0.0	5.5	7.3	33.4	3.2	59.5
Palo Pinto	0.0	0.0	0.7	0.4	0.9	8.8
Parker	0.0	7.5	14.3	37.4	212.6	695.4
Somervell	0.0	0.0	0.0	0.0	0.0	10.6
TarrantH	0.0	0.0	2.7	10.6	61.7	257.1
TarrantVR	3.1	41.1	371.2	318.5	435.8	423.8
TarrantVU	0.0	0.0	27.5	167.5	335.6	565.2
WiseH	0.0	23.9	8.9	24.0	43.6	84.2
WiseV	327.5	517.9	935.3	1,146.0	906.2	843.1
Total	**702.4**	**1,806.5**	**3,325.8**	**3,787.8**	**4,267.6**	**7,214.3**

County polygons are defined in Section V. H=Horizontal, V=Viola, R=Rural, U=Urban; some counties are divided into polygons corresponding to the main completion type (presence or not of Viola Limestone, urban or rural setting)

Table 2. 2000-2005 estimated historical ground water use in the Barnett Shale (AF/yr)

County Polygon	2000	2001	2002	2003	2004	2005
Bosque	0.0	0.0	0.0	0.0	0.0	2.0
ClayH	0.0	0.0	0.0	0.0	0.0	0.0
ClayV	0.0	6.4	0.4	0.0	0.0	0.0
Comanche	0.0	0.0	0.0	0.0	0.0	0.0
Cooke	0.0	0.0	0.0	5.7	13.8	28.5
Coryell	0.0	0.0	0.0	0.0	0.0	0.0
Dallas	0.0	0.0	0.0	0.0	0.0	0.0
DentonR	214.5	687.5	1,062.2	1,139.7	988.1	1,070.4
DentonU	0.0	0.0	4.7	3.7	3.9	126.1
Ellis	0.0	0.0	0.0	0.0	0.0	11.0
Erath	0.0	0.0	0.0	0.0	1.0	13.6
Hamilton	0.0	0.0	0.0	0.0	0.0	0.0
Hill	0.0	0.0	0.0	0.0	0.0	0.0
Hood	0.0	1.2	2.2	0.0	5.8	190.0
Jack	0.0	3.6	1.5	5.2	9.5	22.9
JohnsonH	0.0	0.0	58.6	31.2	282.4	976.1
JohnsonV	0.0	0.0	0.0	2.3	0.0	113.4
McLennan	0.0	0.0	0.0	0.0	0.0	0.0
Montague	0.0	5.0	6.5	30.0	2.9	35.7
Palo Pinto	0.0	0.0	0.4	0.2	1.1	5.3
Parker	0.0	5.5	10.4	27.3	155.4	417.3
Somervell	0.0	0.0	0.0	0.0	0.0	6.4
TarrantH	0.0	0.0	1.2	4.8	27.7	154.3
TarrantVR	1.4	18.5	167.0	143.3	196.1	254.3
TarrantVU	0.0	0.0	12.4	75.4	151.0	339.1
WiseH	0.0	14.2	5.3	14.2	25.8	50.5
WiseV	193.9	306.6	555.8	678.4	536.4	505.9
Total	**409.8**	**1,048.4**	**1,888.6**	**2,161.6**	**2,401.0**	**4,322.6**

Note: County polygons are defined in Section V. Note: H=Horizontal, V=Viola, R=Rural, U=Urban; some counties are divided into polygons corresponding to the main completion type (presence or not of Viola Limestone, urban or rural setting). Ground water use was estimated from total water use (Table 1) to which county ground water use coefficient from Table 11 is applied, except for year 2005 where a blanket 60% coefficient is used.

III-3. A Few Relevant Numbers: Amount of Water Used per Well

The technology is fast progressing, with numerous operators still seeking out the best approach. Papers sometimes publish contradictory statements, but a few general rules can be derived. This section first cites water-use data from a few selected papers. We then derive our own numbers from drillinginfo.com and IHS Energy databases and contrast them with information provided by Galusky (2006). We conclude that data from all sources are consistent.

III-3-1 Literature Review

Early in the development of horizontal wells, short laterals were uncemented. Longer horizontal sections that required multiple frac stages were cemented. Cemented horizontal wells are now the most common type of well (Ketter et al., 2006; Lohoefer et al., 2006). Large (>4 MGal) single water fracs have been performed on uncemented wells (Fisher et al., 2004), whereas the current trend is to do multistage frac jobs on several perforation clusters at once (in the 1–2.5 MGal range) instead of numerous smaller frac jobs on each cluster (~0.5 MGal) (Fisher et al., 2004). Ketter et al. (2006) suggested that the number of frac stages for horizontal wells is, on average, around three and that each stage is 400 to 600 ft long. In the vertical wells of the core area, two main stages, one in the Upper Barnett and one in the Lower Barnett, can be implemented when the Forestburg Limestone exists (Figure 3). Depending on the number of other limestone intervals, more stages may be needed.

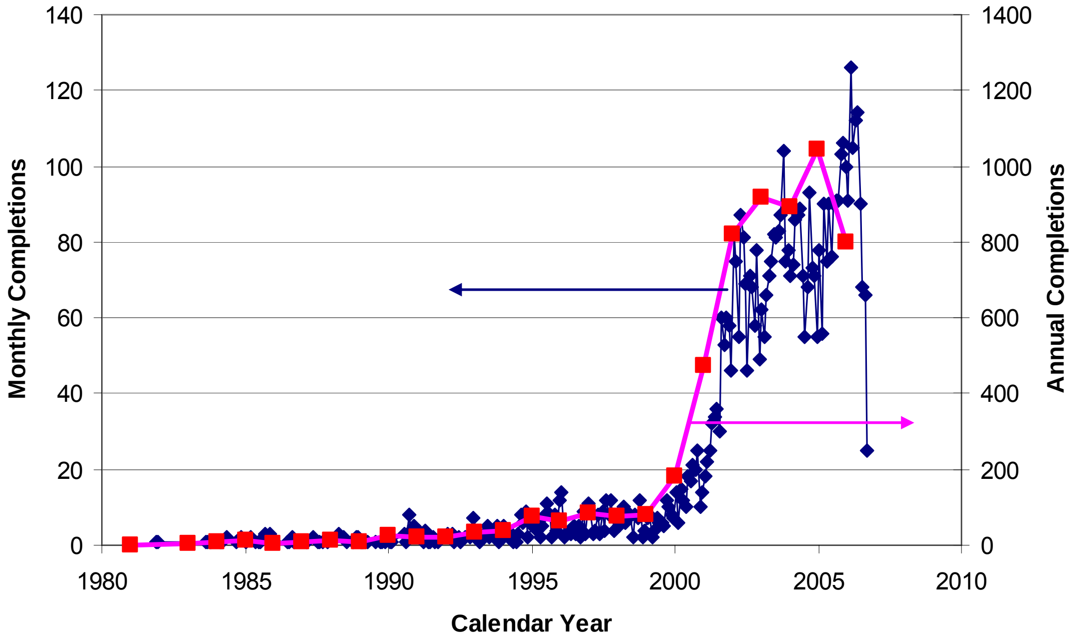
Lohoefer et al. (2006) mentioned a seven-stage completion over 3,300 ft, (that is, ~470 ft/stage) for the API#42-121-32350 well in Denton County using up 111,314 bbl (1,417 gal/ft). Montgomery et al. (2005, p.171) also cited stage lengths varying from 500 to more than 3,500 ft, as well as treatment volume varying from 0.5 MGal to more than 2 MGal. It is clear that the amount of water used in a multistage stimulation varies widely. It follows that it is not the best metric to use for water use projections. Water use per unit length of lateral is an intensive metric that speaks more to the user and that is more easily scalable to future wells. Grieser et al. (2006) presented statistics from ~400 wells, half using a crosslinked gel approach and half using the newer slickwater approach. Their data-set slickwater volumes range from 564,000 to 1,575,000 gallons, with an average of 929,139 gallons and 3,282 gal/ft of lateral. Schein et al. (2004) put forward a water-use value of 2,000 to 2,400 gal/ft for water fracs.

III-3-2 Statistical Analysis of the RRC Database

We analyzed the RRC database as communicated by drillinginfo.com and IHS Energy. The first well intended to test the Barnett Shale was drilled in 1981, and the number of total completions stayed below 100 until 1991. The number of annual completions then rose steadily, to reach more than 1,000 for the first time in 2005 (Figure 9). Projections for 2006 suggest that this number will be exceeded in 2006. The first-order sorting of the completion job involves vertical wells (mainly in the core area) vs. horizontal wells. A second level of classification involving mainly the vertical wells is the 1997 date. Before that date, most wells were treated using a technology that is currently considered inappropriate for the Barnett Shale play. Consequently, data on these wells was not used to develop predictions.

The total number of wells (Table 3) completed in the Barnett Shale is over 5,000 (~5,600 wells as of November 3, 2006, according to IHS Energy, including ~10 completed in the Delaware

Basin). Numbers may vary depending on the inclusion of only dry gas wells and/or wells with condensate. The vast majority of these wells were drilled in Denton and Wise Counties (~1,600 and ~1,800, respectively), followed by Tarrant County (~700 wells) and Johnson and Parker Counties (Table 4).



Note: drop in 2006 is due to incomplete reporting

Figure 9. Historical annual and monthly completions in the Barnett Shale.

Table 3. Annual completion statistics in the Barnett Shale

Year	DrillingInfo / IHS Energy			
	H	V	U	**Total**
≤2000	14	703	42	**759**
2001	22	424	27	**473**
2002	50	745	23	**818**
2003	195	685	38	**918**
2004	359	430	100	**889**
2005	679	242	122	**1043**
Total	1319	3229	352	**4900**

Note: H = horizontal wells; V = vertical wells; U = unknown

Table 4. Barnett Shale well statistics by county

	Bosque	Cooke	Dallas	**Denton**	Ellis	Erath	Hamilton	Hill	Hood	Jack	**Johnson**	Montague	Palo Pinto	**Parker**	Somervell	**Tarrant**	**Wise**
1981																	1
1982																	
1983																	2
1984																	6
1985																	13
1986				1													5
1987																	6
1988				1												1	10
1989				3													4
1990				6													19
1991				5													15
1992				2							1						16
1993				11								2				3	16
1994				16													23
1995				24													50
1996				31													32
1997			2	8							1					1	68
1998				22							2					4	49
1999				21												1	59
2000				93												1	87
2001		2		269			1		2	6		7		5		15	159
2002				427					7	3	6	8	1	7		110	248
2003		4		398						7	18	13	2	16		153	306
2004		8		267		1			1	16	78	4	6	87		202	218
2005	1	14		216	3	9			44	30	217	15	10	108	1	213	162
2006	2	11		136		21		19	49	13	215	20	4		1	108	90
sum to ‘05	1	28	2	**1821**	3	10	1	0	54	62	**323**	49	19	**223**	1	**704**	**1574**

A compilation of data on these wells, in which water use and location information are available, shows that a sizable percentage of frac jobs performed on vertical wells range from 1 to 1.5 MGal/well (Figure 10). The numbers represent the sum of water use in all stages performed on a given well at a given date. The distribution was computed on the basis of the 5 previous years, to which results available from 2006 were added. It is thought that vertical-well frac technology is mature enough to have (at least temporarily) stabilized in its water use. On the other hand, horizontal well technology, as applied to the Barnett play, is still evolving, and only those frac jobs performed in 2005 and 2006 were included in the histogram (Figure 11). If vertical well water use was clearly unimodal, the distribution of water use for horizontal wells appears much noisier and has a much larger spread with multiple peaks. One of the reasons could be that, contrary to vertical wells, whose length is constrained by the thickness of the formation, horizontal-well laterals can be made as long as technology allows. It follows that a better metric for water use in horizontal wells is water-use "intensity," or water volume per unit length (gal/ft) (Figure 12). The transformation filtered out some noise from the raw number distribution and appears now to be unimodal. Although using the mode as a representative value is tempting, it probably underestimates the true average because of the long tail on the high values clearly visible on the histograms. On the other hand, taking a simple average of the results is not a robust solution because instances where water use had extra zeros or units were reported as barrels instead of gallons have been observed. This practice will tend to overestimate the true average. Undoubtedly, a similar difficulty can happen on the low side when a digit is not entered or when the unit is entered as a gallon instead of a barrel. The solution was to use the average of those frac jobs composing between the 10^{th} and 90^{th} percentiles.

The raw average and average of the values between the 10^{th} and 90^{th} percentiles for vertical wells is 1.25 and 1.19 MGal, respectively. A value of 1.2 MGal is retained. The raw average for horizontal wells (2005–2006) is 3.07 MGal/well, whereas the truncated average is 2.65 MGal/well. Water-use intensity raw average is ~10,000 gal/ft, obviously biased by inaccurate entries, either in water use or in lateral-length columns. The averages of values truncated beyond two complementary percentiles vary somewhat because of the additional uncertainty due to the lateral length, although a value of 2,400 gal/ft seems conservatively reasonable for the medium scenario. Values of 2,000 and 2,800 gal/ft are retained for low and high scenarios, respectively.

These numbers agree well with data provided by Galusky (2006). Average water use for vertical wells is given as 1.25 MGal/well, with no change in the 3 years considered (2005–2007) and no variations across counties. Average water use for horizontal wells varies from 3.30 MGal/well in 2005 to 3.23 MGal/well in 2006 and is projected to be 3.25 MGal/well in 2007, with an overall approximate average of 3.25 MGal/well. The survey seems to suggest an increase in water use in horizontal wells, although it is unclear whether it is due to a true increase or to longer laterals. Galusky (2006, personal communication) proposed an average lateral length of 1,800 to 2,000 ft/well. Using year 2007 projections as representative of current technologies, this datum translates into 1,625 to 1,805 gal/ft of lateral. This number is consistent with the mode of the distribution, as displayed in Figure 12. It is likely that operators have to use more water in some locations, as illustrated by the long tail of Figure 12, yielding an average higher than that reported by Galusky (2006).

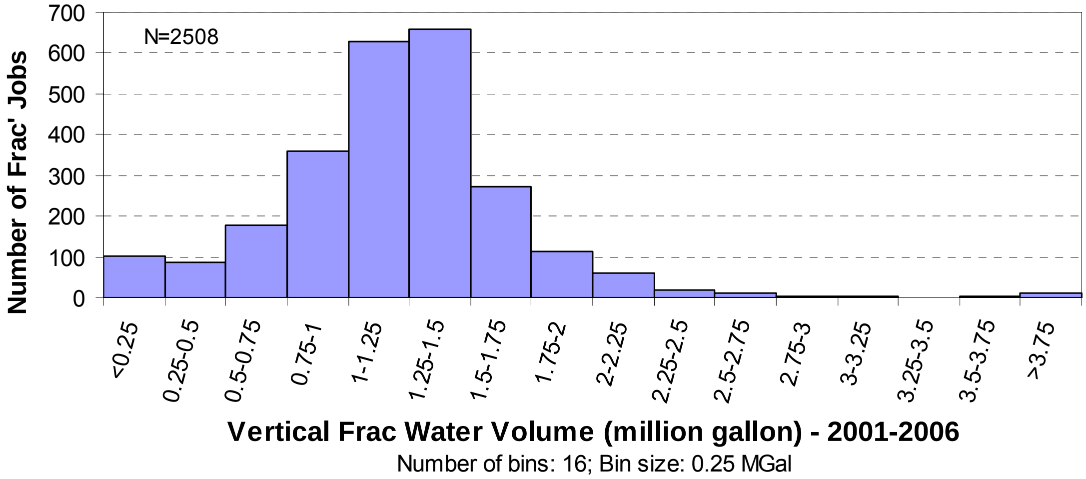


Figure 10. Distribution of water use for vertical-well frac jobs (all water sources).

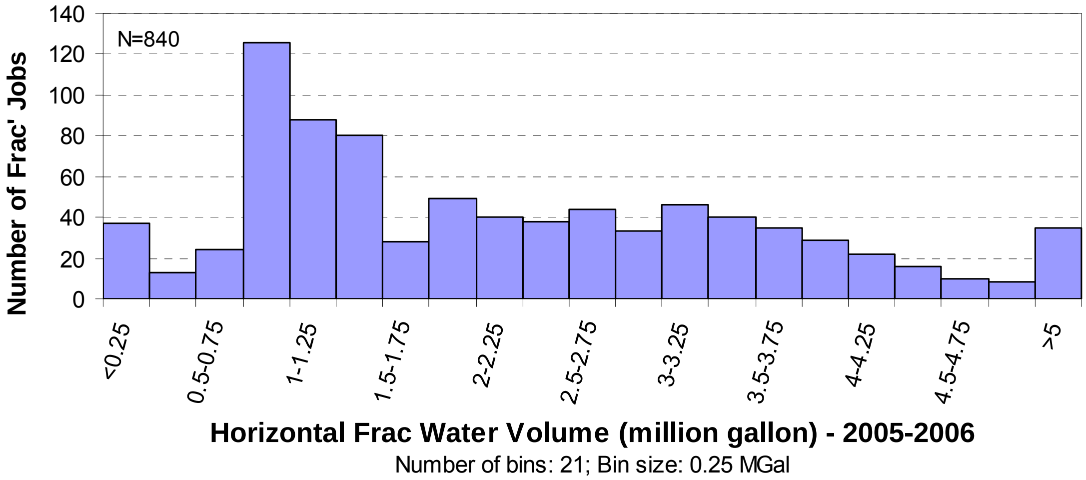


Figure 11. Distribution of water use for horizontal-well frac jobs (all water sources).

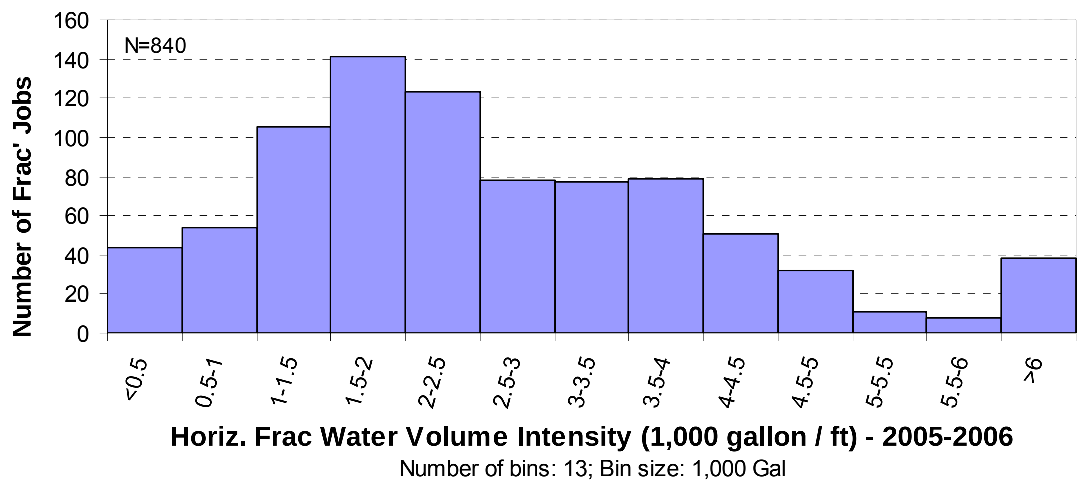


Figure 12. Distribution of water use intensity for horizontal-well frac jobs (all water sources).

IV. Water-Use Projections

Projections of water use hinge on an understanding of both geology and technological controls and advances. Regional features, regional faulting, formation thickness, thermal maturity, and cave-collapse features fall into the former category, whereas water restimulation, recycling, water-use intensity, and well spacing drive the latter. One can add regulatory control. RRC regulations prohibit pollution of surface and subsurface water during drilling, treating, producing, and plugging of oil and gas wells. In McCulloch, San Saba, and parts of Lampasas and Burnet Counties, the Cambrian Hickory and Ellenburger aquifers are a potential source (with or without treatment) of drinkable water (see 3,000-ppm concentration contour in Figure 1).

For all parameters, we defined high, medium, and low scenarios at the county polygon level, mostly on the basis of geologic and cultural constraints. We then add time-dependent constraints: availability of drilling rigs, growth of recycling techniques, and recompletion frequency. Projections are done on an annual basis, the final product of this report being annual water use by county polygons (defined in the next section). The reader should not focus on projections for a given year but, rather, on cumulative water use within a few years' range. In any case, a regional groundwater model, such as the GAM model, is not too sensitive to temporal pumping details, but more to their cumulative impact.

Given a much larger data set, projections would be done by developing parameter distribution and their correlations. Correlations appear when parameters are interdependent. For example, if gas price is high, the play could be drilled out at a small spacing that will generate competition for water and, consequently, a strong incentive to develop technologies frugal in terms of water use, as well as to recycle used water. Unfortunately, the short history of drilling in gas-rich-shale unconventional resources precludes the development of statistics that could be safely applied to the next 20 years. On the contrary, we made a lot of judgment calls that we think are reasonable and defensible but that do not necessarily include all plausible scenarios.

IV-1. Impact of Geologic Features

IV-1-1 Regional Features

In addition to gas prices, extension of gas production in the Barnett Shale is ultimately controlled by geology. Assuming adequate thickness and total organic carbon content, the single most important parameter is thermal maturity. Oil and gas formation requires that the source organic matter be exposed to elevated temperatures long enough for the kerogen to mature. It could occur by simple deepening of the basin. The core area of the Barnett Shale was indeed buried to a depth >10,000 ft (Montgomery et al., 2005) and subsequently uplifted. However, it seems that the burial depth is not the only control on Barnett organic matter maturity. The story is more complex, involving in particular hot fluid circulation. It follows that the rock potential for hydrocarbon generation is spatially complicated in the details and not yet well known and that a lot will be learned during exploration/production.

An indirect way to assess rock potential is to examine vitrinite-reflectance values (measured by a parameter called R_0) of the rock. Gas-prone areas producing mostly dry gas are present toward the east in the basin, along the Ouachita thrust fold belt, with a R_0>1.4%. Maturity levels are more favorable for gas generation along an NNE-SSW axis parallel to the Ouachita structural belt from Denton to Tarrant to Somervell to Hamilton to San Saba Counties (Pollastro et al., 2003, Fig.3), and it is reasonable to assume that the play will preferentially grow in that direction. This observation is also consistent with the vitrinite-reflectance map presented in Montgomery et al. (2005, Fig. 6). Moving toward the west, still within the gas window, R_0 is in the 1.1 to 1.4% range and the Barnett Shale can produce both gas and condensate (wet gas). More oil-prone production is less economically attractive because of the complexities of multiphase flow in extremely low permeability porous media and in particular the oil's ability to plug pores and block gas flow. Farther west still, in the western Forth Worth Basin, over the Bend Arch and beyond, the Barnett Shale has generated oil which has been commercially produced from traps in different formations (Jarvie et al., 2001), and it is not conducive to gas generation but to oil generation. Givens and Zhao (2005) stated that Tarrant, Johnson, Hood, Somervell, Bosque, most of Wise and Parker and parts of Dallas, Denton, and Ellis Counties are interpreted to be in the gas window, whereas Clay, Montague, Cooke, and most of Jack Counties are in the oil window. Counties between oil-prone and gas-prone areas are expected to produce a mix of oil and gas. Examining maps of Montgomery et al. (2005), we can add parts of Palo Pinto, Erath, Hamilton, Coryell, McLennan, and Hill Counties as belonging to the transition between oil and gas. On the west and south edges of the play, the Barnett Shale may be too thin. However, the minimum productive thickness of the Barnett has not yet been established but is possibly less than 100 feet.

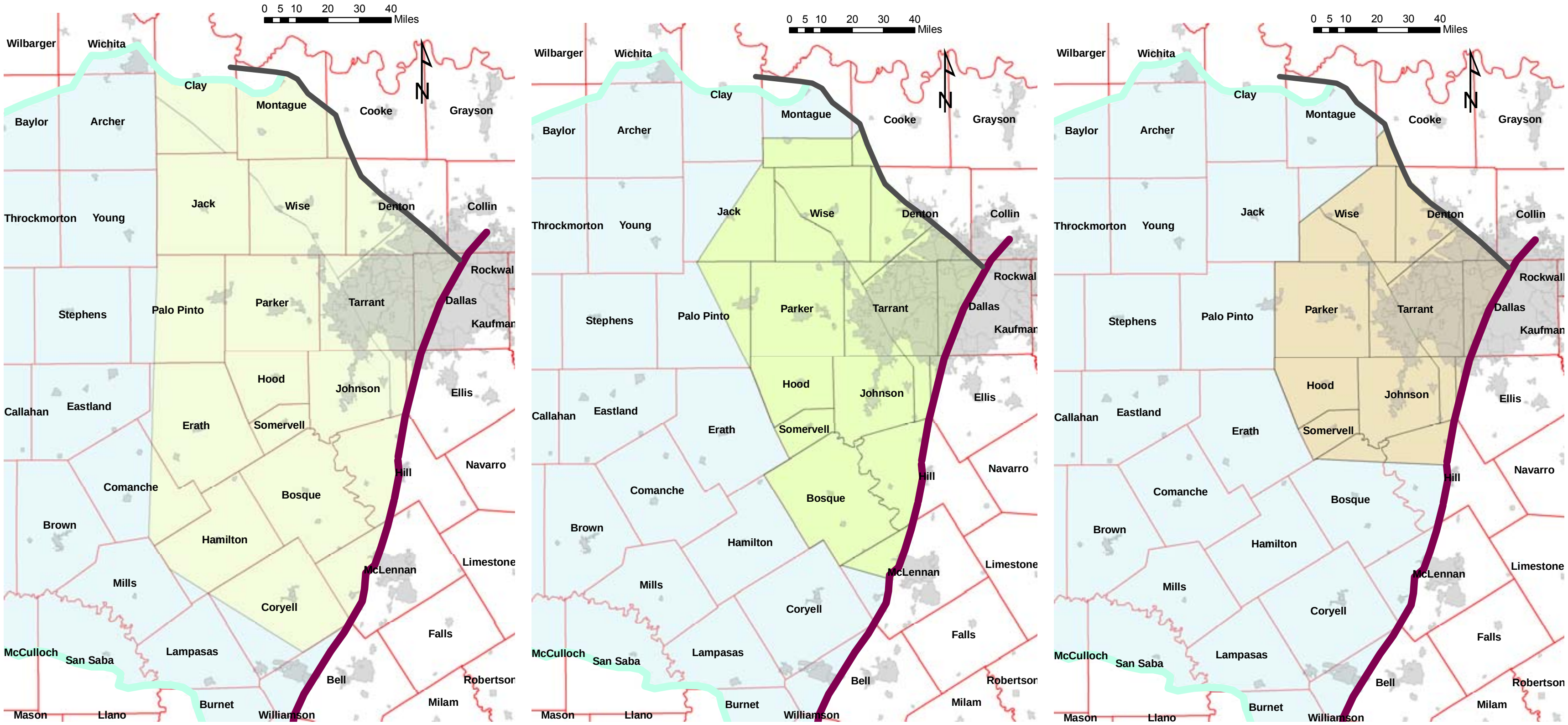
High, medium, and low scenarios for the ultimate extent of the play (Figure 13 and Figure 14) were drawn by integrating knowledge (and uncertainty) about the boundary of the gas window, thickness of the formation, current exploration trends, and economic yield of wells. Histograms in Figure 15 illustrate the differences in surface area of the various counties that will translate later in the report into water use differences even at similar well density. The high scenario represents the maximum extent of the play if gas prices stay acceptable. The low scenario corresponds to a case where gas prices are low and operators retreat to an area of the Barnett in which they know that the Barnett responds well and where they could carry out infill drilling and recompletions. The medium scenario is intermediate. Because the Barnett Shale play is dependent on gas prices, it is not appropriate to say that the medium case is the most likely. A more accurate statement would be to formulate that the medium case is the most likely under the condition that gas prices stay at their current level.

Table 5 presents a summary of ranges of all parameters to be developed in the following sections and relevant to computing projections.

Table 5. Summary description of parameters used in the water-use projections.

Category	Comment	High Water Use	Medium Water Use	Low Water Use
County Polygon	There are three binary variable couples: rural/urban—horizontal/vertical wells—within Viola footprint or not, resulting in four main categories: Viola/urban (only horizontal wells) Viola/rural (both horizontal and vertical wells) No Viola/urban (only horizontal wells) No Viola/rural (only horizontal wells)			
Footprint Fraction	A county polygon cannot be covered by more than 90% (vertical wells) or 80% (horizontal wells) of the maximum possible well coverage.			
Vertical Well Spacing		1 well/40 acres	0.5 well/40 acres	0.25 well/40 acres
Horizontal Well Lateral Spacing	No Viola and/or urban	800 feet	1,000 feet	2,000 feet
	Viola rural	800 × 4 feet	1,000x4 feet	2,000 ×4 feet
Sag Feature Avoidance (“Karst”)	Vertical well	100%		
	Horizontal well	100%	75%	40%
Average Water Use	Vertical well	1.2 million gallons		
	Horizontal well (spread reflects uncertainty)	2,800 gal/ft	2,400 gal/ft	2,000 gal/ft
Water-Use Progress Factor[A]	(variations reflect technological progress)	1%	0%	0%
		Water-use annual incremental improvement as a fraction of total water use, e.g., 100% of current use in 2005 with a 1% increment translates into 80% of water use in 2025 compared with the same frac job executed in 2005.		
Recompletion	Vertical well	100%	50%	0%
		of initial completions executed 5 years before		
	Horizontal well	0%	0%	0%
Recycling[A]		1%	0.33%	0%
		Recycling annual increment as a fraction of total water use (e.g., 0% in 2005 with a 1% increment translates into 20% recycling in 2025).		
Maximum Number of Sustained Annual Completions		3,000 completions/year	2,100 completions/year	1,500 completions/year
Additional Water Use in Overlying Formations		0%	0%	0%
Barnett Groundwater Use Expressed as % of Total Barnett Water Use	In year 2005–2006	60%	60%	60%
	Annual increment in following years	2%	1%	0%
	In year 2025	100%	80%	60%

Note: [A] These parameters do not maximize water use, but the likely competition for water in the high scenario case suggests that recycling and water-use intensity will get better through time.



(a) (b) (c)

Figure 13. Spatial definition of high (a), medium (b), and low (c) Barnett play development scenarios.

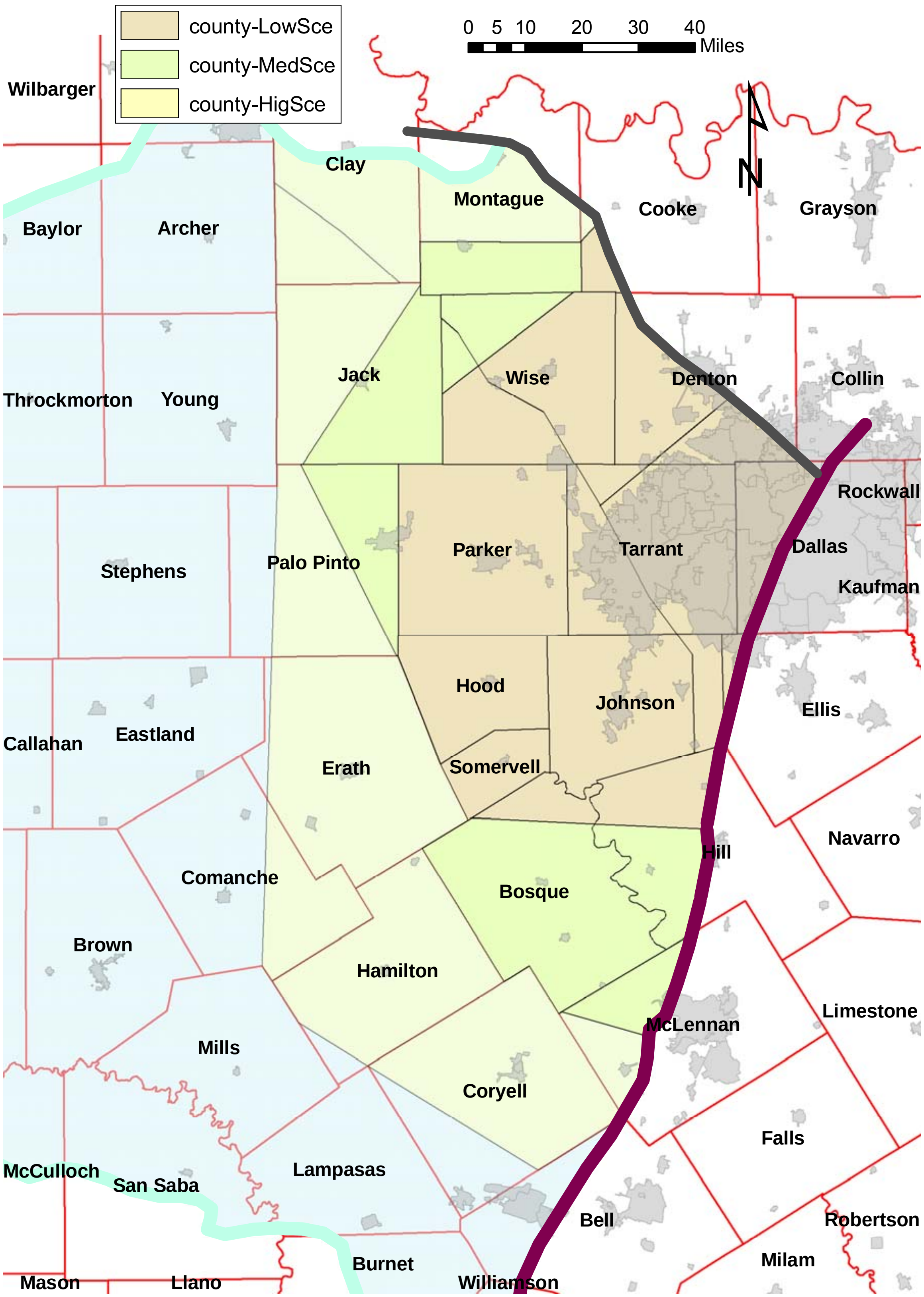
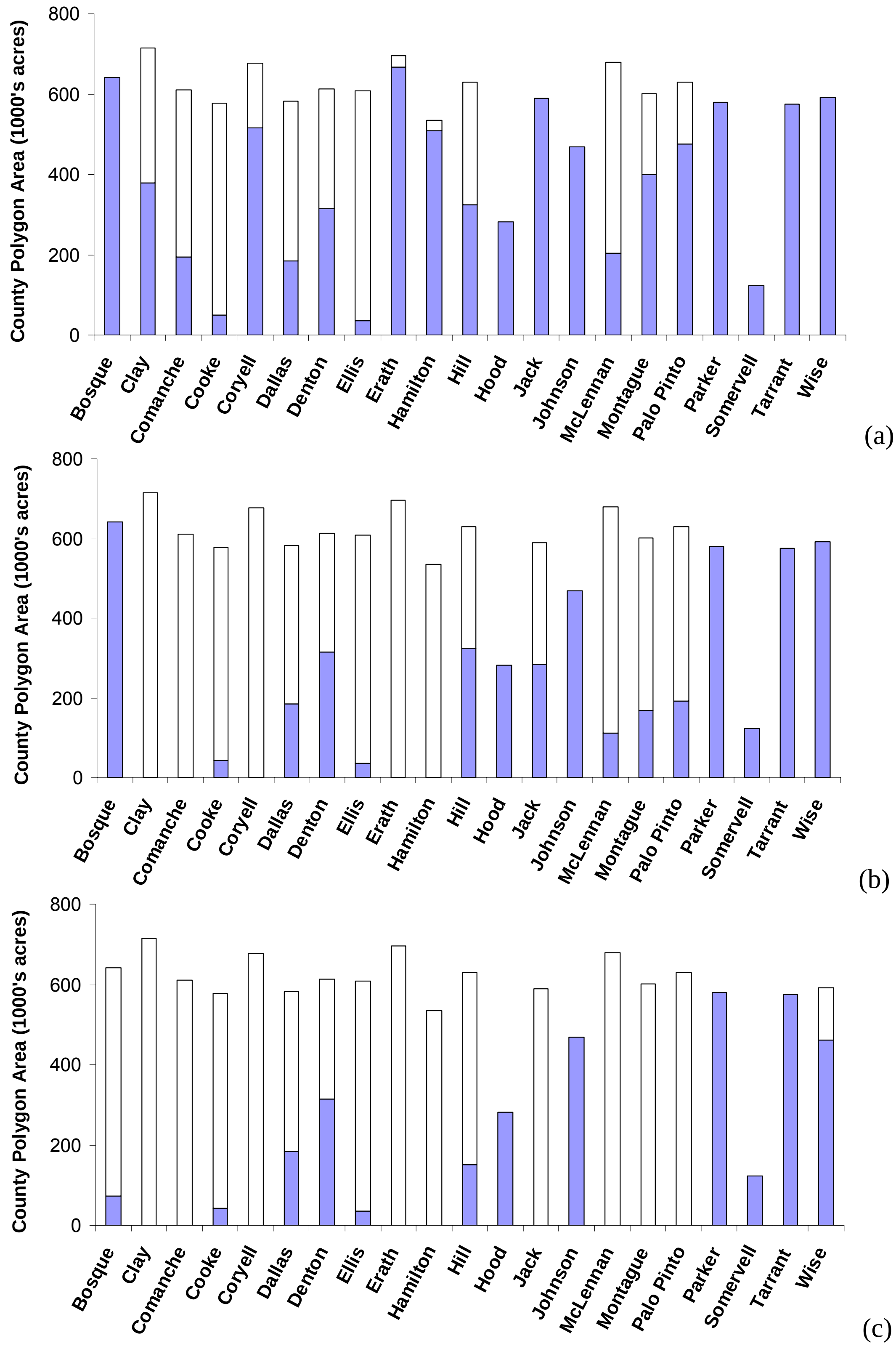


Figure 14. Spatial definition of high, medium, and low scenarios (combined).



Note: projected gas-producing fraction of county is filled

Figure 15. Bar plot of counties in the high (a), medium (b), and low (c) Barnet Play development scenarios.

IV-1-2 Sags Over Cave-Collapse “Karst” Features

Operators switched to horizontal drilling west of the Viola pinch-out because of the negative impact of the water-rich wet Ellenburger on gas productivity. This behavior of the Ellenburger Formation is due to its collapsed caverns. It has been observed, mostly through seismic, that the caverns, although initially devoid of rock, have subsequently collapsed (Figure 16). The collapse-related features propagated into the overlying formations and occurred along newly created small faults at the periphery of the collapse. The small faults, intercepted by horizontal drilling, would then put in communication the formation water in the Ellenburger and the horizontal borehole. Hardage et al. (1996), in a study of Ellenburger karstic features on a 26-mi^2 area straddling the Jack-Wise County limits, just west of the Barnett Shale core area, found that they tend to be circular (sometimes improperly called *breccia pipes*), with a diameter varying between 500 and up to 3,000 ft in some cases. The features were spaced at a high spatial density, between 2,000 and 6,000 ft apart, on average, and sometimes aligned on a NW-SE trend. Observation of the same structures cropping out near El Paso, Texas, suggests that the feature is widespread in the Ellenburger and thus may impact the Barnett Shale throughout its extent. Loucks et al. (2004) conducted a recent study on Ellenburger subcrops in Central Texas showing similar results. Recent work by A. McDonnell (BEG, personal communication, 2006) and McDonnell (2006a and b) confirms both the size of the structures (1,500–4,500 ft in diameter) and their alignment along NW-SE and NE-SW structural trends by looking at their impact on the Bend Conglomerate. Givens and Zhao (2005) provided a map of areas more karsted than elsewhere. However, there is little public information to support it. Consequently, we make no assumption about the geographic distribution of collapse features but rather assume that they are evenly distributed throughout the Barnett. The assumption is reasonable because the basis for the projections is a county, or at least large fractions of counties, which averages spatial variations. Figure 16 illustrates the shapes of the sags related to collapse features in one location. The current understanding of the Ellenburger karst does not allow concluding whether the picture, created from the study by McDonnell (2006a and b), is representative of the Ellenburger as a whole or where it sits relative to the collapse-structure density spectrum.

Cavern/collapse features are considered a hazard that must be avoided, although apparently a few operators are considering drilling horizontal wells through them to learn how to deal with them. We applied a sag avoidance factor (only to horizontal wells), measuring the fraction of the area left undrilled because of the collapse features. In the high scenario case, we assumed that technology overcame the problem (100% of the area is drilled). The medium and low scenarios were given a factor of 75% and 40%, respectively. The choice of 75% is guided by the observation that on an areal basis about 25% of the Ellenburger is somehow impacted by these collapse features. The low scenario of 40% is based on a principle of precaution that operators would follow by staying farther away from the sag/collapse structures.

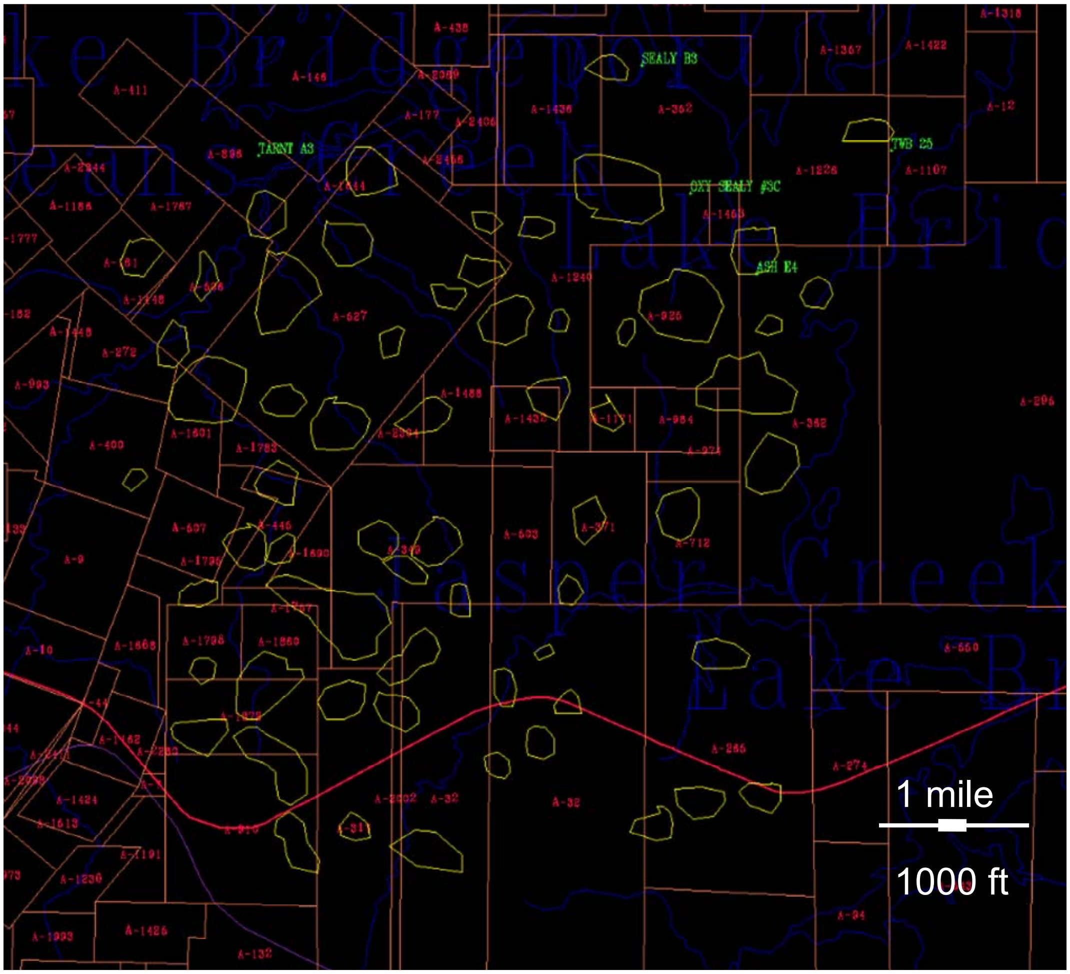
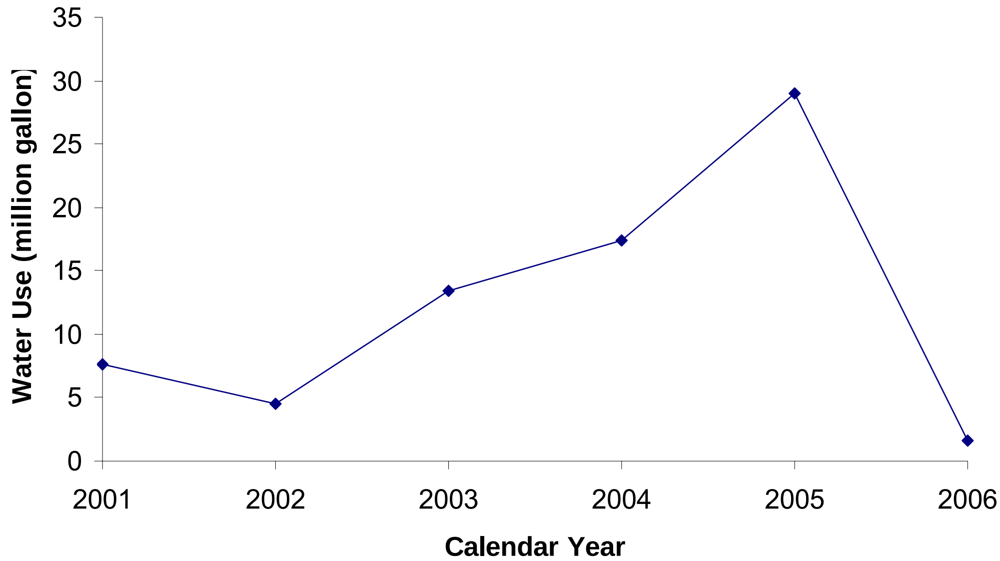


Figure 16. Example of collapse features in the Ellenburger Fm. on the Wise-Jack county line as seen from a seismic survey. The picture may or may not be representative of the Ellenburger as a whole.

IV-1-3 Development in Overlying Formations

A possible additional need for water is the development of the overlying Bend/Atoka Formation. These formations trapped gas migrating from the Barnett Shale. Water use in a six-county area (Denton, Tarrant, Wise, Jack, Palo Pinto, Erath), including those formations (Figure 19) in the 2001 to 2005 period, is only 74 MGal (221 AF), although increasing (Figure 17) probably by taking advantage of the infrastructure for frac jobs in the Barnett. Most of the frac jobs are typically small frac jobs (Figure 18). Only about 25 of them are comparable in size to those performed in the Barnett, with individual water use >0.5 MGal, making up about 85% of the 74 MGal.

These volumes are very small, compared with those used in the Barnett. Even a 10-fold increase of water use in the overlying formations (~300 MGal/yr, or 90 AF/yr using 2005 numbers) is much smaller than the noise in the Barnett data and the uncertainty in the Barnett projections. There is no need to include them in the calculations.



Note: incomplete data for 2006

Figure 17. Water use in a six-county area in the Atoka/Bend Formations (2001–2006).

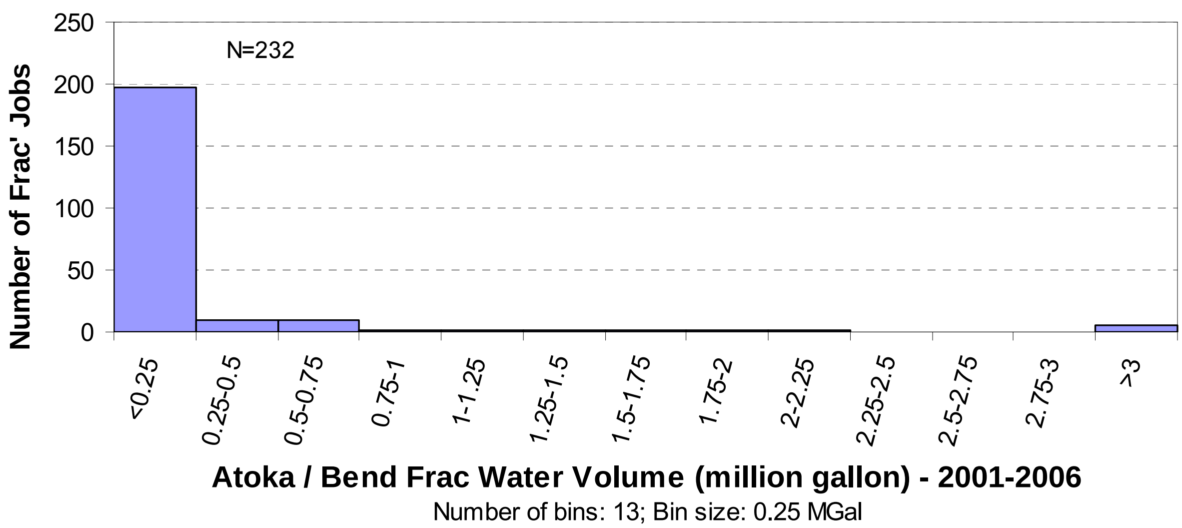


Figure 18. Distribution of water use in the six-county area in the Atoka /Bend Formation (2001–2006).

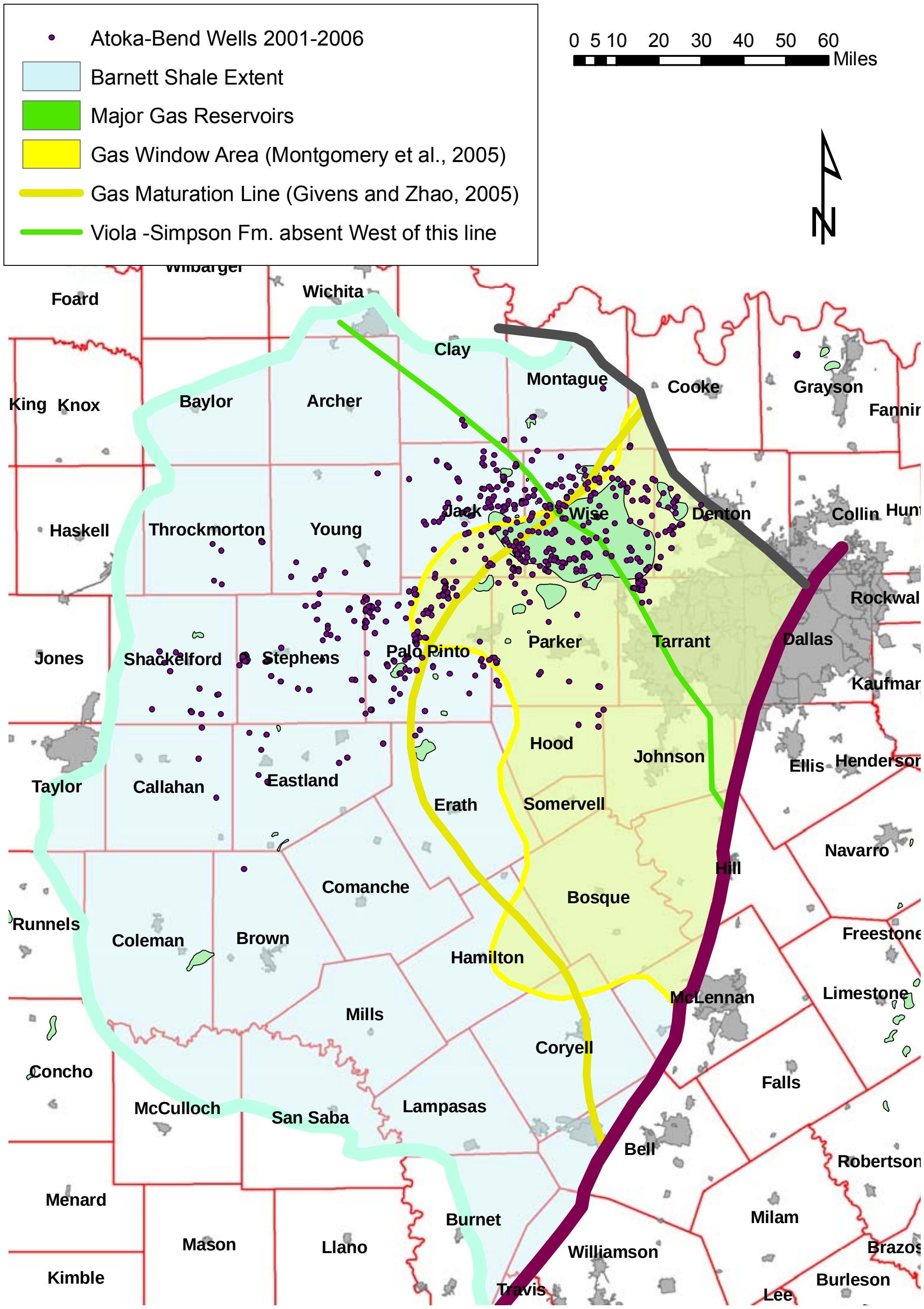
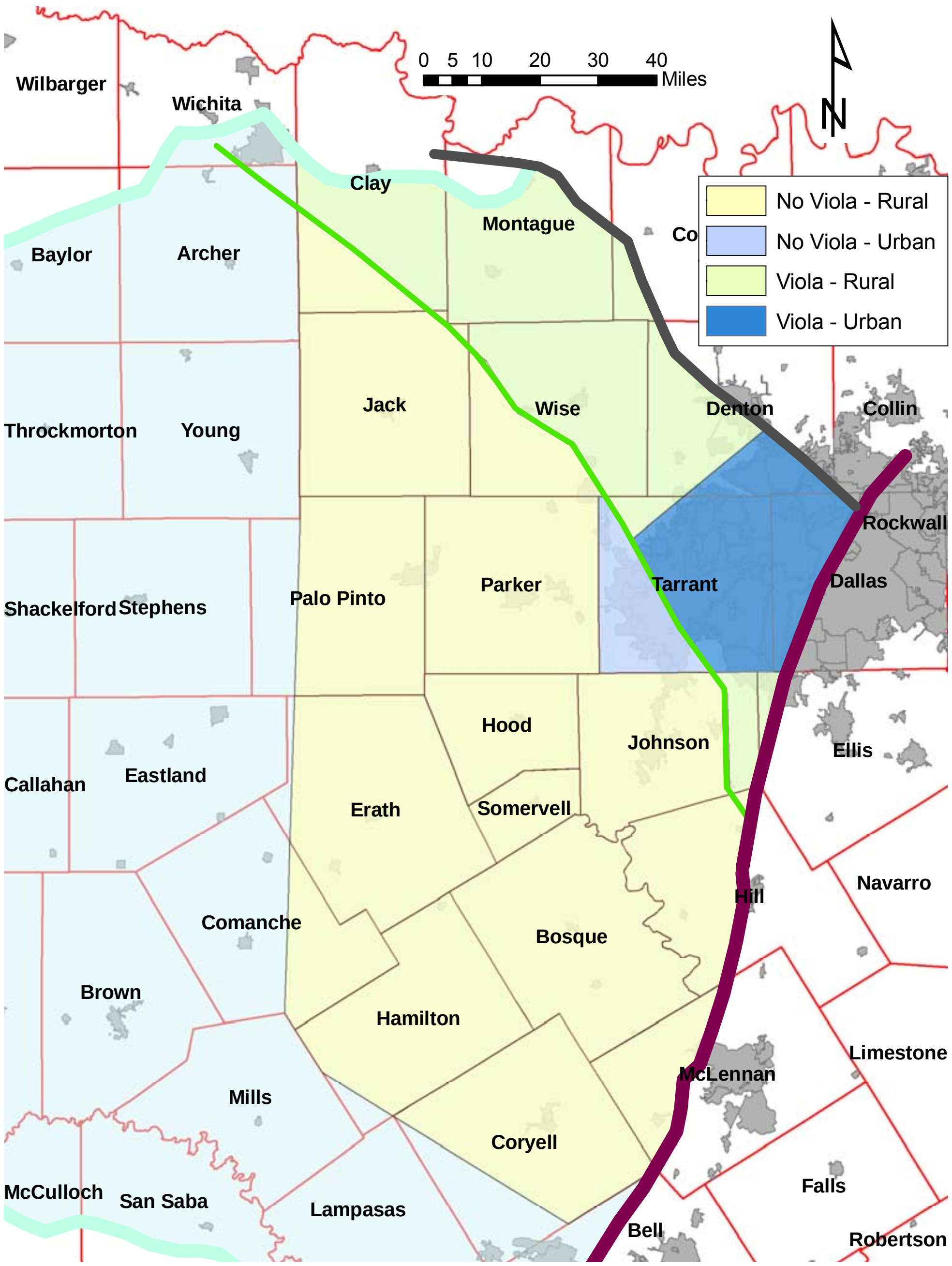


Figure 19. Recent (2001–2006) well completion in the Atoka/Bend Conglomerate of the Fort Worth Basin.

IV-2. Technological and Cultural Controls

IV-2-1 Horizontal/Vertical Technology and Rural/Urban Environment

In the late 1990's. – early 2000's, the core area contained only vertical wells. When technology and operator technical abilities made horizontal well drilling successful, play prospects increased considerably. As explained earlier, the county unit is the basis for prediction work. However, because their boundaries do not match geology very well, we created multiple polygons in some counties using ArcView GIS software by superimposing geology and urban area limits.



Note: Viola or no Viola denote the presence or absence of the Viola Limestone.

Figure 20. County polygons for water-use projections.

The following categories resulted (Figure 20):

(1) No Viola—Rural: this category includes a large fraction of the high scenario area, most of it in early production stages or relatively unknown potential. All wells are horizontal because the absence of the Viola-Simpson Limestone generally precludes successful vertical frac job completions.

(2) No Viola—Urban: this category includes only the underdeveloped southwest third of Tarrant County. Lack of the Viola-Simpson Limestone, as well as urban environment, requires use of horizontal wells as in the previous category, but development will be slower.

(3) Viola—Rural: this category initially represented the core area (Wise and Denton Counties), that is, numerous vertical wells because of the presence of the Viola-Simpson Limestone and unimpeded by urban environment constraints. This category contains a combination of horizontal and vertical wells, as shown by the current infilling of the core area with horizontal wells. In addition to the core area, this category contains parts of two counties of limited potential, Clay and Montague, as well as a small sliver of Cooke County.

(4) Viola—Urban: this category encompasses the west half of the Dallas-Fort Worth metroplex. The current lack of development of this area illustrates the difficulties and challenges of urban drilling. The area will be developed with horizontal wells only but at a slower pace than that of the No Viola—Rural category.

Overall, development in urban areas is likely to be much slower because of cultural controls such as acquiring mineral rights, respect of local ordinances, and access issues.

IV-2-2 Restimulation

Gas production is initially high after a frac job, but a steady decline quickly follows, relayed by a long sloping plateau in the decline curve. Operators have long noticed that a new frac job can lead to production level similar to or higher than that of the initial completion. Empirical evidence shows that refrac'ing wells every few years does improve the total production. It is thought that restimulation works because new fractures are created (e.g., Wright and Weijers, 1991) with a different orientation than the previous ones because the stress field, to which induced fractures respond, has changed. There are many examples of successful recompletions. Moore and Ramakrishnan (2006) showed an example of successful restimulation after 2.5 years of initial production. However, most of these cases deal with vertical wells.

As of the end of 2006, few if any horizontal well recompletions have occurred. Only some of those vertical wells initially not frac'ed with slickwater have been restimulated. It is uncertain whether any recompletion will occur in the future and if so, how often. Shirley (2002) suggested that re-fracing a well after approximately 5 years of production can be very beneficial. In the high water use scenario (Table 5), we assume very conservatively that all vertical wells are refrac'ed 5 years after their initial completion but only once: All wells completed before 2005 will have been refrac'ed by 2010. In the medium and low water use scenarios, we assume that 50% and 0% of the vertical wil be restimulated. We assume that horizontal wells will not be restimulated.

IV-2-3 Recycling

Most used (flowback) water is currently hauled away to be injected into disposal wells with little recycling. It is estimated that approximately 30% of the frac water stays in the subsurface and that 70% flows back to the surface. About 30% of the injected water returns without too much of a quality decrease, whereas the remaining 40% is more degraded. It would seem less costly to treat the used water than to transport it to off-site disposal. In Wise County, it costs operators more than $40 per 1,000 gallons of water (~<$2/bbl) to transport and inject produced brine in saltwater-disposal facilities (Dave Burnet, Texas A&M, oral communication, 2004).

As of October 2006, three pilot tests for recycling flowback water have been attempted (DOE, 2004; Texas Drilling Observer, 2006). The first was initiated in Wise County, south of Decatur, by Fountain Quail Water Management in 2005. The treatment method was evaporation based and consisted of a series of heat exchangers. Fresh-water recovery was 85% (RRC Website). The company Website reports a feed capacity of 2,500 gal/day/unit (~2 gpm). The Website states that three mobile units are already running in Wise County and that six more will be delivered in less than a year ($2.5 million a piece). There is no indication of how the 15% solid-rich concentrate was disposed of in the pilot test, but there is a suggestion in the vendor material that the concentrate can be used as kill fluid. The second pilot was granted to DTE Gas Resources, also in 2005, to test simple filtration methods. The third pilot has been undertaken by Devon and also predicts 85% water recovery. The chosen method is based on membrane technology. Other groups (e.g., GeoPure Water Technologies) are also active in this field.

To conclude, it seems that the technology is available and tested but not likely to make a significant dent in water use in the near future. In the projections (Table 5), we assume that, in the high scenario, recycling will slowly increase in annual increments of 1% to reach a value of 20% of total water use from recycling. In the medium scenario, a smaller increment of 0.3% yields a total water use of 6% due to recycling. The low scenario assumes no significant recycling.

IV-2-4 Water Use Intensity

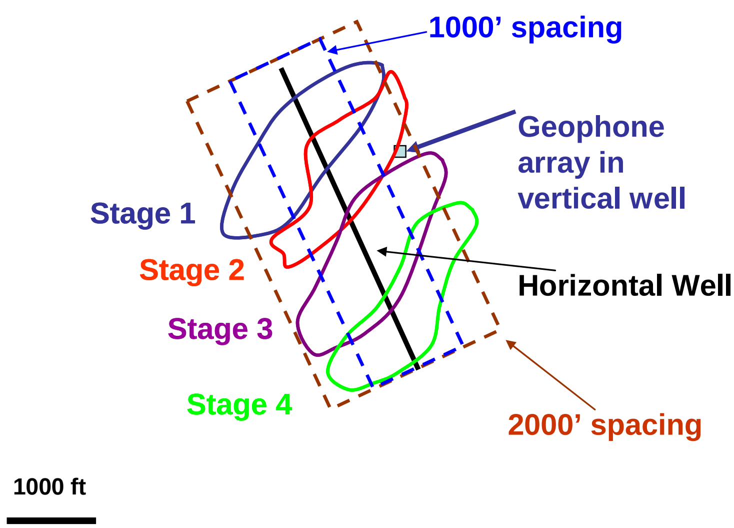
Although there is no hard data and only anecdotal evidence to support it, we assumed that operators will become more water efficient in the future (maybe through use of better additives). For the low and medium water-use scenario, no change in water-use intensity is assumed. However, in the high water scenario, because of likely competition for water, it is anticipated that water use per well (vertical wells) or per unit length of lateral (horizontal well) will decrease by a 1% increment every year from 2005 through 2025 (that is, in 2025, 80% of the current water amount will be used compared with that of the same frac job that would have been performed in 2005).

IV-2-5 Well Spacing—Infilling

The usual well spacing for vertical wells is 1 well per 40 acres, although Devon Energy recently tested a 20-acre spacing array (Devon Energy website). For the purpose of this work a 1 well/40 acres density is assumed in the high scenario. It is half this number in the medium scenario, and another decrease by a factor of 2 in the low scenario (Table 5).

If vertical well density is suggested by the RRC regulations, currently no consistent one is enforced relative to multilateral horizontal wells. A dense network of multiple laterals could potentially originate from one single well head. The industry as a whole is still investigating the optimal lateral density. Hydraulic fracturing ideally produces two wings of equal size in symmetrical position relative to the well bore. Spacing between horizontal wells is a function of the shape of the induced fractures. Ketter et al. (2006) suggested that spacing between laterals should be at least 1.5 times the fracture height, which they estimate typically in the 300- to 400-ft range (that is, spacing of at least 450 to 600 ft). On the other hand, Givens and Zhao (2005, p. 6) suggested a minimum distance of 1,500 to 2,000 ft. Passive microseismic mapping has become a standard tool for understanding propagation of induced fractures or opening of natural closed fractures (e.g., Fisher et al., 2004). These studies have shown that induced fractures are organized in a complex network along fairways and could open sealed natural fractures. Fisher et al. (2004) calculated that a vertical well frac job created such a fairway with a half-length of 2,000 ft, width of 1,000 ft, and total fracture network length of 30,000 ft.

Several recent field studies have tried to identify the distance from the well to the fracture zone ends (e.g., Figure 21). The figure shows that a fracture can propagate up to 1,000 ft from one side of the well (2,000 ft total). However, some have suggested that microseismic results also include matrix adjustments with no actual opening. The operator EOG Resources tried 500-ft spacing pilots with some success in Johnson County (EOG Website). In this report, it is assumed (Table 5) that horizontal well spacing is 800 ft in the high scenario and 1,000 and 2,000 ft in the medium and low scenarios, respectively. In the case of horizontal drilling in rural areas of the Viola footprint (core area and its numerous vertical wells), horizontal infill spacing is assumed to be four times less dense than that of areas with no vertical wells. This number derives from a crude calibration of the annual completion distribution as described later (see Section V-4-3).



Note: modified from www.eogresources.com/media/slides/analystconf_barnett.pdf

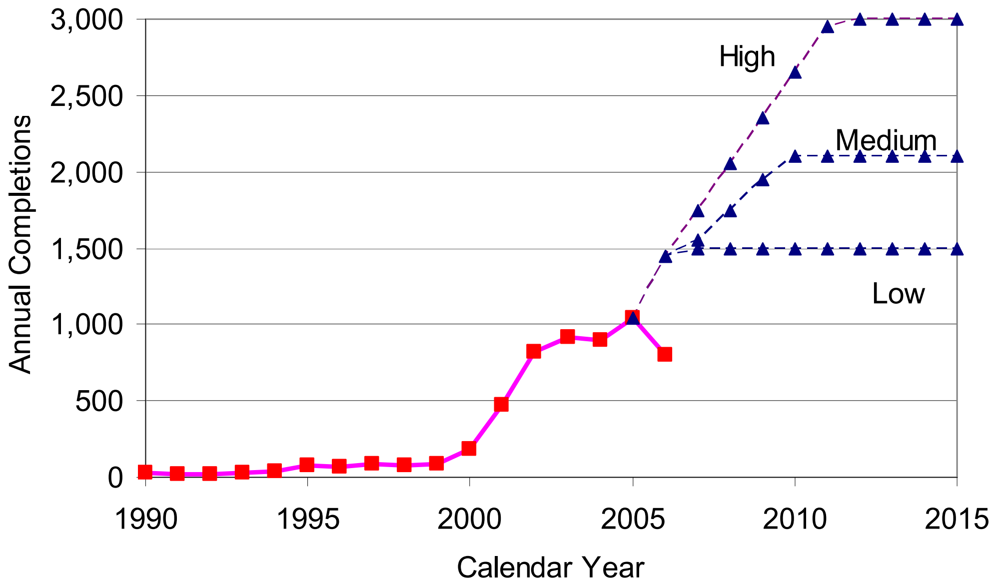
Figure 21. Schematics of pilot test results of lateral spacing in Johnson County (map view).

Operators have learned that it is better to wait some time before executing a frac job next to an already stimulated well. This is one of the reasons that there is no clear front to the advance of Barnett production in a map sense, but multiple advances followed by infilling.

IV-3. Operational Controls

The number of wells drilled is obviously limited by the number of drilling rigs and/or trained workers available. The number of completions for 2005 is ~1,050 (Table 4). If the current trend continues, the total number of completions for 2006 will be ~1,500. This value is retained as a constant annual rate of completions (up to 2025) in the low scenario (Figure 22). In the high scenario case (Table 5), it is assumed that the completion rate will grow to twice the 2006 value (that is, 3,000 completions/year) at a maximum annual incremental rate of 300 completions/year. The medium case is intermediate, with a maximum of 2,100 completions a year and an increment of 200 completions/year.

These numbers compared well with the data provided by Galusky (2006). He collected information from operators totaling about 600 completions done in 2005, which is about 60% of all completions in that year. Operator projections for 2006 and 2007 are 1,000 and 1,341, respectively, translating into a total number of completions for the play of 1,650 and 2,200.



Note: red squares = actual data (incomplete for 2006) – blue triangles = projected completions.

Figure 22. Annual completion projections up to 2015 (constant rate from 2012 to 2025).

IV-4. Numerical Projections

The starting point for numerical projections is 2005, using historical data, as shown in Table 6. Numerical projections for water use follow a defensible series of steps as outlined below:

(1) Calculate the hypothetical maximum water use in a county polygon, accounting for surface area, footprint fraction, number of vertical wells, footage of lateral, sag feature avoidance factor, and average water use per well type (Table 5).

(2) Derive an activity-weighting curve similar to a production curve, with initial ramp-up, peak, and long tail that is assumed valid for all county polygons.

(3) Assign year of peak activity to each county polygon.

(4) Assess quality of resource in county polygons, and apply a prospectivity/risk factor.

(5) Compute an uncorrected water use per year and per county polygon

(6) Throw in the maximum number of annual completions (M_{ca}) to correct the uncorrected water use, if an uncorrected water use is not realistic. Corrected water use is simply scaled for all county polygons from the uncorrected water use by applying a scaling factor equal to the ratio of M_{ca} to the number of wells needed to use up the uncorrected amount of water.

(7) Add water use for recompletion by simply adding on a county polygon basis the water used for vertical-well frac jobs 5 years before in the proportion given in Table 5.

(8) Add water-use savings thanks to recycling in the proportion given in Table 5.

(9) Include the groundwater/surface water split and other issues related to fresh-water sources.

(10) Follow the previous steps for high, medium, and low scenarios.

Table 6. Historical water use (all sources combined) in 2005 per county polygon

County Polygon	County Polygon Area (1000's acres)			Water Use (Gal)	Water Use (AF)
	High	Medium	Low		
Bosque	641	641	73	1,088,094	3.3
ClayH	133			0	0
ClayV	245			0	0
Comanche	194			0	0
Cooke	50	42	42	15,491,922	47.5
Coryell	516			0	0
Dallas	183	183	183	0	0
DentonR	215	215	215	581,308,388	1,784.0
DentonU	100	100	100	68,498,548	210.2
Ellis	36	36	36	5,962,516	18.3
Erath	669			7,409,467	22.7
Hamilton	509			0	0
Hill	325	325	151	0	0
Hood	282	282	282	103,162,534	316.6
Jack	589	284		12,423,365	38.1
JohnsonH	398	398	398	530,096,095	1,626.8
JohnsonV	71	71	71	61,600,697	189.0
McLennan	202	111		0	0
Montague	401	168		19,380,502	59.5
Palo Pinto	476	191		2,859,662	8.8
Parker	581	581	581	226,611,136	695.4
Somervell	122	122	122	3,454,836	10.6
TarrantH	195	195	195	83,773,449	257.1
TarrantVR	30	30	30	138,105,099	423.8
TarrantVU	350	350	350	184,155,872	565.2
WiseH	199	199	169	27,440,474	84.2
WiseV	392	392	292	274,730,880	843.1
Sum				**2,350,775,286**	**7,214.3**

Note: H=Horizontal, V=Viola, R=Rural, U=Urban; some counties are divided into polygons corresponding to the main completion type (presence or not of Viola Limestone, urban or rural setting)

IV-4-1 Hypothetical Maximum Water Use

The hypothetical maximum water use in a county polygon accounts for polygon surface area, footprint fraction, number of vertical wells, lateral footage of horizontal wells, sag feature avoidance factor, and average water use per well type (Table 7).

The value of this parameter varies from 2.75 million AF of water that could eventually be used on the play in the high scenario, to 0.860 and 0.134 million AF in the medium and low scenarios, respectively. There is a factor 20 difference between the high and low scenarios explained by the difference in total surface area and the systematic choice of high water use and low water use for the high and low scenarios, respectively. Those high and low scenarios probably are unrealistic extremes of the large range provided.

Table 7. Derivation of hypothetical maximum water use by county polygon.

County Polygon	Area (acres)			Linear Length of Lateral (1000's ft)[A]			Number of Vertical Wells[B]			Maximum Hypothetical Water Use (1000's AF)[C]		
	High	Medium	Low	High	Medium	Low	High	Medium	Low	High	Medium	Low
Bosque	641,457	641,457	73,266	27,942	22,354	1,277				240	123	3
ClayH	133,197			5,802						50		
ClayV1	245,103						5,515			20		
ClayV2[D]				2,669						23		
Comanche	194,448			8,470						73		
Cooke1	49,697	41,992	41,992				1,118	472	236	4	2	1
Cooke2[D]				541	433	216				5	3	1
Coryell	516,395			22,494						193		
Dallas	183,473	183,473	183,473	7,992	6,394	3,197				69	35	8
DentonR1	215,385	215,385	215,385				4,846	2,423	1,212	18	9	4
DentonR2[D]				2,346	1,876	938				20	10	2
DentonU	99,786	99,786	99,786	4,347	3,477	1,739				37	19	4
Ellis1	35,975	35,975	35,975				809	405	202	3	1	1
Ellis2[D]				392	313	157				3	2	0
Erath	668,543			29,122						250		
Hamilton	509,458			22,192						191		
Hill	324,851	324,851	150,946	14,150	11,320	2,630				122	63	6
Hood	282,000	282,000	282,000	12,284	9,827	4,914				106	54	12
Jack	589,126	283,836		25,662	9,891					221	55	
JohnsonH	398,436	398,436	398,436	17,356	13,885	6,942				149	77	17
JohnsonV1	71,376	71,376	71,376				1,606	803	401	6	3	1
JohnsonV2[D]				777	622	311				7	3	1
McLennan	202,373	111,094		8,815	3,871					76	21	
Montague1	400,537	167,879					9,012	1,889		33	7	
Montague2				4,362	3,489					37	19	
Palo Pinto	476,187	191,216		20,743	6,664					178	37	
Parker	580,919	580,919	580,919	25,305	20,244	10,122				217	112	25

County Polygon	Area (acres)			Linear Length of Lateral (1000's ft)[A]			Number of Vertical Wells[B]			Maximum Hypothetical Water Use (1000's AF)[C]		
	High	Medium	Low	High	Medium	Low	High	Medium	Low	High	Medium	Low
Somervell	122,145	122,145	122,145	5,321	4,257	2,128				46	24	5
TarrantH	194,799	194,799	194,799	8,485	6,788	3,394				73	37	8
TarrantVR1	30,261	30,261	30,261				681	340	170	3	1	1
TarrantVR2 [D]				330	264	132				3	1	0
TarrantVU	350,133	350,133	350,133	15,252	12,201	6,101				131	67	15
WiseH	198,724	198,724	168,629	8,656	6,925	2,938	24,238	16,620	5,876	74	38	7
WiseV1	392,155	392,155	291,735							32	16	6
WiseV2 [D]				4,271	3,416	1,708	11,958	8,199	3,416	37	19	4
Total	8,106,937	4,917,891	3,291,254	306,077	148,512	48,844	59,783	31,152	11,515	2,749	860	134

Note: H=Horizontal, V=Viola, R=Rural, U=Urban; some counties are divided into polygons corresponding to the main completion type (presence or not of Viola Limestone, urban or rural setting); in addition some counties polygons contains mostly vertical wells but also include horizontal wells (names in italics)

[A] Applies lateral spacing and footprint fraction

[B] Applies vertical spacing and footprint fraction

[C] Applies sag feature avoidance factor and average water use

[D] Treats horizontal wells in areas with a combination of vertical and horizontal wells

IV-4-2 Derivation of Activity-Weighting Curve

Time distribution of initial well completion in a somewhat large area goes through several steps: initial ramp, peak, decrease, and long tail (Figure 23 and Figure 24). Three county polygons (Denton Rural, Wise Viola, and Tarrant Viola/Rural) have already passed their peak. They are all located in vertical-well-dominated areas, although it is assumed that the model can be applied to all areas as a first approximation. If the number of wells already drilled is compared with the maximum number of wells, assuming a well spacing of 40 acres, the simplified time distribution displayed in Figure 25 can be derived. An exploratory period ("Year 0") of numerically negligible water use, followed by a 6-year period of sustained development and a 3-year peak is assumed. The tail extends to *n* years after the first year of sustained drilling until total extraction of the resource. If the annual extraction rate stays at 1.5% of the total resource, *n* is equal to 50. At the end of 2005, the three county polygons used to build the model completed Year 10 of the model. The tail period starts in Year 11, and the first 10 years account for 27% of the maximum number of completions/maximum water use of the scenario considered. This basic model should be adapted to areas where slower drilling is expected, such as in urban areas. We assume a rate four times slower in urban areas than in rural areas. The values described above were obtained after a crude calibration of the model using the years 2000 through 2005 in Denton, Tarrant, and Wise Counties.

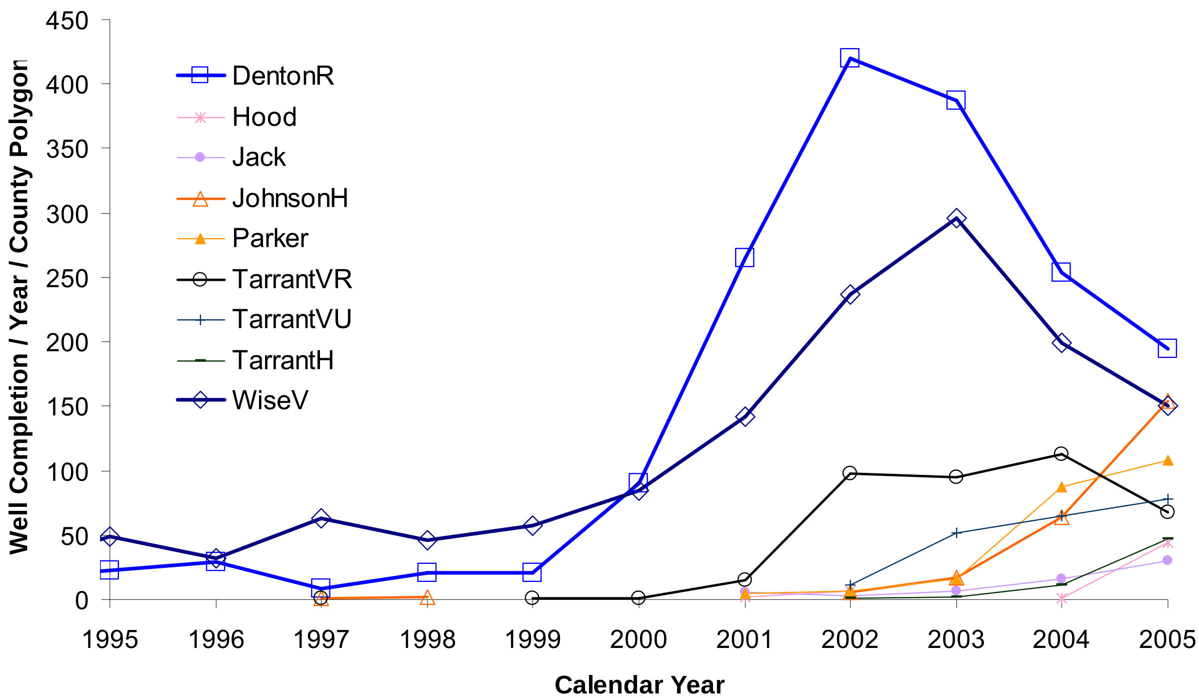
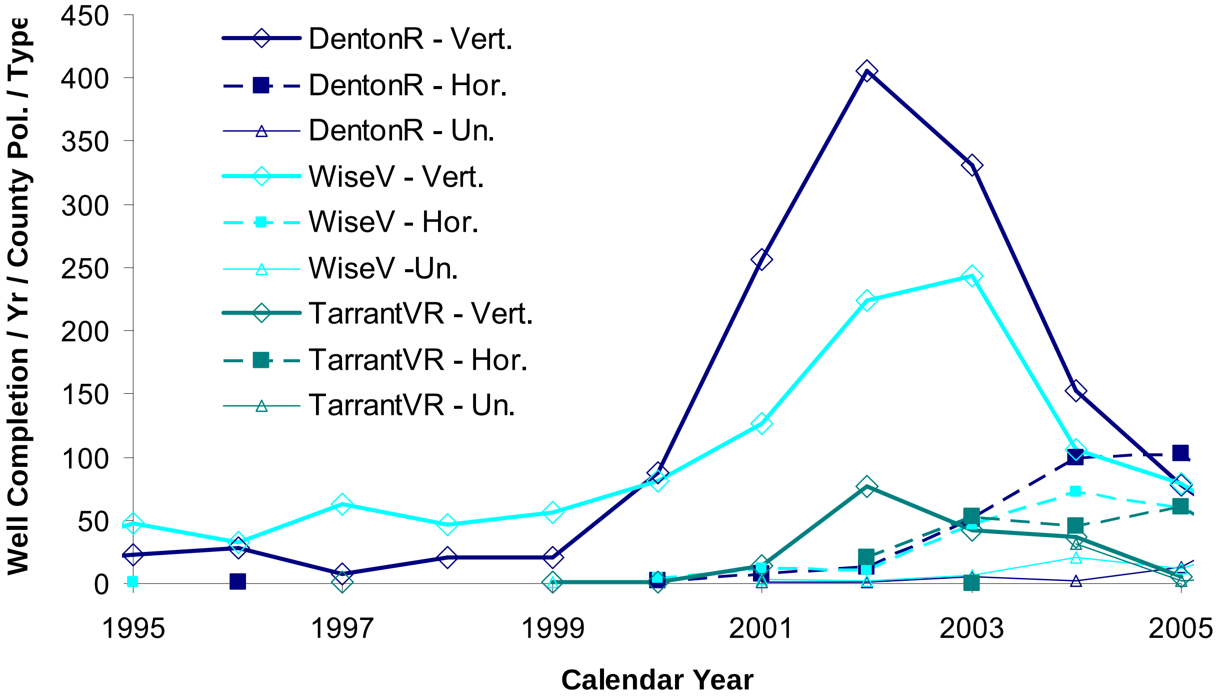


Figure 23. Annual well completion in selected county polygons.



Vert. = vertical; Hor. = horizontal; Un. = unknown

Figure 24. Annual well completion in selected county polygons per well type.

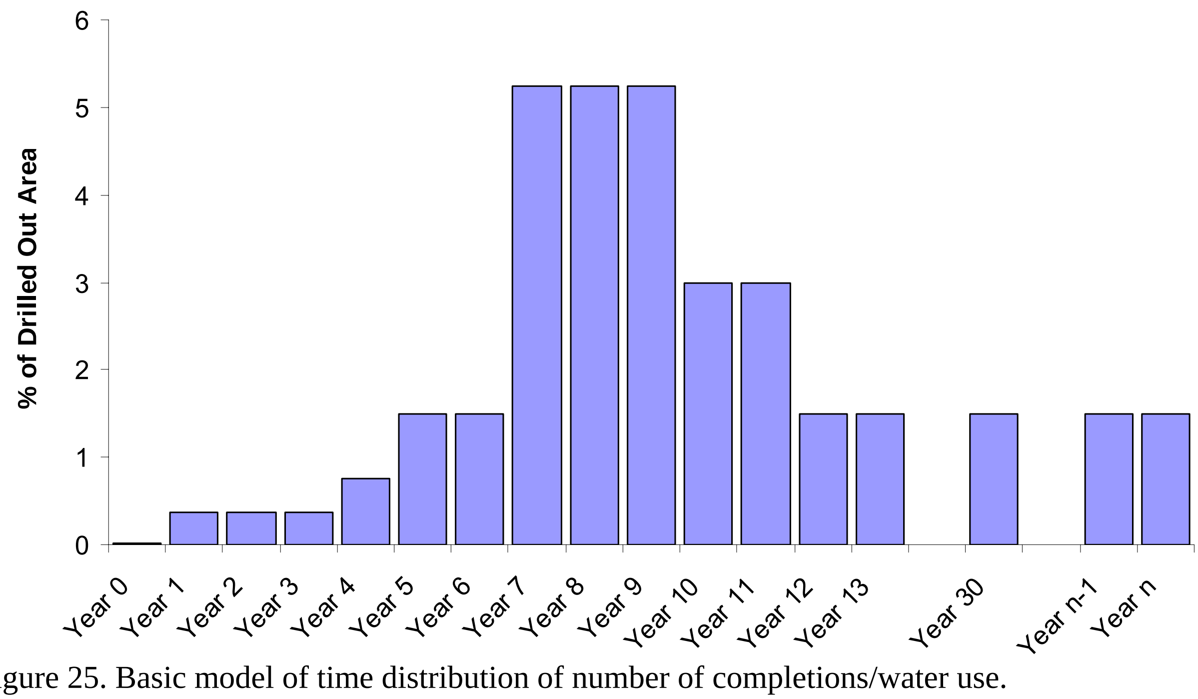


Figure 25. Basic model of time distribution of number of completions/water use.

IV-4-3 Year of Peak Activity and Quality of the Resource in County Polygons

In the previous sections of this report, we derived a maximum water use and an activity-weighting curve. However, all counties will obviously not be developed in parallel. Rather, they will be developed in a somewhat staggered pattern. We derive the calendar year for "Year 1" or start year (Table 8), using a combination of geology, distance to the core area, necessity of having a relatively smooth overall development curve as opposed to a jagged one, and some crude calibration of the model using the years 2001 through 2005 in Denton, Tarrant, and Wise Counties.

Prospectivity/risk factor can be understood either as a fraction of the area that will be developed or, more adequately, as the mean of the probability distribution describing the likelihood of having the county polygon developed (already given the high, medium, or low scenario condition). This factor is used simply as a multiplier of the hypothetical maximum water use.

Rough calibration of these two parameters is shown in Figure 26 as it translates to the three counties with enough data. Water use in these counties of the core area is matched roughly by derived high and medium scenario results. The final values were obtained by varying year of peak activity and prospectivity/risk factor.

Table 8. Start year and prospectivity/risk factor for county polygons.

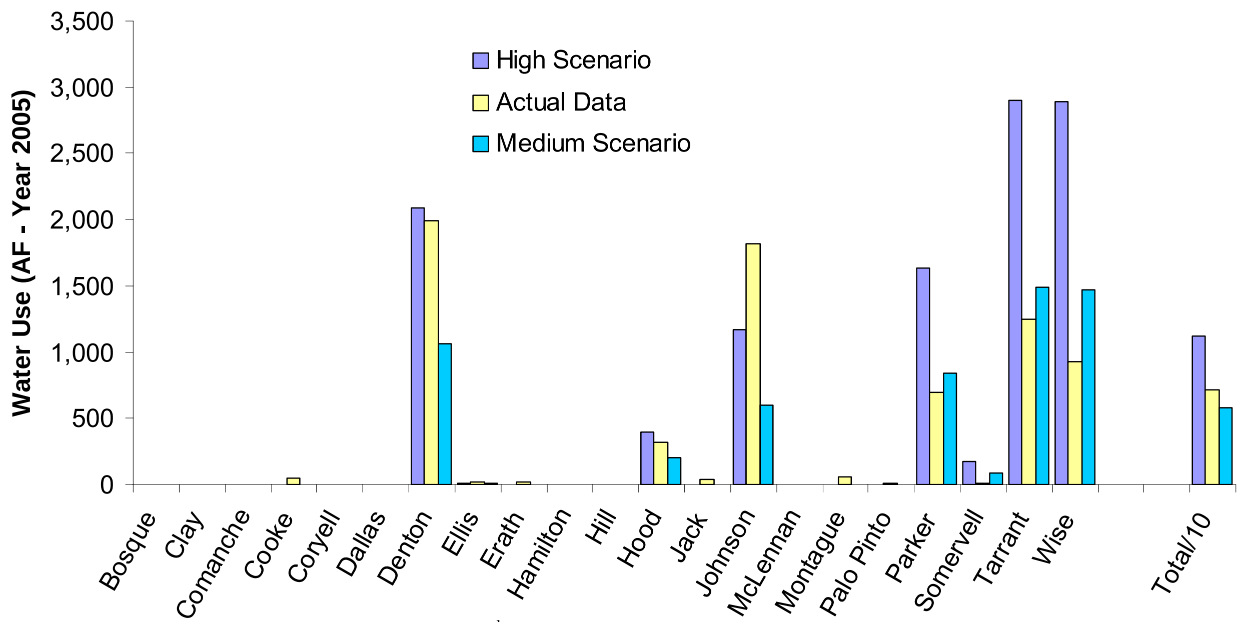
County Polygon	Start Year	Prosp. Factor[A]	Comments
Bosque	2009	0.8	No good wells yet, but expect that NE part (at least) will be good
ClayH	2017	0.5	Likely to be oil prone
ClayV1	2016	0.5	
ClayV2 [B]	2018	0.5	
Comanche	2010	0.5	Likely to be fairly thin and oil prone
Cooke1	2008	1	Not much area in the play
Cooke2 [B]	2010	1	
Coryell	2014	0.5	Thin, may take time to solve frac-height problem
Dallas	2007	1	NW part looks highly prospective; will take time to solve urban drilling issues
DentonR1	1996	1	Mostly developed already
DentonR2 [B]	1998	1	
DentonU	1999	1	Very prospective, but will take time to solve urban drilling issues
Ellis1	2004	1	Small area in NW appears very prospective
Ellis2 [B]	2006	1	
Erath	2007	0.8	Fair results with horizontals so far, especially east and central
Hamilton	2010	0.8	No valid horizontal well results yet; probably more prospective in east half
Hill	2007	0.9	Northwest part already economic; SW not really tested yet
Hood	2004	1	Early horizontals very encouraging

County Polygon	Start Year	Prosp. Factor[A]	Comments
Jack	2006	0.7	Only marginal horizontals so far; SE part seems best
JohnsonH	2002	1	Clearly economic; may be mixed vertical and horizontal development
JohnsonV1	2003	1	
JohnsonV2 [B]	2003	1	
McLennan	2012	0.6	Fairly speculative; small part of county only
Montague1	2010	0.7	Known production of both oil and gas; controls on distribution not well understood
Montague2 [B]	2012	0.7	
Palo Pinto	2010	0.8	Nothing clearly economic yet
Parker	2002	1	In core producing area
Somervell	2004	1	One excellent horizontal so far; promising county
TarrantH	1999	1	Very prospective; urban drilling will require plenty of time to develop
TarrantVR1	1996	1	Very prospective; should be relatively quickly developed
TarrantVR2 [B]	1998	1	
TarrantVU	1999	1	Probably mostly done already where possible
WiseH	2003	1	Clearly prospective in current price environment
WiseV1	1996	0.9	Already reasonably well developed; economics marginal in some areas owing to gas/oil ratio; NW seems least prospective.
WiseV2 [B]	1998	0.9	

Note: H=Horizontal – V=Viola – R=Rural – U=Urban; some counties are divided into polygons corresponding to the main completion type (presence or not of Viola Limestone, urban or rural setting); in addition some counties polygons contains mostly vertical wells but also include horizontal wells (names in italics)

[A] Prosp. Factor = prospectivity/risk factor

[B] Treat horizontal wells in areas with a combination of vertical and horizontal wells



Note: Values showed for overall total is 1/10th of actual total ("Total/10")

Figure 26. Column chart illustrating calibration of county activity.

IV-4-4 Uncorrected Annual Water Use

By introducing the time variable through the activity-weighting curve and applying it to the hypothetical maximum water use modified by the prospectivity/risk factor, an uncorrected annual water use per county polygon is obtained (Table 9). In the high scenario, overall water use increases until 2016, as more and more counties come into production, and then slowly decreases (Figure 27) as production tapers off. The high scenario yields large water use, for example >50,000 AF in 2016. This large water use is not sustainable because it corresponds to more than 5,000 annual well completions. In a previous section, we mentioned and assumed that more than 3,000 completions a year is unlikely. The medium and especially the low scenarios have much lower uncorrected water use (Figure 28). The low uncorrected water use of the low scenario conveys the assumptions used in developing it: no major expansion of the play and low gas price, giving little incentive for operators to expand.

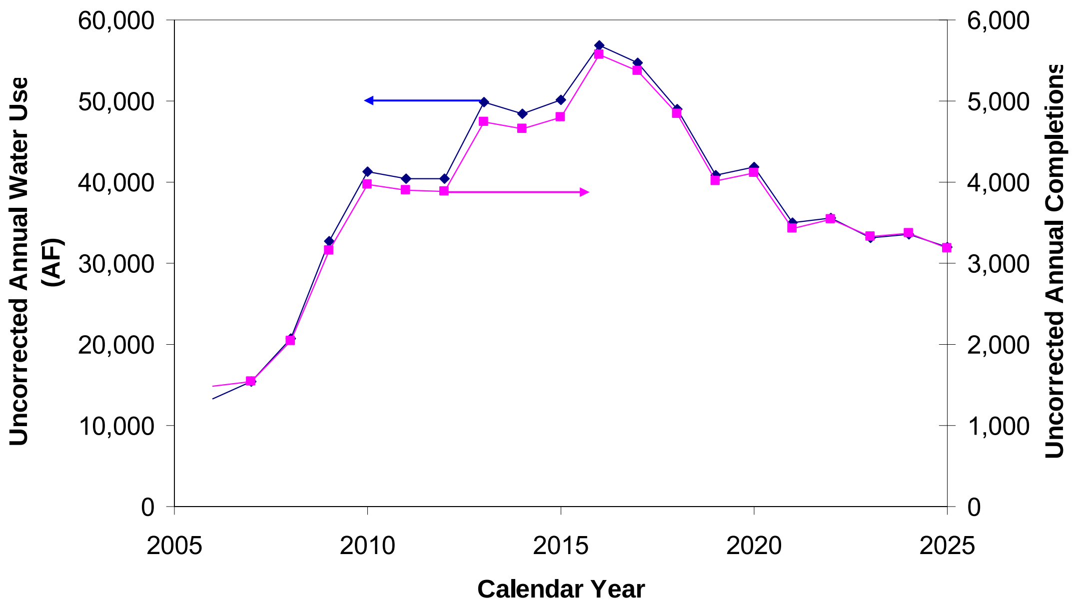


Figure 27. Uncorrected annual water use and completion (high scenario)

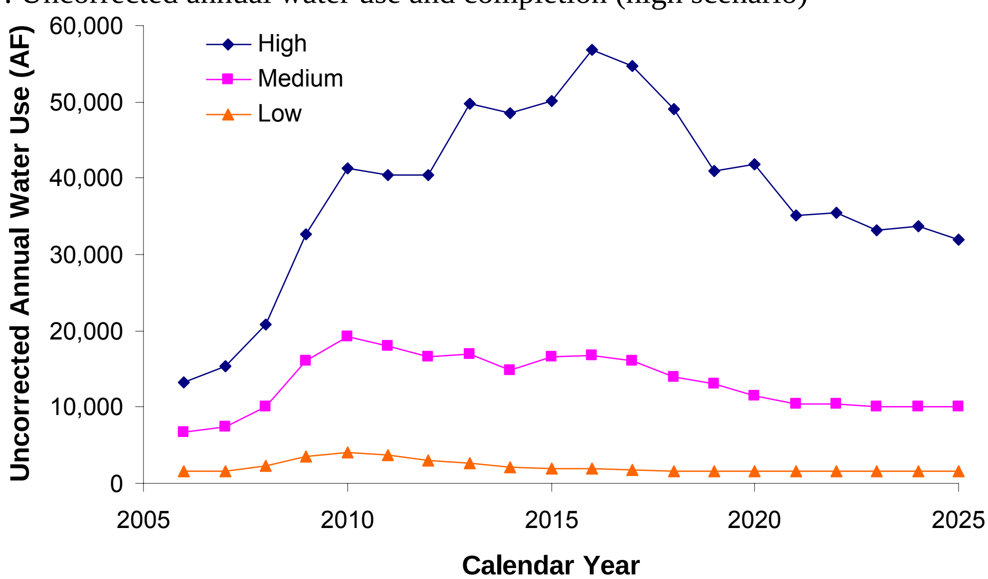


Figure 28. Uncorrected annual water use for high, medium, and low scenarios.

Table 9. Uncorrected annual water use per county polygon for the high scenario (all water sources, 1000's AF).

County Polygon	2006	2007	2008	2009	**2010**	2011	2012	2013	2014	**2015**	2016	2017	2018	2019	**2020**	2021	2022	2023	2024	**2025**
Bosque				0.37	**0.37**	0.37	0.74	1.48	1.48	**5.19**	5.19	5.19	2.96	2.96	**1.48**	1.48	1.48	1.48	1.48	**1.48**
ClayH												0.09	0.09	0.09	**0.19**	0.37	0.37	1.31	1.31	**1.31**
ClayV1											0.04	0.04	0.04	0.08	**0.15**	0.15	0.53	0.53	0.53	**0.30**
ClayV2													0.04	0.04	**0.04**	0.09	0.17	0.17	0.60	**0.60**
Comanche					**0.14**	0.14	0.14	0.27	0.55	**0.55**	1.91	1.91	1.91	1.09	**1.09**	0.55	0.55	0.55	0.55	**0.55**
Cooke1			0.02	0.02	**0.02**	0.03	0.06	0.06	0.22	**0.22**	0.22	0.12	0.12	0.06	**0.06**	0.06	0.06	0.06	0.06	**0.06**
Cooke2					**0.02**	0.02	0.02	0.03	0.07	**0.07**	0.24	0.24	0.24	0.14	**0.14**	0.07	0.07	0.07	0.07	**0.07**
Coryell									0.36	**0.36**	0.36	0.72	1.45	1.45	**5.07**	5.07	5.07	2.90	2.90	**1.45**
Dallas		0.06	0.06	0.06	**0.13**	0.26	0.26	0.90	0.90	**0.90**	0.52	0.52	0.26	0.26	**0.26**	0.26	0.26	0.26	0.26	**0.26**
DentonR1	0.54	0.27	0.27	0.27	**0.27**	0.27	0.27	0.27	0.27	**0.27**	0.27	0.27	0.27	0.27	**0.27**	0.27	0.27	0.27	0.27	**0.27**
DentonR2	1.06	0.60	0.60	0.30	**0.30**	0.30	0.30	0.30	0.30	**0.30**	0.30	0.30	0.30	0.30	**0.30**	0.30	0.30	0.30	0.30	**0.30**
DentonU	0.49	0.49	0.28	0.28	**0.14**	0.14	0.14	0.14	0.14	**0.14**	0.14	0.14	0.14	0.14	**0.14**	0.14	0.14	0.14	0.14	**0.14**
Ellis1	0.01	0.02	0.04	0.04	**0.16**	0.16	0.16	0.09	0.09	**0.04**	0.04	0.04	0.04	0.04	**0.04**	0.04	0.04	0.04	0.04	**0.04**
Ellis2	0.01	0.01	0.01	0.03	**0.05**	0.05	0.18	0.18	0.18	**0.10**	0.10	0.05	0.05	0.05	**0.05**	0.05	0.05	0.05	0.05	**0.05**
Erath		0.75	0.75	0.75	**1.50**	3.00	3.00	10.51	10.51	**10.51**	6.01	6.01	3.00	3.00	**3.00**	3.00	3.00	3.00	3.00	**3.00**
Hamilton					**0.57**	0.57	0.57	1.14	2.29	**2.29**	8.01	8.01	8.01	4.58	**4.58**	2.29	2.29	2.29	2.29	**2.29**
Hill		0.41	0.41	0.41	**0.82**	1.64	1.64	5.75	5.75	**5.75**	3.28	3.28	1.64	1.64	**1.64**	1.64	1.64	1.64	1.64	**1.64**
Hood	0.40	0.79	1.58	1.58	**5.54**	5.54	5.54	3.17	3.17	**1.58**	1.58	1.58	1.58	1.58	**1.58**	1.58	1.58	1.58	1.58	**1.58**
Jack	0.58	0.58	0.58	1.16	**2.32**	2.32	8.10	8.10	8.10	**4.63**	4.63	2.32	2.32	2.32	**2.32**	2.32	2.32	2.32	2.32	**2.32**
JohnsonH	2.24	2.24	7.83	7.83	**7.83**	4.47	4.47	2.24	2.24	**2.24**	2.24	2.24	2.24	2.24	**2.24**	2.24	2.24	2.24	2.24	**2.24**
JohnsonV1	0.04	0.09	0.09	0.31	**0.31**	0.31	0.18	0.18	0.09	**0.09**	0.09	0.09	0.09	0.09	**0.09**	0.09	0.09	0.09	0.09	**0.09**
JohnsonV2	0.05	0.10	0.10	0.35	**0.35**	0.35	0.20	0.20	0.10	**0.10**	0.10	0.10	0.10	0.10	**0.10**	0.10	0.10	0.10	0.10	**0.10**
McLennan							0.17	0.17	0.17	**0.34**	0.68	0.68	2.39	2.39	**2.39**	1.36	1.36	0.68	0.68	**0.68**
Montague1					**0.09**	0.09	0.09	0.17	0.35	**0.35**	1.22	1.22	1.22	0.70	**0.70**	0.35	0.35	0.35	0.35	**0.35**
Montague2							0.10	0.10	0.10	**0.20**	0.39	0.39	1.38	1.38	**1.38**	0.79	0.79	0.39	0.39	**0.39**
Palo Pinto					**0.53**	0.53	0.53	1.07	2.14	**2.14**	7.49	7.49	7.49	4.28	**4.28**	2.14	2.14	2.14	2.14	**2.14**
Parker	1.63	3.26	3.26	11.42	**11.42**	11.42	6.52	6.52	3.26	**3.26**	3.26	3.26	3.26	3.26	**3.26**	3.26	3.26	3.26	3.26	**3.26**
Somervell	0.17	0.34	0.69	0.69	**2.40**	2.40	2.40	1.37	1.37	**0.69**	0.69	0.69	0.69	0.69	**0.69**	0.69	0.69	0.69	0.69	**0.69**

County Polygon	2006	2007	2008	2009	**2010**	2011	2012	2013	2014	**2015**	2016	2017	2018	2019	**2020**	2021	2022	2023	2024	**2025**
TarrantH	0.96	0.96	0.55	0.55	**0.27**	0.27	0.27	0.27	0.27	**0.27**	0.27	0.27	0.27	0.27	**0.27**	0.27	0.27	0.27	0.27	**0.27**
TarrantVR1	0.08	0.04	0.04	0.04	**0.04**	0.04	0.04	0.04	0.04	**0.04**	0.04	0.04	0.04	0.04	**0.04**	0.04	0.04	0.04	0.04	**0.04**
TarrantVR2	0.15	0.08	0.08	0.04	**0.04**	0.04	0.04	0.04	0.04	**0.04**	0.04	0.04	0.04	0.04	**0.04**	0.04	0.04	0.04	0.04	**0.04**
TarrantVU	1.72	1.72	0.98	0.98	**0.49**	0.49	0.49	0.49	0.49	**0.49**	0.49	0.49	0.49	0.49	**0.49**	0.49	0.49	0.49	0.49	**0.49**
WiseH	0.56	1.12	1.12	3.91	**3.91**	3.91	2.23	2.23	1.12	**1.12**	1.12	1.12	1.12	1.12	**1.12**	1.12	1.12	1.12	1.12	**1.12**
WiseV1	0.88	0.44	0.44	0.44	**0.44**	0.44	0.44	0.44	0.44	**0.44**	0.44	0.44	0.44	0.44	**0.44**	0.44	0.44	0.44	0.44	**0.44**
WiseV2	1.73	0.99	0.99	0.50	**0.50**	0.50	0.50	0.50	0.50	**0.50**	0.50	0.50	0.50	0.50	**0.50**	0.50	0.50	0.50	0.50	**0.50**
Total	**13.29**	**15.37**	**20.78**	**32.31**	**40.95**	**40.06**	**39.80**	**48.43**	**47.08**	**45.19**	**51.89**	**49.89**	**46.22**	**38.11**	**40.42**	**33.65**	**34.11**	**31.80**	**32.23**	**30.55**

Note: H=Horizontal, V=Viola, R=Rural, U=Urban; some counties are divided into polygons corresponding to the main completion type (presence or not of Viola Limestone, urban or rural setting); in addition some counties polygons contains mostly vertical wells but also include horizontal wells (names in italics)

IV-4-5 Correction due to Maximum Number of Completions Constraint

Adding the drilling rig constraint to uncorrected water use generates a table closer to the final estimations. An average water use of 1.2 MGal/vertical well and 3.6 MGal/horizontal well is assumed to compute the total number of wells needed to reach the uncorrected water-use goal. Corrected water use is then simply obtained by linearly scaling uncorrected water use by the ratio of the maximum number of wells to the computed total number of wells. Only the high scenario needs such a scaling, the medium and low scenarios always being below but sometimes close to their maximum attributed annual completions.

IV-4-6 Correction due to Recompletions and Recycling and Final Projections for Frac Job Annual Water Use

Correction for recompletion is in general small because it applies only to vertical, whose overall percentage within total number of wells completed on that year decreases through time. It is higher in early years (<2010) because, according to our model, vertical wells drilled 2000 through 2005 will then have been recompleted.

The effect of some recycling is also beneficial to total water use, but the general decrease through time depicted in Figure 29 is due mainly to the diminution of the resource. In the high scenario, total water use climbs from ~8,000 AF in 2005 to a peak of ~30,000 AF in 2011, followed by a slow decease to ~25,000 AF in 2025. The medium scenario follows a similar path, climbing to ~20,000 AF in 2010 and decreasing to ~10,000 AF in 2025. The low scenario shows a constant decrease from the 2006 value to 1,600 AF in 2025. Table 10 tabulates annual projections by county polygons.

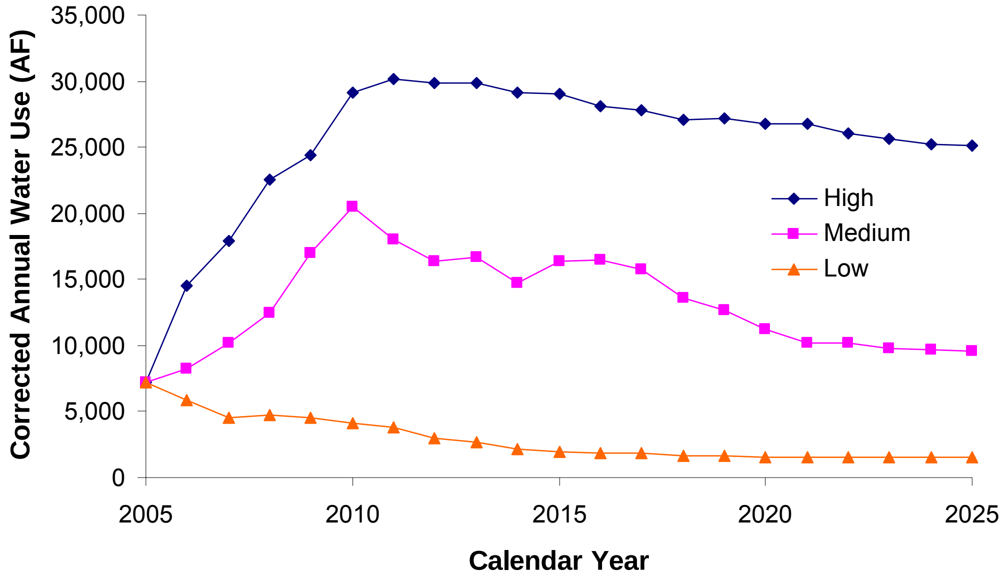


Figure 29. Corrected annual water use for high, medium, and low scenarios (all sources).

Table 10. Corrected annual water use per county polygon for the high scenario (all water sources, 1000's AF).

County Polygon	**2006**	2007	2008	2009	**2010**	2011	2012	2013	2014	**2015**	2016	2017	2018	2019	**2020**	2021	2022	2023	2024	**2025**
Bosque				0.51	**0.46**	0.51	1.03	1.68	1.69	**5.68**	4.84	4.96	3.10	3.71	**1.79**	2.12	2.02	2.13	2.08	**2.17**
ClayH												0.05	0.05	0.06	**0.12**	0.27	0.26	0.97	0.94	**0.99**
ClayV1											0.02	0.02	0.02	0.05	**0.09**	0.13	0.39	0.41	0.43	**0.32**
ClayV2													0.02	0.03	**0.03**	0.06	0.12	0.13	0.43	**0.45**
Comanche					**0.09**	0.10	0.10	0.16	0.32	**0.31**	0.92	0.94	1.03	0.70	**0.68**	0.40	0.38	0.40	0.39	**0.41**
Cooke1			0.01	0.01	**0.05**	0.02	0.04	0.05	0.14	**0.13**	0.12	0.10	0.10	0.16	**0.15**	0.14	0.10	0.11	0.08	**0.08**
Cooke2					**0.01**	0.01	0.01	0.02	0.04	**0.04**	0.12	0.12	0.13	0.09	**0.09**	0.05	0.05	0.05	0.05	**0.05**
Coryell									0.21	**0.20**	0.17	0.36	0.78	0.93	**3.15**	3.72	3.56	2.14	2.09	**1.09**
Dallas		0.06	0.06	0.05	**0.08**	0.18	0.18	0.53	0.53	**0.51**	0.25	0.25	0.14	0.17	**0.16**	0.19	0.18	0.19	0.19	**0.19**
DentonR1	**1.66**	2.01	1.73	0.79	**1.86**	0.68	0.44	0.40	0.34	**0.31**	0.31	0.31	0.29	0.32	**0.31**	0.32	0.31	0.33	0.35	**0.36**
DentonR2	**1.02**	0.59	0.59	0.22	**0.19**	0.22	0.22	0.18	0.18	**0.17**	0.15	0.15	0.16	0.19	**0.19**	0.22	0.21	0.22	0.22	**0.23**
DentonU	**0.47**	0.48	0.27	0.20	**0.09**	0.10	0.10	0.08	0.08	**0.08**	0.07	0.07	0.08	0.09	**0.09**	0.10	0.10	0.10	0.10	**0.11**
Ellis1	**0.01**	0.02	0.04	0.03	**0.12**	0.12	0.13	0.09	0.08	**0.12**	0.13	0.13	0.07	0.08	**0.05**	0.05	0.05	0.06	0.06	**0.06**
Ellis2	**0.01**	0.01	0.01	0.02	**0.03**	0.04	0.13	0.10	0.10	**0.06**	0.05	0.02	0.03	0.03	**0.03**	0.04	0.04	0.04	0.04	**0.04**
Erath		0.74	0.73	0.54	**0.95**	2.14	2.16	6.12	6.16	**5.92**	2.88	2.95	1.62	1.93	**1.86**	2.20	2.11	2.22	2.16	**2.27**
Hamilton					**0.36**	0.41	0.41	0.67	1.34	**1.29**	3.84	3.94	4.31	2.94	**2.84**	1.68	1.61	1.69	1.65	**1.73**
Hill		0.40	0.40	0.29	**0.52**	1.17	1.18	3.35	3.37	**3.24**	1.57	1.61	0.88	1.06	**1.02**	1.21	1.15	1.21	1.18	**1.24**
Hood	**0.38**	0.78	1.54	1.13	**3.51**	3.94	3.98	1.85	1.86	**0.89**	0.76	0.78	0.85	1.02	**0.98**	1.16	1.11	1.17	1.14	**1.19**
Jack	**0.56**	0.57	0.56	0.83	**1.47**	1.65	5.82	4.72	4.75	**2.61**	2.22	1.14	1.25	1.49	**1.44**	1.70	1.63	1.71	1.67	**1.75**
JohnsonH	**2.17**	2.19	7.59	5.59	**4.96**	3.18	3.21	1.30	1.31	**1.26**	1.07	1.10	1.20	1.44	**1.39**	1.64	1.57	1.65	1.61	**1.69**
JohnsonV1	**0.04**	0.09	0.09	0.22	**0.20**	0.26	0.21	0.19	0.26	**0.24**	0.25	0.16	0.15	0.11	**0.10**	0.11	0.10	0.11	0.12	**0.12**
JohnsonV2	**0.05**	0.10	0.10	0.25	**0.22**	0.25	0.14	0.12	0.06	**0.06**	0.05	0.05	0.05	0.06	**0.06**	0.07	0.07	0.07	0.07	**0.08**
McLennan							0.12	0.10	0.10	**0.19**	0.33	0.34	1.29	1.53	**1.48**	1.00	0.96	0.50	0.49	**0.51**
Montague1					**0.11**	0.06	0.06	0.10	0.20	**0.25**	0.64	0.66	0.75	0.64	**0.62**	0.81	0.81	0.88	0.67	**0.67**
Montague2							0.07	0.06	0.06	**0.11**	0.19	0.19	0.74	0.89	**0.85**	0.58	0.55	0.29	0.28	**0.30**
Palo Pinto					**0.34**	0.38	0.38	0.62	1.25	**1.20**	3.59	3.68	4.03	2.75	**2.65**	1.57	1.50	1.58	1.54	**1.61**
Parker	**1.58**	3.20	3.16	8.15	**7.23**	8.12	4.68	3.80	1.91	**1.84**	1.56	1.60	1.76	2.10	**2.02**	2.39	2.29	2.41	2.35	**2.46**
Somervell	**0.17**	0.34	0.67	0.49	**1.52**	1.71	1.72	0.80	0.80	**0.39**	0.33	0.34	0.37	0.44	**0.43**	0.50	0.48	0.51	0.49	**0.52**

County Polygon	**2006**	2007	2008	2009	**2010**	2011	2012	2013	2014	**2015**	2016	2017	2018	2019	**2020**	2021	2022	2023	2024	**2025**
TarrantH	**0.93**	0.94	0.53	0.39	**0.17**	0.19	0.20	0.16	0.16	**0.15**	0.13	0.13	0.15	0.18	**0.17**	0.20	0.19	0.20	0.20	**0.21**
TarrantVR1	**0.11**	0.26	0.15	0.14	**0.43**	0.10	0.06	0.06	0.05	**0.04**	0.04	0.04	0.04	0.05	**0.04**	0.04	0.04	0.05	0.05	**0.05**
TarrantVR2	**0.14**	0.08	0.08	0.03	**0.03**	0.03	0.03	0.02	0.02	**0.02**	0.02	0.02	0.02	0.03	**0.03**	0.03	0.03	0.03	0.03	**0.03**
TarrantVU	**1.67**	1.69	0.95	0.70	**0.31**	0.35	0.35	0.29	0.29	**0.28**	0.24	0.24	0.26	0.32	**0.30**	0.36	0.35	0.36	0.35	**0.37**
WiseH	**0.54**	1.09	1.08	2.79	**2.47**	2.78	1.60	1.30	0.65	**0.63**	0.54	0.55	0.60	0.72	**0.69**	0.82	0.78	0.82	0.80	**0.84**
WiseV1	**1.30**	1.29	1.25	0.66	**1.08**	1.12	0.72	0.66	0.55	**0.51**	0.51	0.51	0.48	0.53	**0.51**	0.52	0.51	0.55	0.58	**0.59**
WiseV2	**1.68**	0.97	0.96	0.35	**0.31**	0.35	0.36	0.29	0.29	**0.28**	0.24	0.24	0.27	0.32	**0.31**	0.36	0.35	0.37	0.36	**0.37**
Total	**14.50**	**17.90**	**22.56**	**24.39**	**29.17**	**30.16**	**29.86**	**29.86**	**29.17**	**28.99**	**28.14**	**27.78**	**27.09**	**27.13**	**26.72**	**26.79**	**26.00**	**25.64**	**25.26**	**25.16**

Note: H=Horizontal, V=Viola, R=Rural, U=Urban; some counties are divided into polygons corresponding to the main completion type (presence or not of Viola Limestone, urban or rural setting); in addition some counties polygons contains mostly vertical wells but also include horizontal wells (names in italics)

V. Groundwater Pumpage for GAM Input

V-1. Groundwater/Surface Water Split

Water-use projections are not sufficient to determine the impact of Barnett Shale production on groundwater resources in general or on the Trinity aquifer in particular. External sources of frac job water, excluding recycling, can be (1) groundwater (2) surface water (river, lake, private pond) or (3) municipal water or treated (municipal) waste water whose primary source is either surface or groundwater but is already accounted for in the current GAM pumping file. Trucking water from miles away to its point of use is expensive, and operators are reluctant to do it when groundwater is available nearby. Figure 30 illustrates that all counties but three (Clay, Jack, and Palo Pinto) are on the Trinity aquifer footprint. This fact, however, does not necessarily mean that frac jobs in those three counties will not use groundwater from the Trinity aquifer. In Texas, as a general rule, amount of surface water decreases toward the south and west (combination of a decrease in precipitation and increase in evaporation). As the play expands southward and westward, the fraction of groundwater use will most likely increase through time.

Records from the TWDB show that groundwater is extracted for frac jobs in all areas where gas wells are drilled. Ridgeway (2006) stated that, using records from 2004 and 2005, a total of 3,731 new water wells were drilled in the study area (including 285 whose drilling reports were submitted online; Figure 31). During these 2 years, water wells drilled for rural domestic use (3,101 wells) account for 83% of the total water wells drilled in the study area. The county that had the most new domestic water wells was Parker County (875 wells), followed by Tarrant County (481 wells). The next-highest use of new water wells drilled is irrigation (9%, or 319 wells), with Tarrant County reporting the highest number of new water wells for this use (129). The third-highest use of new water wells drilled was rig supply (3%, or 103 wells), with Johnson County reporting the highest number of new water wells for this use (35). However, these data capture only wells whose reports include an oil operator name and do not include wells drilled by landowners to provide water to operators (Ridgeway, 2006).

Water wells must meet some minimum yield. Operators start storing water needed for the frac job the day drilling starts or shortly before, and the 3.5 million gallons of water must be ready to be injected a month later, when the well has been drilled. This figure translates into a flow rate of 81 gpm, with no downtime. Assuming that two wells provide the water, a minimum yield of 50 gpm is needed.

Galusky (2006) provided an estimate of groundwater/surface water split per county, including both historical and projected use (Table 11). Galusky (2006) does not specify whether the groundwater origin is from municipal sources, in which case it would have already been accounted for as municipal use. It is assumed that the latter never occurs. We assumed that 60% of total water use is from groundwater in 2005 increasing to 100% in 2025 in the high scenario to account for overall movement to the west and south of the play, areas with globally less surface water available (Table 5). Similarly, increase is assumed from 60% to 80% in the medium scenario but fraction of groundwater use stays constant at 60% for the low case.

Table 11. Groundwater use as a percentage of total water use (county level).

County	Number of Wells	2005	2006	2007	Weighted Average
Bosque	26		60.0	60.0	60.0
Dallas	8	100.0	100.0	100.0	100.0
Denton	321	62.5	63.6	51.0	57.7
Ellis	27	50.0	50.0	45.0	47.5
Erath	65	60.0	61.7	71.3	66.3
Hill	54		62.5	62.5	62.5
Hood	307	45.0	36.7	62.0	50.5
Johnson	608	50.0	51.9	57.6	53.8
Montague	10			90.0	90.0
Parker	423	75.0	71.3	73.1	73.1
Somervell	65		50.0	50.0	50.0
Tarrant	791	43.8	45.0	45.6	45.0
Wise	240	75.0	75.0	51.3	59.2
Total	**2945**	**58.5**	**57.0**	**60.4**	**59.0**

Note: Data from Galusky (2006)

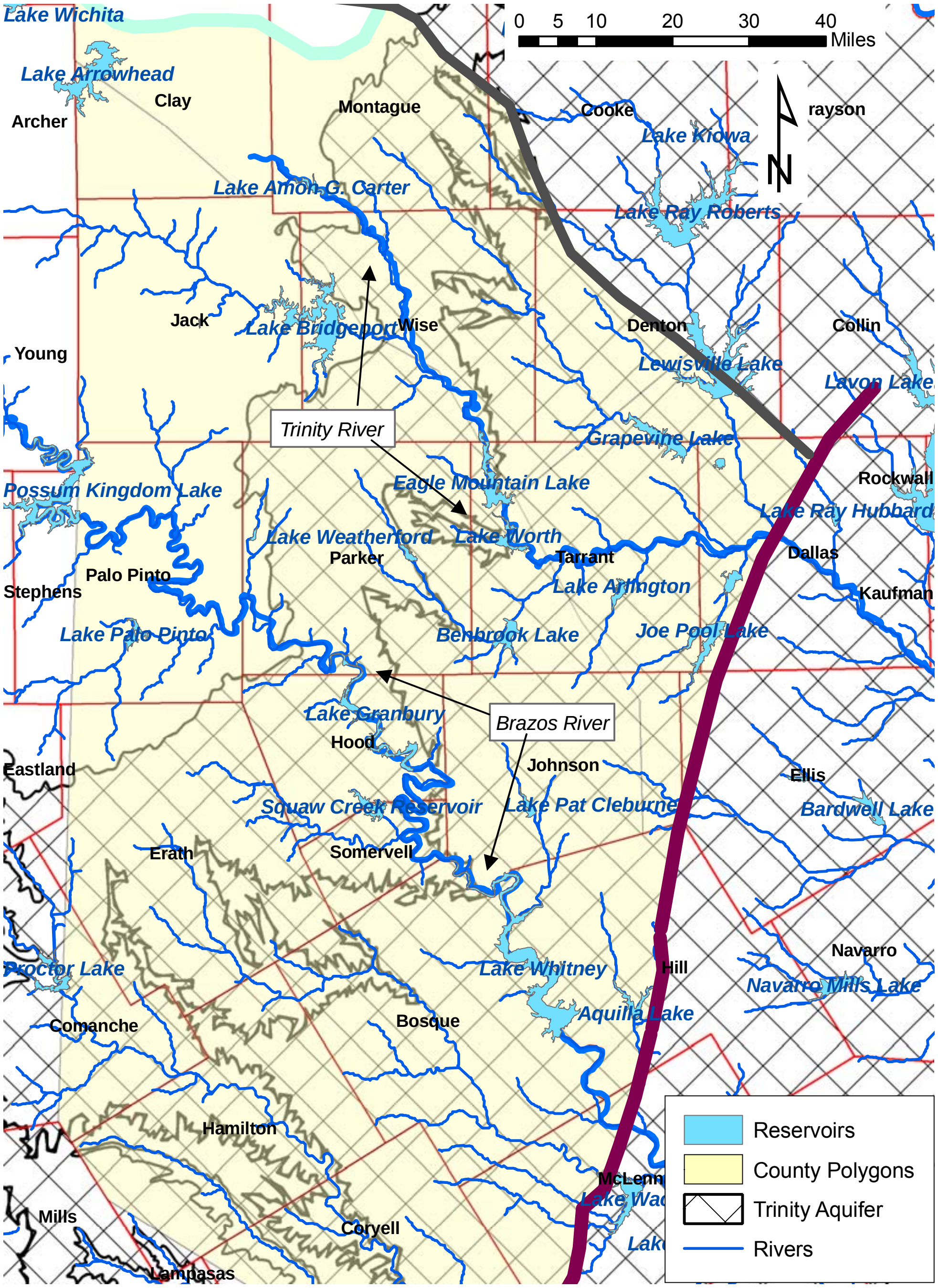
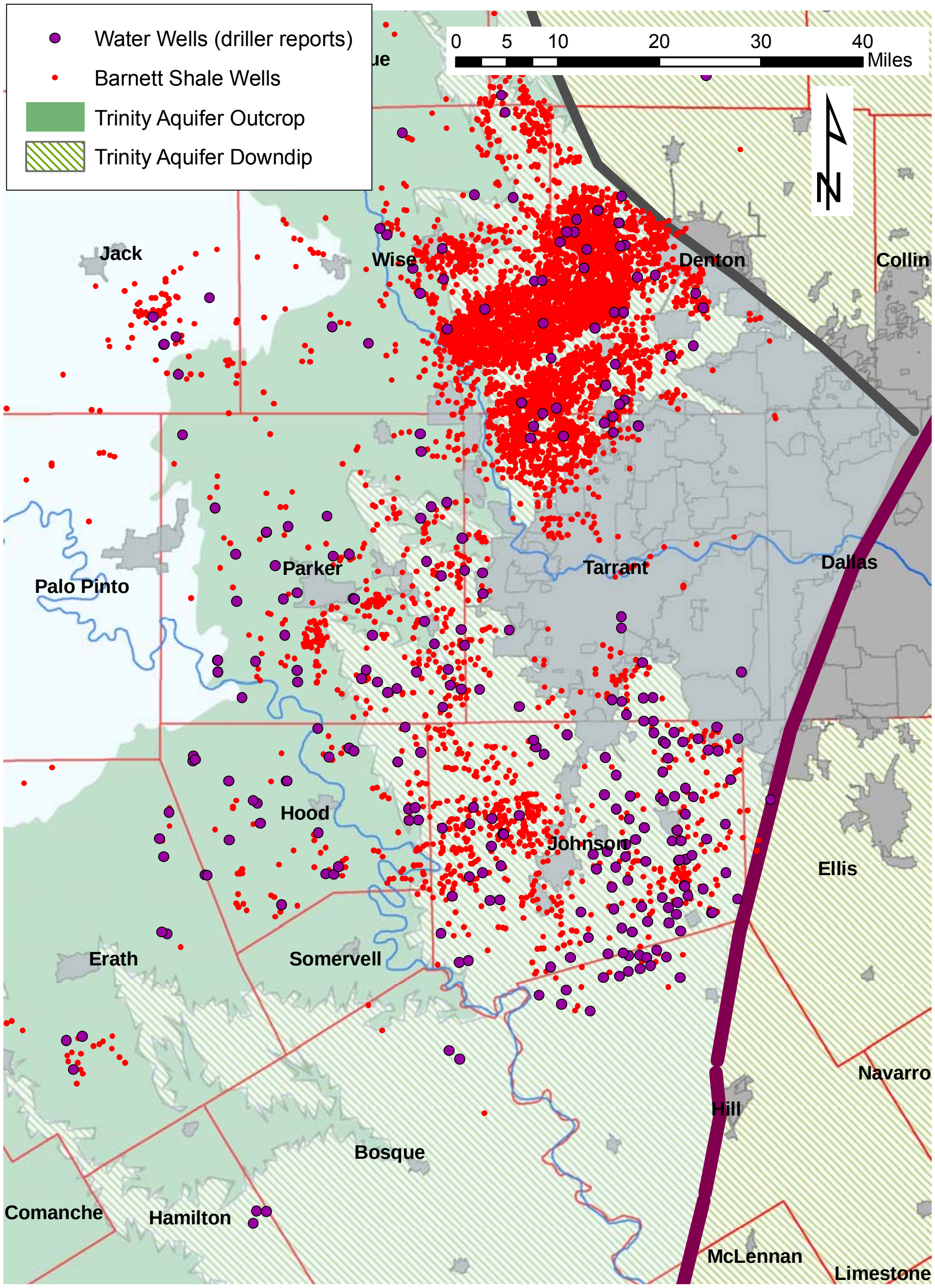


Figure 30. Rivers and reservoirs in the study area.



Note: only those water wells from applications submitted online are plotted

Figure 31. Selected water-supply wells in the study area.

V-2. Final Projections for Groundwater Use

This section provides final groundwater use by county polygons after all corrections have been done. The low scenario utilizes 29,000 AF of groundwater to the 2025 horizon, a clear retreat from current annual rate of water use by the industry, corresponding to a large drop in gas price or the development of sources of cheaper gas elsewhere (Figure 32). The high scenario calls for a total water use between 2007 and 2025 of 417,000 AF of groundwater. It corresponds to sustained gas prices, allowing operators to expand to all economically viable areas and produce most of the accessible resource, but also includes the assumption that water use is not limited. All scenarios assume that operators continue using water at a per-well rate similar to that of today and that no technological breakthrough will bring it down. The medium scenario, not necessarily the most likely, assumes a groundwater use of 183,000 AF. In the high scenario, groundwater use steadily climbs from ~5,000 AF/yr in 2005 to 20,000 AF/yr in 2010 and then slowly increases to a maximum of ~25,000 AF/yr in 2025. The medium scenario follows a similar path, climbing to a maximum of ~13,000 AF/yr in 2010, and then slowly decreases to ~7,500 AF/yr in 2025. Projections for the low scenario are approximately 29,000 AF.

Distributions by county polygons (Figure 33, Figure 34, Figure 35, Table 12, Table 13, and Table 14) follow a similar trend. Plots illustrate the staggered nature of the location of gas production because of the limit on the number of annual completions. The lack of smoothness of some individual county curves, especially in the high scenario, is due to the scaling process (Section V-4-5). It points out the actual competition for rigs in the play. Some rigs may leave a county, depicted by a slump in the curve, to more profitable areas and come back the next year in the same county. Some counties stand out in part because they have a large surface area.

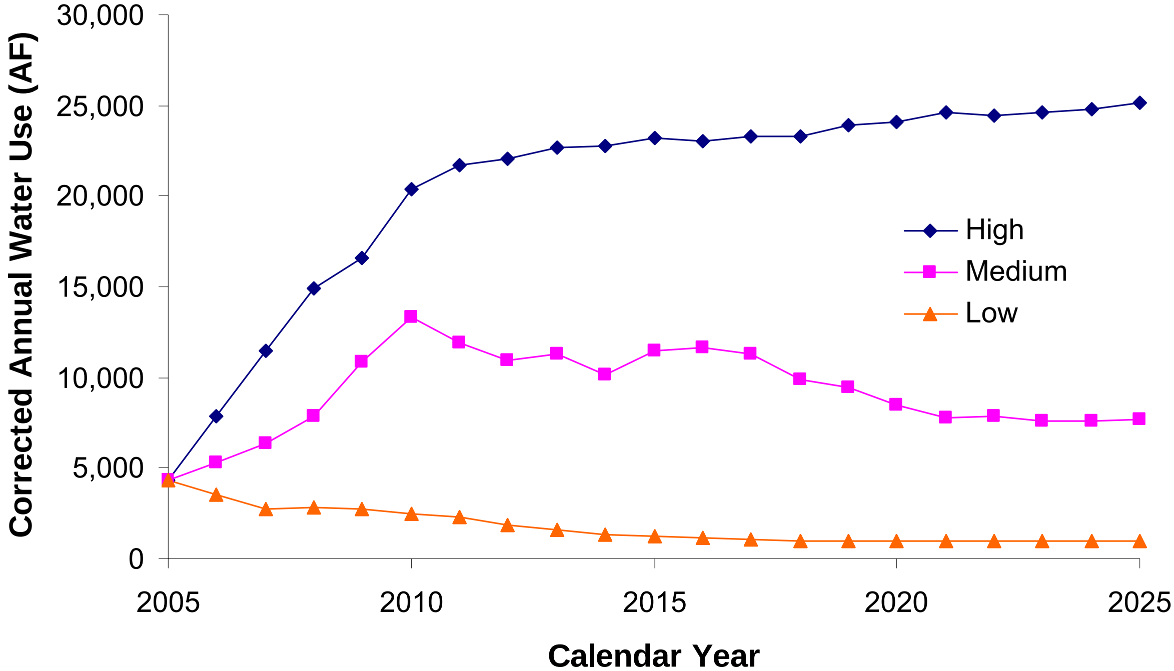


Figure 32. Groundwater annual water use for high, medium, and low scenarios.

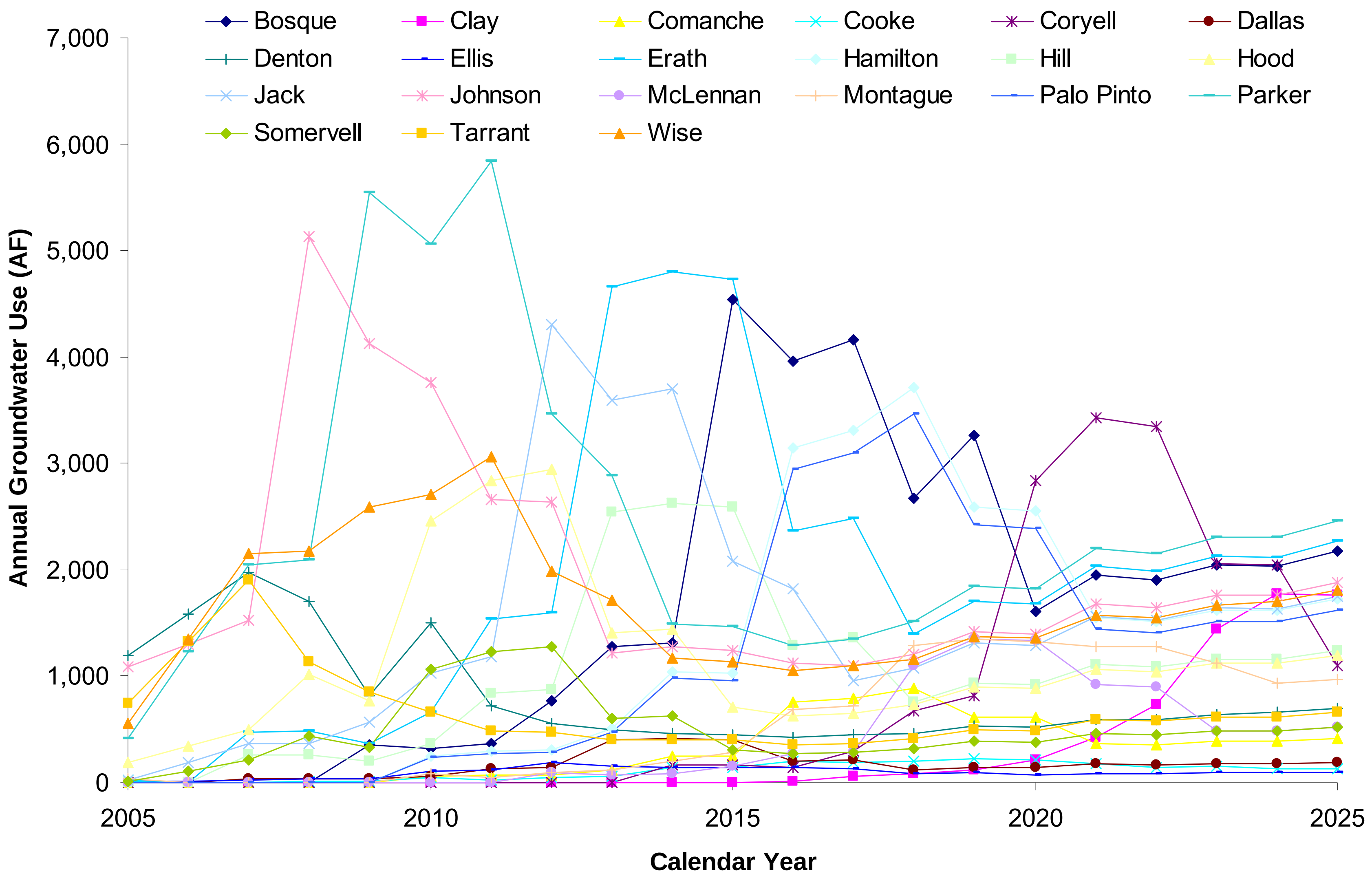


Figure 33. Groundwater annual water use per county polygon for the high scenario.

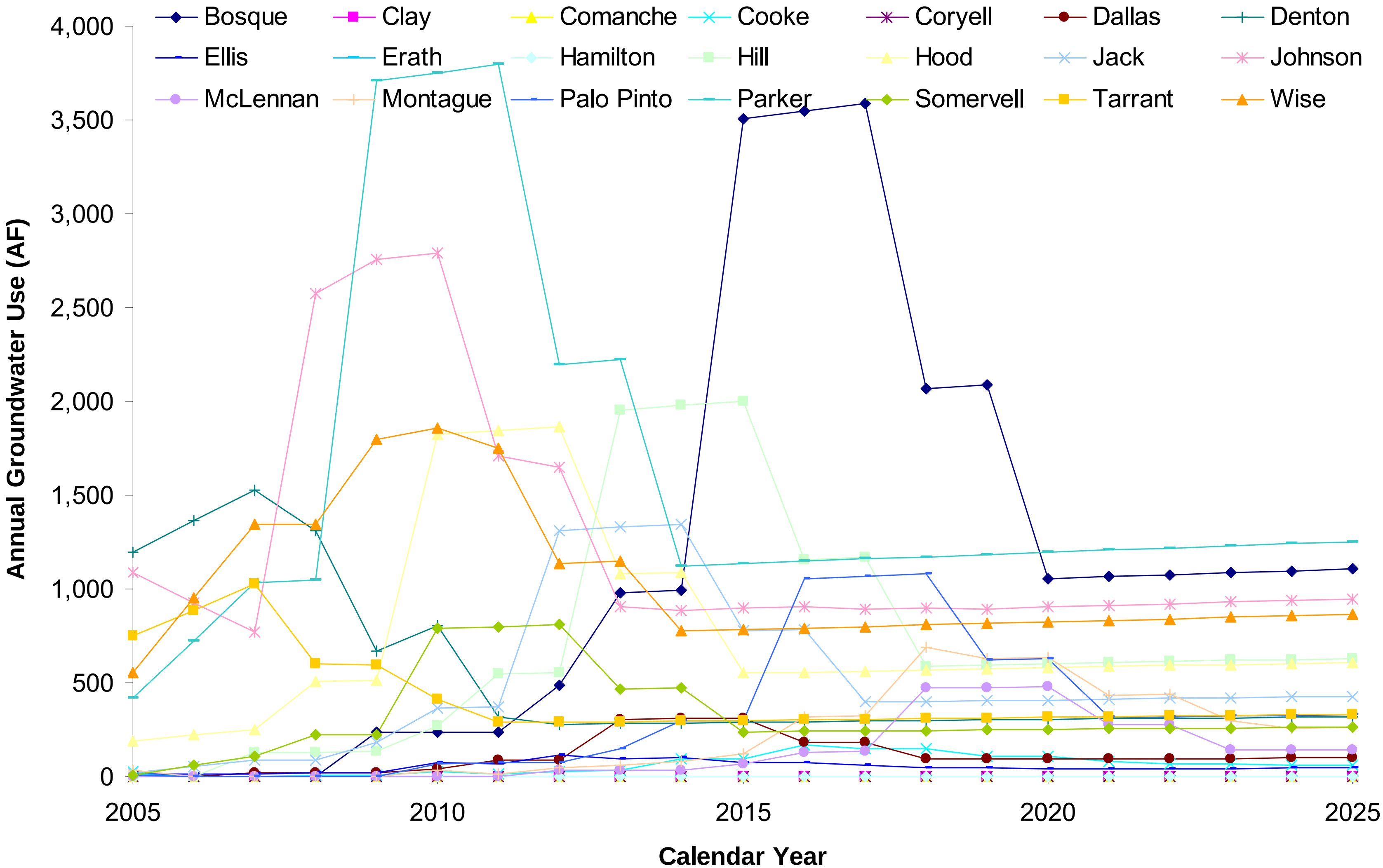


Figure 34. Groundwater annual water use per county polygon for the medium scenario.

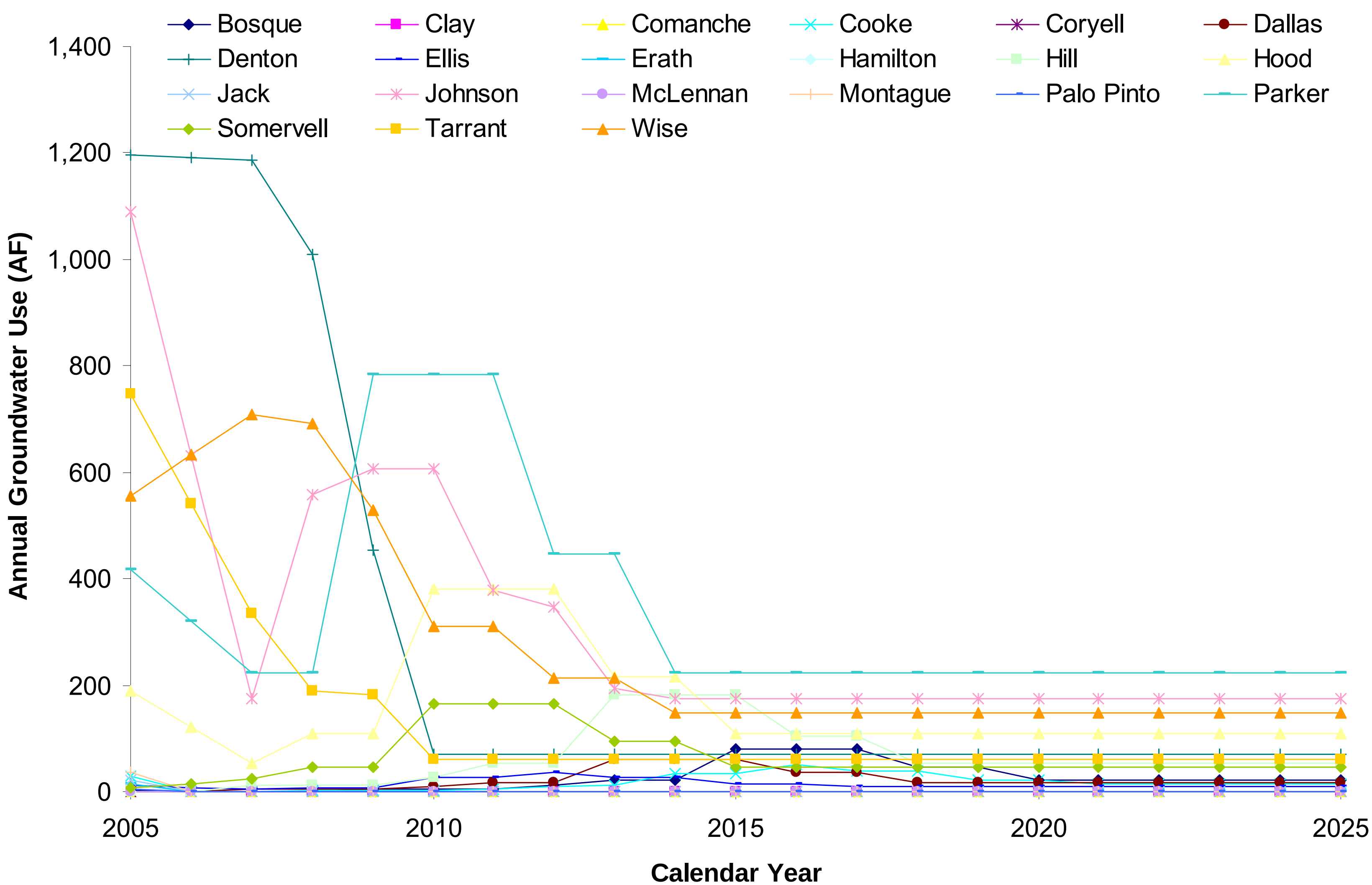


Figure 35. Groundwater annual water use per county polygon for the low scenario.

Table 12. Groundwater annual water use per county polygon for the high scenario (1000's AF).

County Polygon	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Bosque	0.00	0.00	0.00	0.00	0.35	0.32	0.37	0.77	1.28	1.32	4.54	3.97	4.17	2.67	3.26	1.61	1.95	1.90	2.04	2.03	2.17
ClayH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.04	0.05	0.10	0.25	0.25	0.93	0.92	0.99
ClayV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.04	0.07	0.11	0.18	0.48	0.52	0.85	0.77
Comanche	0.00	0.00	0.00	0.00	0.00	0.06	0.07	0.07	0.12	0.25	0.25	0.75	0.79	0.89	0.62	0.61	0.37	0.36	0.39	0.39	0.41
Cooke	0.03	0.01	0.00	0.01	0.01	0.05	0.02	0.04	0.05	0.14	0.14	0.20	0.19	0.20	0.22	0.22	0.18	0.14	0.15	0.13	0.14
Coryell	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.17	0.16	0.14	0.30	0.67	0.82	2.83	3.43	3.35	2.05	2.05	1.09
Dallas	0.00	0.02	0.04	0.04	0.03	0.06	0.13	0.14	0.40	0.41	0.41	0.20	0.21	0.12	0.15	0.14	0.17	0.17	0.18	0.18	0.19
DentonR	1.07	1.37	1.67	1.53	0.68	1.44	0.65	0.49	0.44	0.40	0.39	0.37	0.39	0.39	0.45	0.45	0.50	0.49	0.53	0.56	0.59
DentonU	0.13	0.22	0.31	0.18	0.14	0.06	0.07	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.08	0.08	0.09	0.09	0.10	0.10	0.11
Ellis	0.01	0.02	0.02	0.04	0.03	0.10	0.11	0.19	0.15	0.15	0.14	0.14	0.13	0.09	0.10	0.07	0.08	0.08	0.09	0.09	0.10
Erath	0.01	0.24	0.47	0.48	0.36	0.67	1.54	1.59	4.65	4.81	4.73	2.36	2.48	1.39	1.70	1.68	2.03	1.98	2.13	2.12	2.27
Hamilton	0.00	0.00	0.00	0.00	0.00	0.25	0.29	0.30	0.51	1.05	1.03	3.15	3.31	3.71	2.59	2.56	1.55	1.51	1.62	1.62	1.73
Hill	0.00	0.13	0.26	0.26	0.20	0.36	0.84	0.87	2.54	2.63	2.59	1.29	1.36	0.76	0.93	0.92	1.11	1.08	1.16	1.16	1.24
Hood	0.19	0.34	0.50	1.01	0.77	2.46	2.84	2.94	1.40	1.45	0.71	0.62	0.65	0.73	0.90	0.88	1.07	1.05	1.12	1.12	1.19
Jack	0.02	0.19	0.36	0.37	0.56	1.03	1.19	4.30	3.59	3.71	2.09	1.82	0.96	1.07	1.31	1.29	1.56	1.53	1.64	1.63	1.75
JohnsonH	0.98	1.19	1.40	5.01	3.80	3.47	2.29	2.38	0.99	1.02	1.01	0.88	0.92	1.04	1.27	1.25	1.51	1.48	1.58	1.58	1.69
JohnsonV	0.11	0.12	0.12	0.12	0.32	0.29	0.37	0.26	0.23	0.25	0.23	0.25	0.18	0.17	0.15	0.15	0.16	0.16	0.18	0.19	0.19
McLennan	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.08	0.08	0.15	0.27	0.28	1.11	1.35	1.33	0.92	0.90	0.48	0.48	0.51
Montague	0.04	0.02	0.00	0.00	0.00	0.08	0.04	0.10	0.12	0.20	0.29	0.68	0.72	1.29	1.34	1.33	1.27	1.28	1.12	0.94	0.97
Palo Pinto	0.01	0.00	0.00	0.00	0.00	0.24	0.27	0.28	0.47	0.98	0.96	2.94	3.09	3.47	2.42	2.39	1.44	1.41	1.51	1.51	1.61
Parker	0.42	1.23	2.05	2.09	5.54	5.06	5.85	3.46	2.89	1.49	1.47	1.28	1.35	1.51	1.85	1.82	2.20	2.15	2.31	2.30	2.46
Somervell	0.01	0.11	0.22	0.44	0.33	1.06	1.23	1.27	0.61	0.63	0.31	0.27	0.28	0.32	0.39	0.38	0.46	0.45	0.49	0.48	0.52
TarrantH	0.15	0.38	0.60	0.35	0.27	0.12	0.14	0.15	0.12	0.13	0.12	0.11	0.11	0.13	0.15	0.15	0.18	0.18	0.19	0.19	0.21
TarrantVR	0.25	0.24	0.22	0.16	0.11	0.32	0.09	0.07	0.06	0.06	0.05	0.05	0.05	0.05	0.06	0.06	0.07	0.07	0.08	0.08	0.08
TarrantVU	0.34	0.71	1.08	0.63	0.48	0.22	0.25	0.26	0.22	0.22	0.22	0.19	0.20	0.23	0.28	0.27	0.33	0.32	0.35	0.35	0.37
WiseH	0.05	0.38	0.70	0.71	1.90	1.73	2.00	1.19	0.99	0.51	0.50	0.44	0.46	0.52	0.63	0.62	0.75	0.74	0.79	0.79	0.84
WiseV	0.51	0.98	1.45	1.46	0.69	0.97	1.06	0.80	0.72	0.66	0.63	0.61	0.64	0.64	0.74	0.73	0.81	0.81	0.88	0.92	0.96
Total	**4.32**	**7.89**	**11.46**	**14.89**	**16.58**	**20.42**	**21.72**	**22.10**	**22.69**	**22.75**	**23.19**	**23.07**	**23.33**	**23.30**	**23.87**	**24.05**	**24.65**	**24.44**	**24.61**	**24.76**	**25.16**

Table 13. Groundwater annual water use per county polygon for the medium scenario (1000's AF).

County Polygon	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Bosque	0.00	0.00	0.00	0.00	0.23	0.24	0.24	0.48	0.98	0.99	3.51	3.55	3.58	2.07	2.09	1.06	1.07	1.08	1.09	1.10	1.11
ClayH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ClayV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Comanche	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cooke	0.03	0.01	0.00	0.00	0.00	0.03	0.02	0.02	0.03	0.09	0.09	0.17	0.15	0.15	0.11	0.11	0.08	0.07	0.07	0.06	0.06
Coryell	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dallas	0.00	0.01	0.02	0.02	0.02	0.04	0.09	0.09	0.31	0.31	0.31	0.18	0.18	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.10
DentonR	1.07	1.22	1.37	1.22	0.58	0.76	0.27	0.23	0.24	0.24	0.24	0.24	0.25	0.25	0.25	0.25	0.26	0.26	0.26	0.26	0.27
DentonU	0.13	0.14	0.16	0.09	0.09	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Ellis	0.01	0.01	0.01	0.02	0.02	0.07	0.07	0.11	0.10	0.10	0.08	0.08	0.06	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04
Erath	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hamilton	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hill	0.00	0.06	0.13	0.13	0.13	0.27	0.55	0.55	1.96	1.98	2.00	1.15	1.17	0.59	0.60	0.60	0.61	0.61	0.62	0.62	0.63
Hood	0.19	0.22	0.25	0.51	0.51	1.82	1.84	1.86	1.08	1.09	0.55	0.56	0.56	0.57	0.57	0.58	0.59	0.59	0.60	0.60	0.61
Jack	0.02	0.06	0.09	0.09	0.18	0.37	0.37	1.31	1.33	1.34	0.78	0.78	0.40	0.40	0.40	0.41	0.41	0.42	0.42	0.42	0.43
JohnsonH	0.98	0.84	0.71	2.51	2.54	2.57	1.49	1.51	0.76	0.77	0.78	0.79	0.80	0.80	0.81	0.82	0.83	0.84	0.84	0.85	0.86
JohnsonV	0.11	0.09	0.06	0.06	0.21	0.21	0.22	0.14	0.14	0.12	0.12	0.12	0.10	0.10	0.08	0.08	0.08	0.09	0.09	0.09	0.09
McLennan	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.03	0.03	0.07	0.13	0.13	0.47	0.48	0.48	0.28	0.28	0.14	0.14	0.14
Montague	0.04	0.02	0.00	0.00	0.00	0.03	0.01	0.05	0.06	0.08	0.12	0.32	0.32	0.69	0.63	0.63	0.44	0.44	0.30	0.26	0.26
Palo Pinto	0.01	0.00	0.00	0.00	0.00	0.07	0.07	0.07	0.15	0.30	0.30	1.06	1.07	1.08	0.62	0.63	0.32	0.32	0.32	0.33	0.33
Parker	0.42	0.73	1.03	1.05	3.71	3.75	3.80	2.20	2.22	1.12	1.14	1.15	1.16	1.17	1.18	1.20	1.21	1.22	1.23	1.24	1.25
Somervell	0.01	0.06	0.11	0.22	0.22	0.79	0.80	0.81	0.47	0.47	0.24	0.24	0.24	0.25	0.25	0.25	0.25	0.26	0.26	0.26	0.26
TarrantH	0.15	0.23	0.30	0.18	0.18	0.09	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
TarrantVR	0.25	0.22	0.18	0.11	0.10	0.16	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04
TarrantVU	0.34	0.44	0.54	0.32	0.32	0.16	0.16	0.17	0.17	0.17	0.17	0.17	0.17	0.18	0.18	0.18	0.18	0.18	0.19	0.19	0.19
WiseH	0.05	0.20	0.35	0.36	1.27	1.28	1.30	0.75	0.76	0.38	0.39	0.39	0.40	0.40	0.40	0.41	0.41	0.42	0.42	0.42	0.43
WiseV	0.51	0.75	0.99	0.98	0.53	0.57	0.45	0.38	0.39	0.39	0.40	0.40	0.40	0.41	0.41	0.42	0.42	0.42	0.43	0.43	0.44
Total	**4.32**	**5.32**	**6.31**	**7.87**	**10.85**	**13.34**	**11.92**	**10.94**	**11.33**	**10.15**	**11.45**	**11.66**	**11.32**	**9.89**	**9.40**	**8.43**	**7.76**	**7.82**	**7.60**	**7.62**	**7.69**

Table 14. Groundwater annual water use per county polygon for the low scenario (1000's AF).

County Polygon	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Bosque	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.08	0.08	0.08	0.05	0.05	0.02	0.02	0.02	0.02	0.02	0.02
ClayH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ClayV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Comanche	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cooke	0.03	0.01	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.03	0.03	0.05	0.04	0.04	0.02	0.02	0.01	0.01	0.01	0.01	0.01
Coryell	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dallas	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.06	0.06	0.06	0.04	0.04	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
DentonR	1.07	1.11	1.15	0.99	0.43	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
DentonU	0.13	0.08	0.03	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Ellis	0.01	0.01	0.00	0.01	0.01	0.03	0.03	0.04	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Erath	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hamilton	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hill	0.00	0.01	0.01	0.01	0.01	0.03	0.05	0.05	0.18	0.18	0.18	0.10	0.10	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Hood	0.19	0.12	0.05	0.11	0.11	0.38	0.38	0.38	0.22	0.22	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Jack	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
JohnsonH	0.98	0.56	0.15	0.54	0.54	0.54	0.31	0.31	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
JohnsonV	0.11	0.07	0.02	0.02	0.07	0.07	0.07	0.04	0.04	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
McLennan	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Montague	0.04	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Palo Pinto	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Parker	0.42	0.32	0.22	0.22	0.78	0.78	0.78	0.45	0.45	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Somervell	0.01	0.01	0.02	0.05	0.05	0.16	0.16	0.16	0.09	0.09	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
TarrantH	0.15	0.11	0.07	0.04	0.04	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
TarrantVR	0.25	0.20	0.15	0.08	0.08	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
TarrantVU	0.34	0.23	0.12	0.07	0.07	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
WiseH	0.05	0.06	0.06	0.06	0.23	0.23	0.23	0.13	0.13	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
WiseV	0.51	0.57	0.64	0.63	0.30	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Total	**4.32**	**3.52**	**2.73**	**2.85**	**2.74**	**2.45**	**2.25**	**1.81**	**1.60**	**1.31**	**1.20**	**1.12**	**1.10**	**1.00**	**0.98**	**0.96**	**0.95**	**0.95**	**0.95**	**0.95**	**0.95**

VI. Conclusions

In this work, we carried out an estimation of water use by the oil and gas industry in North Texas as a result of gas production from the Barnett Shale. We presented historical information showing the sharp increase in well completions, as well as in water use, in the past few years. The exploration boom started in Wise and Denton Counties but is currently expanding southward and westward in the core area. Using geological public knowledge and cues from operators, we defined three scenarios that vary in their spatial coverage and water-use attributes. There are still major uncertainties related to evolution of the play: will the price of natural gas stay at its current level or increase or decrease? Is water use by the average frac job going to decrease significantly because of technological progress? Is water recycling going to make up for a possible larger number of annual completions? The numbers provided are reasonable. The high scenario yields a total groundwater use of 417,000 AF, an annual average groundwater use of 22,000 AF over the 2007-2015 period, and a cumulative areal groundwater use of 0.05 AF/acre. The medium and low scenarios utilize a total 183,000 and 29,000 AF of groundwater for an annual average of ~10,000 and 1,500 AF, and a cumulative areal groundwater use of ~0.04 and 0.009 AF/acre, respectively. As evidenced by the large range in the results, much uncertainty remains, including in the spatial distribution of those regional averages.

VII. References

DOE, 2004, Technology to clean produced water for beneficial use: Office of Energy, Eye on Environment, Spring 2005, 10(1), p.1 and ff.

Fisher, M.K., J.R. Heinze, C.D. Harris, B.M Davidson, C.A. Wright, and K.P. Dunn, 2004, Optimizing Horizontal Completion Techniques in the Barnett Shale Using Microseismic Fracture Mapping: SPE Paper 90051.

Galloway, W.E., T.E. Ewing, C.M. Garrett, N. Tyler, and D.G. Bebout, 1983, Atlas of major Texas oil reservoirs: The University of Texas at Austin, Bureau of Economic Geology, 139 p.

Galusky, Jr. L. P. 2006. Hydrological consultant to the Barnett Shale Water Conservation and Management Committee. Personal communication. Final report to be published in January 2007.

Givens, N. and H. Zhao, 2005, The Barnett Shale: not so simple after all: AAPG Bulletin, 89; also on PTTC Website, http://www.energyconnect.com/pttc/archive/emgi-june8-92005.htm, last accessed 10/22/2006.

Grieser, B., B. Shelley, B.J. Johnson, E.O. Fielder, J.R. Heinze, and J.R. Werline, 2006, Data Analysis of Barnett Shale Completions: SPE Paper 100674.

Hardage, B.A., D.L. Carr, D.E. Lancaster, J.L. Simmons Jr., R.Y. Elphick, V.M. Pendleton, and R.A. Johns, 1996, Find more like this: 3-D seismic evidence of the effects of carbonate karst collapse on overlying clastic stratigraphy and reservoir compartmentalization: Geophysics 61(5) 1336-1350.

Jarvie, D.M., B.L. Claxton, F. Henk, and J.T. Breyer, 2001, Oil and Shale Gas from the Barnett Shale, Ft. Worth Basin, Texas (abs.): AAPG Bulletin, 85(13).

Ketter, A.A., J.L. Daniels, J.R. Heinze, and G. Waters, 2006, A Field Study Optimizing Completion Strategies for Fracture Initiation in Barnett Shale Horizontal Wells: SPE Paper 103232.

Kosters, E.C., D.G. Bebout, S.J. Seni, C.M. Garrett, Jr., L.F. Brown, Jr., H.S. Hamlin, S.P. Dutton, S.C. Ruppel, R.J. Finley, and N. Tyler, 1989, Atlas of major Texas gas reservoirs: The University of Texas at Austin, Bureau of Economic Geology, 161 p.

Lohoefer, D., J. Athans, and R. Seale, 2006, New Barnett Shale Horizontal Completion Lowers Cost and Improves Efficiency: SPE paper 103046.

Loucks, R.G., P.K. Mescher, and G.A. McMechan, 2004, Three-dimensional architecture of a coalesced, collapsed-paleocave system in the Lower Ordovician Ellenburger Group, central Texas: AAPG Bulletin, 88(5), p. 545-564.

Mace, R.E., J.-P. Nicot, A.H. Chowdhury, A.R. Dutton, and S. Kalaswad, 2006, Please Pass the Salt: Using Oil fields for the Disposal of Concentrate from Desalination Plants: Texas Water Development Board, Report 366, 198 p.

Martinez, S.J., R.E., Steanson, and A.W. Coulter, 1987, Formation Fracturing, Chapter 55 in Petroleum Engineering Handbook by Bradley, H. B.: Society of Petroleum Engineers, Richardson, TX.

McDonnell, A., T. Dooley, and R. Loucks, 2006a, Collapse/sag features in northern Fort Worth Basin, Texas: suprastratal deformation associated with coalesced paleocave system collapse or wrench fault sags? (abs.), AAPG Convention Official Program, v. 15, p. 71.

McDonnell, A., R.G. Loucks, and T. Dooley, 2006b, Paleocollapse megastructures (suprastratal deformation) related to Lower Ordovician Ellenburger coalesced, collapsed-paleocave systems in the northern Fort Worth Basin, Texas (abs.), *in* Southwest Section AAPG annual meeting: Permian Basin oil: good to the last drop, May 22–24, Midland, Texas, unpaginated.

Montgomery, S.L., D.M. Jarvie, K.A. Bowker, and R.M. Pollastro, 2005, Mississippian Barnett Shale, Fort Worth basin, north-central Texas: Gas-shale play with multitrillion cubic foot potential: AAPG Bulletin, 89(2), p.155-175.

Moore, L.P., and H. Ramakrishnan, 2006, Restimulation: Candidate Selection Methodologies and Treatment Optimization: SPE paper 102681.

Pollastro, R.M., R.J. Hill, D.M. Jarvie, and M.E. Henry, 2003, Assessing undiscovered resources of the Barnett-Paleozoic Total Petroleum System, Bend Arch-Fort Worth Province, Texas, *in* AAPG Southwest Section Convention, Fort Worth, Texas, March 1–5.

Rach, N.M., 2005. Small operator pumps big frac in North Texas Barnett Shale: Oil & Gas Journal, March, p. 41.

Ridgeway, C., 2006, Barnett Shale study area water well analysis using Texas Department of Licensing and Regulation driller's report records: Groundwater Resources Division, Texas Water Development Board, Analysis Paper 06-28, 9 p.

R.W. Harden & Associates, 2004, Northern Trinity / Woodbine Aquifer Groundwater Availability Model: report prepared for the Texas Water Development Board, variously paginated.

Schein, G. W., P. D. Carr, P. A. Canan; R. Richey, 2004, Ultra Lightweight Proppants: Their Use and Application in the Barnett Shale: SPE paper 90838 presented at the SPE Annual Technical Conference and Exhibition, 26-29 September, Houston, Texas

Schmoker, J.W., J.C. Quinn, R.A. Crovelli, V.F. Nuccio, T.C. Hester, 1996, Production characteristics and resource assessment of the Barnett Shale continuous (unconventional) gas accumulation, Fort Worth Basin, Texas: U.S. Geological Survey Open File Report OFR 96-254, 20 p.

Shirley, K., 2002, Barnett Shale living up to potential: AAPG Explorer July.

Texas Drilling Observer, 2006, Agency approves another pilot frac. Fluid recycling operation in Barnett Shale gas play: Texas Drilling Observer, 8(40).

USGS, 2004, Assessment of Undiscovered Oil and Gas Resources of the Bend Arch-Fort Worth Basin Province of North-Central Texas and Southwestern Oklahoma, 2003: U.S. Geological Survey Fact Sheet 2004-3022, 2 p.

Wright, C.A. and L. Weijers, 1991, Hydraulic fracture reorientation: Does it occur? Does it matter? The Leading Edge, 20, p.1185-1189.

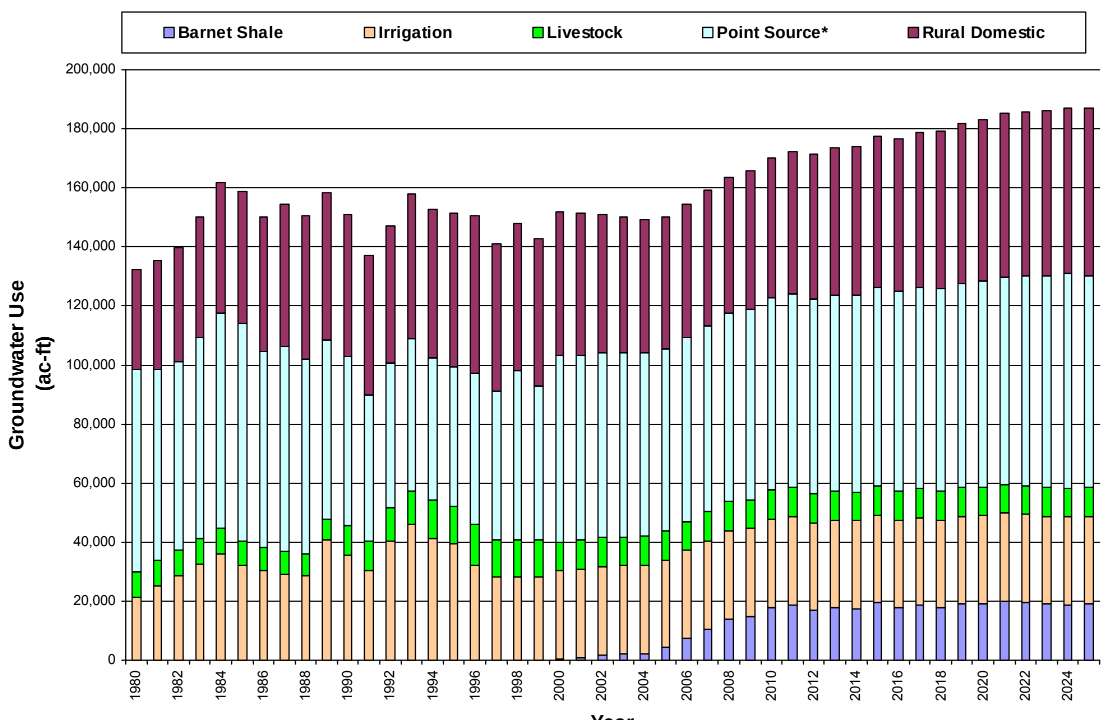
Appendix : Responses to Comments

Comments by TEXERRA

Well restimulation. I believe that the anticipated water use for refracturing (restimulating) vertical wells is overestimated. In speaking with senior geologists of major players in the Barnett, it is not certain that refracturing vertical wells will happen widely and/or uniformly. Thus, I would be inclined to substantially adjust downward the projected water use attributed to vertical well refracturing. If I were to venture a guess, I would take it from 100% of vertical wells to something like 25%.

No horizontal well is assumed restimulated. However 100%, 50%, and 0% of the vertical wells are assumed restimulated in the high, medium, and low scenarios, respectively. Since only 1 recompletion per vertical well is assumerd, the final results are not much impacted. Except from 2007 to 2010 where most of the vertical wells are recompleted (in my projections), recompletion water use adds up to less than 5% of total Barnett water use, which is itself a small fraction of total water use from all usages (see figure below). Wording has been changed in the report.

Groundwater Use - High Estimate



Consists of Municipal, Manufacturing, Mining and/or Power groundwater use.

Comments by the Railroad Commission of Texas

2. In Appendix 2, BEG indicates that it did not consider that the number of wells that could be drilled would be limited by rig availability. Rig availability will be a very important limiting factor when you consider BEG's estimate of an increase from 3000 wells to over 5000 wells per year.
On the contrary, rig availability is a big part of BEG predictions as explained in the "Operational Controls" section in page 2-48 and again in page 2-64. The methodology adopted by BEG to estimate water use was first to produce a "hypothetical maximum water use" that does not account for rig availability. This led to a large number of annual well completions (>5,000 /yr) that was actually capped by rig availability in the following sections.

3. In Appendix 2, the tables are NOT adequately described and in many there is no indication of the units or whether the "water" is ground water, surface water or both. The result is that the tables are confusing and/or misleading in several instances. (I like the way TWDB draft explains its tables.)
Details were added to all tables as well as units when missing.

1. Page 2-13, Figure ?????, Add explanation as to what the white/non-colored dots signify.
Explanation added

2. Page 2-19, dots are too small to be able to distinguish vertical from horizontal from unknown well...
The purpose of the multi-picture figure is to show the growth of the play through time. The changes through time of the blue and red patches (with no need to tell individual well apart) convey the information.

3. Page 2-22, Table 1, Not clear if this is groundwater use or groundwater AND surface water use...
This total water use in AF/yr. Changes made.

4. Page 2-25, 2nd paragraph, second sentence, typo - "his" to "this" ?? Also, according to what??
"his" should read "IHS Energy" (information provider for the oil and gas industry) – correction made

5. Page 2-26, Figure 9: There is no key to this figure. Table 3, Annual completions Statistics on Barnett Shale. Why are these numbers so different?
Figure 9. Arrows show the plotted parameter.
Table 3. BEG kept only those well completion numbers it has a handle on, that is, those provided by vendors. RRC numbers were deleted. There were available from the RRC web site at http://www.rrc.state.tx.us/divisions/og/wateruse_barnettshale.html but no information was given on how the numbers were derived.
In reality, numbers from industry vendors and from RRC are not that different and the small discrepancy has not impact on the water use projections. Table below displays the original table:

Year	DrillingInfo / IHS Energy				RRC		
	H	V	U	**Total**	H	V	**Total**
≤2000	14	703	42	**759**			
2001	22	424	27	**473**	0	368	**368**
2002	50	745	23	**818**	6	711	**717**
2003	195	685	38	**918**	331	532	**863**
2004	359	430	100	**889**	337	490	**827**
2005	679	242	122	**1043**	714	256	**970**
Total	1319	3229	352	**4900**			

6. Page 2-31, 1st paragraph, third sentence: Injection of frac fluids IS NOT underground injection regulated under the federal Safe Drinking
Water Act (or the RRC's delegated Underground Injection Control, (UIC) program), and, therefore, a well that is frac'd IS NOT a Class V or any other class of UIC well. My recommendation is to replace that sentence with the following: "Railroad Commission regulations prohibit pollution of surface and subsurface water during drilling, treating, producing, and plugging of oil and gas wells."
Change made.

7. Page 2-34, Table 5, Parameters used in the water-use projection: "Groundwater Use Expressed as % of Total Water Use." Not clear if this is groundwater use as a % of total surface and groundwater use or ground water use for Barnett Shale expressed as a percent of total water use for all purposes...This table is one of the most important and is the
most confusing.....
Table 5 does summarize the report and the methodology but it is not a stand-alone table. Explanations to the table data is detailed in the text.

8. Page 2-47, second paragraph under "Well Spacing-Infilling": "If vertical density is suggested by the RRC regulations, currently no consistent one is enforced relative to horizontal wells." I have no idea what this sentence means, since the RRC has very specific field rules for spacing of gas wells in the Newark field.
BEG’s understanding is that these rules are mostly applicable to vertical wells (or rather to wellheads) but none exists for multilateral horizontal wells where numerous laterals can originate from a single wellhead. Explanations added in text.

9. Page 2-51, Table 6: This table is also very confusing and needs some brief explanation, rather than make the reader go back and search the text....
Explanations added to the table

10. Page 2-59, Table 8: I am confused as to why the "prospectivity Factor A" is "1" for Dallas, Denton U and Tarrant H (will take time to drill in urban areas) and Tarrant VU (mostly done already where possible). Seems these could have a factor somewhat less than "1".
As indicated in the table, there is a start date associated with each county polygon. A prospectivity factor/ risk of 1 means that the whole county polygon has been or will be subject to gas production with a dense coverage of wells. In essence, historical data shows that a choice of

prospectivity factor of 1 in 1996 for Denton County was justified. Denton Rural county polygon is currently mostly developed. A prospectivity/risk factor of 1 means that what is left to develop will be done thoroughly.

11. Page 2-60, "...This high water use is not sustainable because it corresponds to more than 5,000 annual well completions. In a previous section, we mentioned and assumed that more than 3,000 completions a year is unlikely." This indicates to me that the "High" scenario is completely unrealistic - a fact that should be reflected in the TWDB
report (rather than be buried in BEG's Appendix).
The text specifies that the high scenario is limited at 3,000 completions / yr. The >5000 completions /yr corresponds to "uncorrected" values that are then corrected by the limited availability of rigs. Some confusion may have arisen between "high water use" and "high scenario" . The expression "high water use" was changed to "large water use" to address this. BEG do not agree that the "high scenario" is completely unrealistic. As explained in several instances in the text, the "high scenario" is a reasonably conservative estimate corresponding to high gas prices.

12. Page 2-62 and on, Table 9: There are several lines in which there are two values when there should only be one - OR there should be some explanation.
Explanations added

13. Page 2-66 and 2-67, Table 10: Same comment as #12 above. Also, need to indicate if the "corrected annual water use.." is groundwater or all sources.
Explanations added

14. Page 2-68, 4th paragraph, 2nd sentence: "...it is assumed that all groundwater is accounted for nowhere else." This phrase does not make sense to me. Could it be clarified?
Sentence clarified from "The fraction of groundwater initially originating from municipal sources is not provided, and it is assumed that all groundwater is accounted for nowhere else. to "Galusky (2006) does not specify if the groundwater origin is from municipal sources, in which case it would have already been accounted for as municipal use. It is assumed that the latter never occurs. "

15. Page 2-69, Table 11, Need units.
Legend should read "percentage" (varying from 0 to 100) rather than fraction (varying from 0 to 1). Legend corrected.

16. Page 2-72: Include some of the explanation on water use limits and rig availability and competition in bulk of the report. These are important assumptions....
See answer to RRC Comment 2 and 5.

Comments by TWDB:

(numbering matches stand-alone BEG report provided to both R.W. Harden and TWDB)

Page i, Paragraph 1: Please check whether the total water use value of 8,000 ac-ft reported for 2005 is accurate in light of the number of wells and water use per well. It was reported that more than 5,600 wells were producing gas from the Barnett Shale and each vertical well uses 1.2 million gallons and each horizontal well uses 3.0 to 3.5 million gallons.

There are only ~1,000 completions/year – the 5,600 figure includes wells stimulated in the previous years. The 8,000 AF agrees well with the ~10,000 AF approximate value provided by RRC on their web page for 2005.

Pages 8 and 9: Figures 4 and 5 are not legible particularly the color zones and the legend. Please consider presenting clearer figures.

Those maps were scanned from larger paper copies. The version presented in the final report has a clearer legend.

Survey data incorporated from Galusky (2006) has been frequently discussed in the text. Please consider including the complete survey results from Galuskey (2006) in a table or in an appendix and make cross-reference to it if there is more information available than what was presented in Table 9.

Pete Galusky will publish his survey's final results in January 2007. This BEG report used Pete's input as the information became available. However, because of the timing discrepancy, only partial and preliminary data were used.

Page 7, Figure 3 legend covers Montague County which is discussed in the text (page 5) relative to this figure. Please consider adjusting the location of the legend so the points made in the text are clearly legible in the figure.

Change made

Page 44. The report states the high scenario yields high water use, for example >50 AF in 2016. Please consider correcting to >50,000 AF in 2016.

Change made

Page 47. The report states that an average water use of 1.3 MGal/vertical well and 3.6 MGal/horizontal well is assumed, however on page 20 the report states average water use of 1.2 MGal/vertical well and 2.65 MGal/horizontal well. Please consider clarifying which value was considered in the final estimation of water use and adjust the text accordingly to maintain consistency.

1.3 MGal has been changed to 1.2 MGal for vertical wells (1.2 was used in the calculations). Neither value is used for horizontal well projections. They are done using water use / linear of lateral not the water use / well because there is too much variability. The 3.6 MGal is used to compute the number of annual completion and comes from preliminary results of Pete Galusky's survey of the industry trends in the next few years. The 2.65 MGal includes historical data but it seems that laterals are currently getting longer translating into a larger water use per well. The 3.6 MGal value is subsequently applied to all future wells.

Page 52, Figure 30: Please consider describing the differences between grey and darker shaded squares in the legend. If there is no difference, please make the squares the same levels of grey.
Figure fixed

Comments by Barnett Shale Water Management and Conservation Committee

- Appendix 2. Tables 1 & 2. Need explanation of the key. H =? V = ? etc.

Key added.

- Appendix 2. Figure 20. Please explain "Viola".

Presence or not of Viola Limestone as explained in the paragraph following the figure – key added

- What was the basis for choosing the levels of well completion activity between the High and Low Groundwater Use Figures of Appendix 3? Sometimes the well activity jumps from zero to 200 to 400 wells per year in both cases ---- and sometimes the level of well development goes from zero to several hundred wells per year between the Low and the High Groundwater Use Scenarios. How were these levels arrived at? The years of well installation are compressed to about 3-8 years. How was this decision made?

Those are soft number derived by consensus between the authors of the report through discussions with company geologists and engineers. Time and budget constraints did not allow for an in-depth analysis.

- Need more transparency for assumptions and data sources that were used to construct the report and the appendices. Methods for rollups need to be made more clear.

As mentioned in the previous response, a lot of (educated) guess work went into the projections. There is no other data source than those mentioned in the report.. Some more explanations were added in the text.

Comments by TCEQ

- It is stated that refrac'ing wells every few years does improve the total production, yet you chose to show that wells are refrac'ed only once after 5 years in the high demand scenario. If the price of gas remains high, isn't it likely that at least a percentage of the total wells would be refrac'ed more than once in the time period in question? And only one refrac'ing in the medium demand scenario.

The scenario proposed in the comment was also our initial understanding of the play and the way we planned to compute total water use. However, after discussions with engineers and managers from oil&gas companies involved in the play, we realized that refrac'ing of wells was not a common strategy to get the most out of the play (see comment by Texerra). Operators would rather optimize the initial frac jobs. This is particularly true of horizontal wells where spacing of laterals and distance between frac jobs in a given lateral can be adapted to local conditions.

- Why is refrac'ing of horizontal wells completely left out of the all demand scenario? Again, in the high demand scenario, if prices remain high, isn't it likely that they will refract the horizontal wells as well? If not, why not?

See response to previous comment