Gas, Oil, and Water Production from Wattenberg Field in the Denver Basin, Colorado

By Philip H. Nelson and Stephen L. Santus

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Conversion Factors

Inch/Pound to SI

Multiply	By	To obtain
	Length	
foot (ft)	0.3048	meter (m)
mile (mi)	1.609	kilometer (km)
	Volume	
barrel (bbl), (petroleum, 1 barrel=42 gal)	0.1590	cubic meter (m^3)
cubic foot (ft^3)	0.02832	cubic meter (m^3)
	Flow rate	
cubic foot per day (ft^3/d)	0.02832	cubic meter per day (m^3/d)
	Pressure	
atmosphere, standard (atm)	101.3	kilopascal (kPa)
bar	100	kilopascal (kPa)
pound per square inch (lb/in^2)	6.895	kilopascal (kPa)
	Density	
pound per cubic foot (lb/ft^3)	16.02	kilogram per cubic meter (kg/m^3)
pound per cubic foot (lb/ft^3)	0.01602	gram per cubic centimeter (g/cm^3)

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By Philip H. Nelson and Stephen L. Santus[1]

Abstract

Gas, oil, and water production data were compiled from selected wells in two tight gas reservoirs—the Codell-Niobrara interval, comprised of the Codell Sandstone Member of the Carlile Shale and the Niobrara Formation; and the Dakota J interval, comprised mostly of the Muddy (J) Sandstone of the Dakota Group; both intervals are of Cretaceous age—in the Wattenberg field in the Denver Basin of Colorado. Production from each well is represented by two samples spaced five years apart, the first sample typically taken two years after production commenced, which generally was in the 1990s. For each producing interval, summary diagrams and tables of oil-versus-gas production and water-versus-gas production are shown with fluid-production rates, the change in production over five years, the water-gas and oil-gas ratios, and the fluid type. These diagrams and tables permit well-to-well and field-to-field comparisons. Fields producing water at low rates (water dissolved in gas in the reservoir) can be distinguished from fields producing water at moderate or high rates, and the water-gas ratios are quantified.

The Dakota J interval produces gas on a per-well basis at roughly three times the rate of the Codell-Niobrara interval. After five years of production, gas data from the second samples show that both intervals produce gas, on average, at about one-half the rate as the first sample. Oil-gas ratios in the Codell-Niobrara interval are characteristic of a retrograde gas and are considerably higher than oil-gas ratios in the Dakota J interval, which are characteristic of a wet gas. Water production from both intervals is low, and records in many wells are discontinuous, particularly in the Codell-Niobrara interval. Water-gas ratios are broadly variable, with some of the variability possibly due to the difficulty of measuring small production rates. Most wells for which water is reported have water-gas ratios exceeding the amount that could exist dissolved in gas at reservoir pressure and temperature.

The Codell-Niobrara interval is reported to be overpressured (that is, pressure greater than hydrostatic) whereas the underlying Dakota J interval is underpressured (less than hydrostatic), demonstrating a lack of hydraulic communication between the two intervals despite their proximity over a broad geographical area. The underpressuring in the Dakota J interval has been attributed by others to outcropping strata east of the basin. We agree with this interpretation and postulate that the gas accumulation also may contribute to hydraulic isolation from outcrops immediately west of the basin.

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[1] University of Colorado at Denver, Denver, Colorado

Introduction

Tight gas sandstones are now an important contributor to gas production in the United States. Despite this success, many questions remain concerning the nature of fluids in tight (low-permeability) gas systems. This study is part of an ongoing effort to examine the early production from a number of tight gas systems in the Rocky Mountain region of the United States (Nelson and Hoffman, 2009; Nelson and others, 2009a,b; Nelson and Santus, 2010). Early production, rather than cumulative production, is examined in order to gain a record of fluid flow while minimizing perturbations from well interference and pressure reduction. By conducting a systematic study of a number of tight gas systems, we hope to gain insight into the fluid-flow characteristics of reservoirs and ultimately to relate those characteristics to the geological setting and the particular hydrocarbon-charging scenario. The purpose of this report is to document our findings for gas, water, and oil production from two productive intervals in the Wattenberg field in the Denver Basin in Colorado (fig. 1).

Recognition of productive zones and efficacy of completion techniques vary among operators at any given time, and both factors evolve with time as personnel gain experience in a field and as drilling and completion techniques improve. Thus, the amounts of gas, oil, and water extracted from a given well are dependent upon the level of petrophysical, drilling, and completion expertise applied to that well. This seems even more true in the case of tight gas systems than in high-permeability reservoirs, because the consequences of errors and oversights are greater in low-permeability reservoirs. The exercise conducted in the present paper is susceptible to time-dependent vagaries of evaluation and extraction technologies. Our hope is that our techniques of well selection, presentation of statistical results, and the two-point changes in gas and water quantities are sufficient to overcome some of the difficulties inherent in comparative case studies of fluid extraction from low-permeability systems.

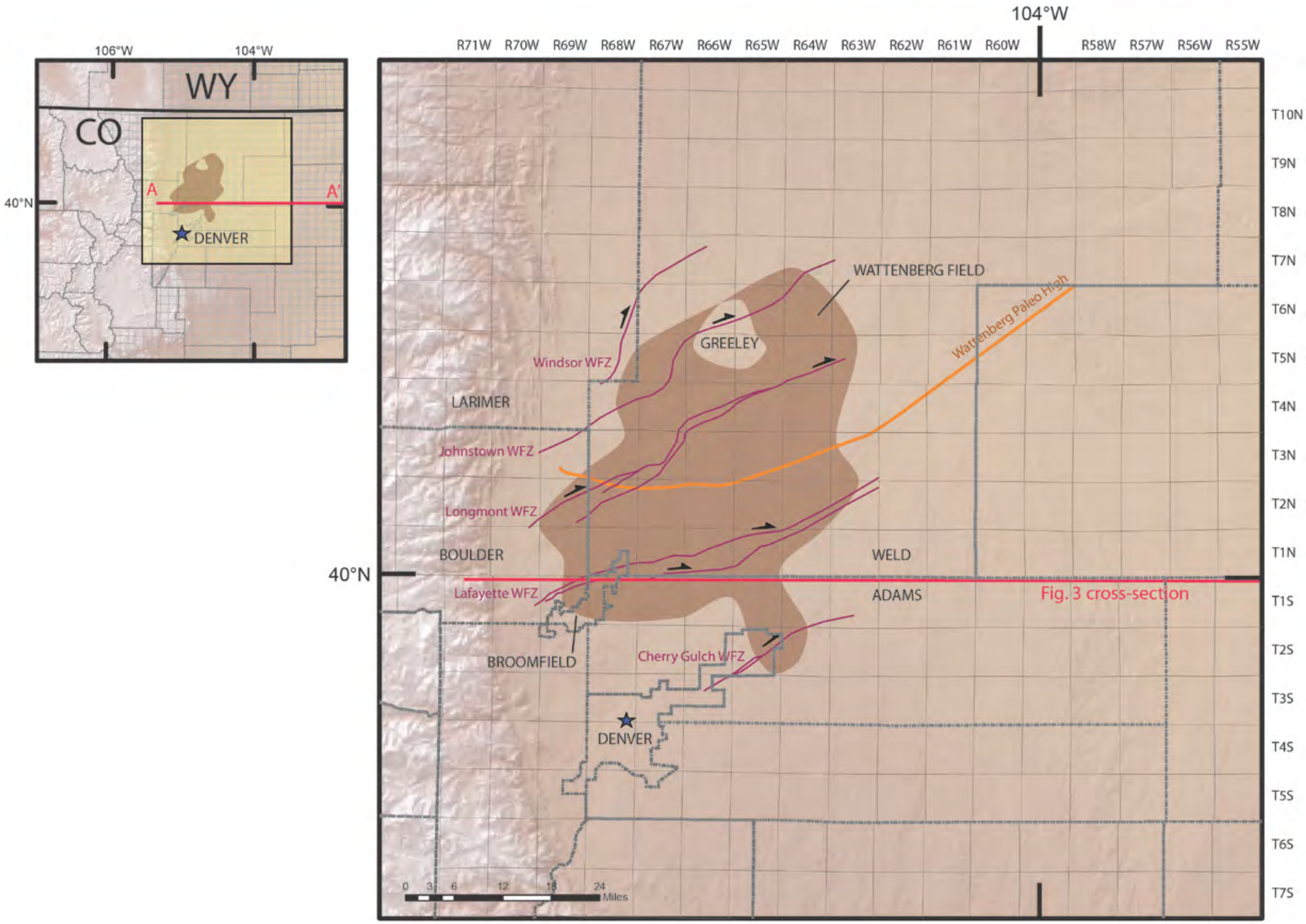

Figure 1. Outline map of the Wattenberg field in the Denver Basin, Colorado, drawn to contain all wells producing from the formations studied in this report. The undrilled area in the northern part of the field is the city of Greeley. The inset map shows the full extent of cross section *A–A'*, which is shown in figure 3. Indication of wrench fault zones (WFZ) is taken from Higley and others (2003). Trace of the Wattenberg paleo high is taken from Birmingham and others (2001).

Geologic Background

The development history and geology of Wattenberg field is presented by Hemborg (1993) and Ladd (2001). Hydrocarbons are nearly continuous within the Wattenberg field, so the area is considered to be a basin-centered gas accumulation with oil occurring as condensate. The boundaries of the Wattenberg field are poorly defined; field outlines generally are based on the extent of economic recovery from either the Codell Sandstone Member of the Carlile Shale or the Muddy (J) Sandstone (Ladd, 2001). The wells selected for this study cover an area of roughly 30 townships (fig. 1). Drilling patterns are not uniform but are dictated by development history and local controls such as faulting, facies changes, and the locus of maximum temperature (Ladd, 2001). Source rocks and sandstone reservoirs in close proximity (fig. 2) assure that migration distances from source rocks to gas reservoirs were short. Wells with production from (1) the Codell Sandstone Member and the Niobrara Formation and (2) the Muddy (J) Sandstone of the Dakota Group were selected for study; hereafter these intervals are referred to as the Codell-Niobrara interval and the Dakota J interval, as indicated in figure 2. The term Dakota J interval is used in this report rather than Muddy (J) Sandstone because of the possibility that a few sandstone units below the Muddy (J) were inadvertently included in the production figures reported by operators. With this minor exception, other sandstones that produce gas in Wattenberg field (fig. 2) were not considered.

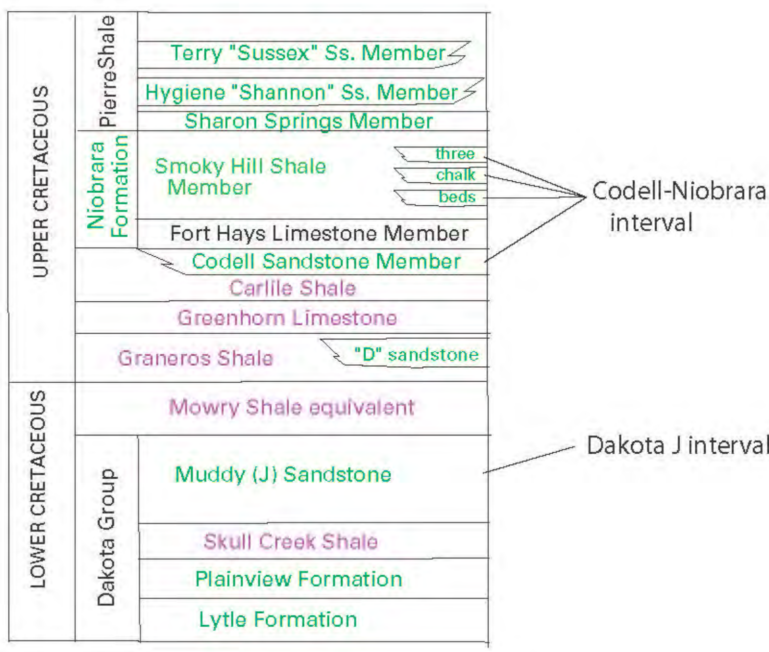

Figure 2. Stratigraphic section for the Denver Basin, Colorado, showing the relationship of the Codell-Niobrara producing interval and the Dakota producing interval (primarily the Muddy (J) Sandstone) to respective formation names. Green text marks formations that produce oil or gas; purple text marks hydrocarbon source rocks. Stratigraphy is modified from Higley and Cox (2007).

The Denver Basin is highly asymmetric, bounded by thrusts of the Front Range on the west and shallowing gradually to the east (fig. 3). The gas accumulations discussed in this report are near the base of a thick Cretaceous section, as indicated by the approximate bounds shown in figure 3.

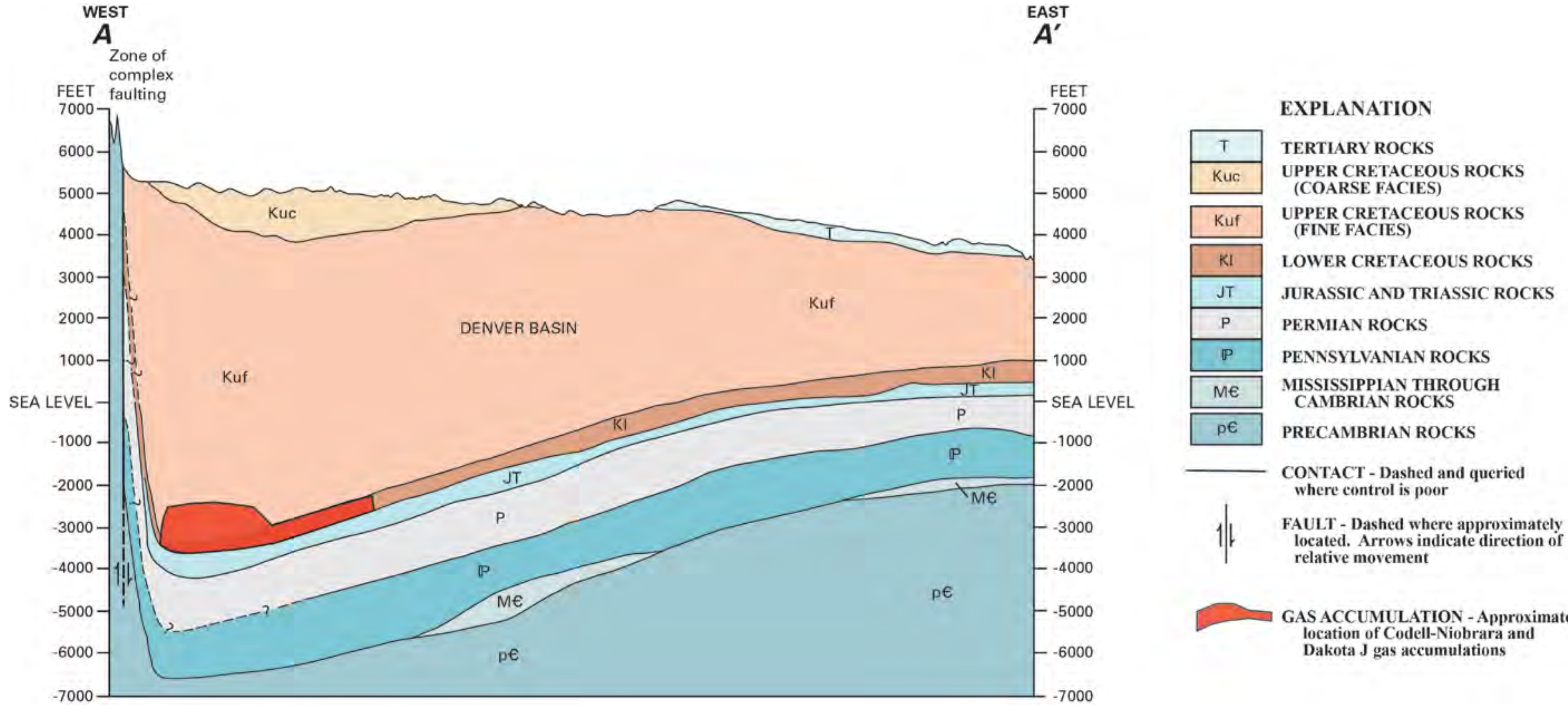

Figure 3. West–east cross section *A–A′* showing structural setting of the Denver Basin, Colorado, adapted from Robson and Banta (1987). Section intersects the southwest portion of Wattenberg field, as shown in figure 1, with shaded area indicating approximate location of gas accumulation in the Codell-Niobrara and Dakota J intervals.

The Codell-Niobrara Interval

The Codell Sandstone Member, a marine shelf sandstone, is the most laterally continuous reservoir in Wattenberg field and is the most widespread producer (Ladd, 2001). During the 1980s, operators realized that additional gas could be produced from 20- to 30-ft-thick chalk zones in the overlying Niobrara Formation (Hemborg, 1993). Hydrocarbon fluids from the two units are commingled in producing wells, and the combined interval is referred to as the Codell-Niobrara interval in this report.

Porosity of the Codell, determined from density logs, ranges from less than 8–22 percent. The thickness of gas-productive net sandstone, defined as a sandstone interval with porosity greater than 10 percent, ranges from 4–20 ft (Hively, 1985). Core measurements show permeability to be in the 0.01–0.1 millidarcy (md) range (Hively, 1985), although Birmingham (1998) indicates that most values fall below 0.01 md. Based on core description by Hively (1985),

> "The Codell Sandstone is a fine to very fine-grained sandstone, medium to dark gray with predominant quartz and feldspar in a light-colored clay matrix. Framework grains are angular to sub-angular, and well sorted. Mineralogic percentages have been determined on a number of samples by x-ray diffraction techniques. A typical composition is 85 percent quartz, 6 percent feldspar, 7 percent illite, 2 percent chlorite and a trace of mixed illite-montmorillonite."

Additional description by Birmingham (1998, p. 48) provides insight into the low permeability values:

> "Much of the tight nature of the Codell can be attributed to abundant incorporated clay which occupies grain replacement, pore-lining, pore-occluding and grain-coating habitats….most clays are interpreted as authigenic by-products of parent feldspar grains and lithic rock fragments, as evidenced by partial to complete grain replacement under standard and scanning electron microscopy….clays can comprise up to 30 percent by volume of the Codell."

Ladd (2001, his figure 3) indicated that the overpressured interval extends from the top of the Niobrara to the base of the informal D Sandstone Member of the Graneros Shale (fig. 2); Gackle and others (2001, their fig. 1), however, placed the top of overpressure at the Terry Sandstone Member of the Pierre Shale and the base of overpressure within the Graneros Shale. In either case, the Codell Sandstone Member is overpressured in the gas-productive area. Twelve subsurface pressure measurements were used to define the area of overpressure, showing that "measured pressure gradients vary from 0.445 psi/ft to 0.587 psi/ft just south of the highest gas-oil ratio (GOR) area (>15,000 cf/bbl), and reach 0.669 psi/ft within the highest GOR region, where gas saturations are highest" (Birmingham and others, 2001, p. 106). An earlier report (Hively, 1985) stated that original bottom-hole pressures were in excess of 4,000 psi, which would correspond to a pressure-depth ratio in excess of 0.6 psi/ft. Reservoir temperature in excess of 240°F also was reported (Hively, 1985), although it is apparent that temperature varies across the field (Birmingham and others, 2001).

The Dakota J Interval

The Muddy (J) Sandstone of the Dakota Group is a low-permeability sandstone containing a large accumulation of gas in the Denver Basin, characterized as a continuous gas accumulation by Higley and others (2003) and as a basin-centered gas accumulation by Hu and Simmons (2001). In 1997 a change in regulations allowed an increase in drilling density from one to five wells per 160 acres, as recounted by Hu and Simmons (2001) in their brief history of field development. Higley and Schmoker (1989) reported a porosity range from 8–12 percent, a permeability range from 0.05–0.005 md, and an average temperature of 260°F for the Muddy (J) Sandstone in the Wattenberg field. Of the subdivisions of the Muddy (J) Sandstone, the J_3 unit is the main gas-productive unit. Deposited as a delta-front facies, it is described as a fine-grained, moderately sorted quartz arenite (Hu and Simmons, 2001). Based on well-log analysis, water saturation ranges from 35–45 percent in the more-productive areas and ranges from 45–55 percent in the less-productive areas (Hu and Simmons, 2001). Most of the wells in this study fall within vitrinite reflectance contours of 0.6–1.3 percent, with values in a core township area exceeding 1.4 percent (Higley and Cox, 2007).

Although the overlying Codell-Niobrara reservoirs are overpressured, the Muddy (J) Sandstone is underpressured. An original formation pressure of 2,750 psi was reported by Higley and others (2003). The depth of the Muddy (J) Sandstone is about 7,000 ft, so the formation is clearly underpressured, because the pressure-depth ratio is less than the hydrostatic gradient of 0.433 psi/ft that characterizes fresh water. Underpressuring in the Dakota J interval is expressed as low hydraulic potential as documented by Hoeger (1968), based on evaluation of drill-stem tests. His potentiometric map for the Dakota J interval (fig. 4) shows hydraulic head decreasing from 3,400 ft in T. 7 S. to values less than 2,400 ft in the Denver Basin, northeast of the Wattenberg field. Drill-stem tests from the Wattenberg area were insufficient for mapping when Hoeger (1968) compiled his data. A potentiometric map by Robson and Banta (1987) with coarser contouring extends from the Front Range to the Colorado-Kansas border. The closely spaced, west-east contours in T. 7 S. become widely spaced and trend north-south to northwest-southeast to the east of Wattenberg field. Hoeger noted that hydraulic head in the Denver Basin, ranging from 2,300–2,600 ft above sea level (fig. 4) is substantially below ground elevation, which ranges from 4,000–5,000 ft above sea level. Hoeger (1968, p. 247) attributed the low hydraulic head in the Denver Basin to hydraulic communication with outcrops to the east:

> "The dominant cause of the low potential in the "J" system in the Denver Basin is indicated to be the low elevation of the Dakota Group outcrops in eastern Nebraska, combined with the regional eastward thickening of the Dakota Group aquifers toward the area of its outcrops. The greater transmissibility of the system in the eastern area has undoubtedly caused the Dakota Group to adjust to a low potential consistent with the low elevations of the eastern outcrops. These outcrop areas are considered as the regional outlets for Dakota Group fluids."

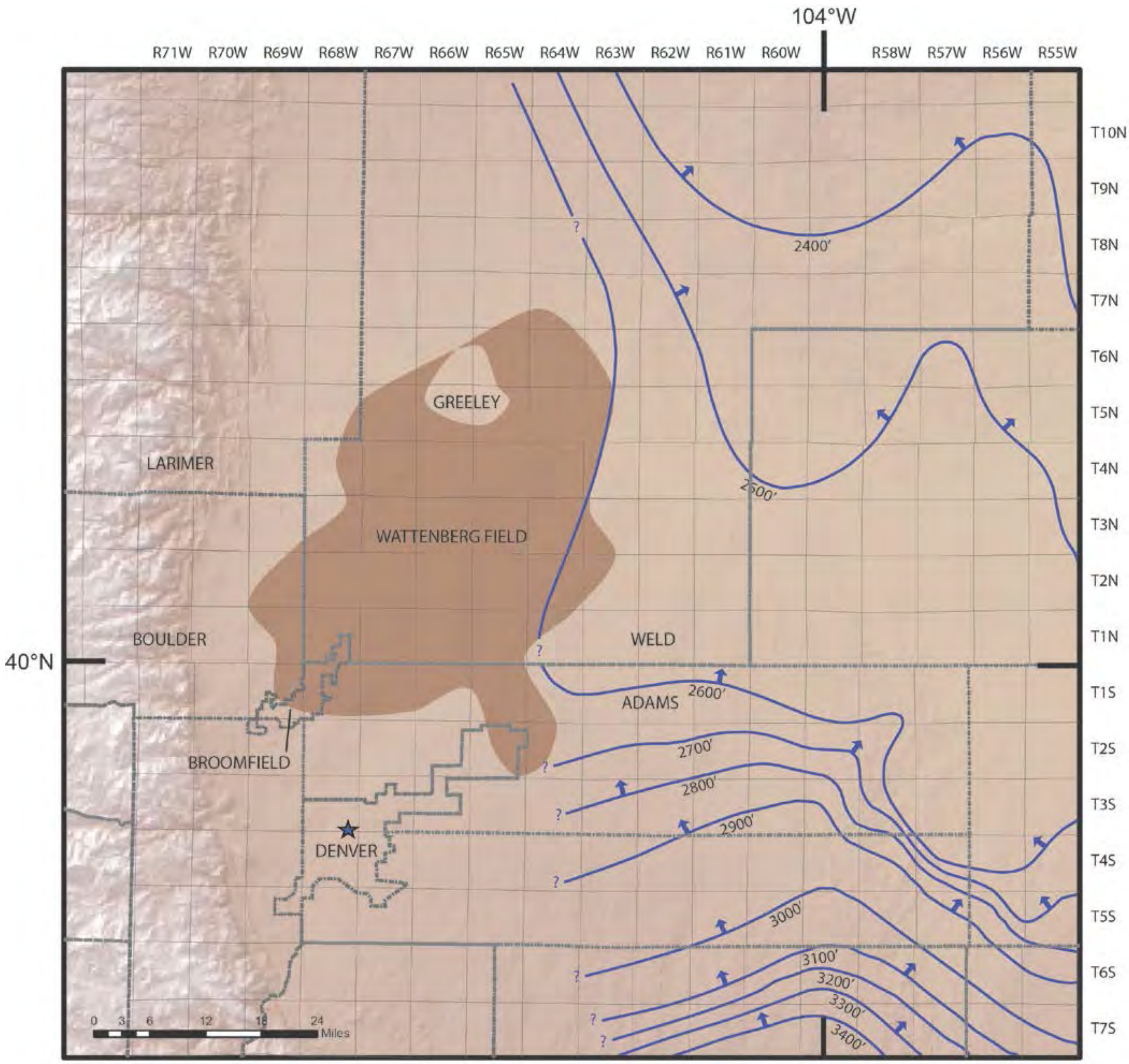

Figure 4. Potentiometric surface contours in the Dakota J interval from Hoeger (1968), showing potentiometric elevations less than 2,600 ft in the Denver Basin, Colorado, rising to 3,400 ft toward outcrop south of the mapped area. Note that Wattenberg field lies immediately west of the change in contour orientation.

A numerical flow model that extended from eastern Colorado into Nebraska, Kansas, and southern South Dakota (Belitz and Bredehoeft, 1988) supported this line of reasoning. The model also showed that the Dakota J interval must be hydraulically isolated from recharge areas along the Front Range of Colorado where rocks of Dakota age crop out. Hoeger (1968) noted that although the Dakota Group crops out at relatively high elevations along the Front Range, those outcroppings seem to have little influence as a high-potential water source on the regional hydrodynamic environment of the J system in the Denver Basin, and he conjectured that regional flow barriers, possibly faults or a facies trend of low transmissibility, must be present to provide that isolation. Hoeger also pointed out that the potentiometric map (fig. 4) indicates that outcrops of the Dakota Group in southern Colorado are the dominant inlet areas for the overall system, showing a northward and northeastward direction for water flow.

It is possible that the gas accumulation of the Wattenberg field contributes to the hydraulic isolation between the outcrops along the Front Range and the basin to the east. The pervasive presence of gas and the sporadic but generally low production of water indicates that the pore space in the Dakota J interval is gas-dominated and that water is not a continuous phase. If water is not a continuous phase, then hydraulic communication from west to east across the Wattenberg field is cut off, and the low-permeability barrier caused by a facies change or faults is made even more effective. Even so, the underpressured state of gas in the Dakota J interval indicates that the western flank of the gas field is more isolated from the surface than is the eastern flank. The overall geologic and hydrologic setting appears to be analogous to the San Juan Basin (Nelson and Condon, 2008).

Well Selection

Well selection in the Wattenberg field was difficult, because individual wells might have been used for production from the Codell only, from the Codell and Niobrara combined, from the Dakota sandstones only, or from the Dakota sandstones combined with the Codell and Niobrara. Records were examined to find wells that were producing from either (1) the Codell-Niobrara or the Codell alone, by setting the producing zone criterion to “Niobrara/Codell” and “Codell” or (2) the Dakota J interval, by setting the producing zone criterion to “Dakota”, “Dakota/J Sand”, and “DakotaJ/SD/.”. The following examples, compiled from the IHS Energy (commercial) production database (IHS Energy, 2010) and completion reports (Colorado Oil and Gas Conservation Commission, 2010), illustrate some of the complexities.

Example 1. Champlin 86 Amoco 9, 05123129290000. This well, which was reported as producing from the Niobrara and Codell intervals, was completed in 1986 with 160 perforations at 8,194–8,214 ft in the Dakota J interval and was hydraulically fractured. In 1994, the well was re-entered (05123129290001), the Dakota J interval was plugged, and the Codell and Niobrara intervals were perforated and hydraulically fractured at 7,706–7,769 ft (9 perforations) and 7,528–7,534 ft (6 perforations), respectively. After four years of production from the Codell-Niobrara, the well was re-entered in 1998 (05123129290002) and deepened to 8,422 ft in the Dakota J interval. No perforations were added; instead the interval from 8,360–8,422 ft was completed open-hole (without casing) and was produced, along with the three previously perforated intervals, through tubing set at 8,341 ft. Monthly production records (Colorado Oil and Gas Conservation Commission, 2010) show separate entries for the Niobrara-Codell and the J interval, but the method used to allocate production between the two intervals is unspecified, so this well was excluded from our data set.

Example 2. Pergola 2-15, 05001090240000. In 1991, this well was drilled to 8,904 ft and completed with hydraulic fracturing through 31 perforations in the Dakota J interval from 8,522–8,557 ft. The well produced from the Dakota J from 1991 until August, 1997. In September, 1997, the well was re-entered (05001090240001), a bridge plug was set at 8,200 ft with no further production from the Dakota J interval, the Codell was completed with 40 perforations at 8,094–8,104 ft, and the well then produced for three months from the Codell. In December, 1997, the well was again re-entered

(05001090240002) and a Niobrara interval from 7,840–7,855 ft was perforated with 60 holes, acidized, and fractured. Production from the Codell and Niobrara intervals was commingled from December 1997 through 2009; our first and second samples from this well were obtained in 2000 and 2005 (Appendix 1).

Data Reduction and Display

Daily production rates were computed by dividing monthly volumes by the number of days of production in a month (referred to as "days-on"). The resulting values of (1) gas rate, in thousands of cubic ft per day (mcf/day); (2) water rate, in barrels per day (bbl/day); and (3) oil rate, in barrels per day (bbl/day) are plotted on a logarithmic scale as a function of time (fig. 5A), and production versus time plots for selected wells are shown in plates 1 and 2. To determine a representative flow rate of gas, oil, or water from a well, a 3-month time interval was selected early in the history of a given production record for which fluid production was judged to be representative of flow. This time interval, referred to as the "first sample" in this report, is generally selected to be about two years after commencement of production; such delay serves to eliminate early transients and early changes in equipment, reduces the likelihood that fracturing fluids are included in the water tally, and begins sampling after a rapid decline that typically occurs during the first two years of production. This approach, which we have used in previous investigations in other gas fields (for example, Nelson and Santus, 2010) is validated by work by Kloepper (1993), who found that the time-normalized average of 254 wells in the Dakota J interval in Wattenberg field shows a rapid decline of gas production for the first two years, followed by a slower decline thereafter. The records of fluid production in the UPRR 42 Pan Am AV1 well (fig. 5A) are of better quality than most production records, making selection of the sample points relatively easy for that well. For the example in figure 5A, the production rates were averaged over the months of March–May, 1990, resulting in the values posted in the figure.

Because operators in the Denver Basin were not required to report the number of days-on prior to the year 1985, we were unable to compute and display a daily production rate for produced fluids on any well before 1985, regardless of start date. Powers 34-22 is a good example of a well included in our sample group that shows a delayed start due to the nonreporting of days-on (fig. 6). Figure 6*A* shows total monthly production beginning in November 1980 and continuing through the end of 1997, when a recompletion was performed to produce commingled production from the Codell-Niobrara interval and the Dakota J intervals. Because days-on numbers were not reported prior to 1985, we were unable to compute a daily production rate, so no production earlier than 1985 is shown in figure 6*B*. (Also note the nearly similar production curves for both plots, indicating that few months reported less than the maximum amount of days-on possible in each month.) As a practical matter, we included wells with a start date of 1980 or later, but did not select any first samples before 1985.

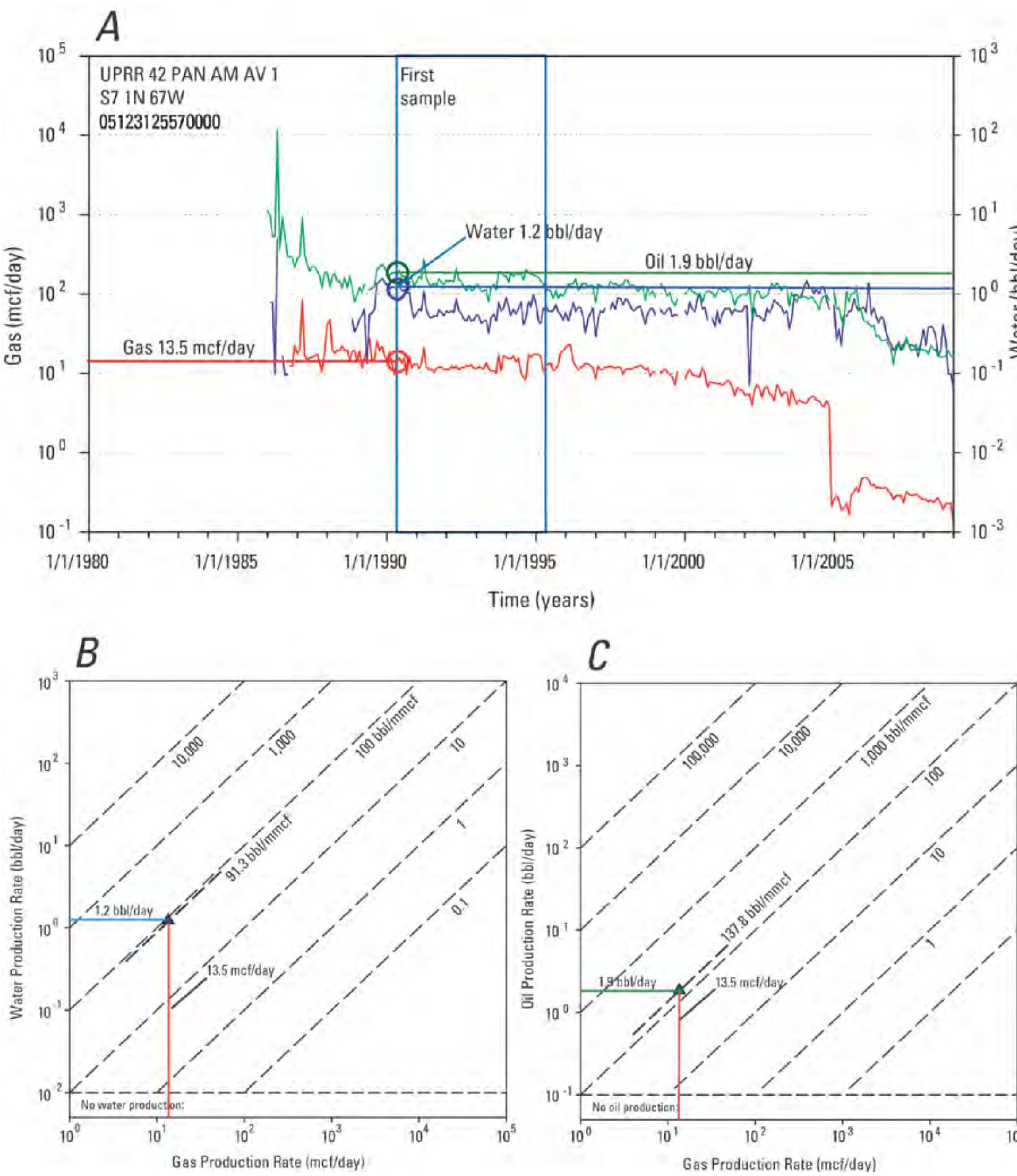

Figure 5. Example plot of fluid production versus time with corresponding bi-logarithmic production plots for the UPRR 42 Pan Am AV1 well in Wattenberg field, Colorado. *A,* Production of gas, water, and oil versus time. Vertical line indicates the first sample, which is generally about two years after onset of production but is four years in this example. Posted values are average production rates for the months of March−May, 1990. *B,* Water versus gas production on logarithmic axes. Triangle symbol shows water and gas rate values from part *A*. The resulting water-gas ratio of 91.3 barrels per million cubic ft (bbl/mmcf) (Appendix 1) falls on a 45-degree line. *C,* Oil versus gas production on logarithmic axes. Green triangle shows oil and gas rates from part *A*. The oil-gas ratio of 137.8 bbl/mmcf, equivalent to a gas-oil ratio of 7,257 scf/bbl, falls on a 45-degree line. [mcf/day, thousand cubic ft per day; scf/bbl, standard cubic ft per barrel; bbl/mmcf, barrels per million cubic ft]

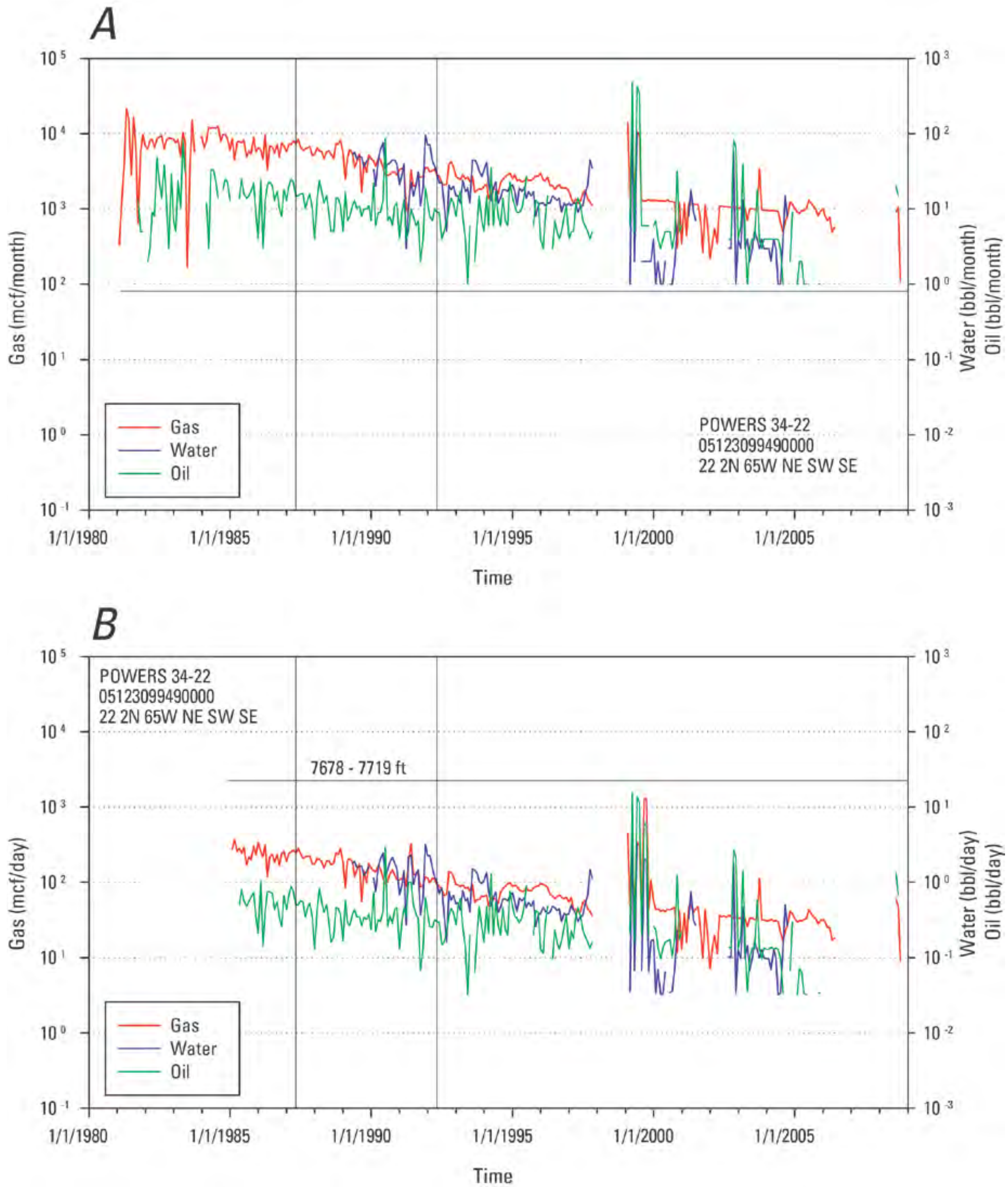

Figure 6. Production plot of the Powers 34-22 well, Colorado, showing *A*, monthly totals of gas, water, and oil; and *B,* daily production rates of gas, water, and oil (monthly rates divided by number of days of production in a month).

Resulting three-month average daily rates are posted on summary plots with bi-logarithmic scales (for example, figs. 5*B* and 5*C*), which accommodate wide ranges of production rates. With the use of bi-logarithmic axes, constant ratios of production rates lie on 45-degree lines, the ratio increasing upward and to the left. Other advantages of bi-logarithmic plots over linear plots are discussed by

Nelson and others (2009b). Water production of 1.2 barrels/day (bbl/day) and gas production of 13.5 mcf/day from the UPRR 42 Pan Am AV1 well determine the location of the single point in figure 5*B*. The water-gas ratio for that well, 91.3 barrels/million cubic ft (bbl/mmcf), which is represented as a diagonal line, is abnormally high among the wells examined in this study from Wattenberg field—most wells producing from the Codell-Niobrara interval had no water recorded at all. In similar fashion, the first-sample oil rate of 1.9 bbl/day and gas rate of 13.5 mcf/day determine the location of the point in figure 5*C*, with a resulting oil-gas ratio of 137.8 bbl/mmcf represented by a diagonal line. Although the definition is not rigorous, gas-oil ratios in retrograde gas reservoirs typically range from 3,300–50,000 standard cubic ft/barrel (scf/bbl), corresponding to oil-gas ratios of 300–20 bbl/mmcf (McCain, 1990). Thus, the representative data point in figure 5*C* lies within the range that can be typified as retrograde gas.

To show the change in gas and water production in each well, a second 3-month average is computed about 5 years after the first average (fig. 7*A*). The gas and water production figures from the second sample are plotted on the bi-logarithmic production plot (red circle in fig. 7*B*). Each second-sample value is linked to its first-sample value (triangles in figs. 5*B* and 7*B*) by a line, producing a vector that shows the amounts and the change of water and gas production over 5 years. On a bi-logarithmic graph, a vector of a given length and angle represents the same fractional changes in daily gas and water production regardless of where it is positioned on the graph. In the example shown in figures 5 and 7, gas production decreases from 13.5 to 12.1 mcf/day over 5 years, water production decreases from 1.2 to 0.65 bbl/day over 5 years, and the water-gas ratio decreases from 91.3 bbl/mmcf (fig. 5*B*) to 54.2 bbl/mmcf (fig. 7*B*) over 5 years.

To clarify the relative changes in water and gas production among wells, a bi-logarithmic plot of the change in water and gas production places all early-time production at a common origin (single square at 1,1 in fig. 7*C*), so that changes in production over a 5-year span can be compared among wells. The length and orientation of each vector is the same in figures 7*B* and 7*C*, but the origin, which is its value at the first sample, has been normalized, or translated to the center (1,1) position of the plot in figure 7*C*. In this example, gas, water, and oil records were complete so a second sample could be obtained 5 years after the first sample. Many wells in the Wattenberg field, however, can not appear on this type of plot, because no water was produced in either one or both samples**.**

As some water can exist as a dissolved phase in gas within the reservoir, the question arises as to how much of the produced water was originally dissolved in the reservoir and then condensed at the surface. The amount of water dissolved in gas in reservoirs increases with increasing temperature and decreases with increasing pressure (McCain, 1990, p. 460). The amount released depends upon the pressure and temperature at the surface; a fixed value of 33 pounds of water per mmcf of gas was assumed, based on considerations by McCain (1990). Requirements for pipeline transport of natural gas restrict the amount of water to be as low as 4 pounds per mmcf (Lyons and Plisga, 2005, sec. 6.7.1). The reduction from 33 to 4 pounds per mmcf, however, which is equivalent to 0.083 bbl/mmcf, does not necessarily occur at the separator, so that small amount of water is not accounted for in our computation. As a result of adopting the 33 pound-per-mmcf criterion, our estimate of water released at the surface could be low by 0.083 bbl/mmcf. Our computations, based upon the approach given by McCain (1990, p. 460–463) and using subsurface temperature and pressure conditions from various sources, indicate that the amount of water likely to be dissolved in reservoir gas and subsequently produced at the surface are 1.25 bbl/mmcf in the Codell-Niobrara reservoir and 2.29 bbl/mmcf in the Dakota J reservoir (table 1). These estimates are included as blue diagonal lines on water-gas plots (fig. 1-2 of plate 1 and fig. 2-2 of plate 2) to indicate how much of the water produced at the surface could originate as water originally dissolved in reservoir gas.

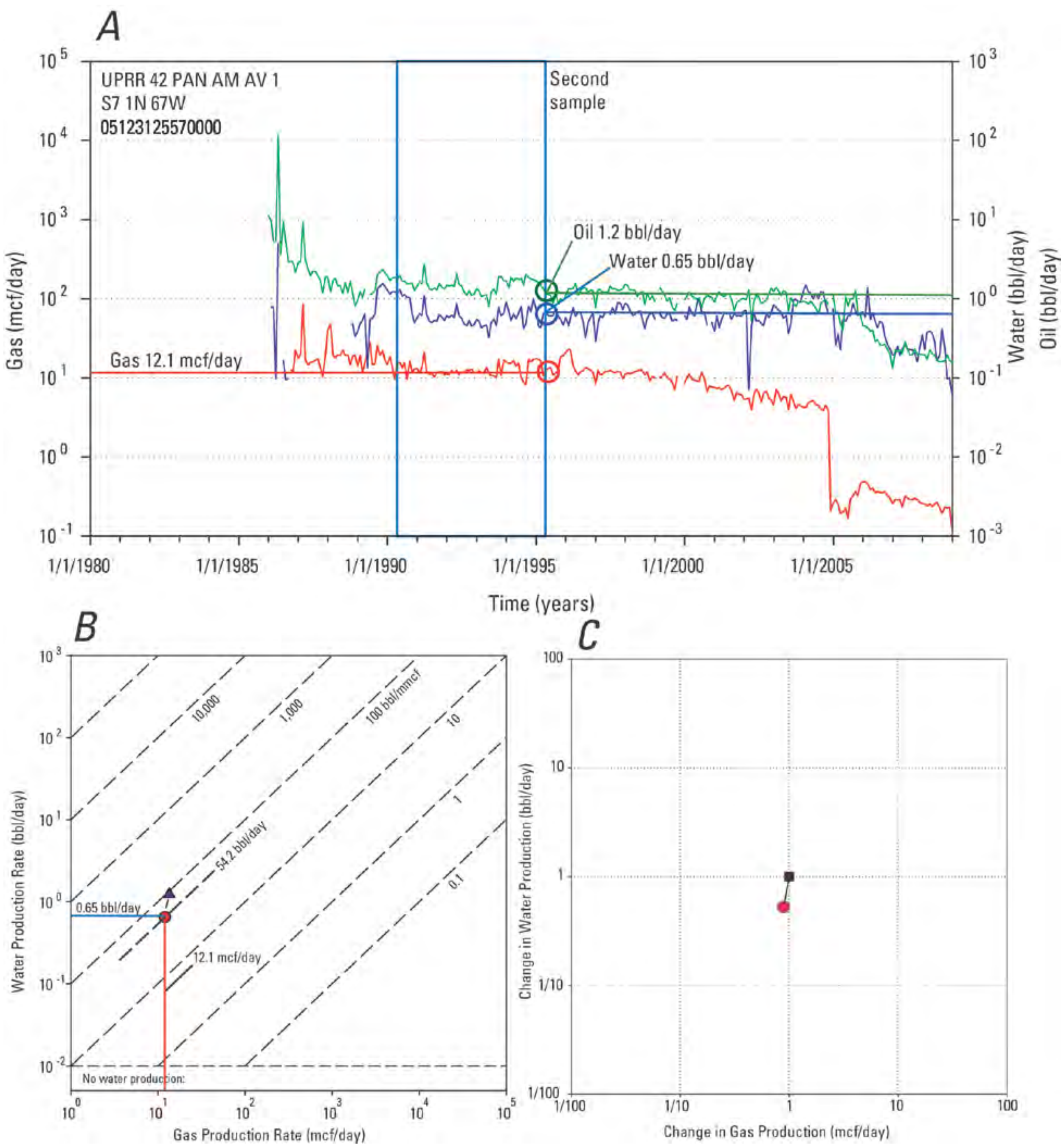

Figure 7. Example plot of fluid production versus time with vector plots of changes in production with time, for the UPRR 42 Pan Am AV1 well in Wattenberg field, Colorado. *A,* Production of gas, water, and oil versus time with values given for the second sample. *B,* Vector plot, with water versus gas production on logarithmic axes. The triangle designates the gas and water production at the first sample, and the red circle shows production at the second sample taken five years later, thus marking the head and tail of a vector. *C,* Normalized vector plot, with change in water production versus change in gas production on logarithmic axes. Values from the first sample are placed at center of plot, so all vectors for a field share a common origin. [mcf/day, thousand cubic ft per day; bbl/mmcf, barrel per million cubic ft]

Table 1. Estimates of water released at the surface that was originally dissolved in gas in the reservoir, for pressure and temperature conditions corresponding to average depths in the Codell-Niobrara and Dakota J reservoirs, Colorado. Solubility of water in gas and estimate of water retained (33 lb/mmcf) are taken from McCain (1990). Values in final column establish the blue diagonal lines in figures 1-2 of plate 1 and 2-2 of plate 2.

[psi, pounds per square inch; lb/mmcf, pounds per million cubic ft; cf, cubic ft; bbl, barrels]

Reservoir	Average depth	Temperature	Pressure	Solubility of water in gas	Correction factor	Water retained	Water released at separator		
	(ft)	(°F)	(psi)	(lb/mmcf)	(lb/mmcf)	(lb/mmcf)	(lb/mmcf)	(cf/mmcf)	(bbl/mmcf)
Codell-Niobrara	7,091	240	4,254	480	470	33	437	7.01	1.25
Dakota J	7,890	260	2,900	850	833	33	800	12.83	2.29

Because oil and gas types are defined as a function of gas-to-oil ratios (McCain, 1990), the fluid types can be displayed on the log-log oil-production versus gas-production diagrams (fig. 8). Black oil types have gas-oil ratios less than 2,000 standard cubic ft per barrel (scf/bbl), and volatile oil types have gas-oil ratios of less than 3,300 scf/bbl of oil; together they occupy the upper left corner of an oil-gas production diagram (fig. 8). In a retrograde gas reservoir, liquid condenses in the reservoir as reservoir pressure declines. Gas-oil ratios in retrograde gas reservoirs typically range from 3,300–50,000 scf/bbl, although they can have values as high as 150,000 scf/bbl; these reservoirs occupy a central diagonal band on an oil-gas diagram (fig. 8). Wet gases, also called condensate gases, have gas-oil ratios in excess of 50,000 scf/bbl (<20 bbl condensate/mmcf gas) and occupy the lower right corner of the diagram. Dry gas produces no oil either in the reservoir or at the surface (McCain, 1990), and corresponding points are plotted in a separate rectangular box at the bottom of the diagram.

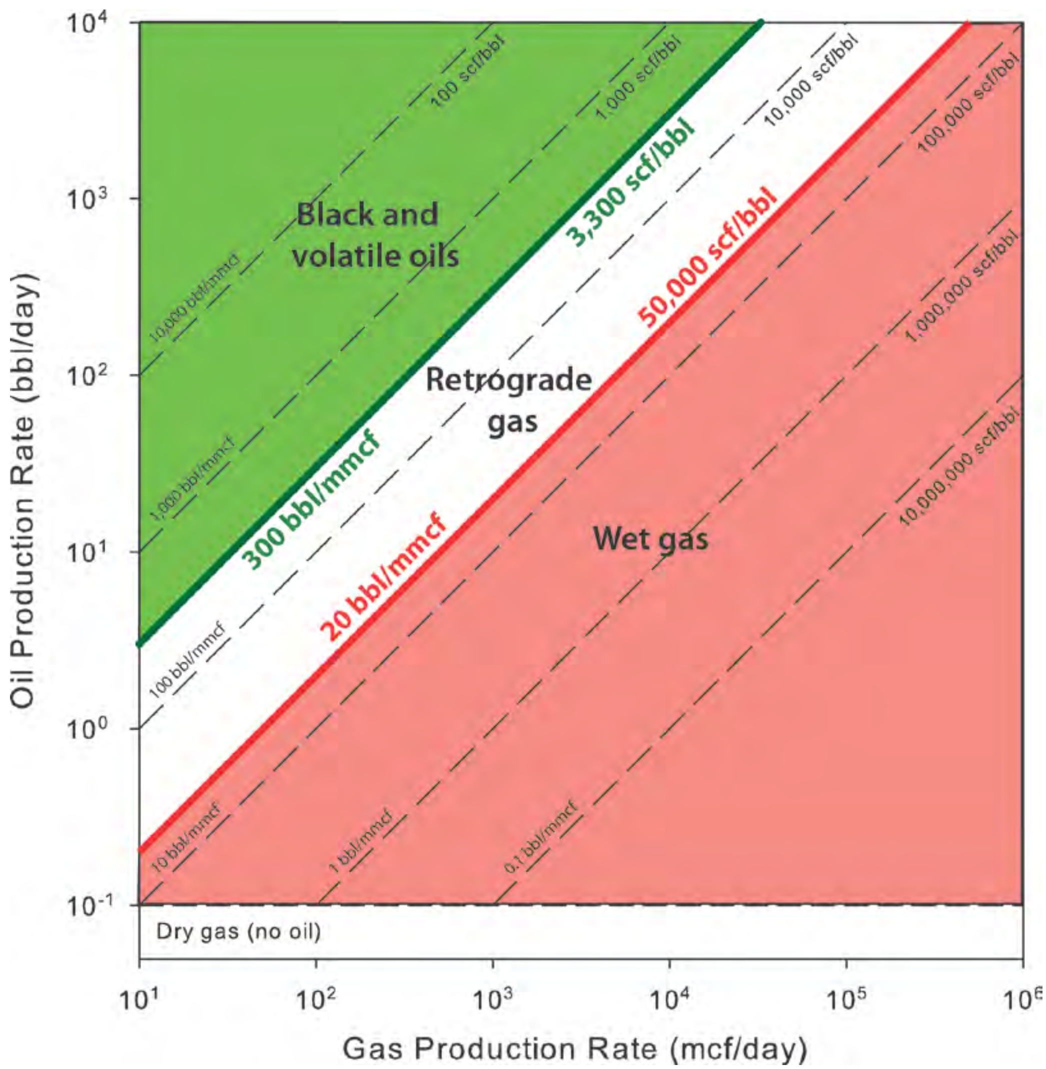

Figure 8. Oil and gas types plotted on a log-log diagram of oil and gas production rates. Fields indicate three reservoir fluid types, based on McCain (1990). [scf/bbl, standard cubic ft per barrel; bbl/mmcf, barrels per million cubic ft; bbl/day, barrels per day; mcf/day, thousand cubic ft per day.]

Maps, production plots for selected wells, and summary plots of data are presented in plates 1 and 2 for the Codell-Niobrara and the Dakota J intervals. The two appendixes contain the location of each well and numerical values of fluid production from the first and second samples for the two production intervals. Production records and other data for this study were drawn from the IHS production data base (IHS Energy, 2010). Well locations were taken from the web site of the Colorado Oil and Gas Conservation Commission (2010).

Production from the Codell-Niobrara Interval

Production data were obtained from the IHS database (IHS Energy, 2010) for Wattenberg field, Colorado, with the date of first production restricted to records with at least 10 years of production commencing after January, 1985. To keep the data set limited to a manageable number and to provide uniform geographical coverage, wells were selected from sections 4, 11, 18, 22, 29 and 36 of densely drilled townships, and from all sections in other townships that were sparsely drilled. Because both Niobrara and Codell production are commingled in many wells, production data were included in the data set if categorized as either Niobrara/Codell or Codell. Inspection of wells selected in this manner showed that some wells produced from both the Codell and Dakota J intervals; those wells were eliminated from the data set. Wells with good record continuity were retained and wells with erratic or discontinuous records were discarded, resulting in the 128 well locations shown in figure 1-1 of pl. 1 and listed in Appendix 1. Depth to the bottom perforations, a good indicator of the depth of the Codell, ranges from 6,538–8,294 ft, with an average of 7,173 ft (Appendix 1).

Of the 128 selected wells, 52 wells produced only from the Codell and 76 produced from the Codell and Niobrara combined. For these two subsets of the data, the first-sample median values of oil, gas, and water production and ratios of oil-to-gas and water-to-gas were all quite similar. For example, the average and standard deviation values of first-sample gas production was 44.5 and 26.5 mcf/day for the Codell-only production, and 50.0 and 31.0 mcf/day for the combined Codell-Niobrara production. Also, a graphical display showed no dependence of first-sample gas production on the depth extent of the perforated interval, nor is there any dependence of first-sample water-gas or oil-gas ratio on depth extent. Thus it was concluded that inclusion of the Niobrara interval with the Codell interval had little impact on the production statistics, and that the 128-well data set could be treated as one.

Half of the 128 selected wells commenced production before 1988, and the other half commenced production between 1989 and 2000. Inspection of data from those wells as a function of first-sample year showed a decline in gas production with time, no substantial change in water production, and no change in oil-gas ratio. A large-scale program of recompletions by hydraulic refracturing in the Niobrara-Codell commenced in 1997 (Birmingham and others, 2001), resulting in marked increases in production as illustrated by the increases in gas, oil, and water production in late 1999 in the Caesar 4-11 well (figure 1-7 of pl. 1) and by the production plots for other wells in plate 1. Data used in this report were drawn from production records prior to such recompletions, as indicated on the plots by the vertical lines for the first and second samples located prior to the increases due to recompletions. As an example, the first and second samples of figure 1-7 of plate 1 are in 1988 and 1993, before the recompletion-related increase in late 1999.

Produced gas at the first sample and the ratio of second-sample to first-sample gas (a measure of decline rate) were plotted (not shown) against the year of the first sample, which ranged from 1986 to 2000 with a median year of 1990. No relationships were found between gas rate or gas-rate decline and the year, indicating that there were no marked improvements in extraction technology during the respective time period. Gas production rates in the Codell-Niobrara range from 6.5–126.9 mcf/day at the first sample, with median and average values of 40.3 and 47.7 mcf/day, respectively. Overall gas production declines to median and average values of 17.5 and 21.0 mcf/day at the second sample. The ratios of second-sample to first-sample gas production are tabulated in Appendix 1 for individual wells. The ratios range from 0.11–1.26 with median and average values of 0.46 and 0.49, respectively, showing that gas production declines by about one-half over the five-year span between the first and second samples.

Oil-gas ratios range from 17.8–759.5 bbl/mmcf at the first sample (fig. 1-3 of pl. 1 and Appendix 1), with median and average values of 80.4 and 109.0 bbl/mmcf, respectively. The ratios decline somewhat with time; median and average values at the second sample are 69.9 and 96.5 bbl/mmcf, respectively. These ratios fall within the range indicated for retrograde gas, as discussed in connection with figure 8 and as indicated on figure 1-3 of pl. 1. The variation in oil-gas ratio, or its reciprocal, the gas-oil ratio, is attributed to temperature, with the area of highest temperature generally associated with the highest gas-oil ratios. The highest gas-oil ratios, exceeding 35,000 scf/bbl, are found in T. 4 N., R. 66 W. and R. 65 W. (fig. 1-1 of pl. 1); the corresponding oil-gas ratios are less than 29 bbl/mmcf. Gas-oil ratios greater than 10,000 scf/bbl are within an area of roughly six townships (fig. 1-1 of pl. 1); outside of this area the oil-gas ratios are greater than 100 bbl/mmcf. The association between the area of high gas-oil ratio of figure 1-1 of pl. 1 and other reservoir parameters is discussed by Birmingham and others (2001).

Inspection of the 10 production plots (figs. 1-6 to 1-15 of pl. 1) and the change in gas and water production between first and second samples (fig. 1-4 of pl. 1) shows that water production is generally either absent or erratic. Of the 128 wells in the data set, 49 had water in the first sample, 48 had water in the second sample, 32 had water in both samples, and 63 had no water in either the first or second sample. Water production generally is less than 1.0 bbl/day; only three wells produced water at a rate slightly greater than 1.0 bbl/day at the first sample. His finding of little or no water from the Codell is compatible with general experience, as “water-free production” over an extensive field area is mentioned by Ladd (2001). Volumes of fluid injected during hydraulic fracturing stimulations are typically 100,000 gallons (approximately 2,400 bbl), only a fraction of which is recovered during cleanup or during production, as a rate of 1.0 bbl/day would require more than 6 years to recover 2,400 bbl. The low returns of fracture fluid during cleanup caused some operators to believe that water produced with gas was mostly “frac water,” and consequently some operators did not report water production (T. Birmingham, Anadarko Petroleum Corp., oral commun., February 2010).

In summary, no water production was reported for 63 of 128 wells, and most of the other 65 wells had either first-sample or second-sample production rates of less than 1 bbl/day (figs. 1-2 and 1-4 of pl. 1 and Appendix 1). Because gas production rates also were low and because low rates, particularly for water, cannot be measured with precision, the water-gas ratios vary considerably among the wells that did produce water. Water-gas ratios range from 0.26–154.7 bbl/mmcf for the 49 wells with first-sample water production, with median and average values of 7.0 and 15.9 bbl/mmcf, respectively (Appendix 1). Of these 49 wells, most have water-gas ratios greater than can be attributed to water dissolved in gas in the reservoir (compare data with diagonal lines in figure 1-2).

Production from the Dakota J Interval

Only half the number of wells met the selection criteria for the Dakota J interval as were chosen for the Codell-Niobrara interval, and the resulting distribution of wells for the Dakota J interval is not as uniform as that of the Codell-Niobrara interval (compare fig. 2-1 of pl. 2 with fig. 1-1 of pl. 1). Production from the Dakota J interval is centered in T. 1 N.–T. 3 N. and R. 65 W.–R. 68 W., an area that lies south of the main area of Codell-Niobrara production. The bottom of the perforation interval ranges from 7,320–8,484 ft in depth, and the depth extent of the perforation interval (typically one perforation interval per well) ranges from 5–64 ft with an average of 35 ft (Appendix 2). This range of values is commensurate with the net sand isopach of Hu and Simmons (2001).

Gas production in the 62 wells at the first sample ranges from 25.6–1,014.6 mcf/day, with median and average values of 132.5 and 169.8 mcf/day, respectively. These values are substantially greater than values for the Codell-Niobrara interval. For our sample set, gas production shows no dependence upon first-sample year, which ranges from 1986–2003 with a median year of 1992. The ratios of second-sample to first-sample gas production are tabulated in Appendix 1 as "Gas2-Gas1 ratio". These ratios range from 0.23–0.92 with an average value of 0.50, showing that gas production declines, on average, by about one-half over the five-year span between the first and second samples. The five-year declines in gas and water production are shown on the normalized vector plot of figure 2-5 of pl. 2, where the typical decline in gas production of one-half is manifested in the vertical trend of data.

Average oil production is 2.0 and 1.0 bbl/day at the first and second samples, respectively. Oil-gas ratios at the first sample range from 2.0–76.4 with median and average values of 10.4 and 15.7 bbl/mmcf, respectively. The median value of 10.4 bbl/mmcf is very close to the median oil-gas ratio of 10.5 bbl/mmcf (gas-oil ratio of 95.5 mcf/bbl) reported by Higley and others (2003) for 1,900 wells. Most oil-gas ratios fall within the wet gas field, although some ratios exceed the upper limit of the wet gas field and fall within the retrograde gas field (fig. 2-3 of pl. 2).

Water production lacks continuity, as can be seen from the production-vs.-time plots in figures 2-6 through 2-15 of pl. 2 and by the links between samples with water and with no water on the water-gas plot of figure 2-4 of pl. 2. Of the 62 wells examined, water is present in the first and second samples in 49 and 52 wells, respectively. Six of 62 wells had no reported water at either sample. Median values of water production at the first and second samples are 1.64 and 0.73 bbl/day, respectively. Thus, water production is substantially greater in the Dakota J than in the Codell-Niobrara, for which median values at the first and second samples are 0.31 and 0.19 bbl/day, respectively. [Note: To accommodate the low gas and water production rates from the Codell-Niobrara, the axes on the logarithmic plots of figures 1-2 through 1-4 on pl. 1 are shifted by a factor of ten with respect to the axes on figures 2-2 through 2-4 on pl. 2. Be aware of the shift in scales when making comparisons between figures on pls. 1 and 2.] More samples show a decrease in water from the first to the second sample than show increases (fig. 2-5 of pl. 2); the magnitudes of both increases and decreases are as much as a factor of ten.

Water-gas ratios at the first sample range from 0.7–81.1 bbl/mmcf with median and average values of 11.9 and 14.5 bbl/mmcf, respectively. The expected value of water-to-gas, based on the amount of water that can be dissolved in gas in the reservoir, is 2.3 bbl/mmcf (table 1), so most samples with water production are well above the amount that could be dissolved in the reservoir (fig. 2-2 of pl. 2).

Summary

The two Denver Basin gas reservoirs considered here—the Codell-Niobrara and the Dakota J intervals—display production characteristics that differ significantly between the two gas accumulations, even though they are located in the same basin, are stratigraphically contiguous, and were sampled over the same time periods so that completion techniques were comparable. A well in the Dakota J interval is likely to be more than three times as productive, in terms of gas production, as a well in the Codell-Niobrara interval, as shown in figure 9 and in the statistical summaries in Appendixes 1 and 2.

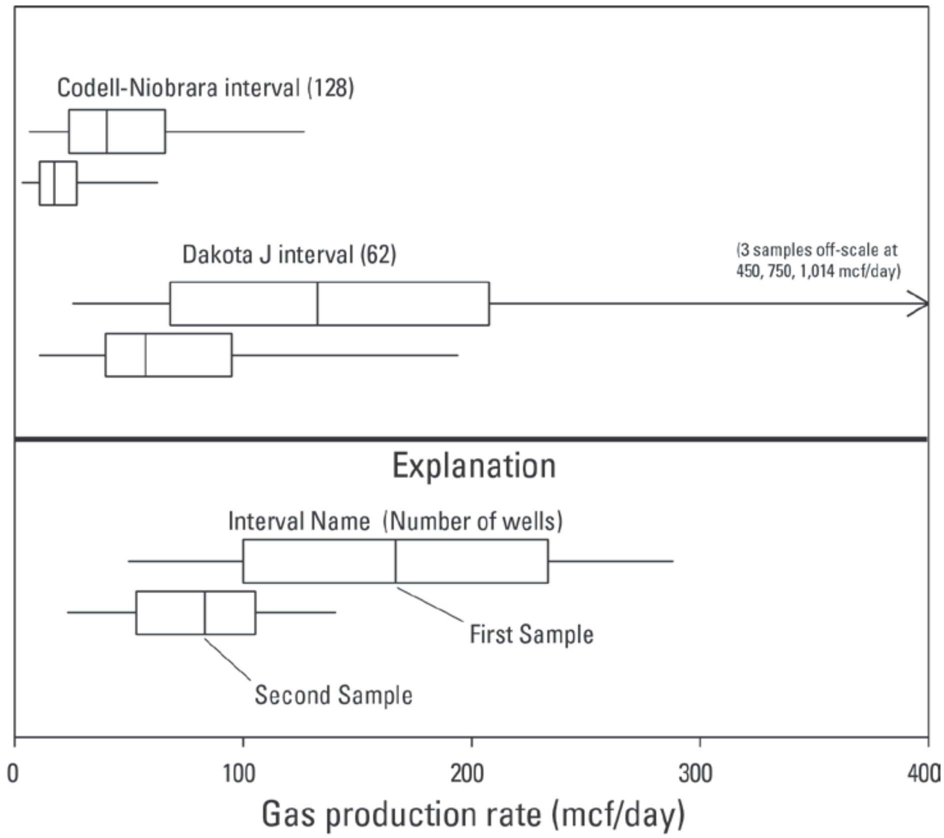

Figure 9. Box-and-whiskers plots of gas production from the Codell-Niobrara and Dakota J intervals. Each box and each whisker represents one quartile (25 percent of the samples); vertical line separating the two boxes represents the median value (50th percentile).

Oil-gas ratios in the Dakota J interval, which fall in the upper part of the wet gas range (median value of 10.4 bbl/mmcf, equivalent to a gas-oil ratio of 96,150 scf/bbl), are roughly one-tenth of the ratios in the Codell-Niobrara interval, which fall in the retrograde gas range (median value of 80.4 bbl/mmcf, equivalent to a gas-oil ratio of 12,440 scf/bbl). These differences in oil-gas ratios can be viewed by noting the separation between the oil and gas production curves in the production plots for the two gas systems (figs. 1-6 through 1-15 of pl. 1 vs. figs. 2-6 through 2-15 of pl. 2), by comparing the oil-gas plots (fig. 1-3 of pl. 1 vs. fig. 2-3 of pl. 2), and by examining the statistical summaries in Appendixes 1 and 2.

Water-production records are discontinuous in both the Codell-Niobrara and Dakota J gas systems. Half of the 128 wells penetrating the Codell-Niobrara interval recorded no water at either sample, whereas only 6 of 62 wells examined in the Dakota J gas system had no water at either sample. Water-gas ratios are roughly the same in both systems, but the water-production rates are lower in the Codell-Niobrara than in the Dakota J, just as the gas-production rates are lower. Water-gas ratios in both systems are greater than the amount expected to be dissolved in gas in the reservoir (fig. 1-2 of pl. 1 and fig. 2-2 of pl. 2).

Finally, the Codell-Niobrara interval is overpressured and the Dakota J interval is underpressured. Underpressuring in the Dakota J interval is attributed to outcrop exposures east of the Denver Basin and to hydraulic isolation of strata east of the basin from outcropping strata along the Front Range of Colorado. We hypothesize that the gas accumulation in the Wattenberg field is the cause of the hydraulic isolation, either partially or entirely, because water continuity is disrupted in the gas-dominated pore system of the Dakota J interval. We also note that the pressure differences between the Codell-Niobrara and the Dakota J intervals show them to be hydraulically separate entities.

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