

Composition Variety Complicates Processing Plans for US Shale Gas

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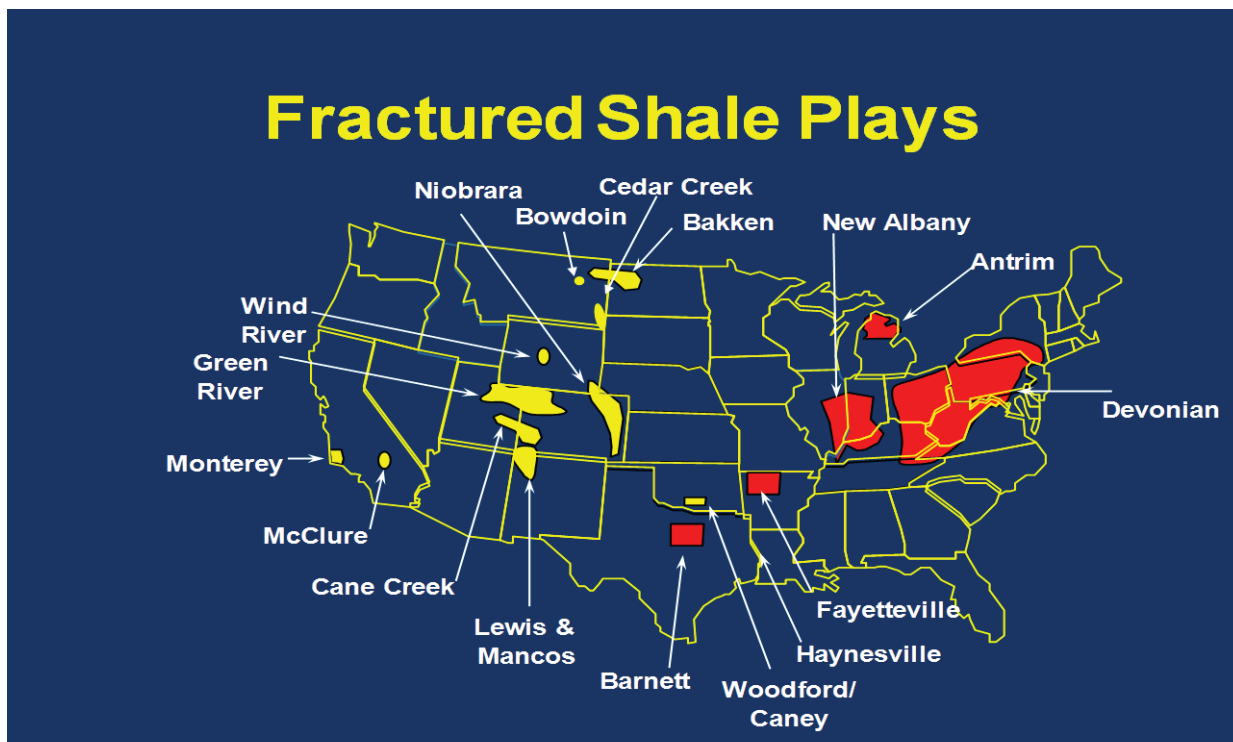
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This article reviews which gas processing technologies are appropriate for the variety of US shale gas qualities being produced and planned to be produced.

Recently higher gas prices and improved drilling technology have spurred shale gas drilling across the US. Fig. 1 shows the shale plays currently being explored.

Figure 1: Shale Gas Regions in the US



http://www.energyindustryphotos.com/new_albany_shale.htm

Some of the more popular areas are the Barnett, Haynesville, and Fayetteville shales in the South and the Marcellus, New Albany, and Antrim shales in the East and Midwest. These plays represent a large portion of current and future gas production.

But all shale gas is not the same, and gas processing requirements for shale gas can vary from area to area. As a result, shale gas processors must be concerned about elevated ethane and nitrogen levels across a field. Other concerns are the increased requirements of urban gas processing. In addition, the rapid production growth in emerging shale areas can be difficult to handle.

This article will review which gas processing technologies are appropriate for the variety of gas qualities being produced and planned to be produced.

Gas processing

Gas processing removes one or more components from harvested gas to prepare it for use. Common components removed to meet pipeline, safety, environmental, and quality specifications include H₂S, CO₂, N₂, heavy hydrocarbons, and water. The technique employed to process the gas varies with the components to be removed as well as with the properties of the gas stream (e.g. temperature, pressure, composition, flow rate).

Acid-gas removal is commonly by absorption of the H₂S and CO₂ into aqueous amine solutions. This technique works well for high-pressure gas streams and those with moderate to high concentrations of the acid-gas component.

Physical solvents such as methanol or the polymer DEGP, or Selexol may also be used in some cases. And, if the CO₂ level is very high, such as in gas from CO₂ flooded reservoirs, membrane technology affords bulk CO₂ removal in advance of processing with another method. For minimal amounts of H₂S in a gas stream, scavengers can be a cost effective approach to H₂S removal.

Natural gas that becomes saturated with water in the reservoir requires dehydration to increase the heating value of the gas and to prevent pipeline corrosion and the formation of solid hydrates.

In most cases, dehydration with a glycol is employed. The water rich glycol can be regenerated by reducing the pressure and applying heat. Another possible dehydration method is use of molecular sieves that contact the gas with a solid adsorbent to remove the water. Molecular sieves can remove the water down to the extremely low levels required for cryogenic separation processes.

Distillation uses the different boiling points of heavier hydrocarbons and nitrogen for separation. Cryogenic temperatures, required for separation of nitrogen and methane, are achieved by refrigeration and expansion of the gas through an expander. Removal of the heavy hydrocarbons is dictated by pipeline quality requirements, while deep removal is based on the economics of NGL production.

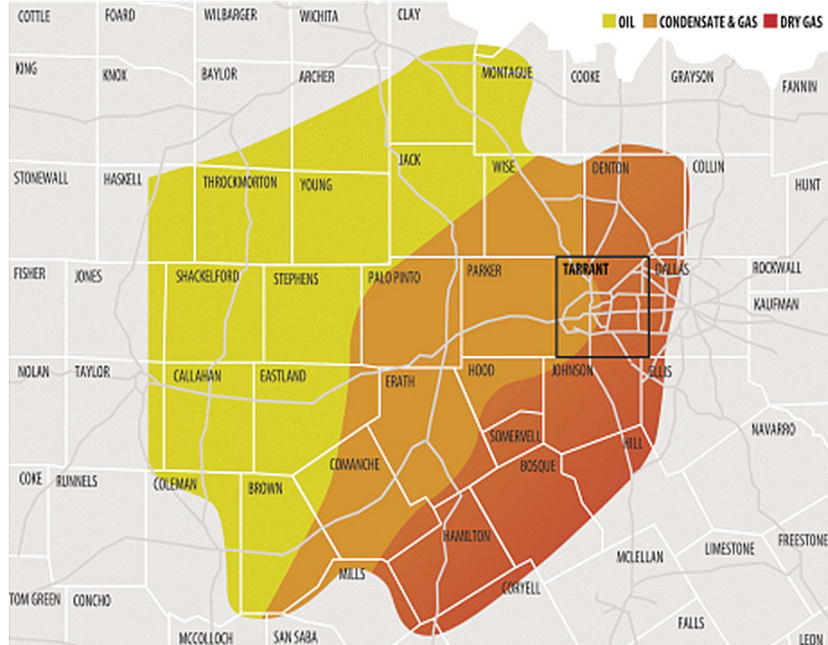
Shale gas processing requirements

The following reviews six shale gas plays, their compositions, and processing needs: Barnett, Marcellus, Fayetteville, New Albany, Antrim, and Haynesville.

Barnett

The Barnett shale formation is the grandfather of shale gas plays. Much of the technology used in drilling and production of shale gas has been developed on this play. The Barnett shale formation lies around the Dallas-Ft. Worth area of Texas (Fig. 2) and produces at depths of 6,500–9,500 ft. The average production rate varies throughout the basin from 0.5 MMscfd to 4 MMscfd with estimates of 300 – 350 scf of gas per ton of shale¹. The most active operators in the region are Chesapeake Energy, Devon, EOG Resources, and XTO.

Figure 2: Texas Barnett Shale Resource Map



The initial discovery region was in a core area on the eastern side of the play. As drilling has moved westward, the form of the hydrocarbons in the Barnett shale has varied from dry gas prone in the east to oil prone in the west.

Table 1: Barnett Shale Gas Composition

Well	C1	C2	C3	CO2	N2
1	80.3	8.1	2.3	1.4	7.9
2	81.2	11.8	5.2	0.3	1.5
3	91.8	4.4	0.4	2.3	1.1
4	93.7	2.6	0.0	2.7	1.0

The compositions have been normalized to the reported compounds. Adapted from Ronald J. Hill, Daniel M. Jarvie, John Zumberge, Mitchell Henry, and Richard M. Pollastro Oil and gas geochemistry and petroleum systems of the Fort Worth Basin, AAPG Bulletin, v. 91, no. 4 April 2007, pp. 445–473.

Table 1 shows the composition of four wells in the Barnett. These wells appear from east to west with the eastern most well on the top (Well No. 1). As the table suggests, there is a large increase in the amount of ethane and propane as the wells move west.

One well sample on the western edge of the play (Well No. 4) shows a high level—7%—of nitrogen. This level is high enough to require treating, but blending with other gas in the area is the most economical solution.

The gas processing industry has scrambled to keep up with the tremendous growth of the Barnett Shale. Production has jumped from almost nothing in 1999 to approximately 4 BCFD currently. To sustain this growth, the gas processing industry has added the equivalent of a 100 MMscfd cryogenic facility to the area every 3 months for ten years. Some of the major gas plants processing Barnett shale gas are the Devon Bridgeport Facility (1 BCFD), Quicksilver Cowtown Plant (200 MMSCFD) and Corvette Plant (125 MMSCFD), Enbridge Weatherford Facility (75 MMSCFD), Energy Transfer Godley Plant (300 MMSCFD), the Crosstex Silver Creek (200 MMSCFD), Azle (55 MMCFD) and Goforth (35 MMCFD) plants, the Targa Chico (150 MMSCFD) and Shackelford (125 MMSCFD). Crosstex has announced plans to add the Bear Creek Plant with an additional 200 MMSCFD capacity in late 2009.

The majority of these plants include compression, CO₂ treating with amine units, cryogenic separation, and fractionation. The processed gas heads East toward Carthage where it can reach the Midwest via the Perryville Hub, or the Northeast via the Transco or Texas Eastern pipeline, or the Southeast via the Transco or Florida Gas pipeline. With the richness of the gas, the Barnett plants remove about 3.5 gallons of natural gas liquids per MSCF of gas. Based on the current 4 BCFD of gas production, approximately 325,000 barrels of natural gas liquids are produced each day.

One of the greatest challenges to gas processing in the Barnett shale region is operating in an urban environment. As an example, the town of Flower Mound has an extensive list of regulations for the gas processing industry for operations within its city limits. These regulations cover appearance (color, landscaping, fences, and lighting) as well as operations (equipment height and noise level). These extensive regulations force the gas plants to move to less densely populated areas when possible.

Marcellus

The Marcellus shale lies in western Pennsylvania, Ohio, and West Virginia (Fig. 3) and has tremendous potential. It is shallow at depths of 2,000–8,000 ft and 300–1,000 ft thick. Initial production rates have been reported in the 0.5–4 MMscfd range with estimates of 60–100 scf of gas per ton of shale.

Table 2 shows the composition for four natural gas wells in the Marcellus shale. The gas composition varies across the field, much as it does in the Barnett: The gas becomes richer from east to west.

Figure 3: Marcellus Shale Fairway

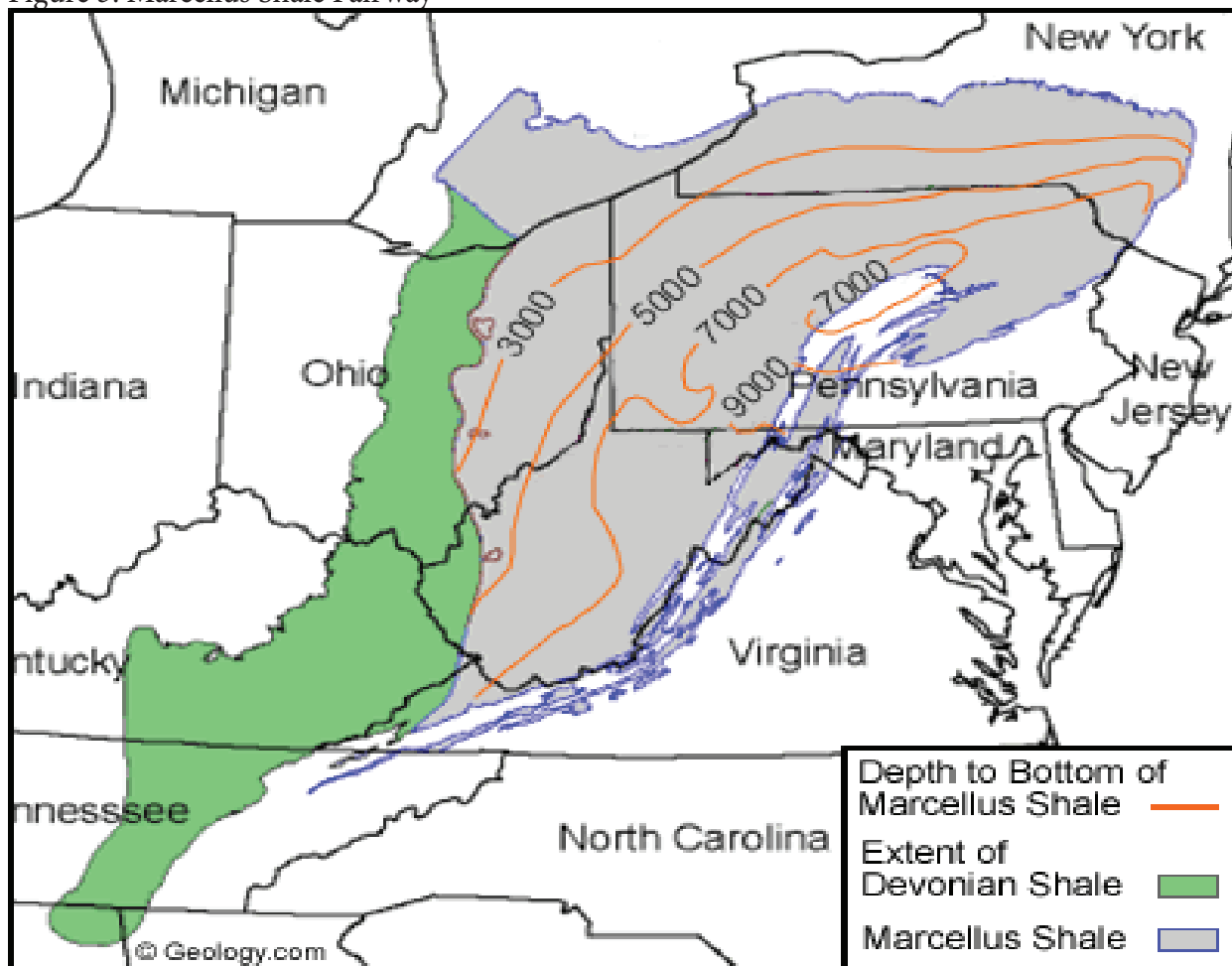


Table 2: Marcellus Shale Gas Composition

Well	C1	C2	C3	CO2	N2
1	79.4	16.1	4.0	0.1	0.4
2	82.1	14.0	3.5	0.1	0.3
3	83.8	12.0	3.0	0.9	0.3
4	95.5	3.0	1.0	0.3	0.2

From a gas processing point of view, the Marcellus region does not have the gas blending luxury of the Barnett shale because there is little infrastructure.

The Marcellus is blessed, however, with little CO₂ and nitrogen. The greatest obstacle for the area—a lack of facilities to dispose of wastewater and completion fluids—has limited growth in this region. A complex terrain of hills, trees, and streams, creates access and environmental challenges to drilling and production. Operators compensate with custom rigs to reduce footprints.

Most existing Pennsylvania and Northern Appalachia gas is dry and does not require removal of NGLs for pipeline transportation. Early indications are that the Marcellus gas has sufficient liquids to require processing.

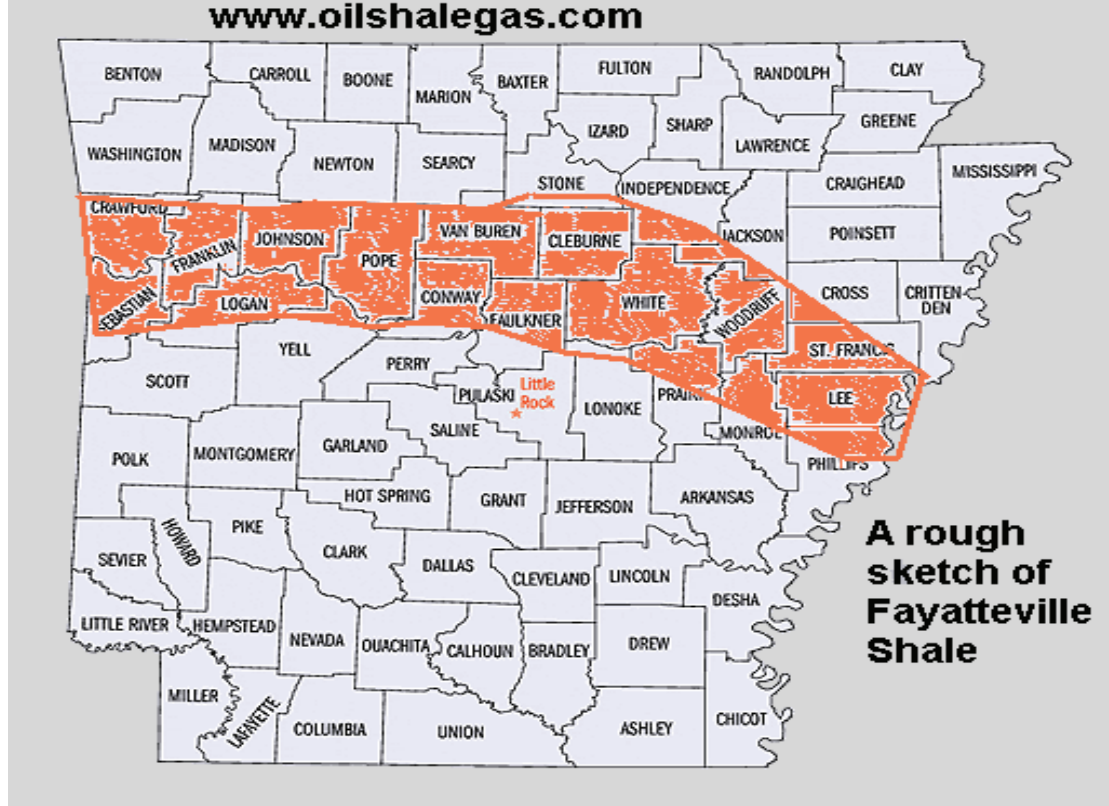
Markwest Energy Partners recently announced the installation of a 30 MMSCFD refrigeration unit to process Marcellus gas from Range Resources. Markwest is also currently constructing a 30 MMSCFD cryogenic processing plant that is expected to commence operations late in the first quarter of 2009. An additional 120 MMSCFD cryogenic plant with a fractionation train is planned for completion in late 2009. The liquid propane will be marketed regionally.

Some anticipate that the Marcellus shale could hold as much gas as the Texas Barnett shale. If this is the case, gas processing could generate substantial volumes of natural gas liquids for the region with no clear market or access to the Texas Gulf Coast.

Fayetteville shale

The Fayetteville shale is an unconventional gas reservoir located on the Arkansas side of the Arkoma Basin (Fig. 4).

Figure 4: Approximate Location of the Fayetteville Shale Across Arkansas



oilshalegas.com/fayettevilleshale.html

The shale ranges in thickness from 50 – 550 feet at a depth of 1,500 to 6,500 feet and is estimated to hold between 58 – 65 BCF per square mile². Reported initial production rates are 0.2–0.6 MMscfd for vertical wells and 1.0–3.5 MMscfd for horizontal wells. In 2003 Southwestern Energy discovered the play and has grown their production to approximately 500 MMSCFD.

Table 3 shows gas composition of one area of the Fayetteville shale. The gas primarily requires only dehydration to meet pipeline specifications. Lack of infrastructure also has limited growth of this area.

Table 3: Fayetteville Shale Gas Composition

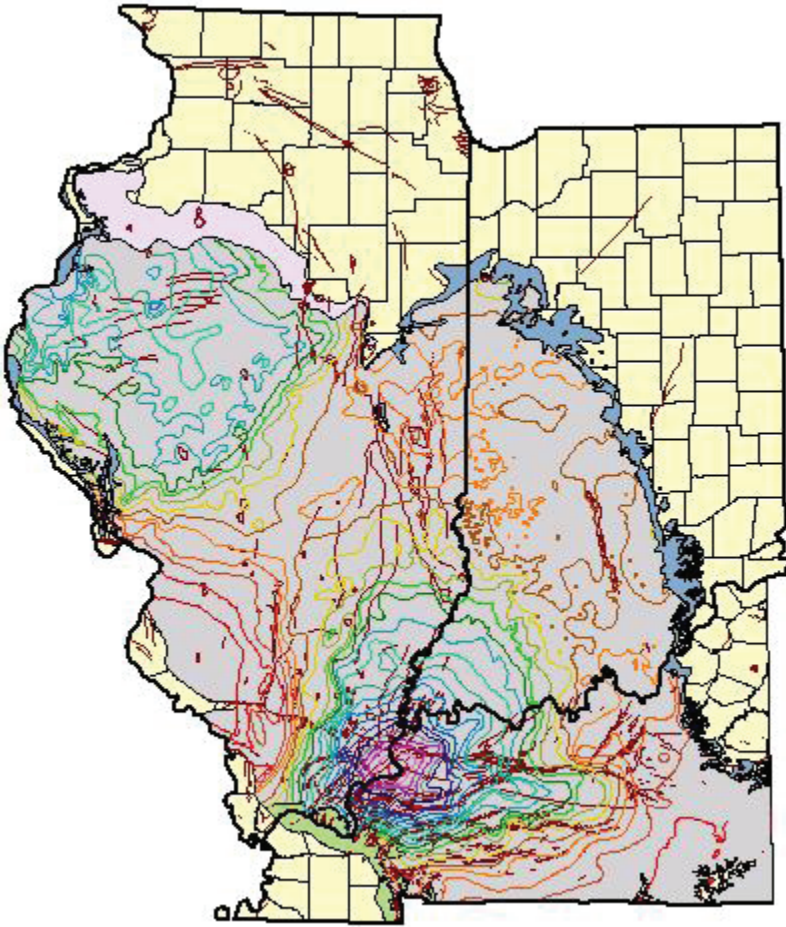
Well	C1	C2	C3	CO2	N2
Avg	97.3	1.0	0	1.0	0.7

Additional pipeline capacity is on the way with the Texas Gas 1.3 BCFD Fayetteville Lateral pipeline which is under construction. An additional 2 BCFD of pipeline capacity has been announced by Kinder Morgan Energy Partners LP and Energy Transfer Partners LP which is scheduled for completion in 2010-11. Southwestern Energy and Chesapeake have agreed to 10-year commitments to use the 187 mile line. The full scope of the Fayetteville shale is still unknown. Southwestern Energy has approximately 850,000 acres leased while the remainder of the industry has an additional 1 million acres.

New Albany

The New Albany shale is a black shale in Southern Illinois extending through Indiana and Kentucky (Fig. 5). It is 500–4,900 ft deep and 100–400 ft thick. Vertical wells typically produce 25–75 Mscfd initially, while horizontal wells can have initial production rates of up to 2 MMscfd.

Figure 5: New Albany Shale Resource Map



http://www.kentuckynaturalgas.com/New_Albany_Shale.html

Table 4 shows the composition from four wells in Meade County. In this region the gas contains 8–10% CO₂. Low flow rates of wells in the New Albany shale require that production from many wells must be combined to warrant processing the gas.

Table 4: **New Albany Shale Gas Composition**

Well	C1	C2	C3	CO ₂
1	87.7	1.7	2.5	8.1
2	88.0	0.8	0.8	10.4
3	91.0	1.0	0.6	7.4
4	92.8	1.0	0.6	5.6

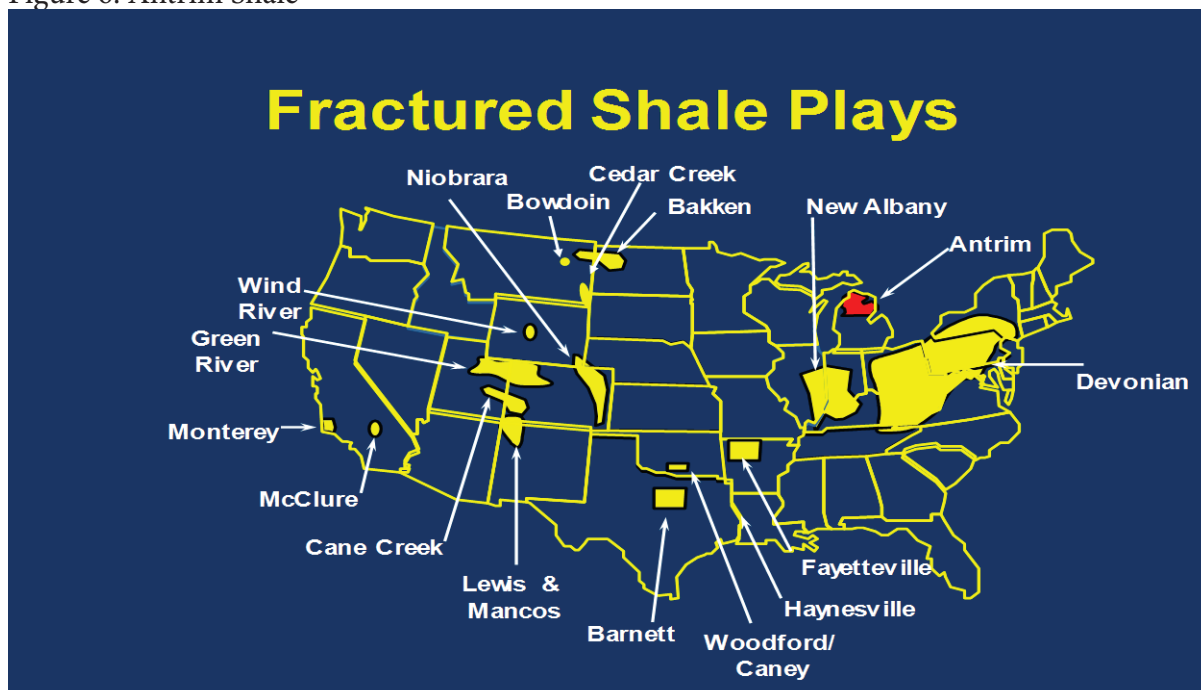
The compositions have been normalized to the reported compounds. Nitrogen content was not reported. Adapted from Anna M. Martini, Lynn M. Walter, and Jennifer C. McIntosh, Identification of microbial and thermogenic gas components from Upper Devonian black shale cores, Illinois and Michigan basins, AAPG Bulletin, v. 92, no. 3, March 2008, pp. 327–339.

NGAS Resources announced in October 2008 that they completed field gathering and gas processing facilities in Christian County Kentucky. The processed gas from 26 wells is flowing into the Texas Gas interstate pipeline. They have two rigs running in the area with expected recoveries of 135–200 million cubic feet per well.

Antrim

The Antrim shale is a shallow shale gas play in Michigan (Fig. 6) whose development was accelerated due to the non-conventional gas tax incentives of the 1980's.

Figure 6: Antrim Shale



http://www.energyindustryphotos.com/new_albany_shale.htm

Today, the over 9000 wells in the Antrim shale have cumulatively produced 2.5 TCF. Individual well production ranges from 50–60 Mscfd. Despite these small initial production rates, extremely long well life resulted in substantial production over the life of the well. The Antrim shale is unique because the gas is predominately biogenic: methane is created as a bi-product of bacterial consumption of organic material in the shale. Significant associated water is produced requiring central production facilities for dehydration, compression and disposal.

Table 5 shows the compositions of the gas produced from four wells in this area. The carbon dioxide level in these samples varies from 0-9%. Carbon Dioxide is a naturally occurring byproduct of shale gas produced by desorption. As a result, the CO₂ levels in produced Antrim Gas steadily grow during a wells productive life, eventually topping 30% in some areas. MarkWest is the dominant gas processor in this region with 340 MMcf/d capacity at five plants (Kenova, Maytown, Boldman, Kermit, and Cobb). The residue gas is delivered to Columbia Gas Transmission while the NGLs are shipped to the Siloam fractionators for further processing where they are sold by truck, rail, or barge.

Table 5: Antrim Shale Gas Composition

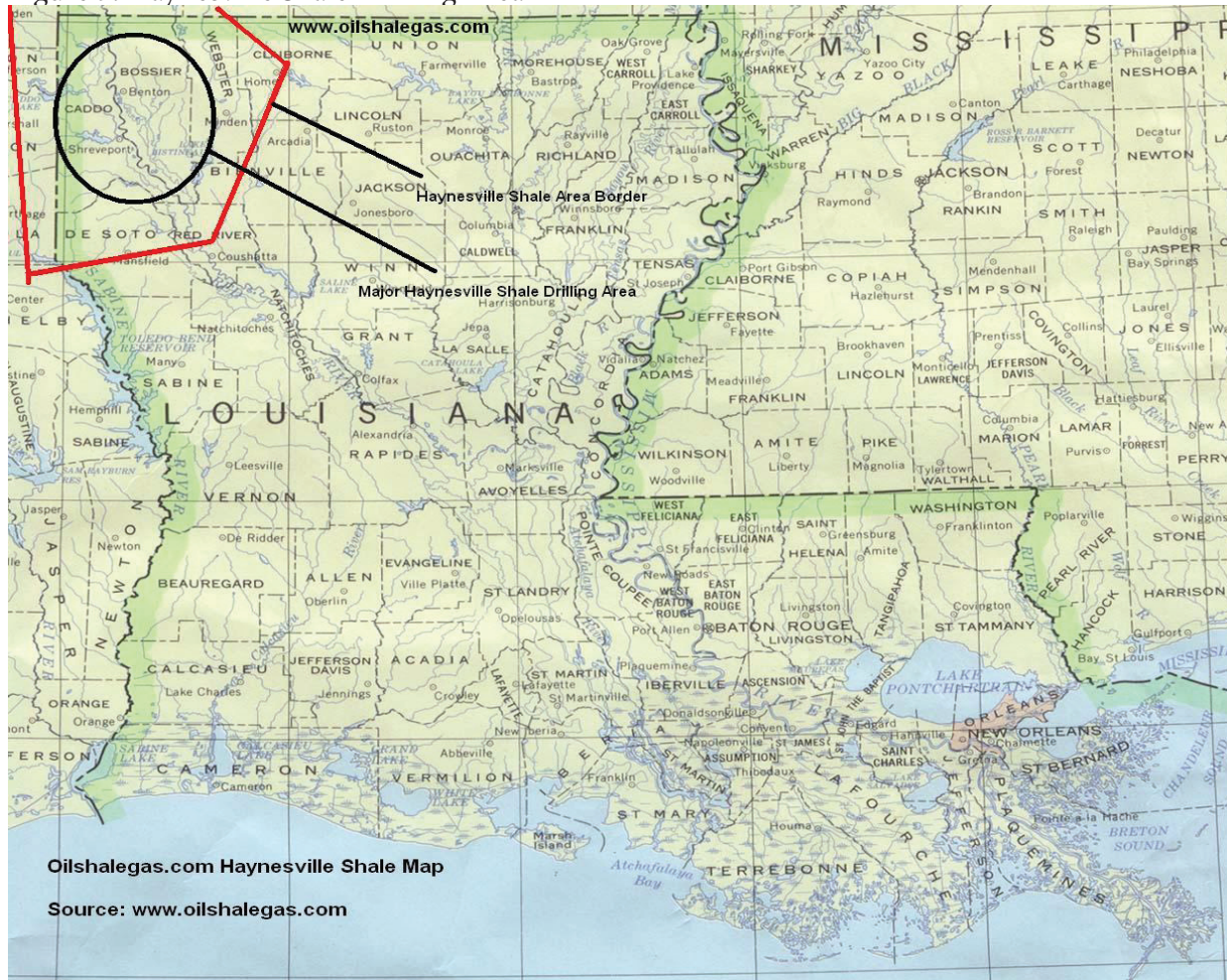
Well	C1	C2	C3	CO ₂	N ₂
1	27.5	3.5	1.0	3.0	65.0
2	57.3	4.9	1.9	0	35.9
3	77.5	4.0	0.9	3.3	14.3
4	85.6	4.3	0.4	9.0	0.7

The compositions have been normalized to the reported compounds. Adapted from Anna M. Martini, Lynn M. Walter, Tim C. W. Ku, Joyce M. Budai, Jennifer C. McIntosh, and Martin Schoell, Microbial Production and modification of gases in sedimentary basins: A geochemical case study from a Devonian shale gas play, Michigan basin, AAPG Bulletin, v. 87, no. 8, August 2003, pp. 1355–1375

Haynesville

The Haynesville shale play is the newest and hottest shale area to be developed. It lies in northern Louisiana and East Texas (Fig. 7).

Figure 7: Haynesville Shale Drilling Area



It is deep (10,000+ ft), hot (350° F. bottomhole temperature), and exhibits high pressure (3,000–4,000 psi). The wells have shown initial production rates of 2.5–20+ MMscfd with estimates of 100 – 330 scf of gas per ton of shale. The Haynesville shale area is believed to hold large potential and projected to draw resources away from the other shale plays in the near future.

Table 6 shows a field average concentration for the Haynesville play. This gas requires treating for CO₂ removal. Operators in this field are using amine treating to remove the CO₂ with a scavenger treatment on the tail gas to remove the H₂S. Most of the treating is currently performed with traditional amine units with 60-100 gpm capacities. These units are placed on a rental or purchased basis. The bulk of the processed gas enters the Carthage system where it can be distributed across the country.

Table 6: Haynesville Shale Gas Composition

Well	C1	C2	C3	CO ₂	N ₂
Avg	95.0	0.1	0	4.8	0.1

One of the biggest issues faced by gas processors in the Haynesville area is the large production addition from each well as it is brought on line. Plants that are oversized today become undersized tomorrow. Area operators suggest designing units that scale up and down easily during the growth process. This includes units that employ valve trays, variable speed pumps, and multiple trains.

Chesapeake announced that the initial production rate for the last seven horizontal Haynesville wells averaged 16 MMscf/d each. If the pipeline announcements are any clue, the industry is anticipating a scramble for processing facilities for the Haynesville area much like the rapid growth of the Barnett. DCP Midstream Partners and M2 Midstream

LLS have recently announced a joint venture for a 1.5 BCFD pipeline to be completed in early 2010. Energy Transfer Partners and Chesapeake announced plans for the 42" Tiger Pipeline to connect from Carthage, Tx to near Delhi, La to be completed by mid-2011.

1 Hayden, J., and Pursell, D. The Barnett Shale. Visitor's Guide to the Hottest Gas Plant in the US. Oct 2005

2 SHALE GAS – A Supplement to Oil and Gas Investor. January 2006. pp 18-20.