ATTACHMENT E

FORECASTING OIL AND GAS ACTIVITIES

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FINAL REPORT

Prepared for:

Texas Commission on Environmental Quality
Air Quality Division

Prepared by:

Eastern Research Group, Inc.

August 31, 2012

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Forecasting Oil and Gas Activities

FINAL REPORT

Prepared for:

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List of Acronyms

EIA	Energy Information Administration
EUR	Estimated Ultimate Recovery
BCF	Billion cubic feet
TCF	Trillion cubic feet
TRC	Texas Railroad Commission
MBO	Thousand barrels of oil
BBO	Billion barrels of oil
TRR	Technically Recoverable Resources
MCF	Thousand cubic feet
BBL	Barrels
URR	Ultimately Recoverable Resources
SCC	Source Classification Code

List of Units

yr	year
mi^2	square miles

Executive Summary

This report is a deliverable for Texas Commission on Environmental Quality (TCEQ) Work Order No. 582-11-99776-FY12-12 to develop area-specific growth factors to forecast oil and gas activities in the following areas: Barnett, Haynesville, and Eagle Ford Shales. Production in these three shale play regions began to increase around 2001 with the advent of horizontal drilling and hydraulic fracturing, with significant production increases seen in the region over the last five to seven years. Initially, the Barnett Shale in North-central Texas was the focal point of shale gas development, but recently more activity has occurred in the Eagle Ford Shale area in South-central Texas as this play contains both oil and gas shale deposits.

Historical monthly production data were obtained from the Texas Railroad Commission (TRC) for the years 2000 through February 2012. These data were obtained at the county level, and included gas well gas production (MCF/month), oil production in barrels per month (BBL/month), casinghead gas production (MCF/month), and condensate production (BBL/month). ERG segregated the monthly production data based on the counties that compose the Barnett, Eagle Ford, and Haynesville shale play regions. This data was then used to project future production activity based on the following 5 forecasting methodologies:

> <u>Methodology 1</u>: Project future production assuming that current production remains constant into the future.
>
> <u>Methodology 2</u>: Project future production levels based on the historical production timeline for each specific shale play, on a county-by-county basis.
>
> <u>Methodology 3 (Hubbert's model)</u>: Project future production levels based on the historical production timeline for each specific shale play, on a county-by-county basis, with a capped limit based on the size of the reserves.
>
> <u>Methodology 4</u>: Project future production levels for counties in the Barnett shale play and use as a surrogate for the counties in the Haynesville Shale and Eagle Ford Shale plays.
>
> <u>Methodology 5</u>: Project future production by using natural gas commodity price projections as a surrogate for future production.

Growth factors were developed using the results of these analyses to represent the change in annual production in years 2012 through 2035 relative to the annual production in the base year of 2011. Once the growth factors were calculated, the factors were applied to the 2011 annual production for each product in each shale play region to estimate annual production in each year 2012 through 2035. The estimated annual production values were then summed across the years 2012 through 2035 resulting in an estimated cumulative production for the same time period. Three growth scenarios (high growth, moderate growth, and low growth) were then identified from the estimated cumulative production values.

Based on the findings of this effort, Methodology 3 (Hubbert's model) is the preferred forecasting methodology. The Hubbert model was developed for each shale play region based on historical data for the region, but also takes into account changes in production rates due to the size of reserves and estimated ultimate recovery. While there is a great amount of uncertainty in reserve estimation and even published Technically Recoverable Resources (TRR) values (and those values continue to change over time due to advances in technology and estimation methods), the Hubbert model accounts for estimated maximum cumulative production. The gradual leveling of total cumulative production as resources near depletion is reflected in the production rate curve when the cumulative production curve is differentiated. The result is a clear peak in the annual production curve indicating when maximum annual production is estimated to occur. For emissions modeling and estimation purposes, this peak would also correspond to the period of peak emissions resulting from production activities. Except under Methodology 4 (modeling based on existing and projected Barnett Shale growth), the other projection methodologies do not produce a distinct production peak which results in production either increasing (at a constant or variable rate) or remaining constant indefinitely, which are likely very unrealistic or improbable scenarios.

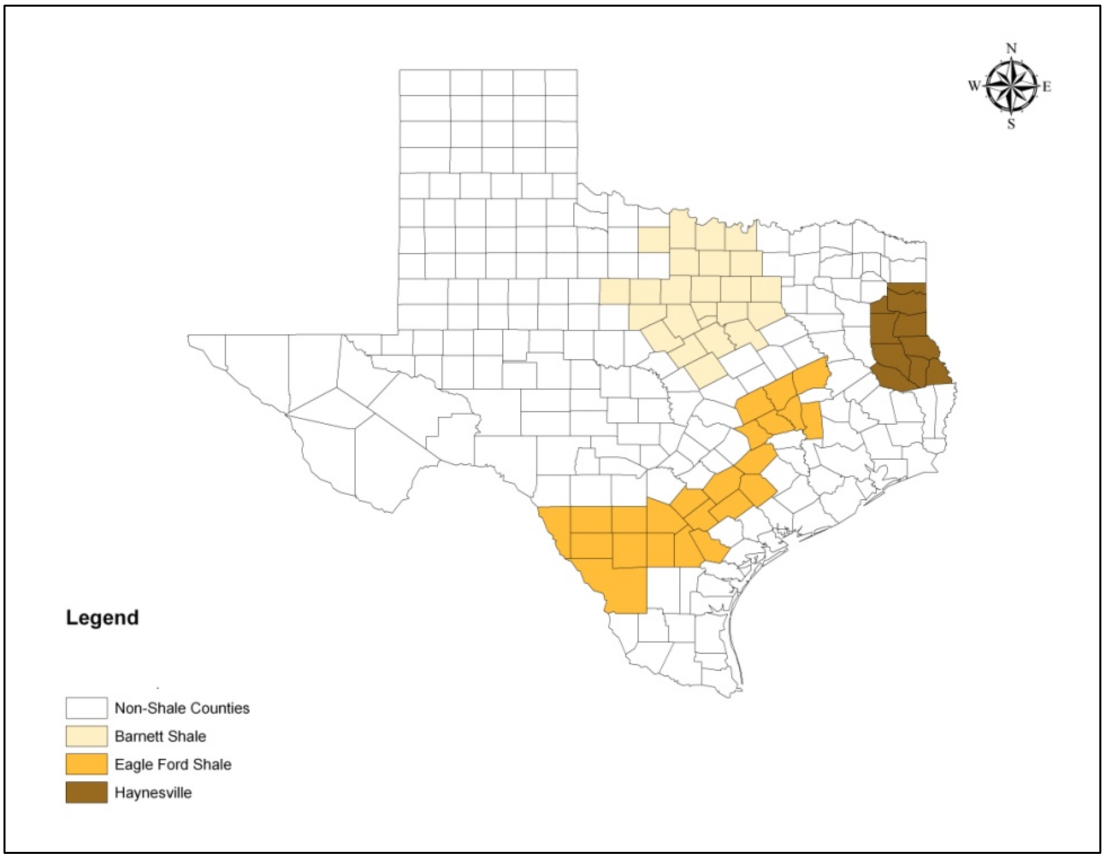
1.0 Introduction

Under a contract with the Texas Commission on Environmental Quality (TCEQ), Eastern Research Group, Inc. (ERG) developed area-specific growth factors to forecast oil and gas activities in the Texas counties that comprise the Barnett, Eagle Ford, and Haynesville Shale plays. This report describes the methodologies and results of that effort.

2.0 Characteristics of the Texas Shale Plays

Shale gas and oil development across the United States has increased dramatically in the last 10 years due to technological advances in drilling and well completion activities. In particular, horizontal drilling and hydraulic fracturing have allowed for development of shale gas and oil deposits. Several counties in Texas compose the three different shale plays covered under this report as illustrated by Figure 2-1. Additional details on each of these areas is provided below.

Figure 2-1. Texas Shale Play Counties



2.1 Barnett Shale Gas Play

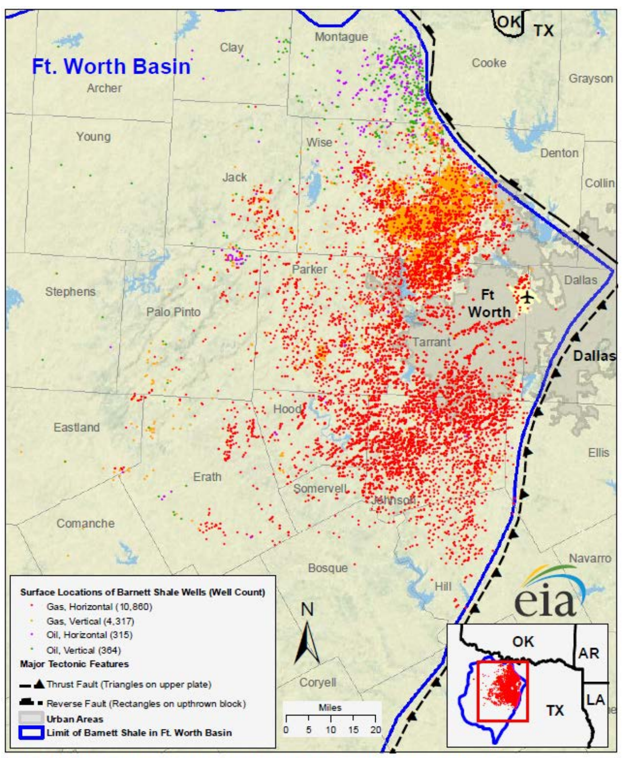
The Barnett shale gas play is situated around the Dallas-Fort Worth metropolitan area and covers approximately 6,000 square miles (mi^2). Table 2-1 identifies the twenty-four counties in Texas that compose the Barnett shale play region:

Table 2-1. Texas Counties Comprising the Barnett Shale Gas Play Region

ARCHER	BOSQUE	CLAY
COMANCHE	COOKE	CORYELL
DALLAS	DENTON	EASTLAND
ELLIS	ERATH	HAMILTON
HILL	HOOD	JACK
JOHNSON	MONTAGUE	PALO PINTO
PARKER	SHACKELFORD	SOMERVELL
STEPHENS	TARRANT	WISE

Figure 2-2 shows the location of oil and gas wells in the Barnett Shale.

Figure 2-2. Barnett Shale Gas Play, Fort Worth Basin, Texas



Source: US Energy Information Administration based on data from HPDI, USGS, Pollastro et al (2007)
Updated: May 31, 2011

Production in the Barnett shale play region began to increase around 2001 with the advent of horizontal drilling and hydraulic fracturing, with significant production increases seen in the region over the last five to seven years. The Barnett Shale play was the first area in Texas to experience increased development.

A report by the U.S. Department of Energy, Energy Information Administration (EIA) reviewed key statistics and resource estimates for the Barnett Shale gas play, which are listed in Table 2-2 below.

Table 2-2. Barnett Shale Gas Play Statistics and Resource Estimates[1]

	Active	Undeveloped
Area (mi^2)	4,075	2,383
EUR (BCF/well)	1.6	1.2
Well Spacing (wells/mi^2)	5.5	8
TRR (TCF)	23.81	19.56

BCF – billion cubic feet
EUR – Estimated Ultimate Recovery
TCF – trillion cubic feet
TRR – Technically Recoverable Resources

2.2 Eagle Ford Shale Oil and Gas Play

The Eagle Ford Shale is a hydrocarbon producing formation of significant importance due to its capability of producing gas, condensate, and more oil than other traditional shale plays. The Eagle Ford Shale is situated in south Texas and is roughly 50 miles wide and 400 miles long. The area of the dry gas zone is estimated at 200 mi^2; the area of the condensate zone is estimated at 890 mi^2; and the area of the oil zone is estimated at 2,233 mi^2. The Eagle Ford Shale is located in the Western Gulf basin within the Texas Railroad Commission (TRC) Districts 1 thru 6. Table 2-3 identifies the twenty-three counties in the Eagle Ford shale region:

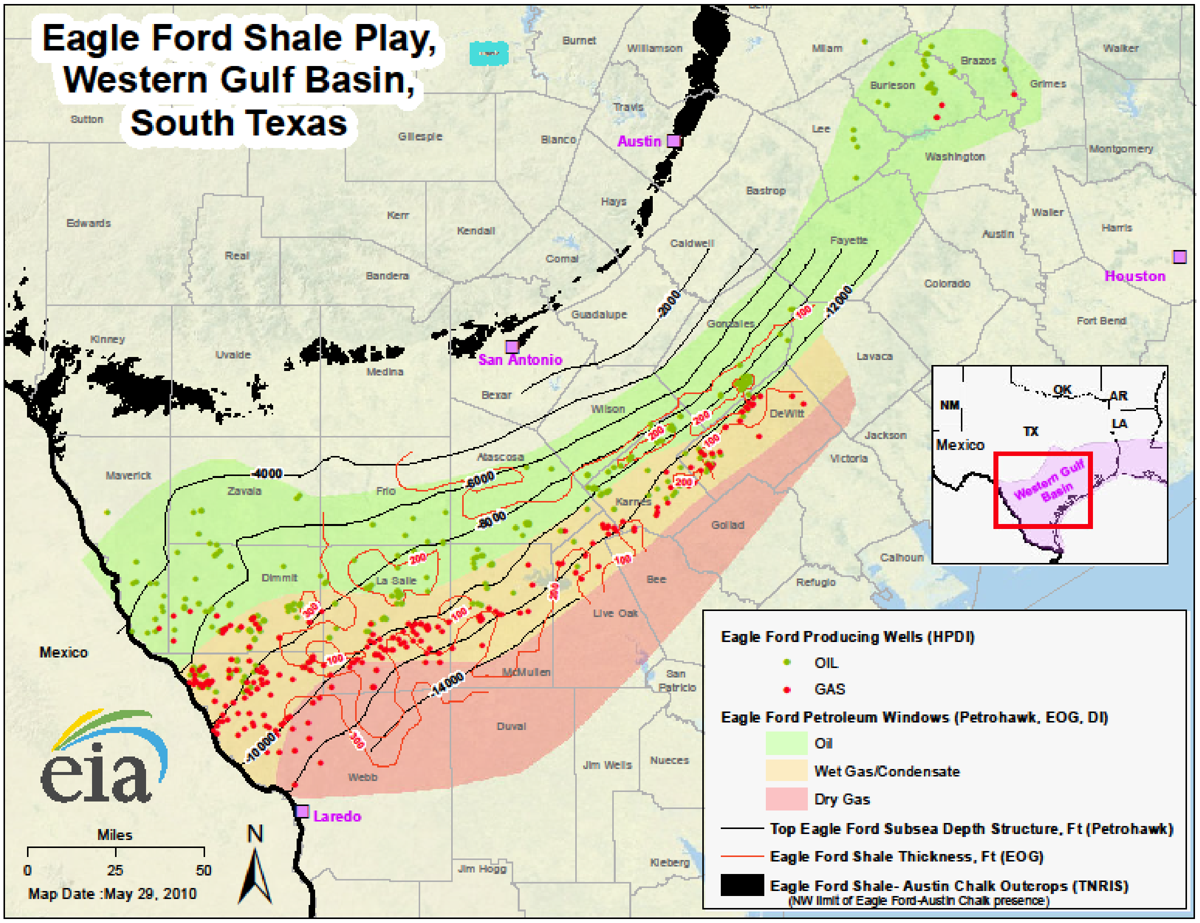
Table 2-3. Texas Counties Comprising the Eagle Ford Shale Oil and Gas Play Region

ATASCOSA	BEE	BRAZOS
BURLESON	DE WITT	DIMMIT
FAYETTE	FRIO	GONZALES
GRIMES	KARNES	LA SALLE
LAVACA	LEE	LEON
LIVE OAK	MAVERICK	MCMULLEN
MILAM	ROBERTSON	WEBB
WILSON	ZAVALA	

Figure 2-3 shows the location of oil and gas wells in the Eagle Ford Shale.

[1] "Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays," U.S. Energy Information Administration, July 2011.

Figure 2-3. Eagle Ford Shale Oil and Gas Play, South Texas



Source: US Energy Information Administration, 2012, http://www.eia.gov/oil_gas/rpd/shaleusa9.pdf

The first of the Eagle Ford Shale wells was drilled in 2008, using horizontal drilling and multi-stage hydraulic fracturing. The number of wells drilled in this region has increased steadily since then. The number of producing gas wells has increased from 67 in 2009, to 158 in 2010, and 155 in 2011. The number of producing oil leases has increased from 40 in 2009, to 72 in 2010, and 368 in 2011.

A report by the EIA reviewed key statistics and resource estimates for the Eagle Ford shale play, which are listed in Table 2-4 below.

Table 2-4. Eagle Ford Shale Gas Play Statistics and Resource Estimates[2]

	Dry Gas Zone	Condensate Zone	Oil Zone
Area (mi^2)	200	890	2,233
EUR (BCF/well)	5.5	4.5	
EUR (MBO/well)			300
Well Spacing (wells/mi^2)	4	8	5
TRR (BBO)			3.35
TRR (TCF)	4.38	16.43	

BBO – billion barrels of oil
MBO – thousand barrels of oil

2.3 Haynesville Shale Gas Play

The Haynesville shale gas play, also known as the Haynesville-Bossier shale play, is located in East Texas and Western Louisiana. The Haynesville shale has a total area of approximately 9,000 square miles. Table 2-5 identifies the ten counties in Texas that compose the Texas portion of the Haynesville shale play region:

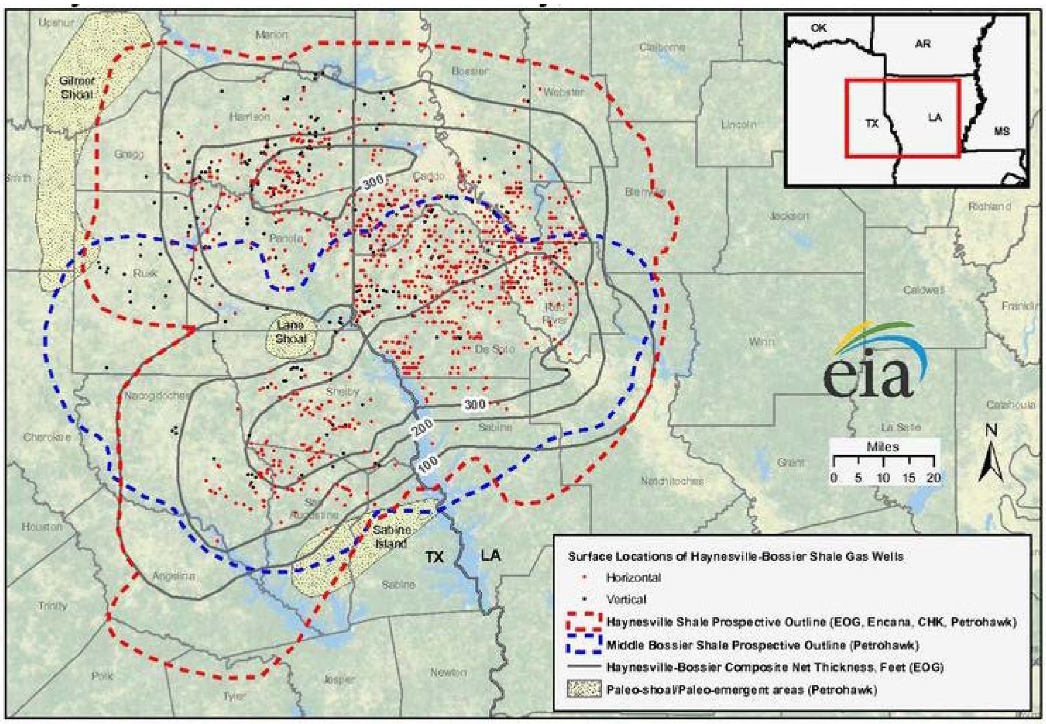
Table 2-5. Texas Counties Comprising the Haynesville Shale Gas Play Region

ANGELINA	GREGG
HARRISON	MARION
NACOGDOCHES	PANOLA
RUSK	SABINE
SAN AUGUSTINE	SHELBY

Figure 2-4 shows the location of oil and gas wells in the Haynesville Shale.

[2] "Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays," U.S. Energy Information Administration, July 2011.

Figure 2-4. Haynesville Shale Gas Play, Eastern Texas



Source: Energy Information Administration based on data from HPDI, TX Railroad Commission, LA Dept. of Natural Resources, Operators.
Updated May 26, 2011

Production in the Haynesville shale play region has doubled in the past ten years with the introduction of directional drilling and hydraulic fracturing techniques and the higher natural gas prices which occurred from 2005 to 2008 (over $5 per thousand cubic feet (MCF)). The combination of these factors made extraction of the gas economically feasible. With the recent decline in natural gas prices, drilling activity and production have been curtailed.

Key statistics and resource estimates from the EIA for the Haynesville gas shale play are listed in Table 2-6 below.

Table 2-6. Haynesville Shale Gas Play Statistics and Resource Estimates[3]

	Active	Undeveloped
Area (mi^2)	3,574	5,426
EUR (BCF/well)	6.5	1.5
Well Spacing (wells/mi^2)	8	8
TRR (TCF)	53.30	19.41

[3] "Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays," U.S. Energy Information Administration, July 2011.

3.0 Historical Production and Well Completion Statistics

Historical monthly production data were obtained from the TRC for the years 2000 through February 2012. These data were obtained at the county level, and included gas well gas production (MCF/month), oil production in barrels per month (BBL/month), casinghead gas production (MCF/month), and condensate production (BBL/month). ERG segregated the monthly production data based on the listing of counties that compose the Barnett, Eagle Ford, and Haynesville shale play regions (see Tables 2-1, 2-3, and 2-5 above).

3.1 Barnett Shale Play

Figures 3-1 through 3-8 below show county-by-county monthly casinghead gas production and oil production for the counties comprising the Barnett shale play. Montague and Palo Pinto counties began to experience significant increases in monthly casinghead gas production in 2008. Production increases were also seen in Cooke and Jack counties beginning around 2010. These increases roughly correspond to increases in oil production in those counties during the same time period, although oil production in Palo Pinto County has declined steadily since late 2008. The six counties shown in Figure 3-1 produce the majority of the casinghead gas in the Barnett Shale, while the three counties shown in Figure 3-4 produce the majority of oil in the Barnett Shale.

Figure 3-1. Monthly Casinghead Gas Production (MCF/month) in the Barnett Shale Play (Montague, Cooke, Wise, Palo Pinto, Stephens, and Jack Counties)

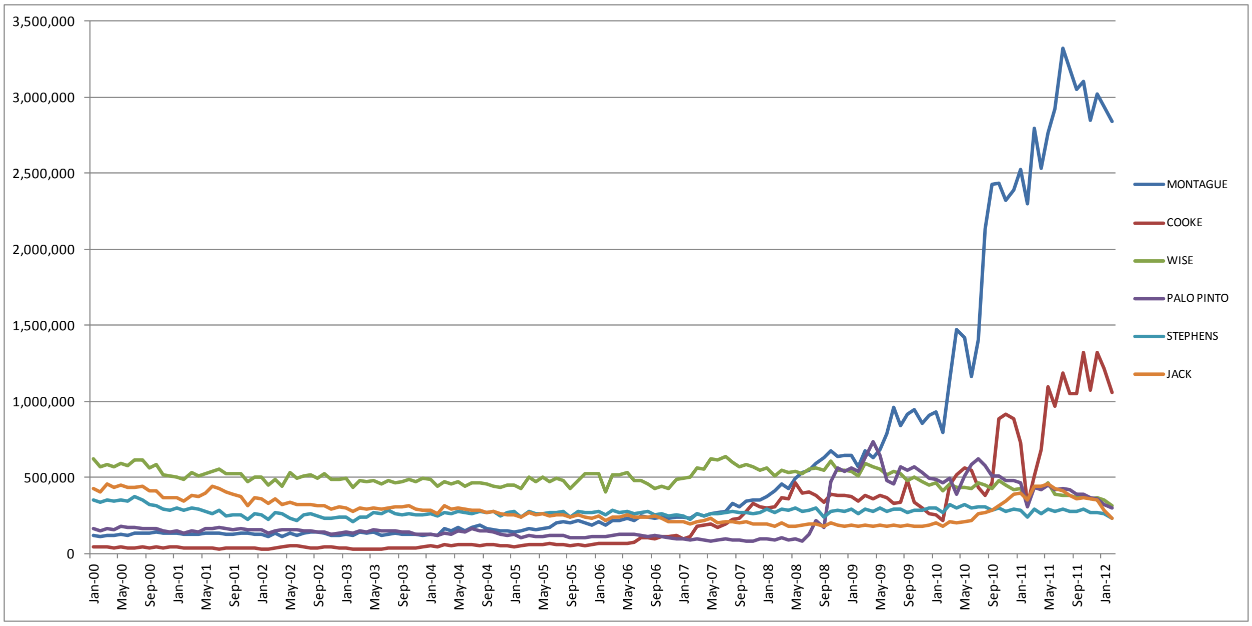


Figure 3-2. Monthly Casinghead Gas Production (MCF/month) in the Barnett Shale Play (Denton, Shackelford, Eastland, Parker, Clay, Archer, Erath, Comanche, and Hood Counties)

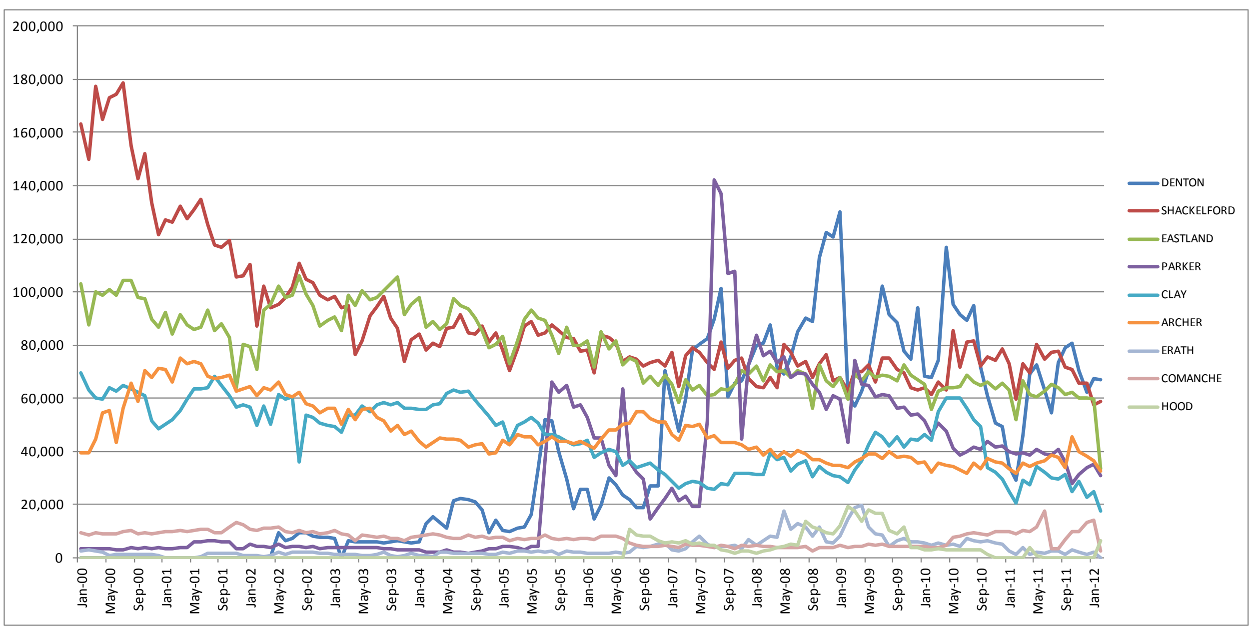


Figure 3-3. Monthly Casinghead Gas Production (MCF/month) in the Barnett Shale Play (Ellis, Hamilton, Hill, Bosque, Coryell, Dallas, Johnson, Somervell, and Tarrant Counties)

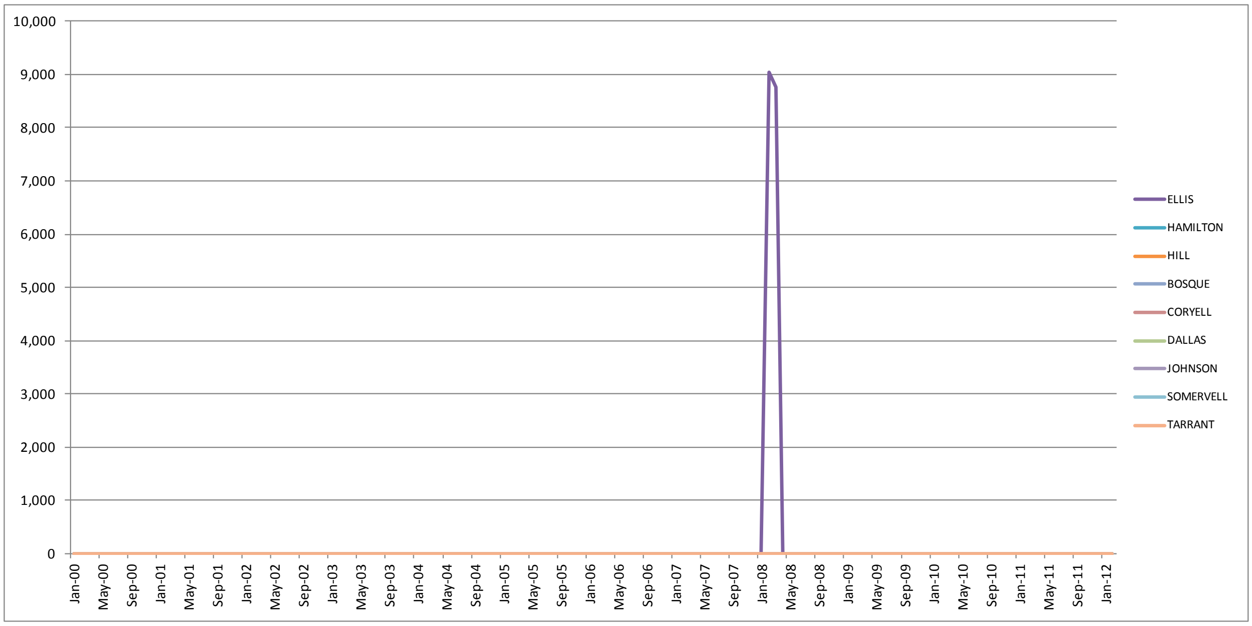


Figure 3-4. Monthly Oil Production (BBL/month) in the Barnett Shale Play (Cooke, Montague, and Stephens Counties)

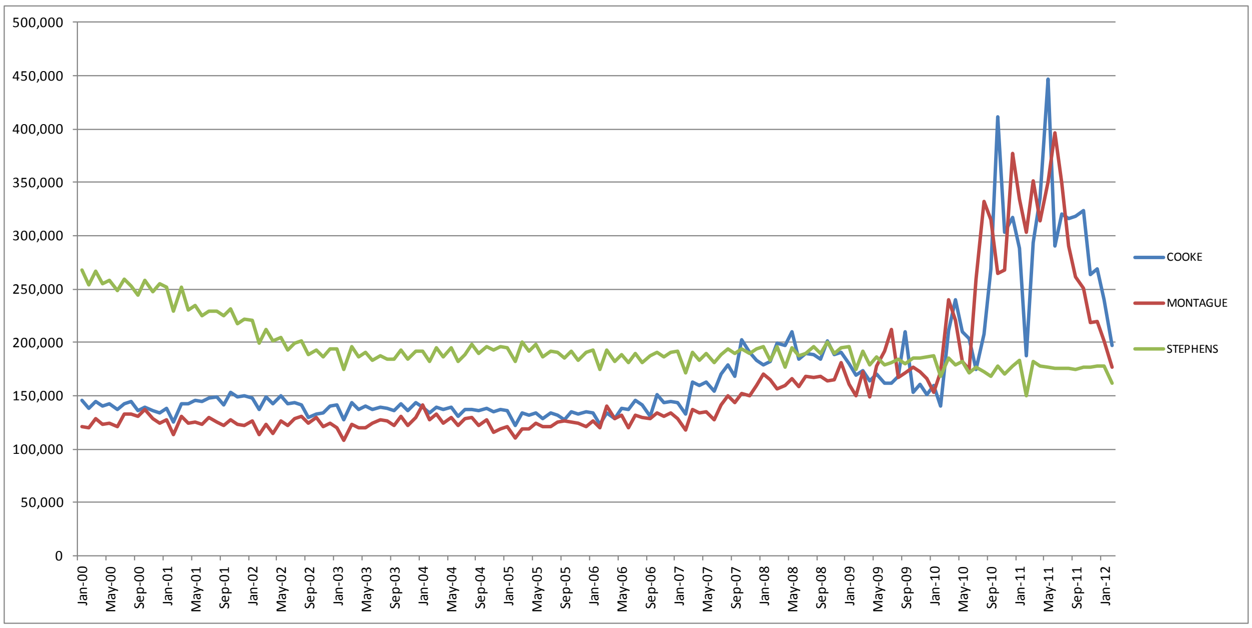


Figure 3-5. Monthly Oil Production (BBL/month) in the Barnett Shale Play (Archer, Jack, Shackelford, Clay, Palo Pinto, Wise, and Eastland Counties)

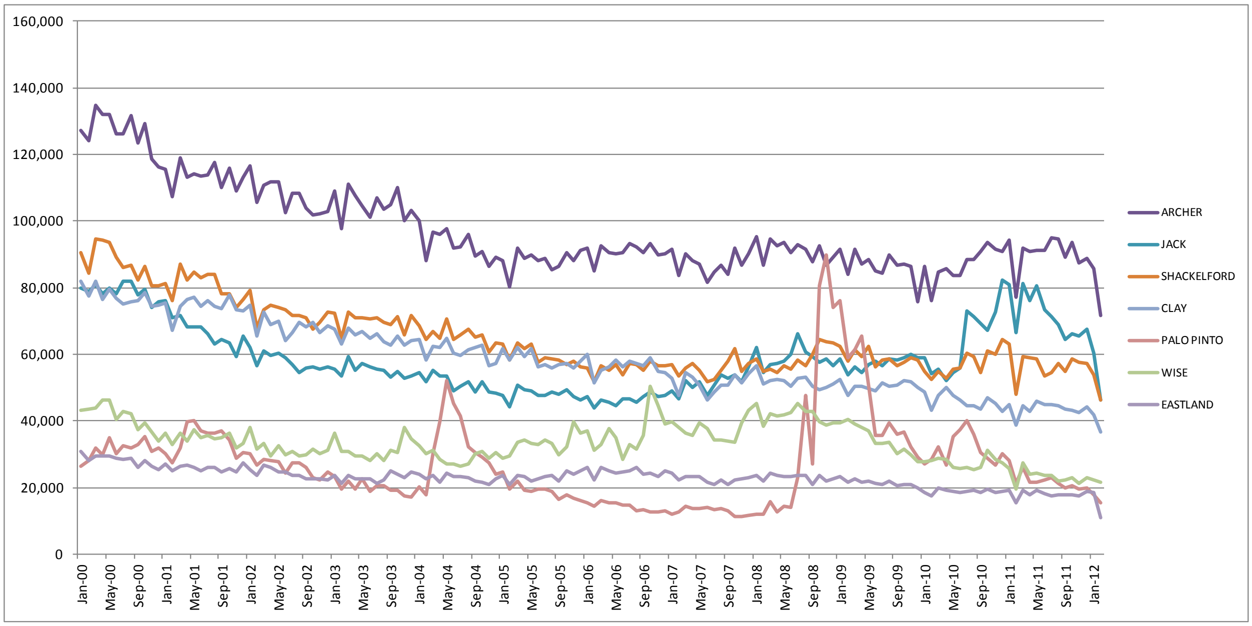


Figure 3-6. Monthly Oil Production (BBL/month) in the Barnett Shale Play (Denton, Comanche, and Parker Counties)

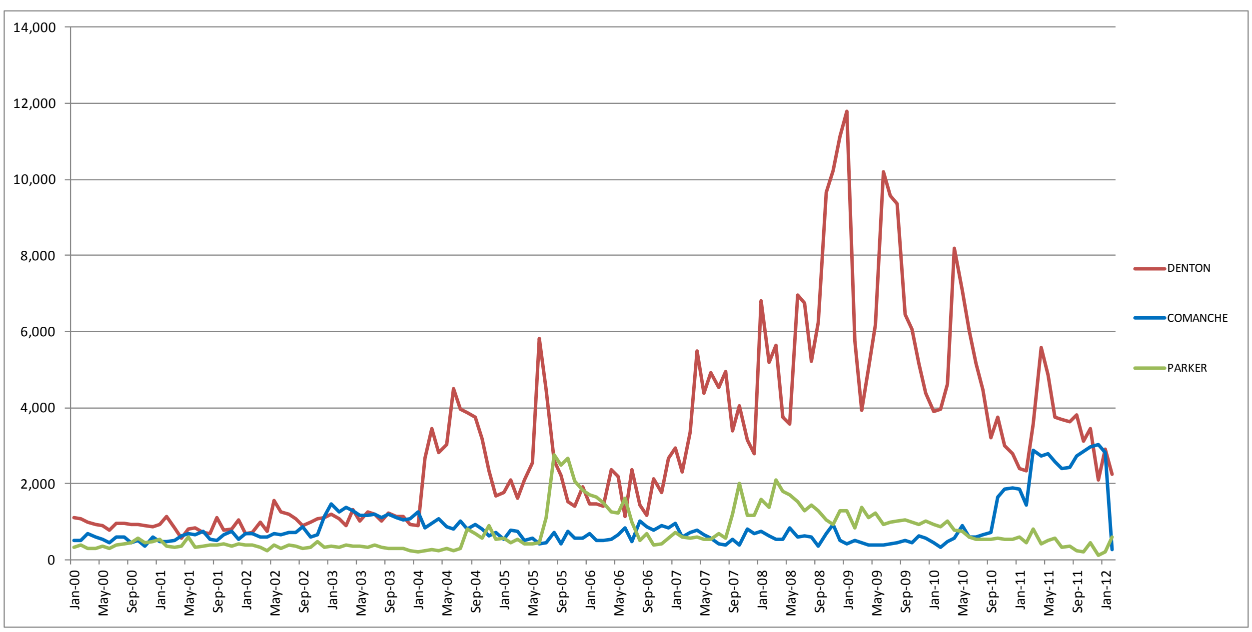


Figure 3-7. Monthly Oil Production (BBL/month) in the Barnett Shale Play (Erath, Hill, and Hood Counties)

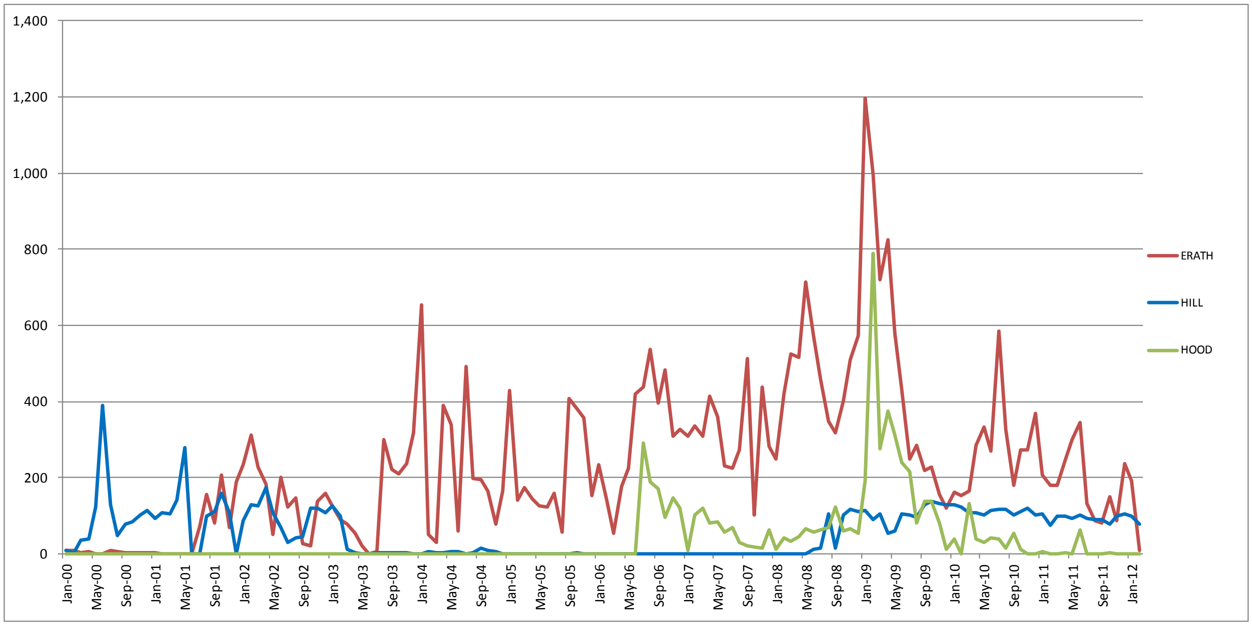
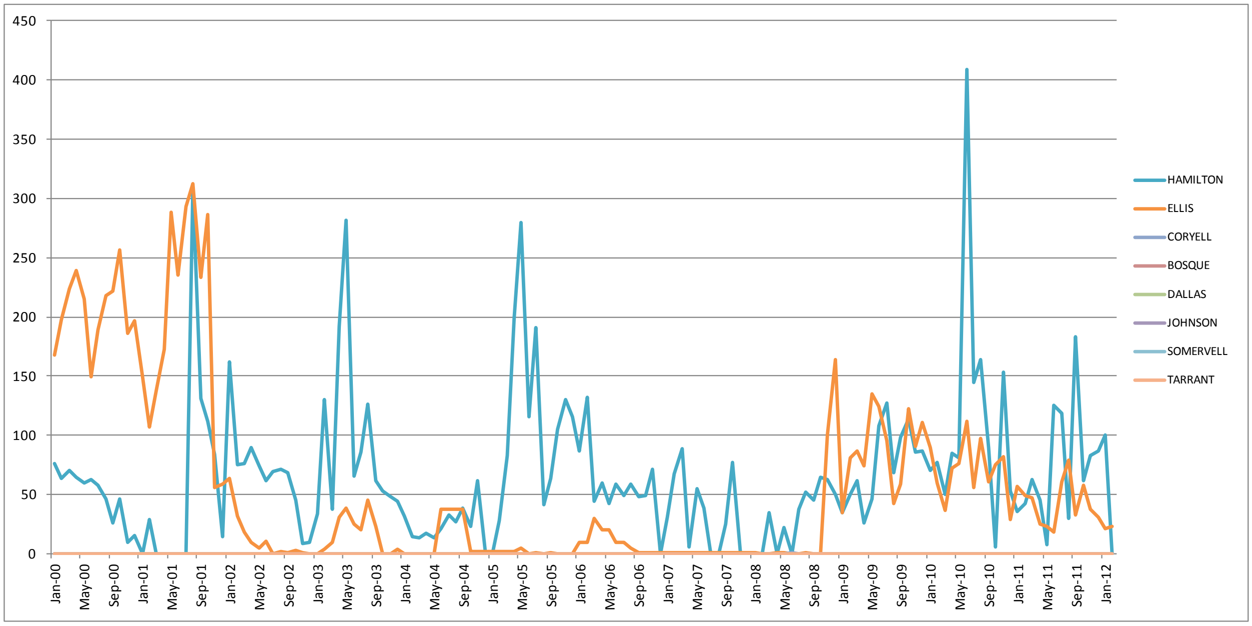


Figure 3-8. Monthly Oil Production (BBL/month) in the Barnett Shale Play (Hamilton, Ellis, Coryell, Bosque, Dallas, Johnson, Somervell, and Tarrant Counties)



Total gas well gas production rates from all counties in the Barnet shale play have generally been increasing steadily since around 2006. The highest gas well gas producing counties are Tarrant and Johnson counties (Figure 3-9), but increases in monthly gas production have also been experienced in other counties (Figures 3-10 and 3-11). Condensate production by county is shown in Figures 3-12 through 3-14. The gas produced in the Barnett Shale is dry, so very little condensate is produced relative to the volume of gas.

Figure 3-9. Monthly Gas Well Production (MCF/month) in the Barnett Shale Play (Tarrant, Johnson, Denton, Wise, Parker, and Hood Counties)

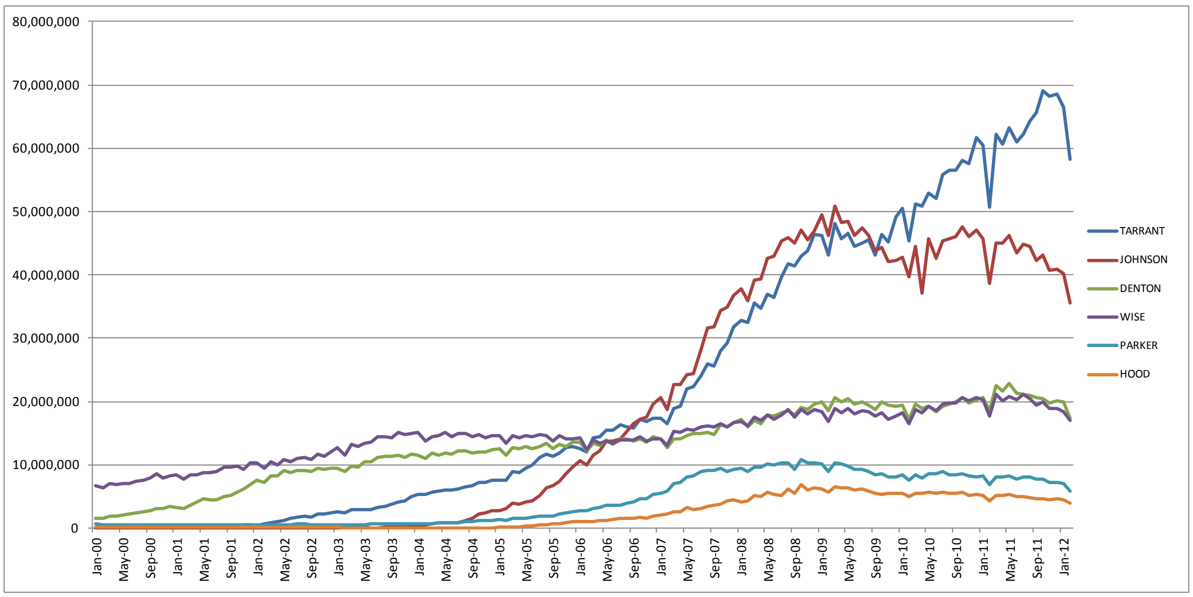


Figure 3-10. Monthly Gas Well Production (MCF/month) in the Barnett Shale Play (Hill, Jack, Palo Pinto, Stephens, Erath, Ellis, Somervell, Dallas, Eastland, and Shackelford Counties)

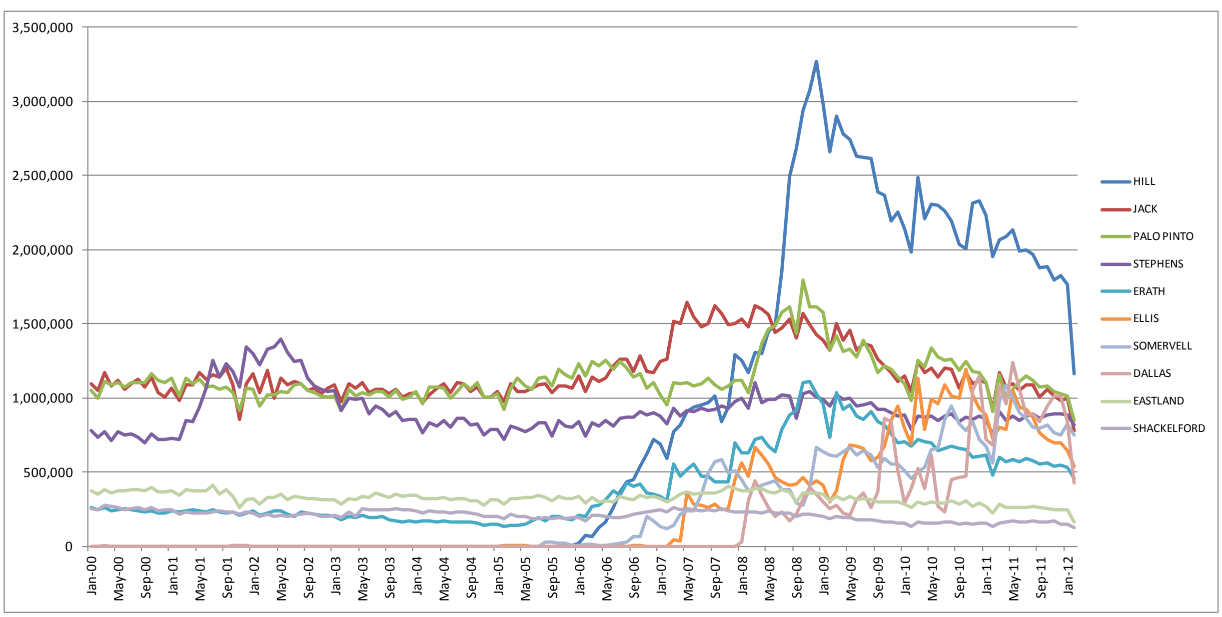


Figure 3-11. Monthly Gas Well Production (MCF/month) in the Barnett Shale Play (Montague, Comanche, Cooke, Clay, Bosque, Hamilton, Archer, and Coryell Counties)

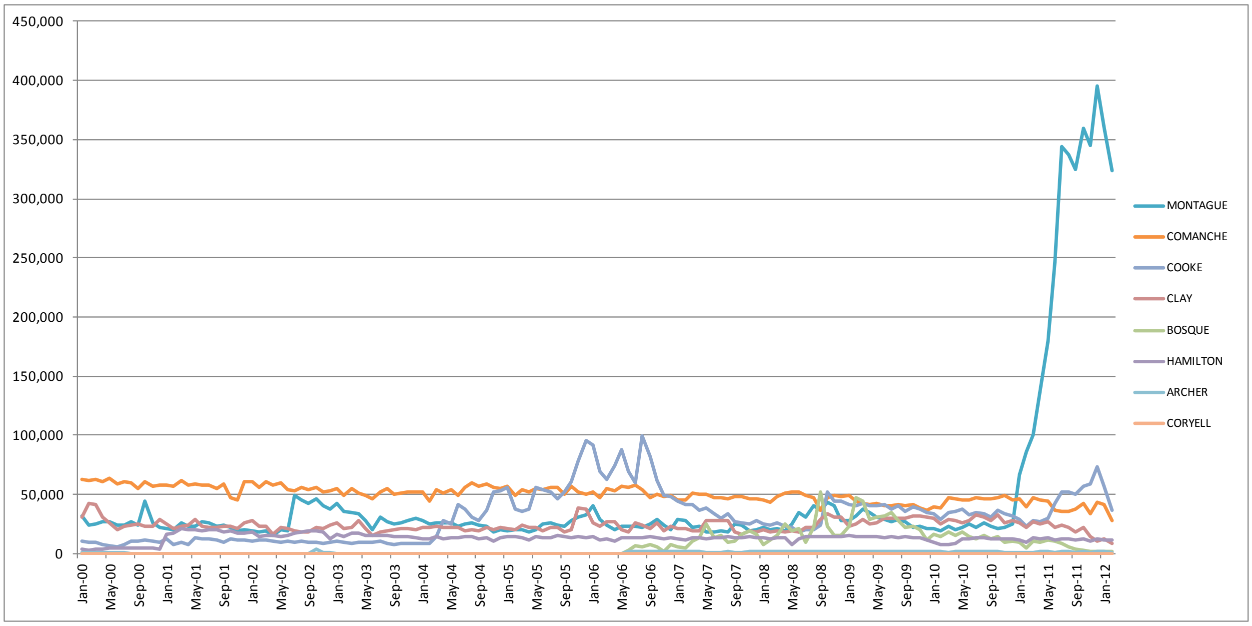


Figure 3-12. Monthly Condensate Production (BBL/month) in the Barnett Shale Play (Wise, Denton, Hood, Parker, Jack, Palo Pinto, and Montague Counties)

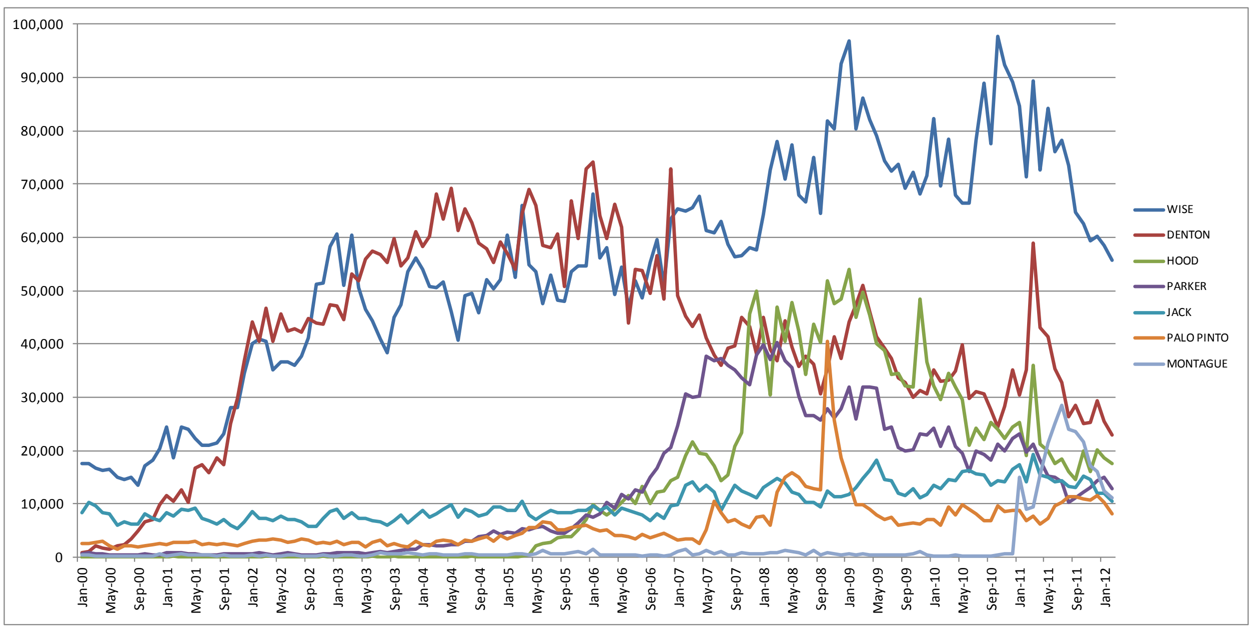


Figure 3-13. Monthly Condensate Production (BBL/month) in the Barnett Shale Play (Stephens, Johnson, Tarrant, Erath, Shackelford, Somervell, Clay, Comanche, Hamilton, Archer, Hill, Bosque, Dallas, Ellis, and Coryell Counties)

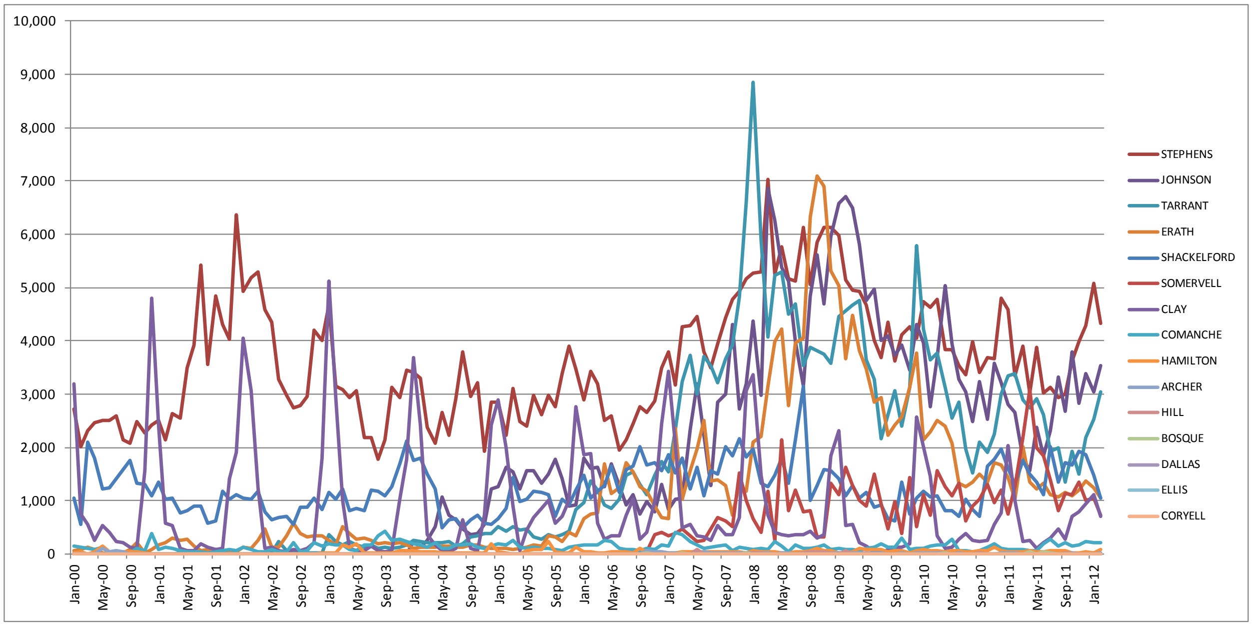
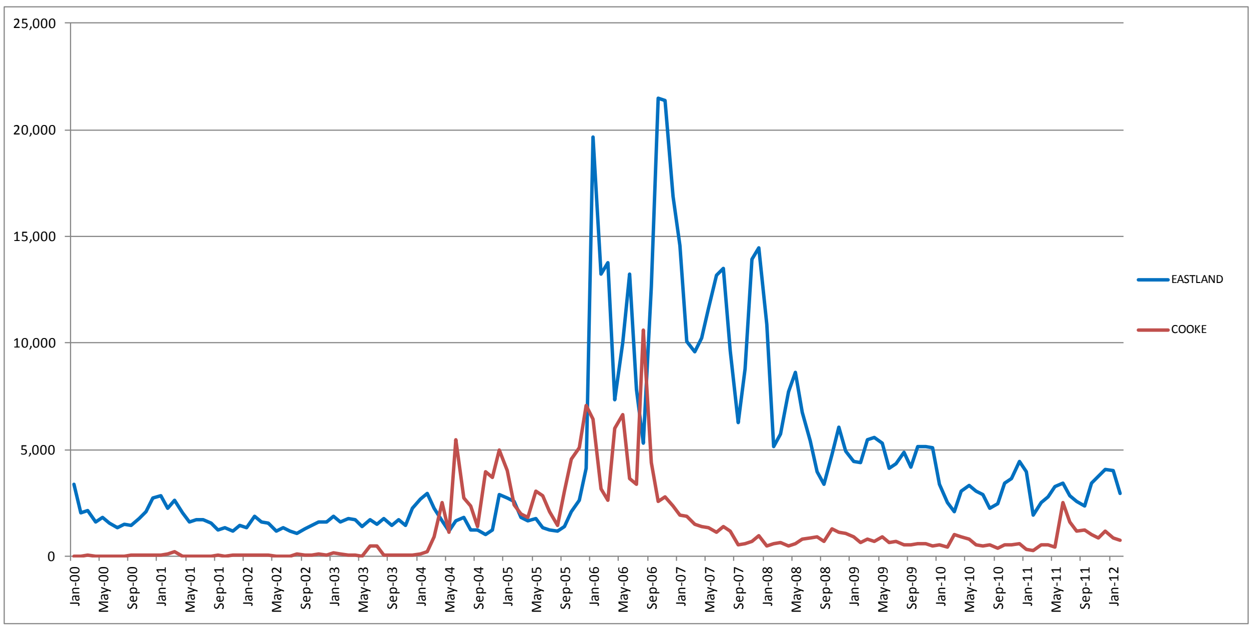


Figure 3-14. Monthly Condensate Production (BBL/month) in the Barnett Shale Play (Eastland and Cooke Counties)



3.2 Eagle Ford Shale Oil and Gas Play

Figures 3-15 through 3-25 show the oil, condensate, and gas production from wells in the Eagle Ford Shale counties. The Eagle Ford is unique among Texas shale plays in that it contains regions that are rich in oil and condensate. With the introduction of horizontal drilling and fracturing in early 2010, production of both oil and condensate (Figures 3-15 through 3-19) has increased to five times the 2009 levels. While the production of casinghead gas associated with oil production (Figures 3-23 through 3-25) has more than doubled in the last two years, the production of gas well gas (Figures 3-20 through 3-22) has increased only by 30%. This is most likely due to the differential between high prices for oil and low prices for natural gas.

Figure 3-15. Monthly Oil Production (BBL/month) in the Eagle Ford Shale Play (Karnes, Gonzales, Dimmit, Burleson, La Salle, and McMullen Counties)

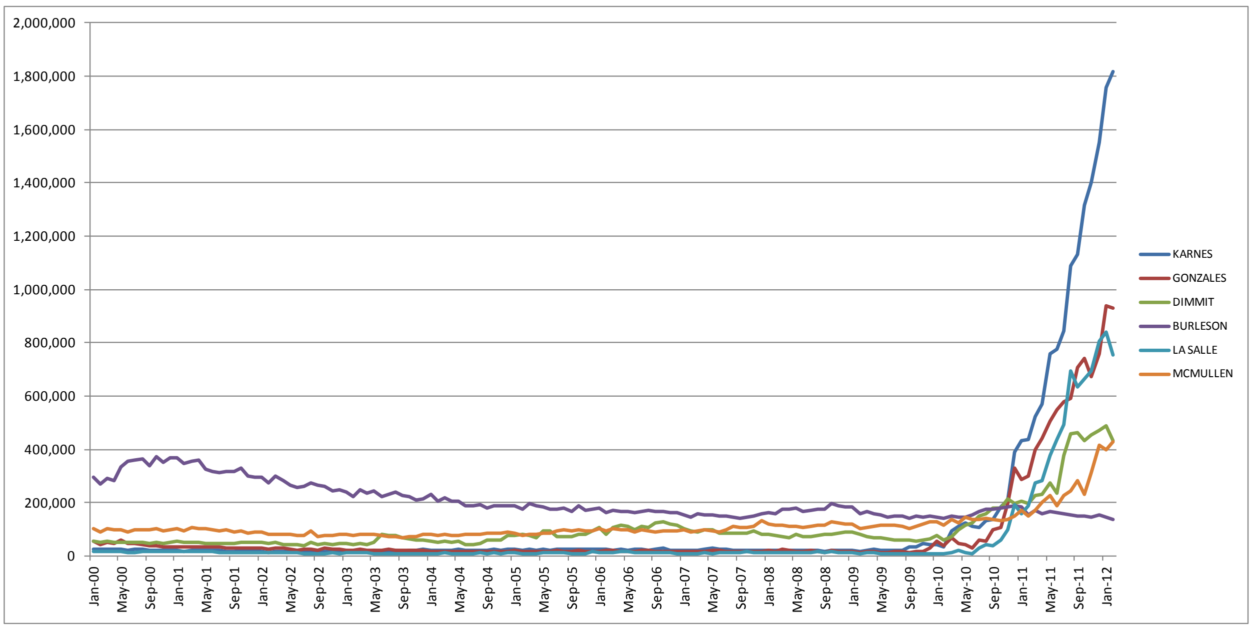


Figure 3-16. Monthly Oil Production (BBL/month) in the Eagle Ford Shale Play (Brazos, Maverick, Live Oak, Robertson, Lee, Fayette, Atascosa, and Frio Counties)

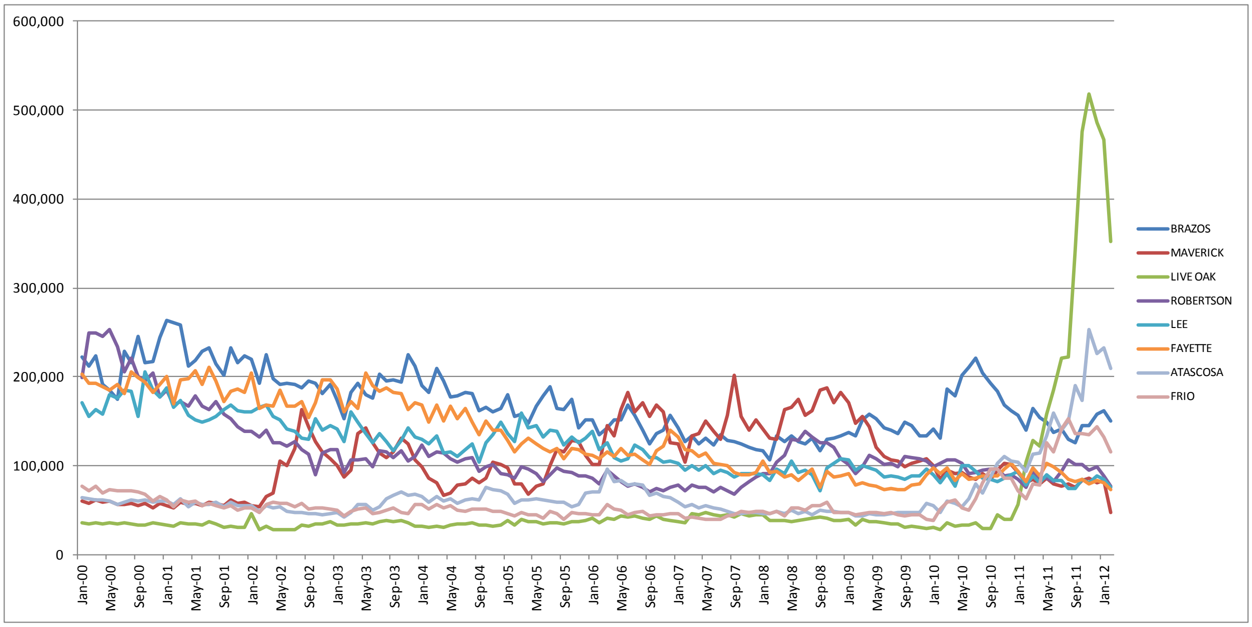


Figure 3-17. Monthly Oil Production (BBL/month) in the Eagle Ford Shale Play (Leon, Zavala, Wilson, De Witt, Milam, Bee, Grimes, Lavaca, and Webb Counties)

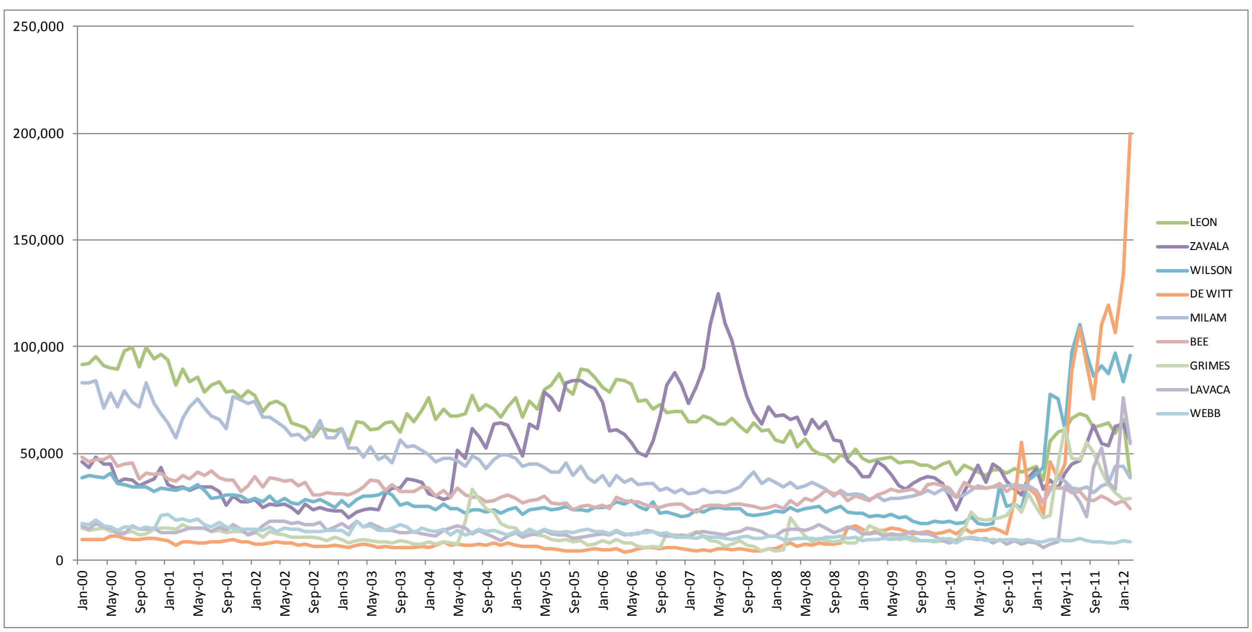


Figure 3-18. Monthly Condensate Production (BBL/month) in the Eagle Ford Shale Play (Webb, De Witt, Dimmit, Karnes, Live Oak, McMullen, and La Salle Counties)

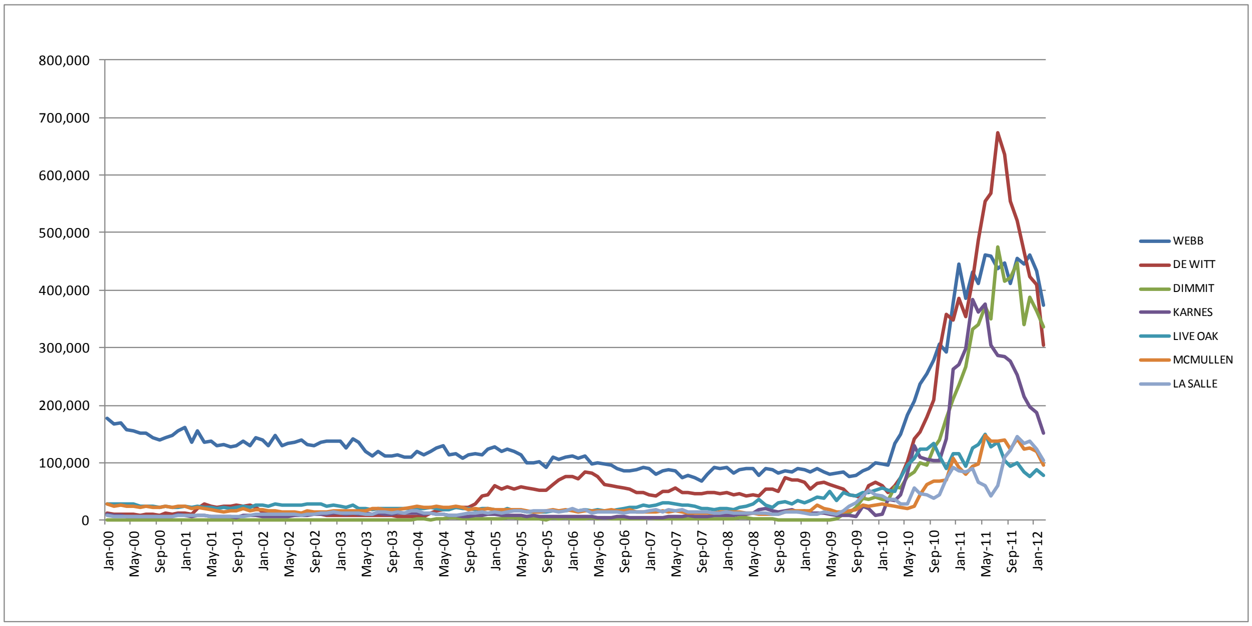


Figure 3-19. Monthly Condensate Production (BBL/month) in the Eagle Ford Shale Play (Lavaca, Fayette, Bee, Leon, Grimes, Brazos, Atascosa, Gonzales, Burleson, Lee, Maverick, Robertson, Frio, Wilson, Zavala, and Milam Counties)

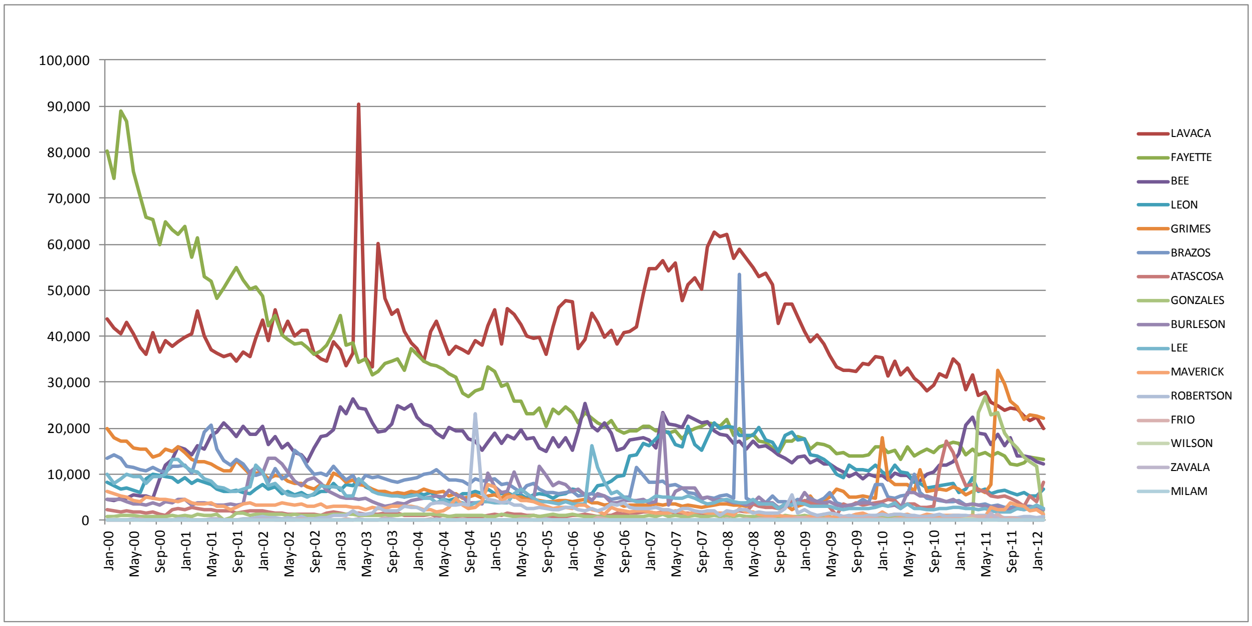


Figure 3-20. Monthly Gas Well Production (MCF/month) in the Eagle Ford Shale Play (Robertson, Webb, Leon, De Witt, and Lavaca Counties)

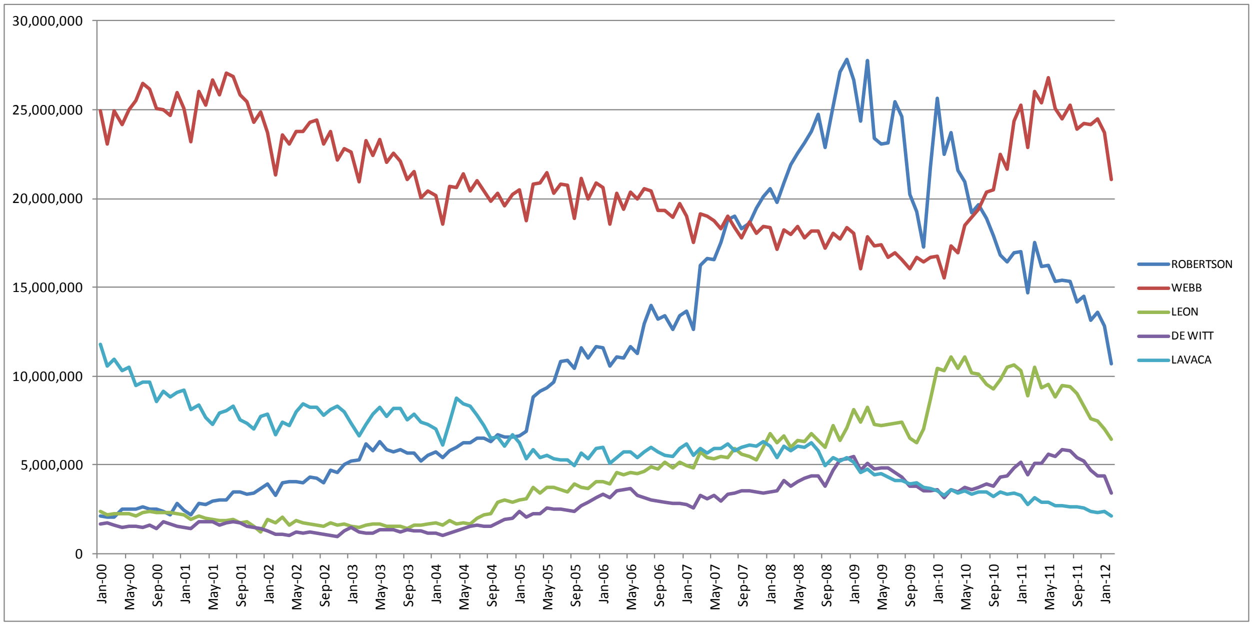


Figure 3-21. Monthly Gas Well Production (MCF/month) in the Eagle Ford Shale Play (La Salle, Bee, Live Oak, McMullen, Grimes, Karnes, Dimmit, and Fayette Counties)

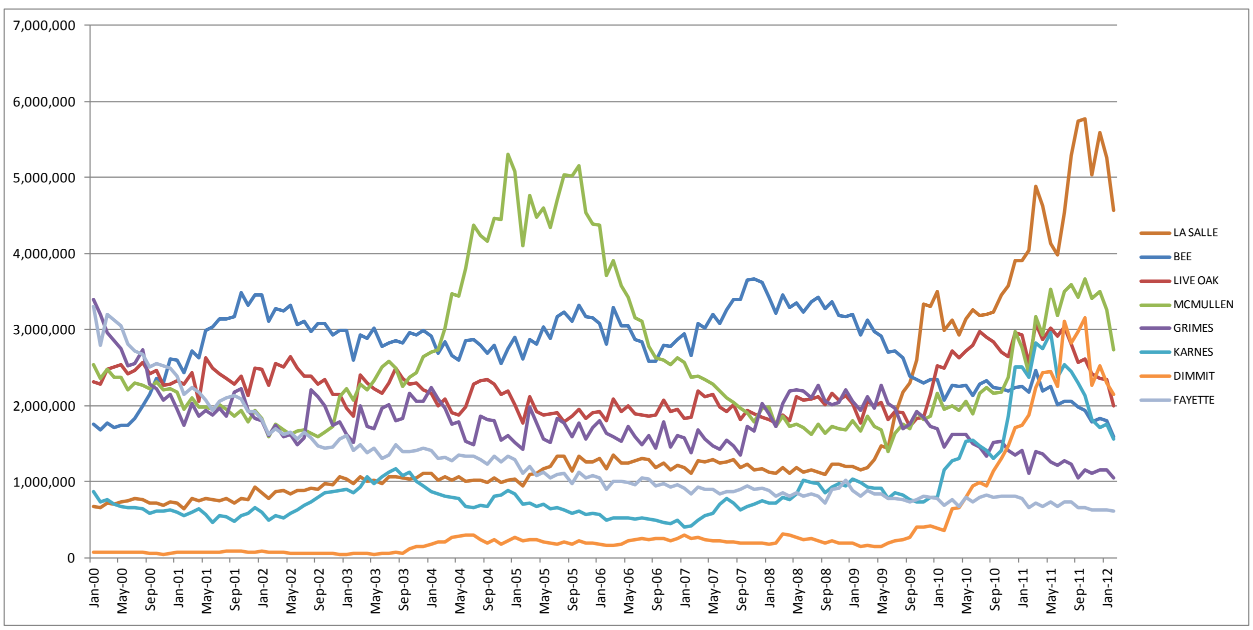


Figure 3-22. Monthly Gas Well Production (MCF/month) in the Eagle Ford Shale Play (Atascosa, Brazos, Maverick, Burleson, Lee, Frio, Gonzales, Zavala, Milam, and Wilson Counties)

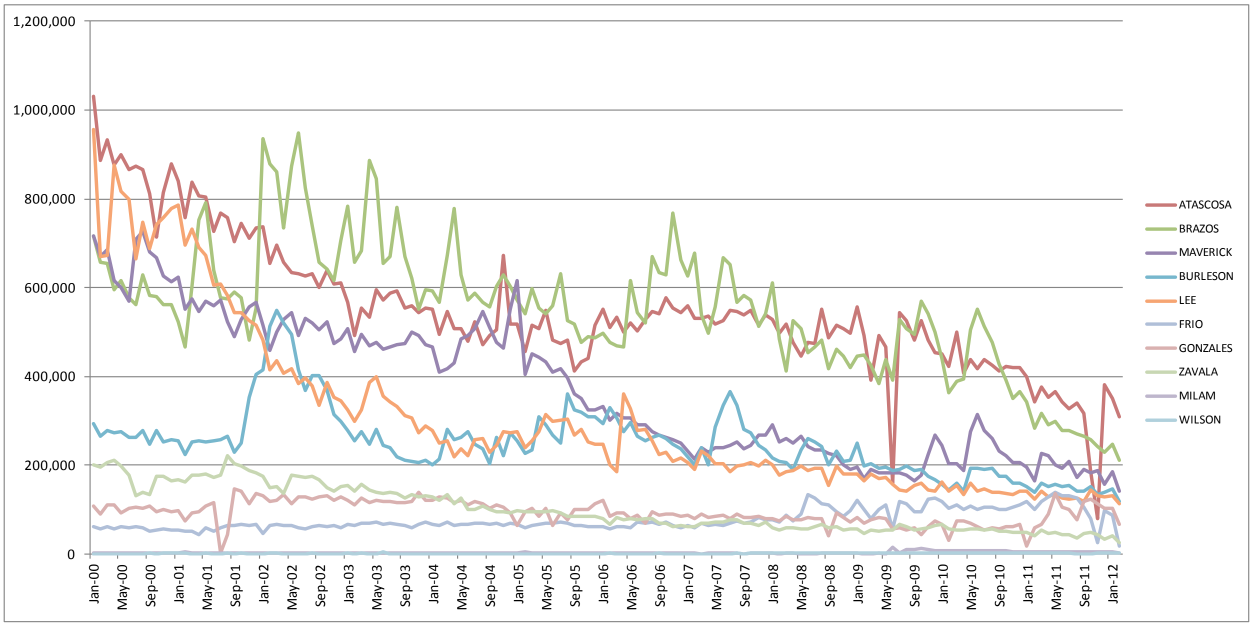


Figure 3-23. Monthly Casinghead Gas Production (MCF/month) in the Eagle Ford Shale Play (Burleson, Lee, Fayette, Brazos, and McMullen Counties)

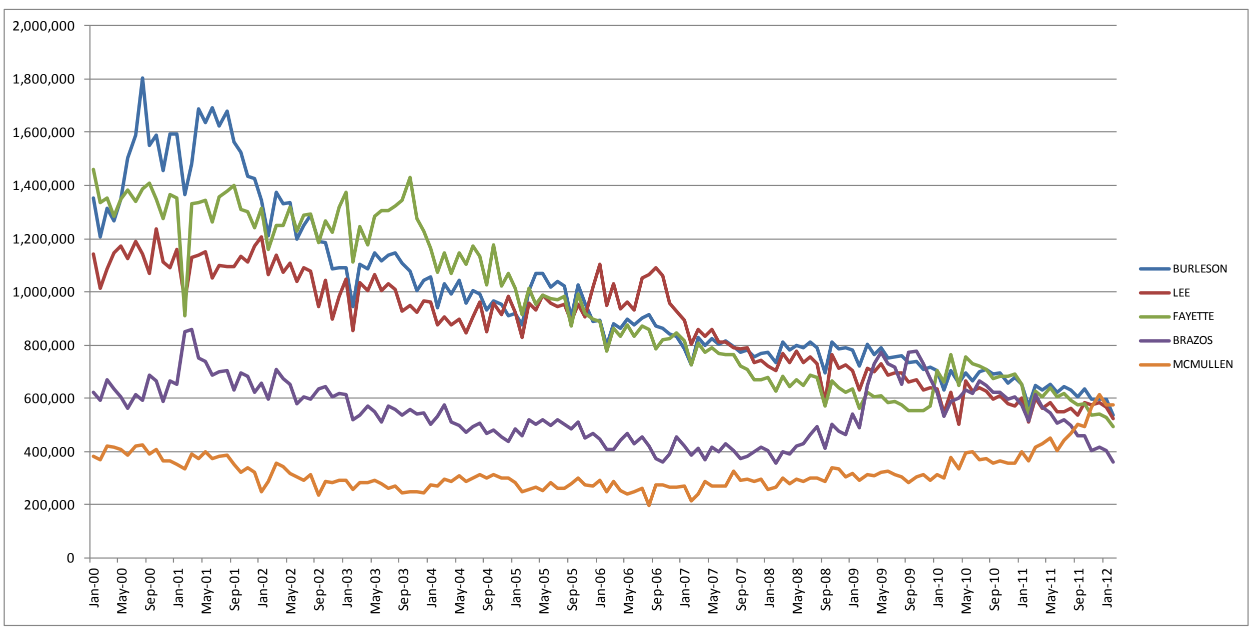


Figure 3-24. Monthly Casinghead Gas Production (MCF/month) in the Eagle Ford Shale Play (Karnes, Dimmit, La Salle, Live Oak, and Gonzales Counties)

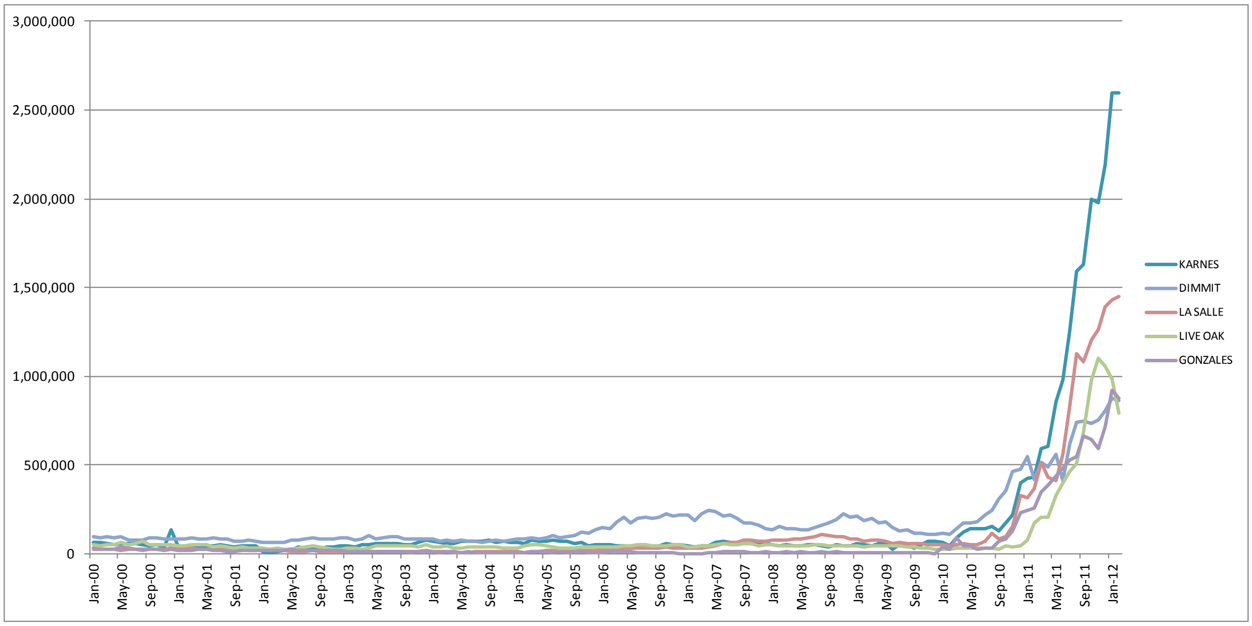
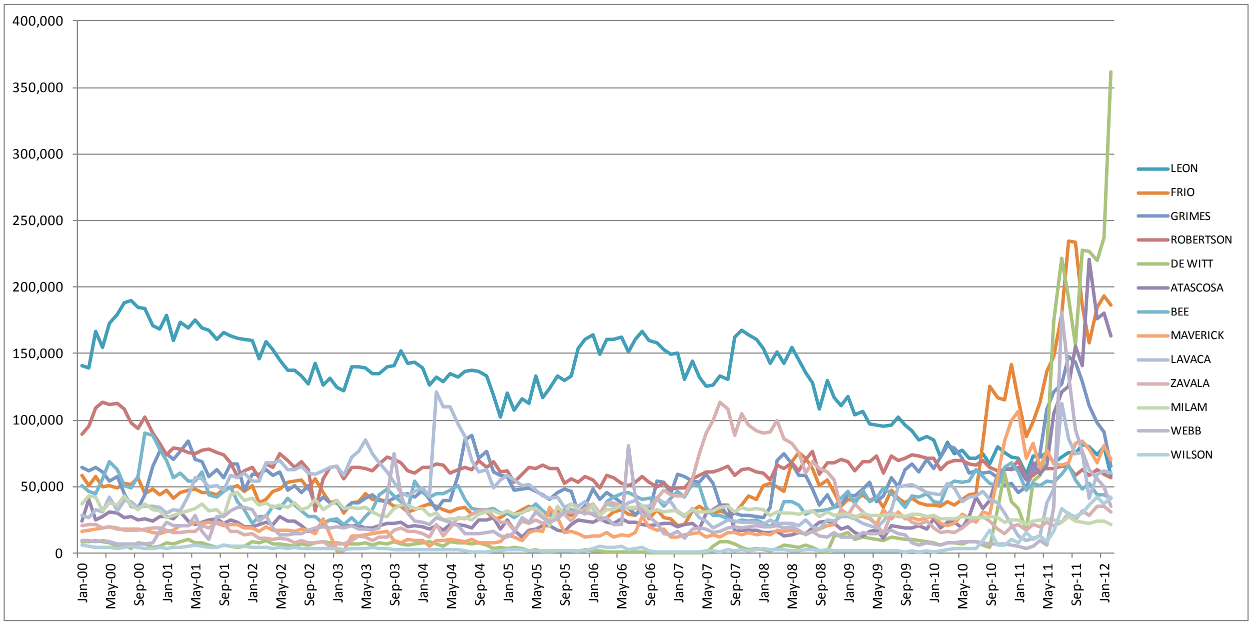


Figure 3-25. Monthly Casinghead Gas Production (MCF/month) in the Eagle Ford Shale Play (Leon, Frio, Grimes, Robertson, De Witt, Atascosa, Bee, Maverick, Lavaca, Zavala, Milam, Webb, and Wilson Counties)



3.3 Haynesville Shale Gas Play

Figures 3-26 through 3-34 show the oil, condensate, and gas production from wells in the Haynesville Shale counties. There is no oil produced from the Haynesville Shale formation; the oil production shown in Figures 3-26 through 3-28 is likely from wells tapping other geologic formations.

Figure 3-26. Monthly Oil Well Production (BBL/month) in the Haynesville Shale Play (Gregg, Rusk, Harrison, and Panola Counties)

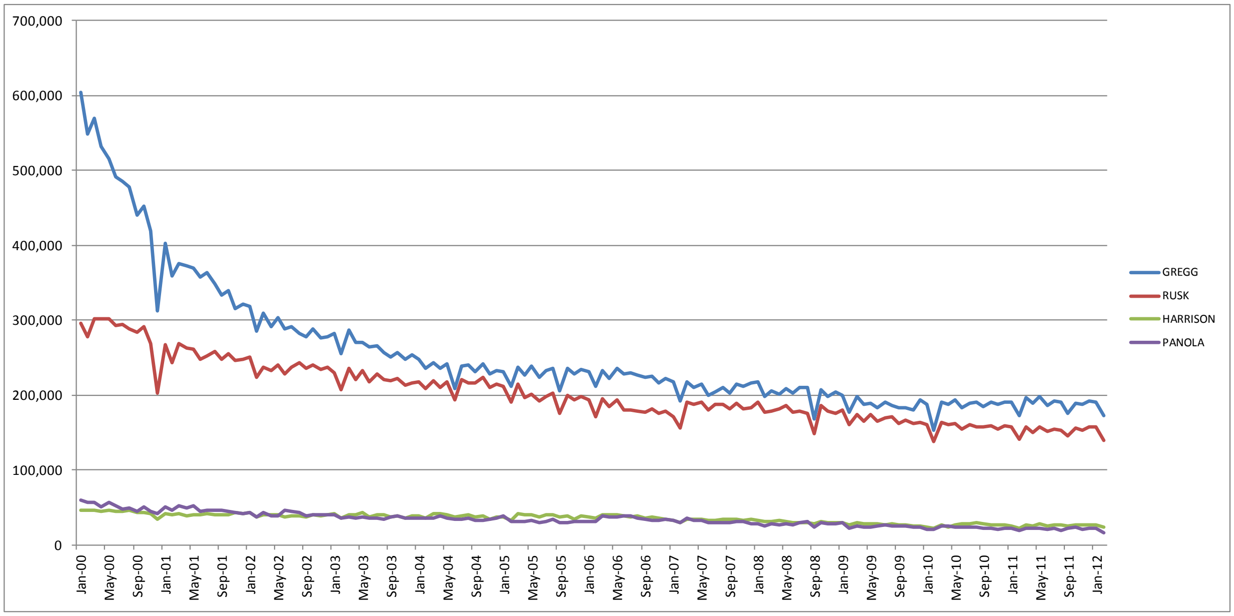


Figure 3-27. Monthly Oil Well Production (BBL/month) in the Haynesville Shale Play (Shelby, Marion, and San Augustine Counties)

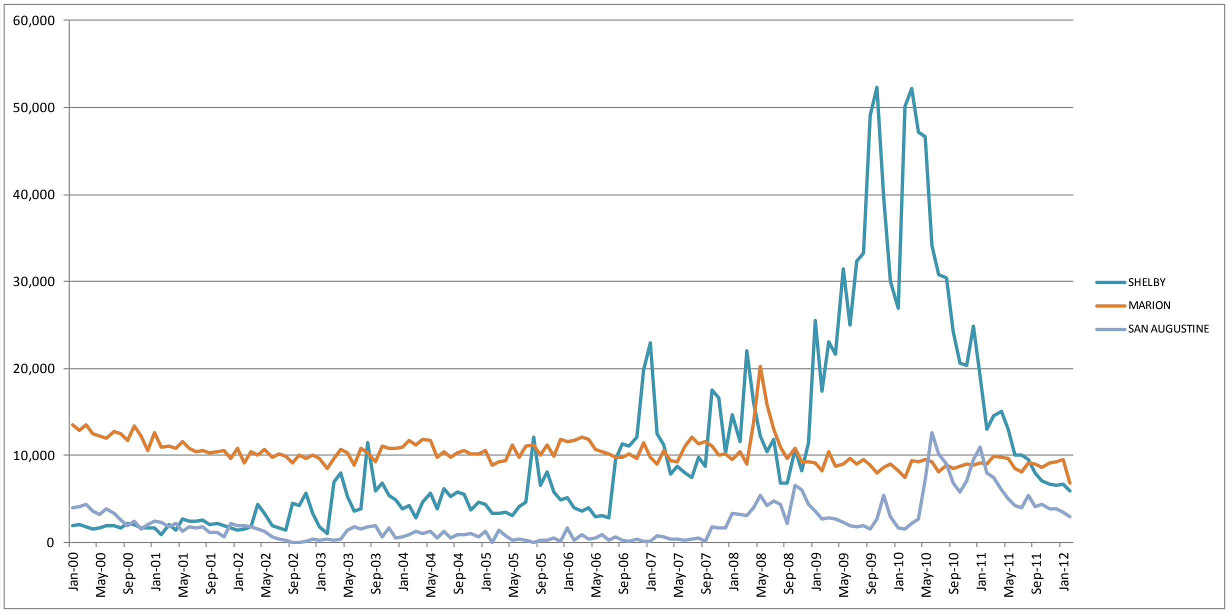
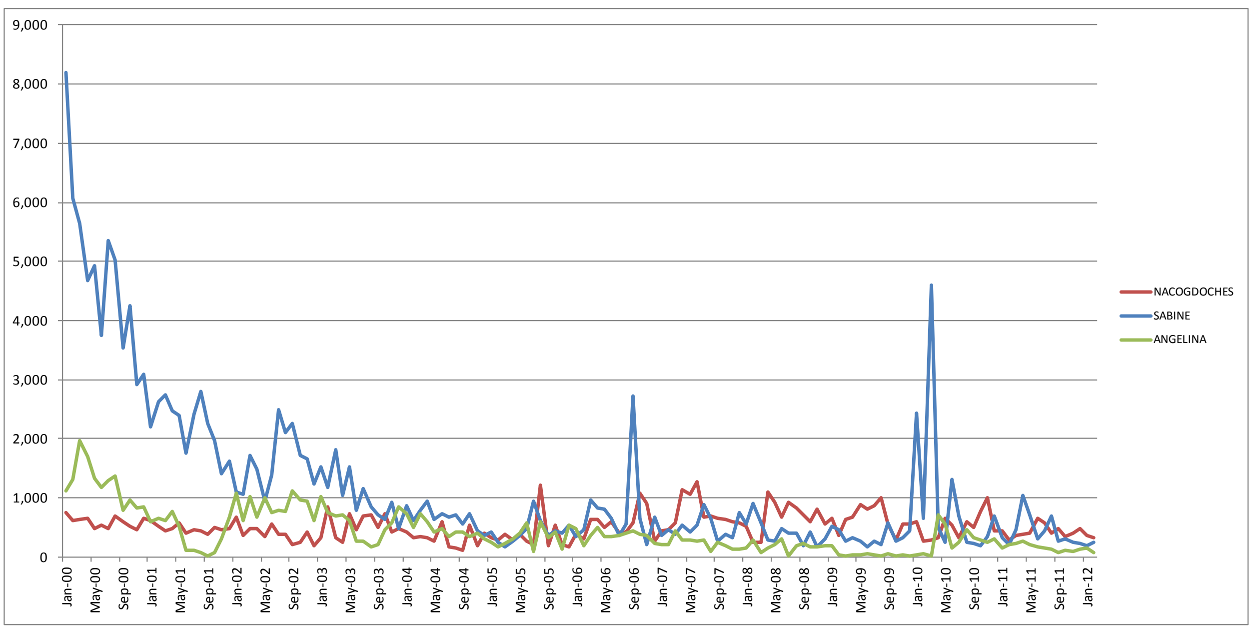


Figure 3-28. Monthly Oil Well Production (BBL/month) in the Haynesville Shale Play (Nacogdoches, Sabine, and Angelina Counties)



Similar to the Barnett Shale, the gas produced in the Haynesville Shale is a dry gas, so there is very little condensate associated with gas production. Condensate production peaked in early 2009.

Figure 3-29. Monthly Condensate Production (BBL/month) in the Haynesville Shale Play (Panola, Harrison, Rusk, Nacogdoches, and Gregg Counties)

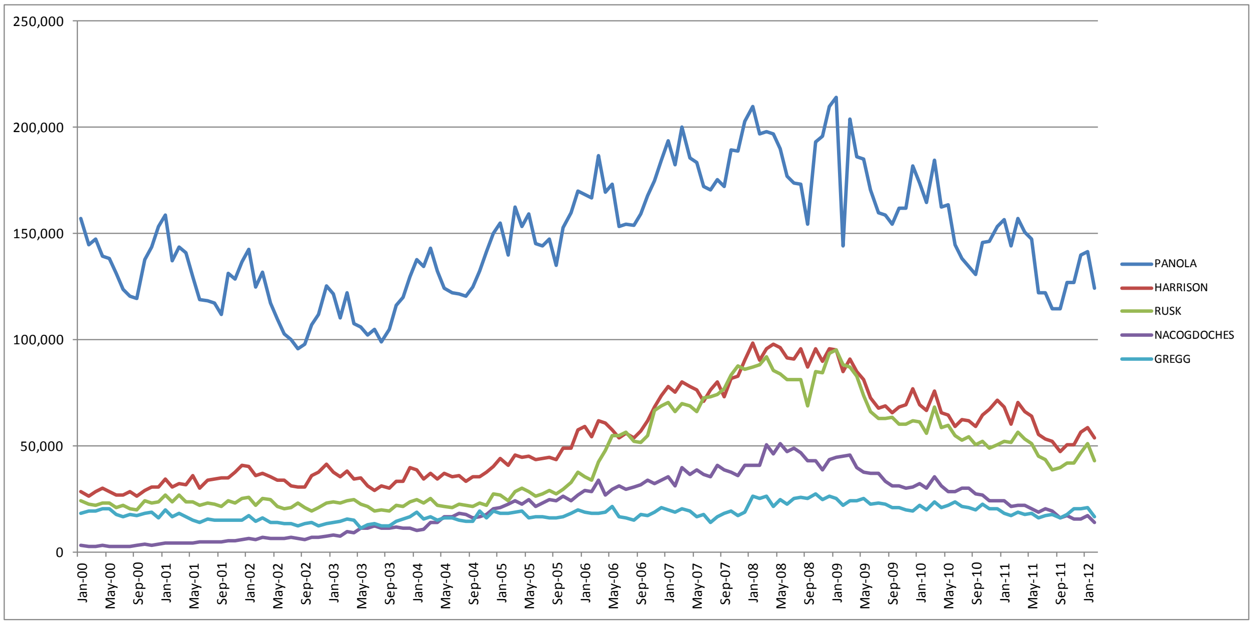
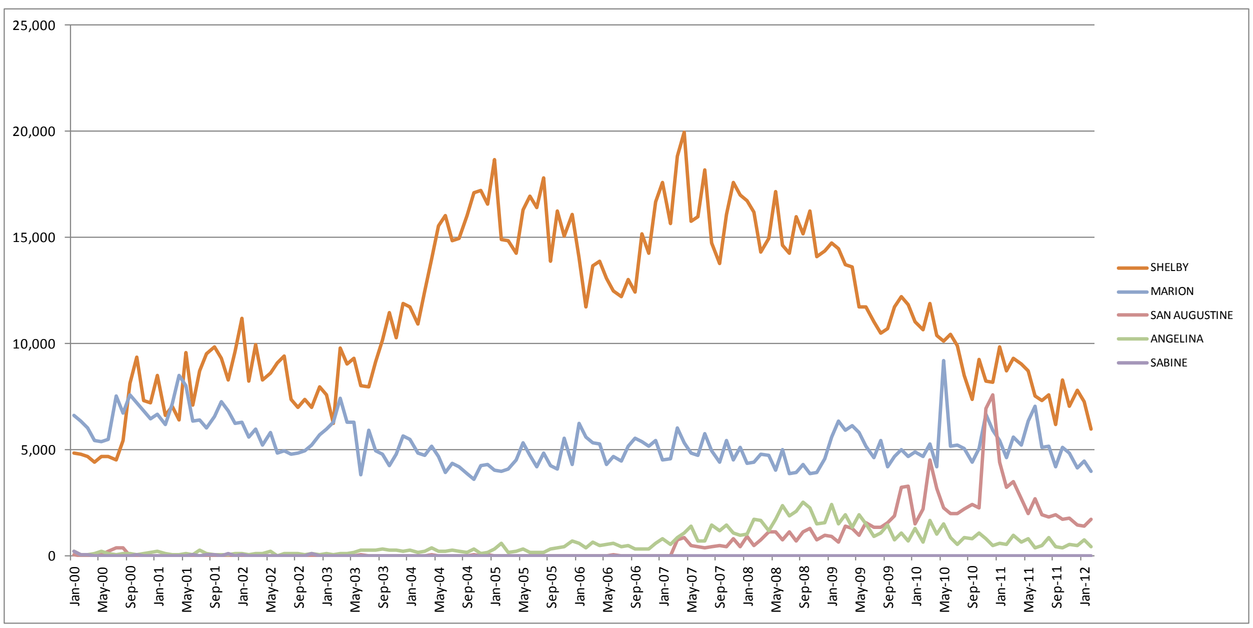


Figure 3-30. Monthly Condensate Production (BBL/month) in the Haynesville Shale Play (Shelby, Marion, San Augustine, Angelina, and Sabine Counties)



The total amount of casinghead gas produced in the Haynesville Shale (Figures 3-31 and 3-32) is insignificant relative to the amount of gas well gas produced in that region (Figures 3-33 and 3-34). TRC figures indicate that casinghead gas production was approximately 1 million cubic feet (MMCF) per month in 2011, while gas well gas production was approximately 80 MMCF/month in the same period. Production of gas appears to have peaked in 2010, and has decreased since that time. The decline is most likely due to the drop in price of natural gas.

Figure 3-31. Monthly Casinghead Gas Production (MCF/month) in the Haynesville Shale Play (Shelby, Panola, Gregg, Rusk, and Harrison Counties)

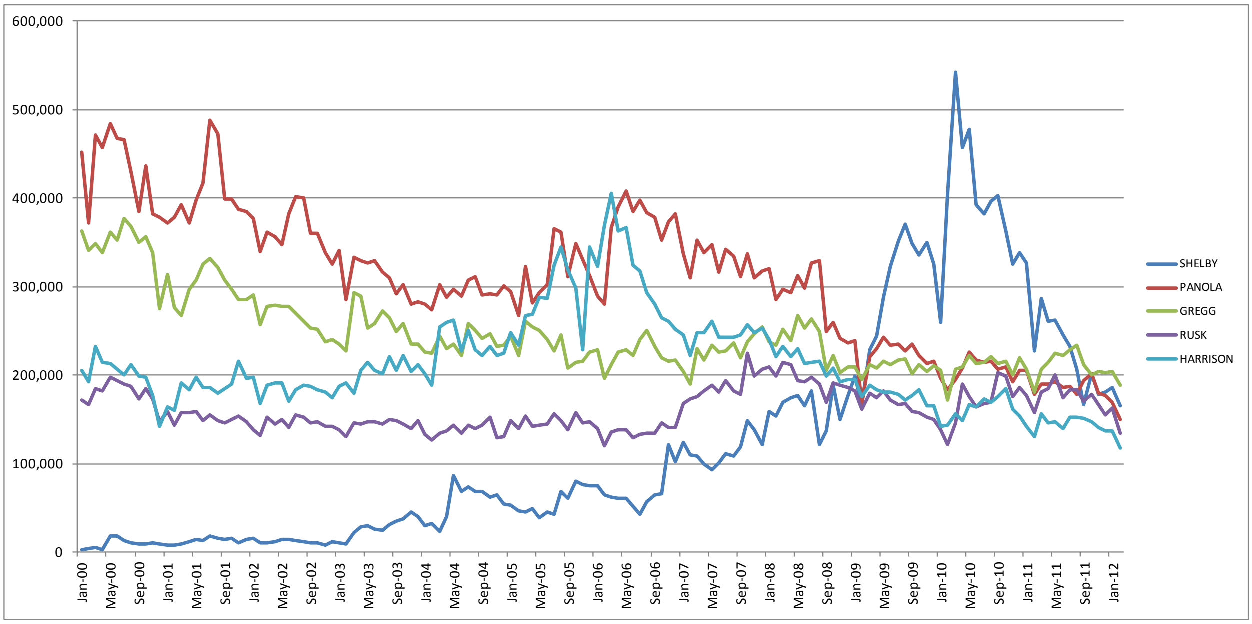


Figure 3-32. Monthly Casinghead Gas Production (MCF/month) in the Haynesville Shale Play (San Augustine, Marion, Nacogdoches, Sabine, and Angelina Counties)

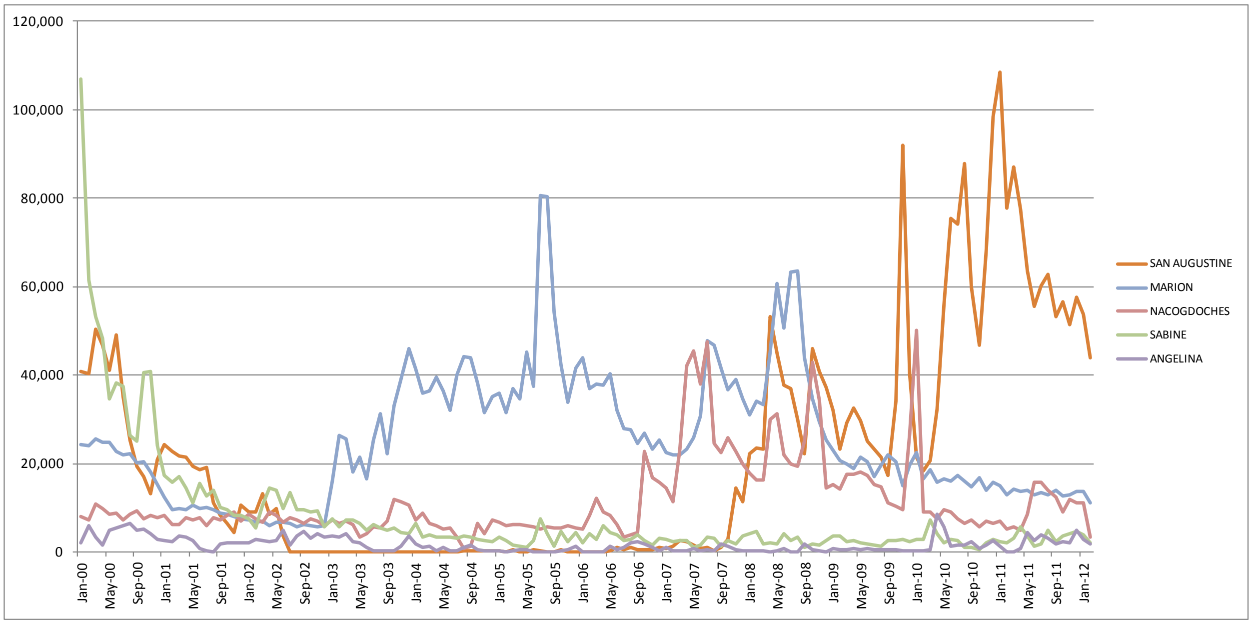


Figure 3-33. Monthly Gas Well Production (MCF/month) in the Haynesville Shale Play (Panola, Harrison, Rusk, Nacogdoches, and Shelby Counties)

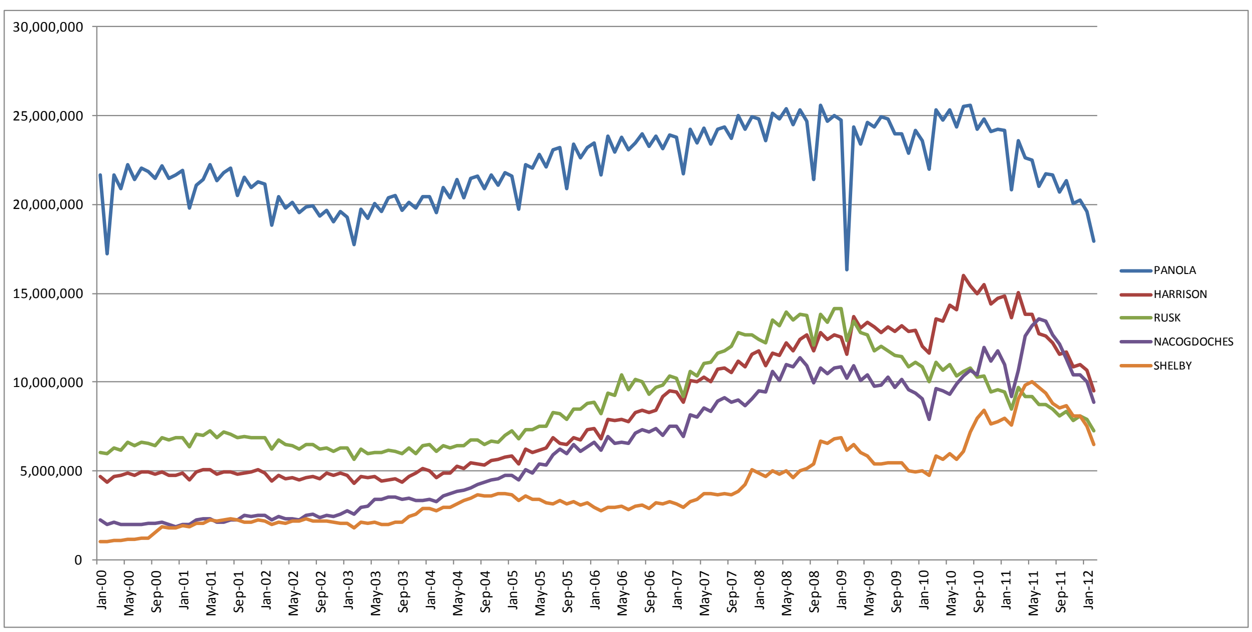
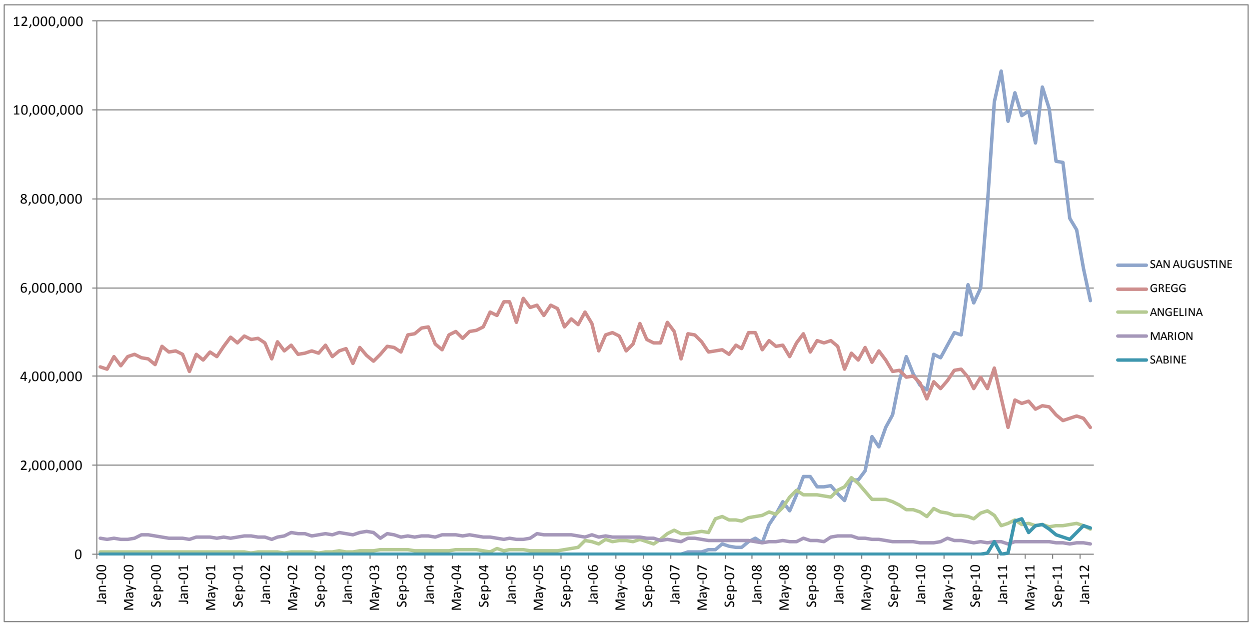


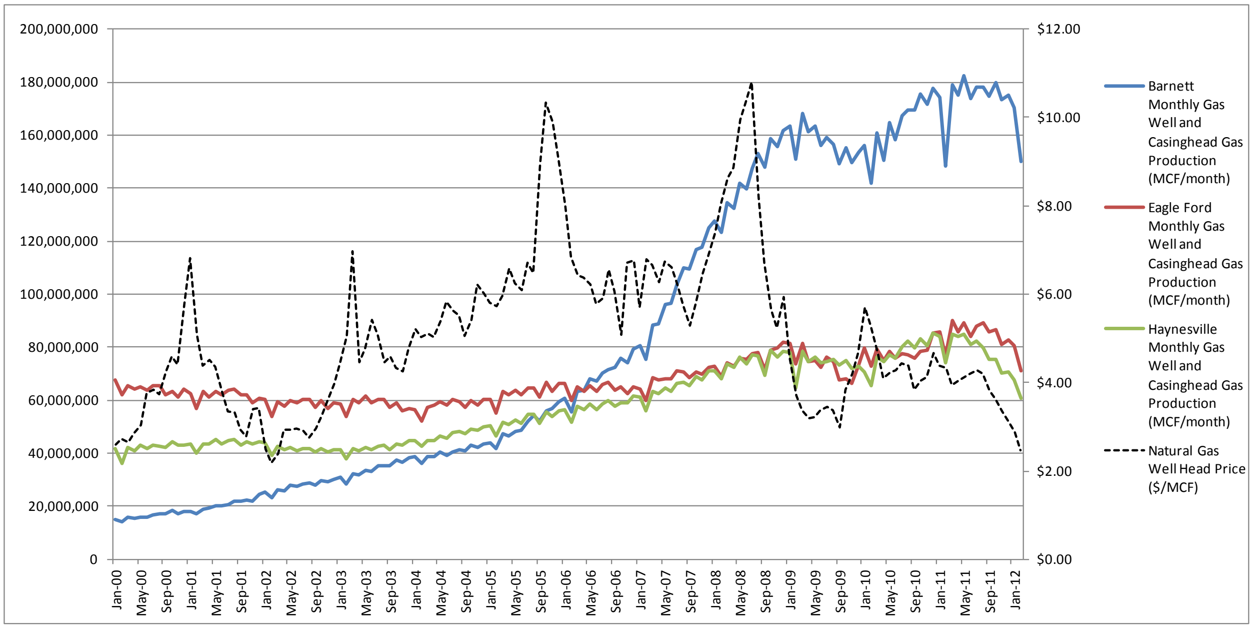
Figure 3-34. Monthly Gas Well Production (MCF/month) in the Haynesville Shale Play (San Augustine, Gregg, Angelina, Marion, and Sabine Counties)



3.4 Shale Play Production

Figure 3-35 below shows the effects of the price of natural gas on production of gas. Prices peaked in 2008, and declined below $5 per MCF in 2009. Production began to decline two years later. This lag is likely due to the time delay between signing leases with landowners, drilling the well, and producing gas in order to 'hold' the lease.

Figure 3-35. Combined Monthly Gas Well and Casinghead Gas Production (MCF/month) by Texas Shale Play Region, Compared with the Price of Natural Gas



Cumulative gas production from the Eagle Ford and Haynesville shale regions has increased steadily over the last decade, while gas production from the Barnett Shale has steadily accelerated. There has also been a steady increase in oil and condensate production in the Eagle Ford shale play region since 2010 (Figures 3-36 through 3-38).

Figure 3-36. Combined Cumulative Gas Well and Casinghead Gas Production (MCF) by Texas Shale Play Region

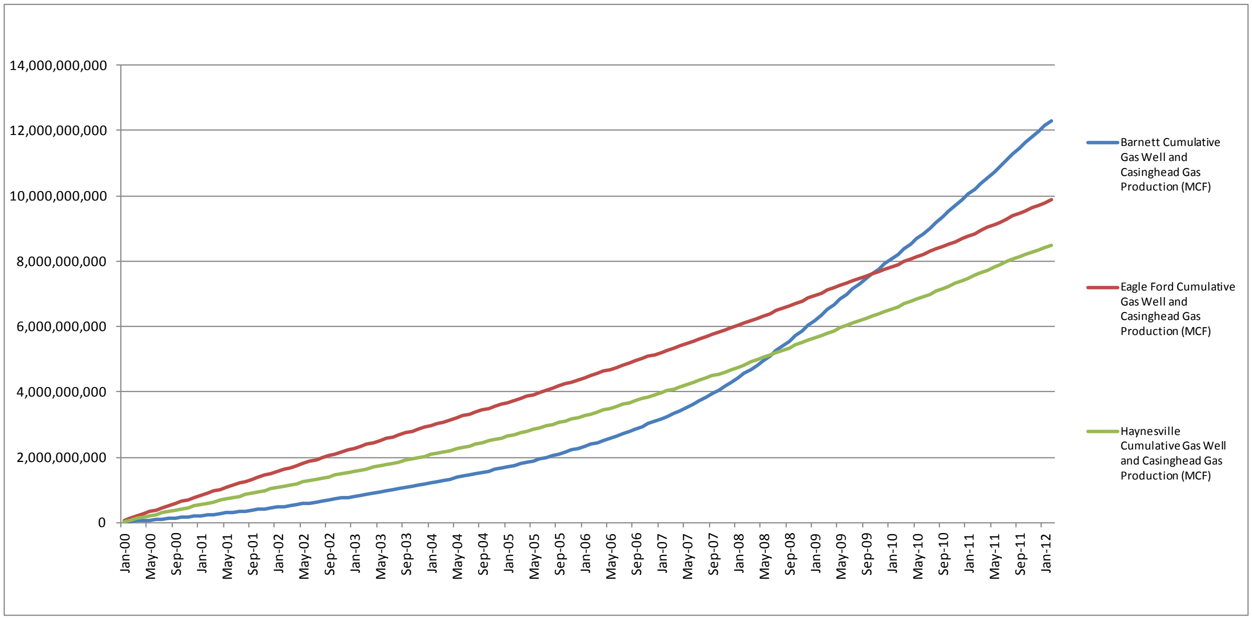


Figure 3-37. Combined Monthly Oil Well and Condensate Production (BBL/month) by Texas Shale Play Region, Compared to WTI Crude Oil Spot Price ($/BBL)

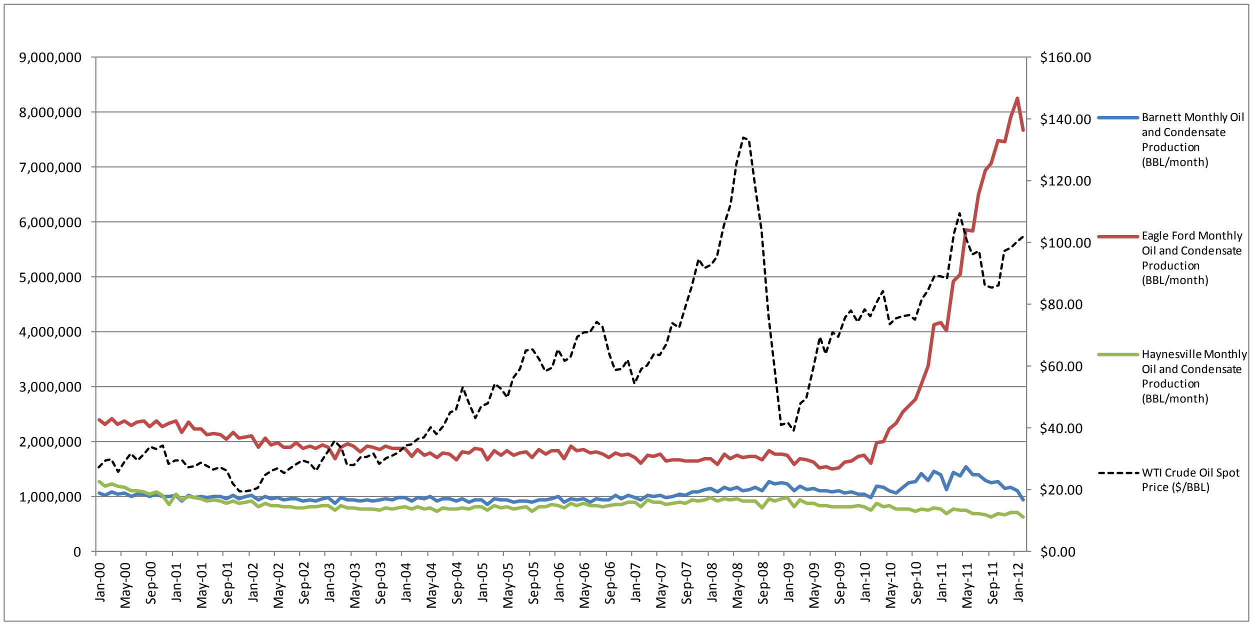
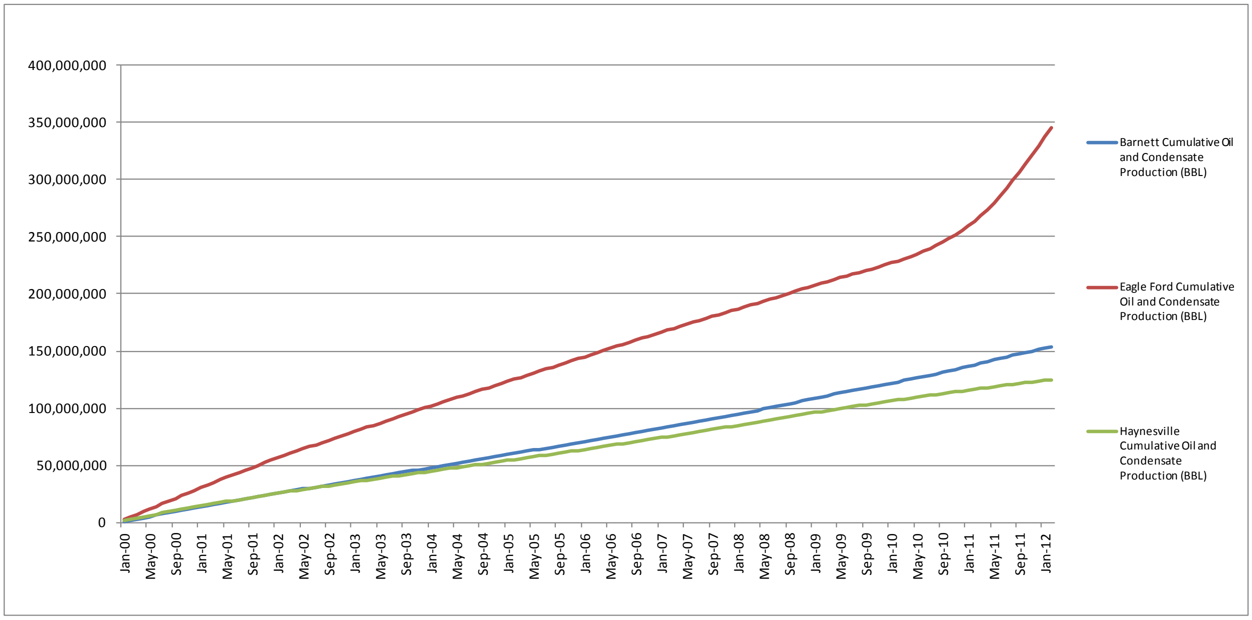


Figure 3-38. Combined Cumulative Oil Well and Condensate Production (BBL) by Texas Shale Play Region



3.5 2011 Shale Play Well Completions

Information on well completions in each of the shale play regions in 2011 was obtained through a commercial vendor (RigData®). Tables 3-1 through 3-3 summarize the number of completed wells in each county, by shale play region, for the year 2011.

Table 3-1. Barnett Shale Play Well Completions, 2011

County	Gas				Oil/Gas				Oil				GRAND TOTAL	Percent of Total		
	DIR	HOR	VER	TOTAL	DIR	HOR	VER	TOTAL	DIR	HOR	VER	TOTAL		Gas	Oil/Gas	Oil
ARCHER						2	54	56		2	56	58	114	0%	49%	51%
CLAY						4	6	10			2	2	12	0%	83%	17%
COMANCHE							3	3			2	2	5	0%	60%	40%
COOKE					8	88	7	103		1	18	19	122	0%	84%	16%
CORYELL							1	1					1	0%	100%	0%
DALLAS		2		2		4		4					6	33%	67%	0%
DENTON		67	1	68		26		26					94	72%	28%	0%
EASTLAND							9	9			2	2	11	0%	82%	18%
ELLIS						4		4					4	0%	100%	0%
ERATH			4	4			6	6					10	40%	60%	0%
HOOD		25		25		13		13					38	66%	34%	0%
JACK			3	3	1	7	47	55		3		3	61	5%	90%	5%
JOHNSON		141		141		104		104					245	58%	42%	0%
MONTAGUE		1		1	3	195	7	205		1	8	9	215	0%	95%	4%
PALO PINTO			2	2	1	4	12	17			3	3	22	9%	77%	14%
PARKER		78		78		16		16					94	83%	17%	0%
SHACKELFORD						1	31	32			16	16	48	0%	67%	33%
SOMERVELL		5		5									5	100%	0%	0%
STEPHENS			1	1	2	1	77	80			1	1	82	1%	98%	1%
TARRANT		149		149	1	359		360					509	29%	71%	0%

Table 3-1. Barnett Shale Play Well Completions, 2011

County	Gas				Oil/Gas				Oil				GRAND TOTAL	Percent of Total		
	DIR	HOR	VER	TOTAL	DIR	HOR	VER	TOTAL	DIR	HOR	VER	TOTAL		Gas	Oil/Gas	Oil
WISE		70	3	73		84	2	86			1	1	160	46%	54%	1%
TOTAL		538	14	552	16	912	262	1,190		7	109	116	1,858	30%	64%	6%

Table 3-2. Eagle Ford Shale Play Well Completions, 2011

County	Gas				Oil/Gas				Oil				GRAND TOTAL	Percent of Total		
	DIR	HOR	VER	TOTAL	DIR	HOR	VER	TOTAL	DIR	HOR	VER	TOTAL		Gas	Oil/Gas	Oil
ATASCOSA		12		12		38	3	41		23	2	25	78	15%	53%	32%
BEE		1	2	3	1	2	34	37					40	8%	93%	0%
BRAZOS						5		5		15	2	17	22	0%	23%	77%
BRAZOS (S)							1	1					1	0%	100%	0%
BRAZOS LB					1		2	3					3	0%	100%	0%
BURLESON						1	1	2		10		10	12	0%	17%	83%
DE WITT		158	1	159		24	2	26		5	1	6	191	83%	14%	3%
DIMMIT		5		5		311	1	312		62	1	63	380	1%	82%	17%
FRIO		1	1	2		80	8	88		7	3	10	100	2%	88%	10%
GONZALES		1		1		51	3	54		112	1	113	168	1%	32%	67%
HOUSTON					1		24	25					25	0%	100%	0%
KARNES		35	2	37		176	5	181		100	1	101	319	12%	57%	32%
LA SALLE		56	3	59		104		104		122	1	123	286	21%	36%	43%
LAMAR							1	1					1	0%	100%	0%
LAVACA			3	3	1	9	7	17		2		2	22	14%	77%	9%
LEE						6	1	7		9		9	16	0%	44%	56%
LEON	5	9	12	26	2		10	12		9	2	11	49	53%	24%	22%
LIVE OAK	1	30	1	32		55	24	79		10	2	12	123	26%	64%	10%
MAVERICK		2		2		26	5	31		2		2	35	6%	89%	6%

Table 3-2. Eagle Ford Shale Play Well Completions, 2011

County	Gas				Oil/Gas				Oil				GRAND TOTAL	Percent of Total		
	DIR	HOR	VER	TOTAL	DIR	HOR	VER	TOTAL	DIR	HOR	VER	TOTAL		Gas	Oil/Gas	Oil
MCMULLEN		29	4	33		74	16	90		42		42	165	20%	55%	25%
MILAM						3	57	60		2	27	29	89	0%	67%	33%
WEBB	1	144	8	153	10	184	31	225		1	1	2	380	40%	59%	1%
WILSON						21	1	22		17	8	25	47	0%	47%	53%
ZAVALA						24	5	29	1	17	2	20	49	0%	59%	41%
TOTAL	7	483	37	527	16	1,194	242	1,452	1	567	54	622	2,601	20%	56%	24%

Table 3-3. Haynesville Shale Play Well Completions, 2011

County	Gas				Oil/Gas				Oil				GRAND TOTAL	Percent of Total		
	DIR	HOR	VER	TOTAL	DIR	HOR	VER	TOTAL	DIR	HOR	VER	TOTAL		Gas	Oil/Gas	Oil
ANGELINA			1	1			2	2					3	33%	67%	0%
GREGG		1		1		2	2	4					5	20%	80%	0%
HARRISON	1	36	9	46	1	4	3	8					54	85%	15%	0%
MARION						1	2	3					3	0%	100%	0%
NACOGDOCHES		58		58		1	1	2					60	97%	3%	0%
PANOLA	15	36	15	66	9	22	5	36					102	65%	35%	0%
RUSK		11	2	13		2	3	5			2	2	20	65%	25%	10%
SABINE		3		3									3	100%	0%	0%
SAN AUGUSTINE		55		55		1		1					56	98%	2%	0%
SHELBY	1	25	4	30		1		1					31	97%	3%	0%
TOTAL	17	225	31	273	10	34	18	62			2	2	337	81%	18%	1%

4.0 Future Production Scenarios

ERG identified five approaches or methodologies that were used to forecast production.

> Methodology 1: Project future production assuming that current production remains constant into the future.
>
> Methodology 2: Project future production levels based on the historical production timeline for each specific shale play, on a county-by-county basis.
>
> Methodology 3: Project future production levels based on the historical production timeline for each specific shale play, on a county-by-county basis, with a capped limit based on the size of the reserves.
>
> Methodology 4: Project future production levels for counties in the Barnett shale play and use as a surrogate for the counties in the Haynesville Shale and Eagle Ford Shale plays.
>
> Methodology 5: Project future production by using natural gas commodity price projections as a surrogate for future production.

Each of the five methodologies were used to develop production forecasts for each shale play region (Section 5.0). From those, three unique future production scenarios were identified: aggressive production growth, conservative production growth, and moderate production growth. The five projections of future production were based either on the available historical data described previously (see Section 3.0), or on 2011 production data, depending on the forecast methodology used.

Details on the production forecast calculations according to each of the five methodologies are discussed in Section 5.0 below. The approaches for methodologies 2 and 3 employed a "top-down" method of production forecasting based on the entire shale play region in consideration and not on individual well production.

5.0 Calculation Methodologies

5.1 Methodology 1

Under methodology 1, it was assumed that the 2011 annual production for each shale play region would remain constant for each year 2012 through 2035. Under this scenario, it was assumed that there will not be a change in annual average production rate from the base year 2011 to each year 2012 through 2035 and so the production growth factor for each year is 1.

5.2 Methodology 2

For each shale play, the first year of production was assumed to be the year 2000. Cumulative production of oil, natural gas, and condensate were calculated for each shale play region based on the historical monthly production data from 2000 through 2011 obtained from the TRC. For each shale play, models were fit to the cumulative production of oil, natural gas, and condensate for each shale play. The models varied from linear equations to third order polynomials and each model was adjusted by varying the constant in each model equation so that the modeled 2011 cumulative production matched the actual 2011 cumulative production. After developing the cumulative production models, each model equation was differentiated resulting in a model for the annual production rate. Future annual production of oil, natural gas, and condensate in each shale play from 2012 to 2035 was projected based on the annual production rate models. Using a base year of 2011, growth factors for each shale play were developed by dividing the projected annual production of oil, natural gas, or condensate in a given year by the actual production in 2011.

5.3 Methodology 3

As with Methodology 2, cumulative production of oil, natural gas, and condensate were calculated for each shale play region based on the historical monthly production data from 2000 through 2011 obtained from the TRC. Methodology 3 as described in this section was then used to model historic cumulative production and to project cumulative and annual production for oil, natural gas, and condensate from the three Texas shale play regions.

Attempts at calculating depletion times for oil reserves have been made since the early twentieth century.[4] Furthermore, these methods evolved from predicting well or field-level production using exponential or hyperbolic decline curves to

[4] Brandt, A. "Review of mathematical models of future oil supply: Historical overview and synthesizing critique." Energy 35 (2010) 3958-3974.

predicting production at larger regional and global scales using statistical and curve-fitting methods.

One of the most well-known and simplest curve fitting models is Hubbert's logistic model. Hubbert published his model in 1956[5] but did not provide a full derivation until 1980.[6] Brandt classifies Hubbert's model as hypothetical and physically-based and argues that, as a curve-fitting model, it is useful for first order production projections. The model is based on certain simplifying assumptions, as noted by Brandt:

1. Yearly production is modeled as the first derivative of the logistic function;
2. The production profile is symmetric;
3. There is a time lag where production follows discovery; and
4. Production follows a single cycle; increasing and decreasing with a single peak.

Despite the assumptions and simple nature of the model, production profiles in various areas have been successfully modeled using the Hubbert logistic model.[7] However, the model does not account for various economic, political, or other factors or conditions that may affect production but is based on historic cumulative production and estimates of ultimately recoverable resources. Multi-cycle Hubbert models can be used to account for various changes in conditions that affect production, as Clark has demonstrated for the Barnett shale play by matching historical production in the Barnett shale to a multi-cycle Hubbert model based on three cycles: one for original production in the region during the first decade, a second beginning in 2004 with the advent of horizontal drilling and an increase in natural gas prices, and a third cycle beginning in 2010 when natural gas prices again achieved another short term peak.

[5] Hubbert, M. "Nuclear energy and fossil fuels." In: Meeting of the Southern District, Division of Production, American Petroleum Institute. San Antonio, TX: Shell Development Company; 1956.
[6] Hubbert, M. "Techniques of prediction as applied to the production of oil and gas." In: Symposium on oil and gas supply modeling. Washington, DC: Department of Commerce, National Bureau of Standards; 1980.
[7] Clark, AJ. "Decline Curve Analysis in Unconventional Resource Plays Using Logistic Growth Models." Master's Degree Thesis, The University of Texas at Austin, August 2011.

The Hubbert model for cumulative production is a logistic growth function:

$$Q(t) = \frac{Q_\infty}{1 + N_o e^{-a(t-t_o)}}$$

(Eq. 5-1)

Where:

$Q(t)$	= total cumulative production in year t
Q_∞	= estimated ultimate recovery (EUR) or ultimately recoverable resources (URR)
N_o	$= \frac{(Q_\infty - Q_o)}{Q_o}$, where Q_o = cumulative production in base year 2011
a	= model parameter
t	= year
t_o	= base year (2011)

Taking the derivative of the above equation results in an equation for the production rate ($P(t)$):

$$P(t) = \frac{dQ}{dt} = \frac{aQ_\infty N_O e^{-a(t-t_o)}}{(1 + N_o e^{-a(t-t_o)})^2}$$

(Eq. 5-2)

The parameters a and Q_∞ can be determined by plotting the ratio of production rate and cumulative production against cumulative production. Assuming the plot of those data can be fit to a linear function:

$$\frac{\frac{dQ}{dt}}{Q} = \frac{P(t)}{Q(t)} = -\frac{a}{Q_\infty}Q + a$$

(Eq. 5-3)

The parameter a can be determined from the y-intercept of the line. The slope of the line is $-\frac{a}{Q_\infty}$, where $Q_\infty = slope/-a$. After plotting the above equation and making initial estimates for a and Q_∞, the model cumulative production equation was used to determine the goodness-of-fit to the actual cumulative production data using the initial estimates of a and Q_∞. Published EIA estimates of TRRs for Barnett and Haynesville oil and condensate were not available and thus Q_∞ was estimated as a result of using the above linearization approach. Published estimates of TRR from the EIA were available for: Eagle Ford oil, condensate, and natural gas; and Barnett and Haynesville natural gas[8] and are presented in Table 5-1.

[8] "Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays," U.S. Energy Information Administration, July 2011.

Table 5-1. EIA TRR Data for the Texas Shale Plays

	Haynesville		Barnett		Eagle Ford		
	Active	Undeveloped	Active	Undeveloped	Dry Gas Zone	Condensate Zone	Oil Zone
TRR (TCF)	53.3	19.41	23.81	19.56	4.38	16.43	ND
TRR (BBO)	ND	ND	ND	ND	ND	ND	3.35

ND – no data
TRR – Technically Recoverable Resources
TCF – trillion cubic feet

The Eagle Ford and Barnett shale plays are contained entirely within Texas, but the Haynesville play straddles both Texas and Louisiana. Since the TRR values for the Haynesville play reflect natural gas resource estimates for the entire play, a Q_∞ value had to be estimated for the Haynesville play that reflected an estimate of EUR from only the Texas portion of the play. This was accomplished by using the linearization technique described above based on the historic natural gas production data for the Texas portion of the Haynesville shale play region.

For those regions and products where published estimates of TRR were available from the EIA, Q_∞ was calculated using the following equation:

$$Q_\infty = Q(t) + (TRR)\left(1 + \frac{GR_p}{100}\right) \qquad \text{(Eq. 5-4)}$$

Where:

TRR = technically recoverable resources (as of 2011)
GR_p = overall growth rate (2010 through 2035) of TRR for product p, %

TRR estimates change over time largely due to advances in technology or resource estimation methods. EIA data on end of year reserves growth rates from 2010 through 2035 for both lower 48 oil reserves and lower 48 natural gas reserves[9] under the high TRR assumption (1.4% and 1.0% for oil and gas, respectively) were used as surrogates for oil and gas TRR growth rates. It was assumed that the overall TRR growth rate for 2010 through 2035 would be the same for 2011 through 2035. The calculated Q_∞ just described was used in the model cumulative production and model annual production equations for Eagle Ford oil, condensate, and natural gas;

[9] EIA, AEO2012, Oil and Gas Supply Data Tables.

and Barnett natural gas instead of the estimated Q_∞ determined using the linearization approach.

In all cases, after Q∞ was estimated (either by linearization or calculated using the published TRR), the a parameters were adjusted such that the modeled annual cumulative production in 2011 matched the actual cumulative production in 2011.

5.4 Methodology 4

Annual growth factors for oil, natural gas, and condensate production were calculated from historic production for the Barnett shale play region for those three products for the years 2001 through 2035 using a base year of 2000. Those growth factors were calculated for the Barnett shale play region using the modeled annual production results calculated from methodology 3 discussed above (results presented in sections below). It is assumed that since the Barnett shale play region is more mature and has a more robust set of historical data, the annual change in production from the Barnett shale play beginning in the 2000-2001 time frame would mirror the annual change in production for the Eagle Ford and Haynesville shale play regions beginning in the 2008-2009 time frame. That is, the annual change in production for Barnett in the years 2001 through 2027 would be the same for the other two shale play regions for the years 2009 through 2035. The result of this assumption is that the annual growth factors for Eagle Ford and Haynesville calculated beginning in 2012 with a base year of 2011 are the annual growth factors for the Barnett shale play region beginning in 2004 with a base year of 2003 (i.e., a time period shift of 8 years). The results of these calculations are presented in Table 5-2 below and presented graphically in Figure 5-1.

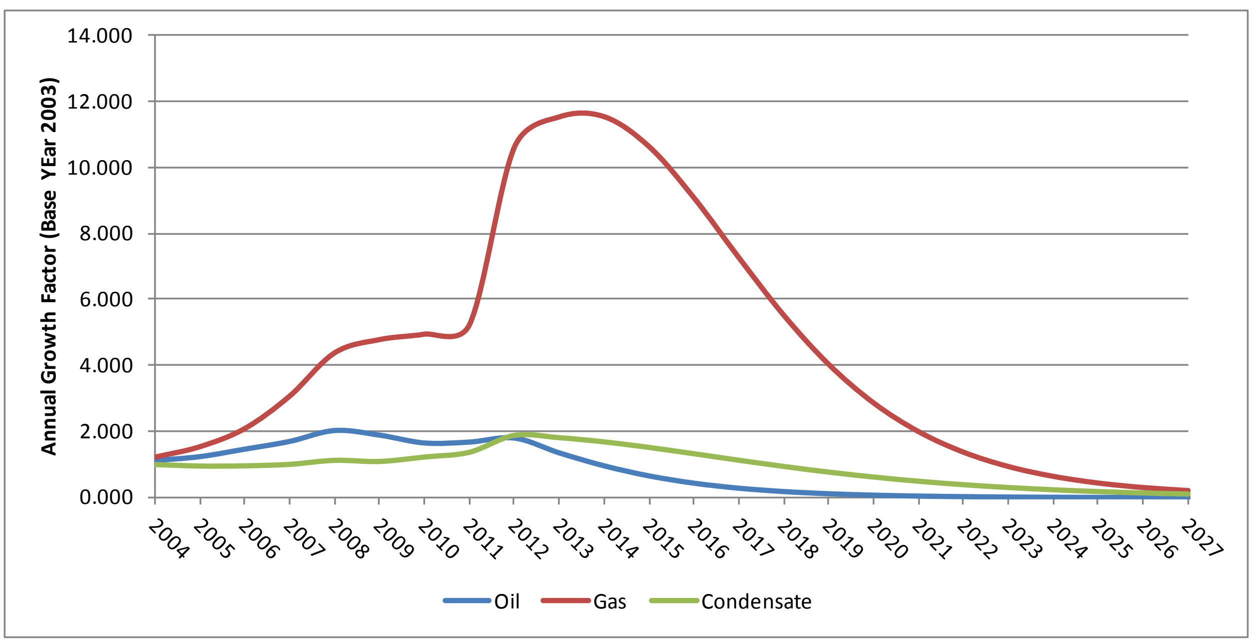
Table 5-2. Barnett Shale Play Region Calculated Annual Growth Factors for Years 2004 through 2027

Year	Methodology 3 Annual Growth Factor for Barnett Shale Play Region (Base Year 2003)			Annual Growth Factor Applies to Eagle Ford and Haynesville Shale Play Regions For Year…
	Oil Production	Gas Production	Condensate Production	
2004	1.108	1.196	0.992	2012
2005	1.224	1.513	0.947	2013
2006	1.447	2.065	0.953	2014
2007	1.678	3.050	0.997	2015
2008	2.003	4.361	1.117	2016
2009	1.864	4.762	1.084	2017
2010	1.631	4.927	1.216	2018
2011	1.658	5.212	1.359	2019
2012	1.777	10.597	1.863	2020

Table 5-2. Barnett Shale Play Region Calculated Annual Growth Factors for Years 2004 through 2027

Year	Methodology 3 Annual Growth Factor for Barnett Shale Play Region (Base Year 2003)			Annual Growth Factor Applies to Eagle Ford and Haynesville Shale Play Regions For Year…
	Oil Production	Gas Production	Condensate Production	
2013	1.335	11.516	1.794	2021
2014	0.949	11.522	1.668	2022
2015	0.648	10.613	1.502	2023
2016	0.431	9.058	1.314	2024
2017	0.282	7.241	1.120	2025
2018	0.182	5.494	0.935	2026
2019	0.116	4.005	0.766	2027
2020	0.074	2.836	0.618	2028
2021	0.047	1.967	0.493	2029
2022	0.030	1.345	0.389	2030
2023	0.019	0.911	0.305	2031
2024	0.012	0.612	0.238	2032
2025	0.008	0.410	0.184	2033
2026	0.005	0.274	0.143	2034
2027	0.003	0.182	0.110	2035

Figure 5-1. Methodology 3 Annual Growth Factors (Base Year 2003) for Oil, Natural Gas, and Condensate Production for the Barnett Shale Play Region (2004-2027)



5.5 Methodology 5

Future production was estimated using the EIA crude oil and natural gas price projections (lower 48 wellhead prices) for 2012 through 2035.[10] Annual changes in price were calculated for both oil and gas production relative to 2011. It was assumed that the calculated annual change in crude oil price would apply to condensate production. Table 5-3 shows the projected price and calculated annual growth factors from base year 2011. Figures 5-2 and 5-3 show the annual change in projected crude oil and natural gas prices from 2012 through 2035, respectively.

Table 5-3. EIA Crude Oil and Natural Gas Wellhead Price Projections (2012-2035) and Calculated Annual Growth Factors

Year	Crude Oil, Lower 48 Average Wellhead Price (2010 $/barrel)	Annual Oil Growth Factor (Base Year 2011)	Natural Gas, Lower 48 Average Wellhead Price (2010 $/MCF)	Annual Natural Gas Growth Factor (Base Year 2011)
2011	94.46	NA	3.81	NA
2012	96.34	1.020	3.40	0.892
2013	104.38	1.105	3.73	0.979
2014	111.90	1.185	3.83	1.005
2015	117.84	1.248	3.94	1.034
2016	119.92	1.270	3.91	1.026
2017	122.09	1.293	3.94	1.034
2018	122.57	1.298	3.98	1.045
2019	123.47	1.307	4.09	1.073
2020	124.44	1.317	4.19	1.100
2021	125.71	1.331	4.41	1.157
2022	127.33	1.348	4.66	1.223
2023	128.40	1.359	4.85	1.273
2024	129.38	1.370	4.97	1.304
2025	130.30	1.379	5.12	1.344
2026	131.07	1.388	5.24	1.375
2027	131.65	1.394	5.39	1.415
2028	131.82	1.396	5.47	1.436
2029	132.51	1.403	5.57	1.462
2030	130.74	1.384	5.69	1.493
2031	131.47	1.392	5.81	1.525
2032	132.94	1.407	5.95	1.562
2033	134.40	1.423	6.06	1.591
2034	135.91	1.439	6.36	1.669
2035	137.55	1.456	6.64	1.743

NA – not applicable

[10] EIA, AEO2012, Oil and Gas Supply Data Tables.

Figure 5-2. EIA Projected Crude Oil Wellhead Price and Annual Growth Factor (2012-2035)

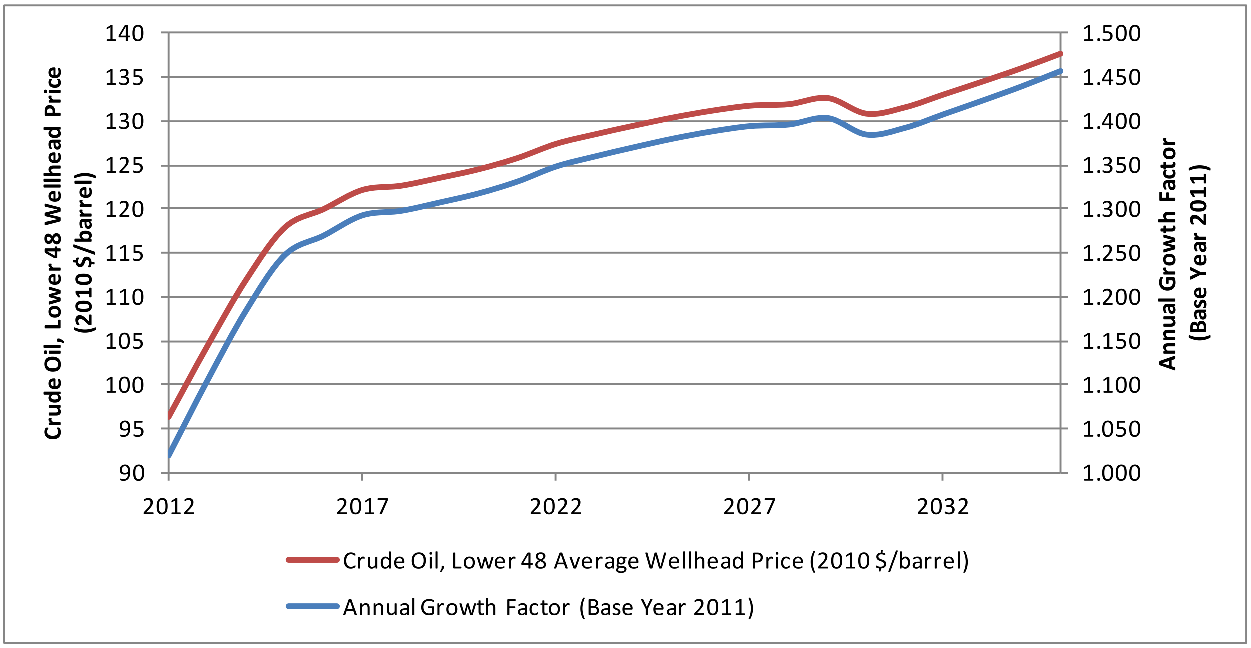
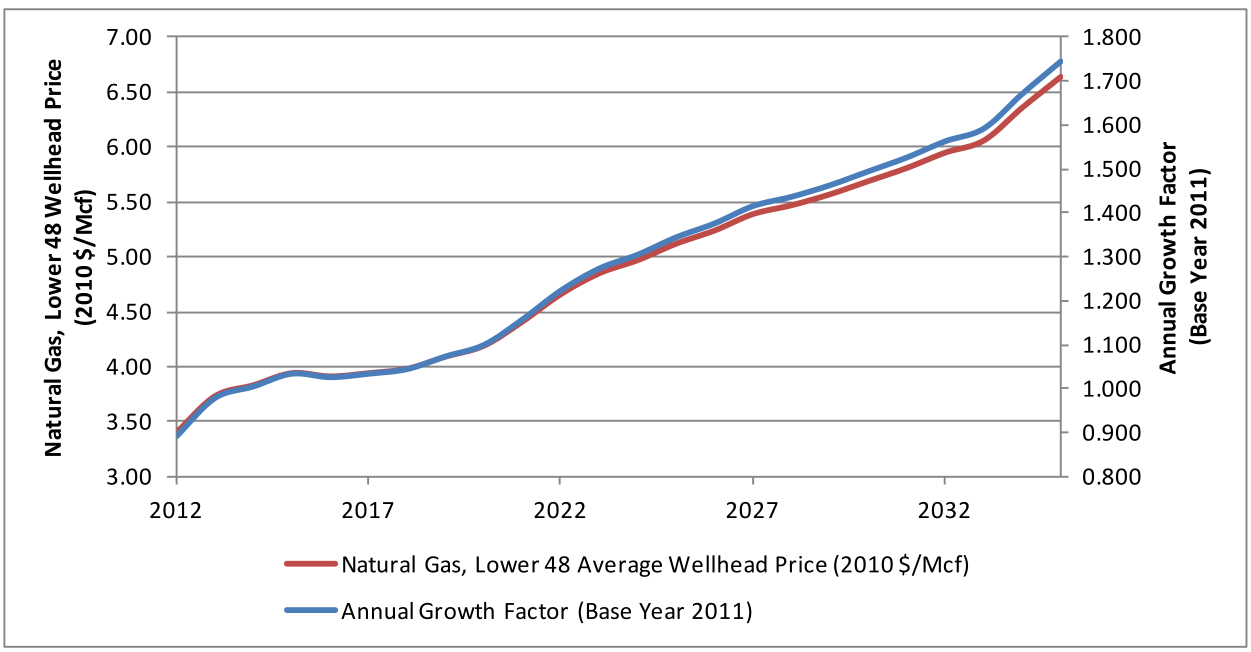


Figure 5-3. EIA Projected Natural Gas Wellhead Price and Annual Growth Factor (2012-2035)



6.0 Results of Methodologies 2 and 3

The results of the growth factor development under methodologies 2 and 3 for the three shale play regions are presented in this section.

6.1 Barnett Shale Play Region

6.1.1 Methodology 2

Curve fitting under methodology 2 for the Barnett shale play region resulted in the models for cumulative production and annual production as shown in Table 6-1. Gas volumes are stated as MCF.

Table 6-1. Methodology 2 Production Models for Barnett Shale Play Region

Product	Cumulative Production	Annual Production
Oil	$Q_{Oil,B-2}(barrels) = (10{,}292{,}556)(t) - 20{,}569{,}673{,}956$	$P(t)_{Oil,B-2} = \frac{dQ}{dt}_{Oil,B-2}\left(\frac{barrels}{yr}\right) = 10{,}292{,}556$
Gas	$Q_{G,B-2}(MCF) = 112{,}910{,}668(t^2) - 451{,}844{,}908{,}182(t) + 452{,}047{,}677{,}466{,}719$	$P(t)_{G,B-2} = \frac{dQ}{dt}_{G,B-2}\left(\frac{MCF}{yr}\right) = 225{,}821{,}336(t) - 451{,}844{,}908{,}182$
Condensate	$Q_{C,B-2}(barrels) = 99{,}414(t^2) - 396{,}665{,}142(t) + 395{,}673{,}095{,}960$	$P(t)_{C,B-2} = \frac{dQ}{dt}_{C,B-2}\left(\frac{barrels}{yr}\right) = 198{,}828(t) - 396{,}665{,}141$

Figures 6-1 and 6-2 present actual and modeled historic oil production, and projected oil production, respectively. Figures 6-3 and 6-4 present actual and modeled historic natural gas production, and projected natural gas production, respectively. Figures 6-5 and 6-6 present actual and modeled historic condensate production, and projected condensate production, respectively.

Figure 6-1. Methodology 2 Model Fit to Historic Oil Production from the Barnett Shale Play Region (2000-2011)

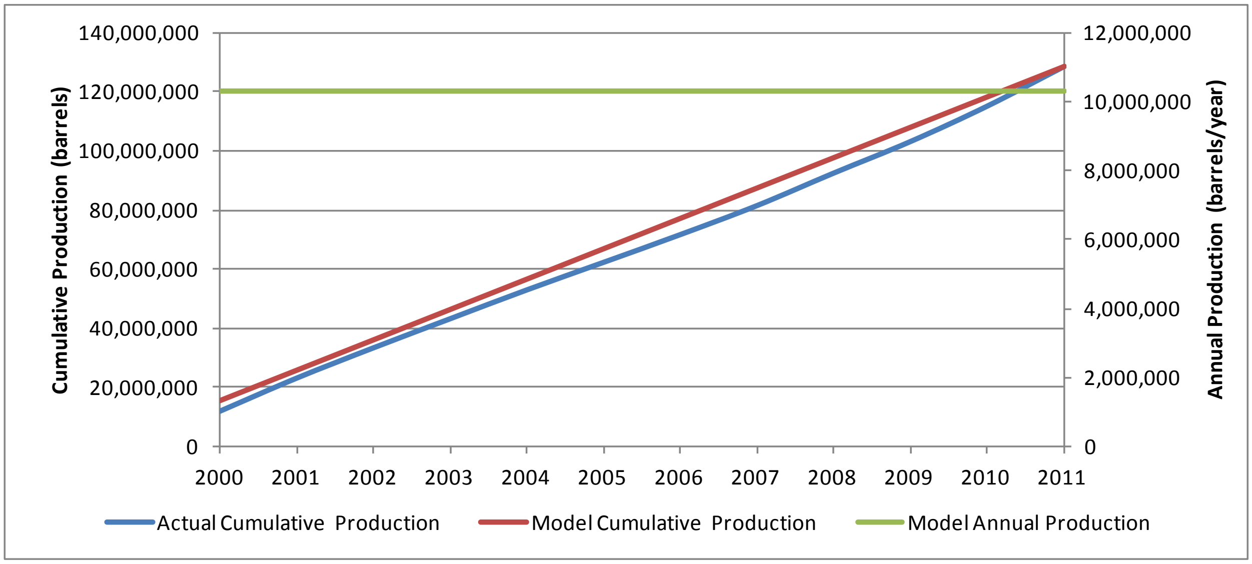


Figure 6-2. Methodology 2 Projected Cumulative and Annual Oil Production from the Barnett Shale Play Region (2012-2035)

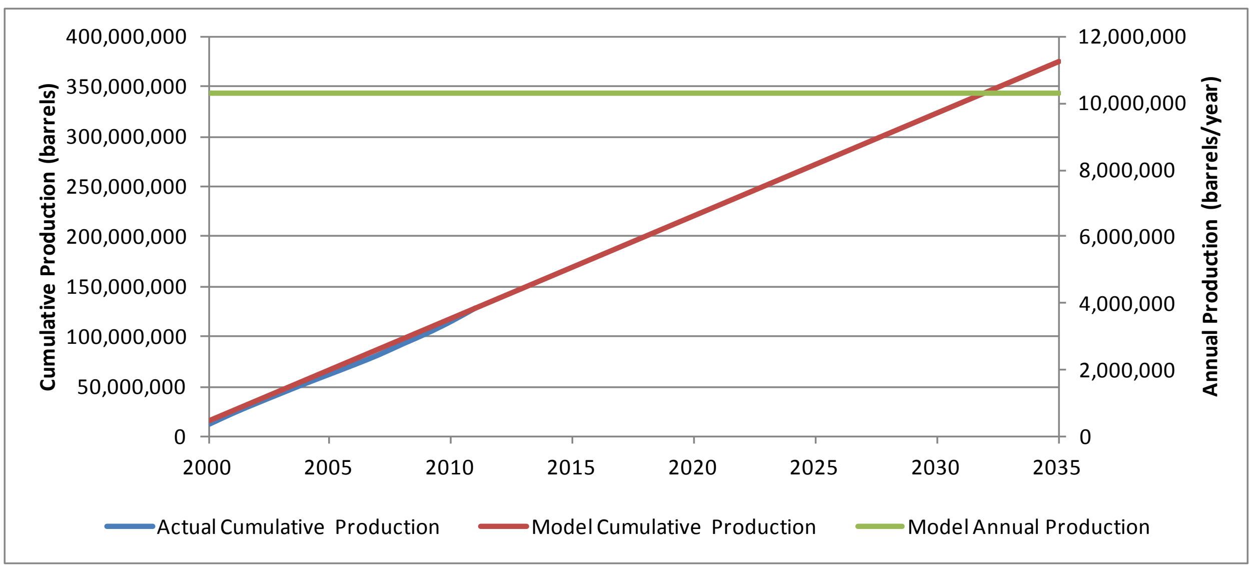


Figure 6-3. Methodology 2 Model Fit to Historic Natural Gas Production from the Barnett Shale Play Region (2000-2011)

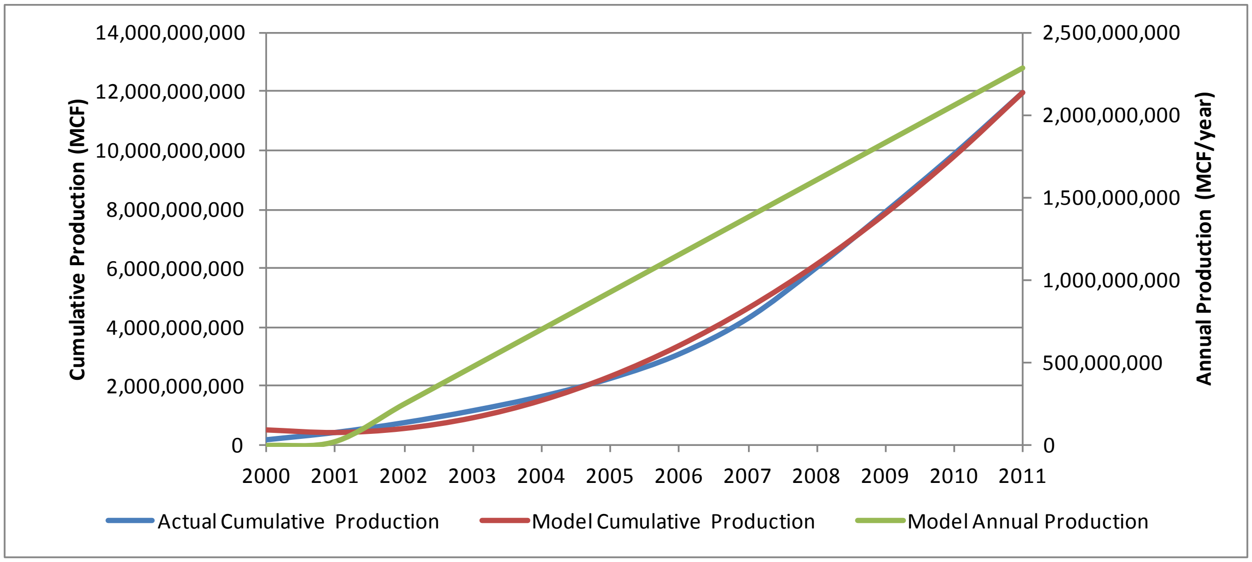


Figure 6-4. Methodology 2 Projected Cumulative and Annual Natural Gas Production from the Barnett Shale Play Region (2012-2035)

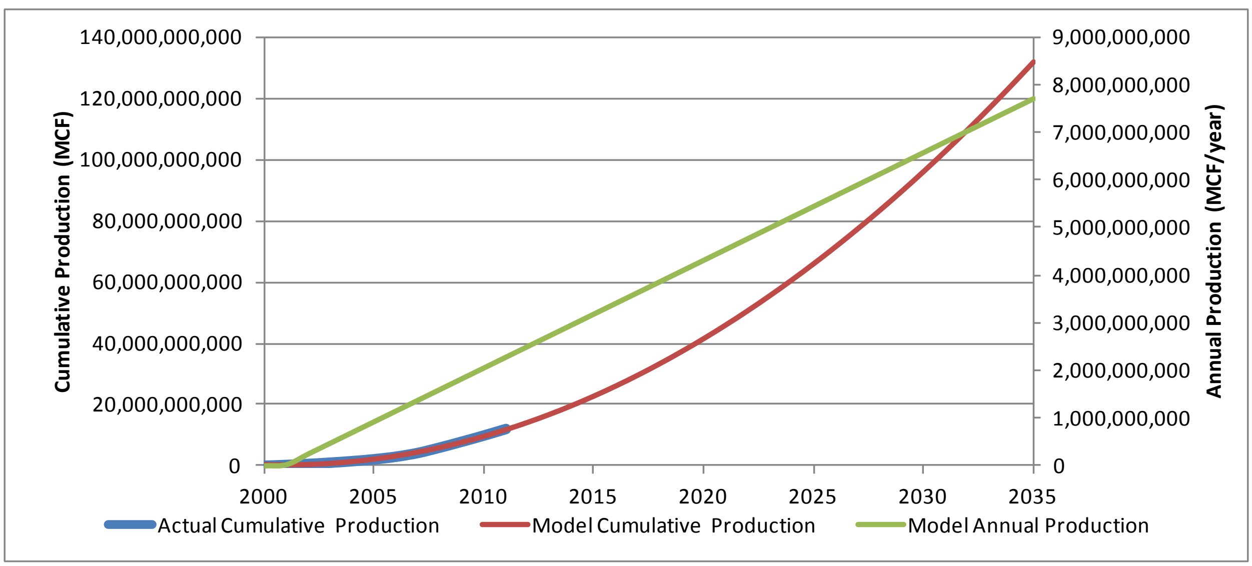


Figure 6-5. Methodology 2 Model Fit to Historic Condensate Production from the Barnett Shale Play Region (2000-2011)

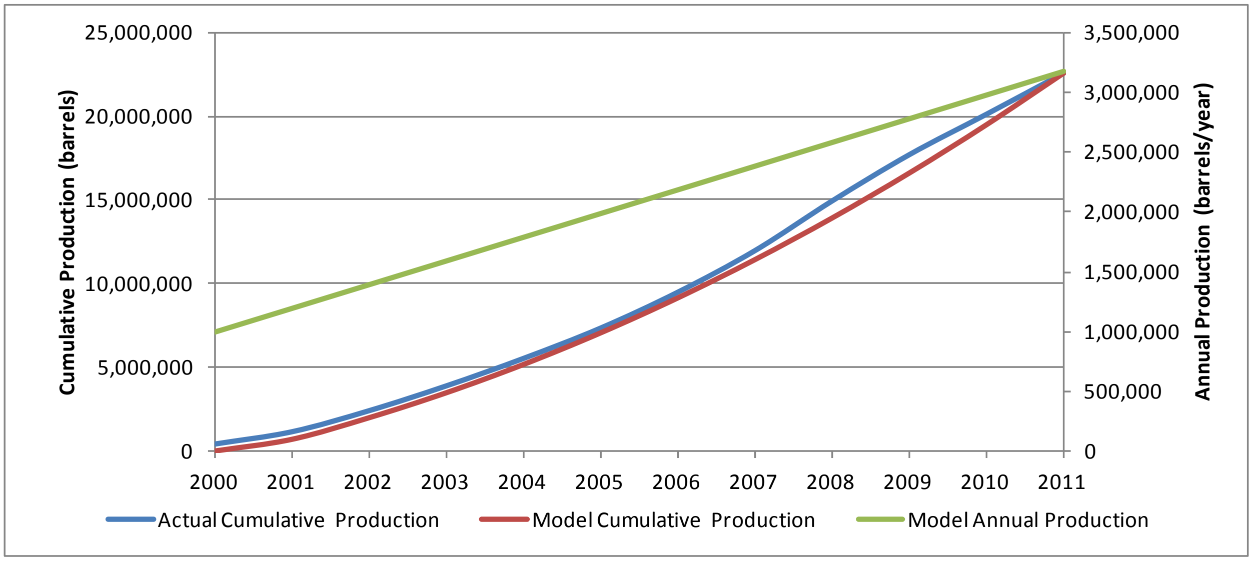
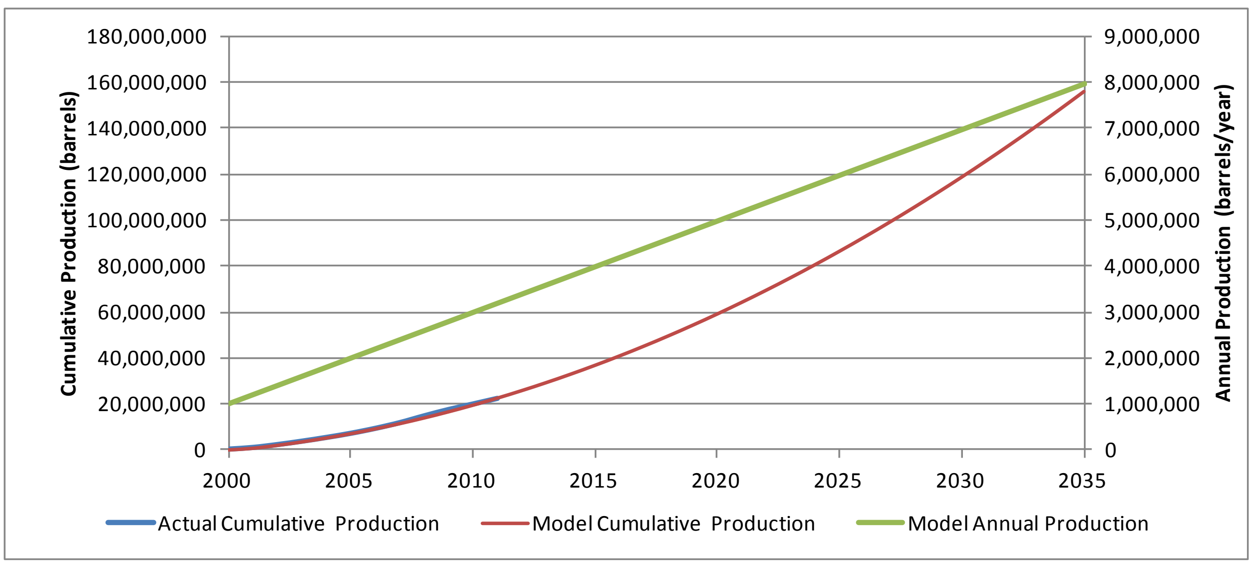


Figure 6-6. Methodology 2 Projected Cumulative and Annual Condensate Production from the Barnett Shale Play Region (2012-2035)



6.1.2 Methodology 3

Model development under methodology 3 for the Barnett shale play region resulted in the models for cumulative production and annual production as shown in Table 6-2.

Table 6-2. Methodology 3 Production Models for Barnett Shale Play Region

Product	Cumulative Production	Annual Production
Oil	$Q_{Oil,B-3}(barrels) = \frac{273{,}909{,}069}{1+(22.91)e^{-0.2696(t-2011)}}$	$P(t)_{Oil,B-3}\left(\frac{barrels}{yr}\right) = \frac{dQ}{dt}_{Oil,B-3} = \frac{(0.2696)(273{,}909{,}069)(22.91)e^{-0.2696(t-2011)}}{(1+(22.91)e^{-0.2696(t-2011)})^2}$
Gas	$Q_{G,B-3}(MCF) = \frac{44{,}086{,}646{,}422}{1+(254.7)e^{-0.4102(t-2011)}}$	$P(t)_{G,B-3}\left(\frac{MCF}{yr}\right) = \frac{dQ}{dt}_{G,B-3} = \frac{(0.4102)(44{,}086{,}646{,}422)(254.7)e^{-0.4102(t-2011)}}{(1+(254.7)e^{-0.4102(t-2011)})^2}$
Condensate	$Q_{C,B-3}(barrels) = \frac{32{,}871{,}770}{1+(71.08)e^{-0.4586(t-2011)}}$	$P(t)_{C,B-3}\left(\frac{barrels}{yr}\right) = \frac{dQ}{dt}_{C,B-3} = \frac{(0.4586)(32{,}871{,}770)(71.08)e^{-0.4586(t)}}{(1+(71.08)e^{-0.4586(t-2011)})^2}$

The estimated model parameters are summarized in Table 6-3.

Table 6-3. Summary of Methodology 3 Production Model Parameters

Product	Q_∞	a	No
Oil	273,909,069	0.2696	21.91
Gas	44,086,646,422	0.4102	254.7
Condensate	32,871,770	0.4586	71.08

Figures 6-7 and 6-8 present actual and modeled historic oil production, and projected oil production, respectively. Figures 6-9 and 6-10 present actual and modeled historic natural gas production, and projected natural gas production, respectively. Figures 6-11 and 6-12 present actual and modeled historic condensate production, and projected condensate production, respectively.

A summary of the annual growth factors calculated for the Barnett Shale play region under all five methodologies is presented in Table 6-4. Annual growth factors for 2012 through 2035 calculated for all five methodologies are presented in Figures 6-13 through 6-15 for oil production, gas production, and condensate production, respectively.

Figure 6-7. Methodology 3 Model Fit to Historic Oil Production from the Barnett Shale Play Region (2000-2011)

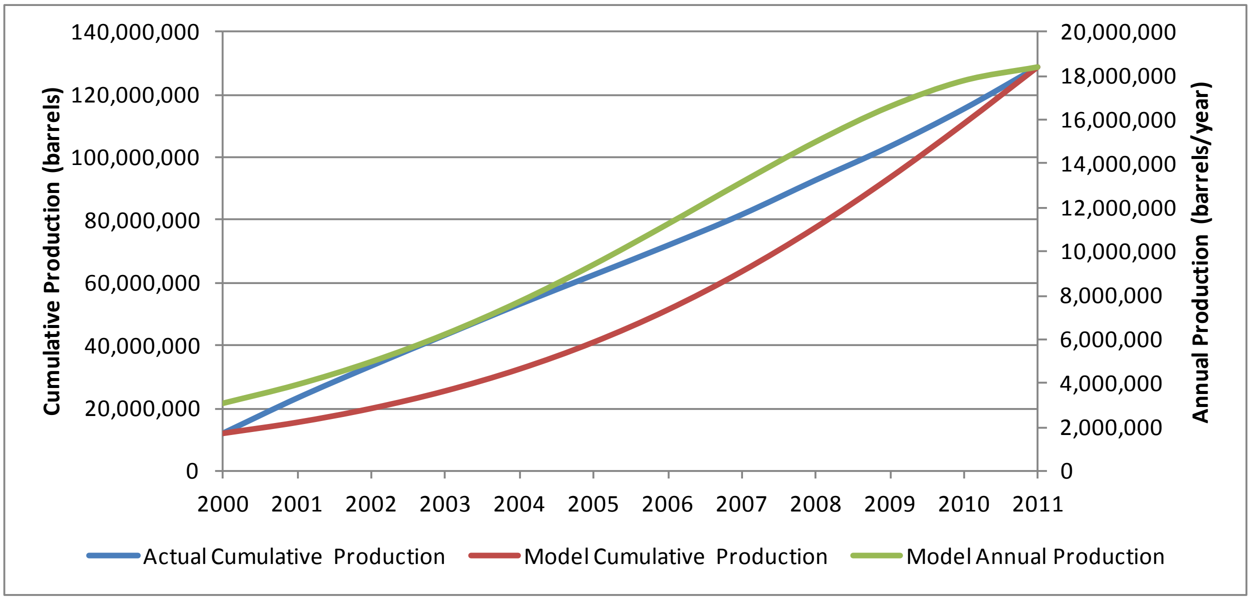


Figure 6-8. Methodology 3 Projected Cumulative and Annual Oil Production from the Barnett Shale Play Region (2012-2035)

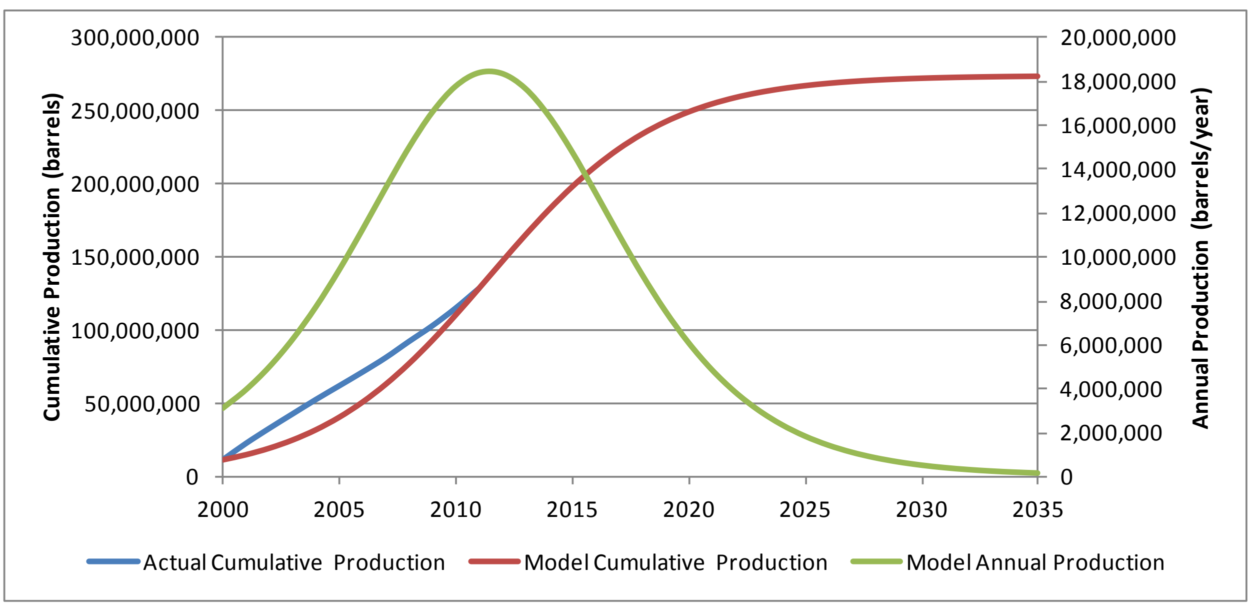


Figure 6-9. Methodology 3 Model Fit to Historic Natural Gas Production from the Barnett Shale Play Region (2000-2011)

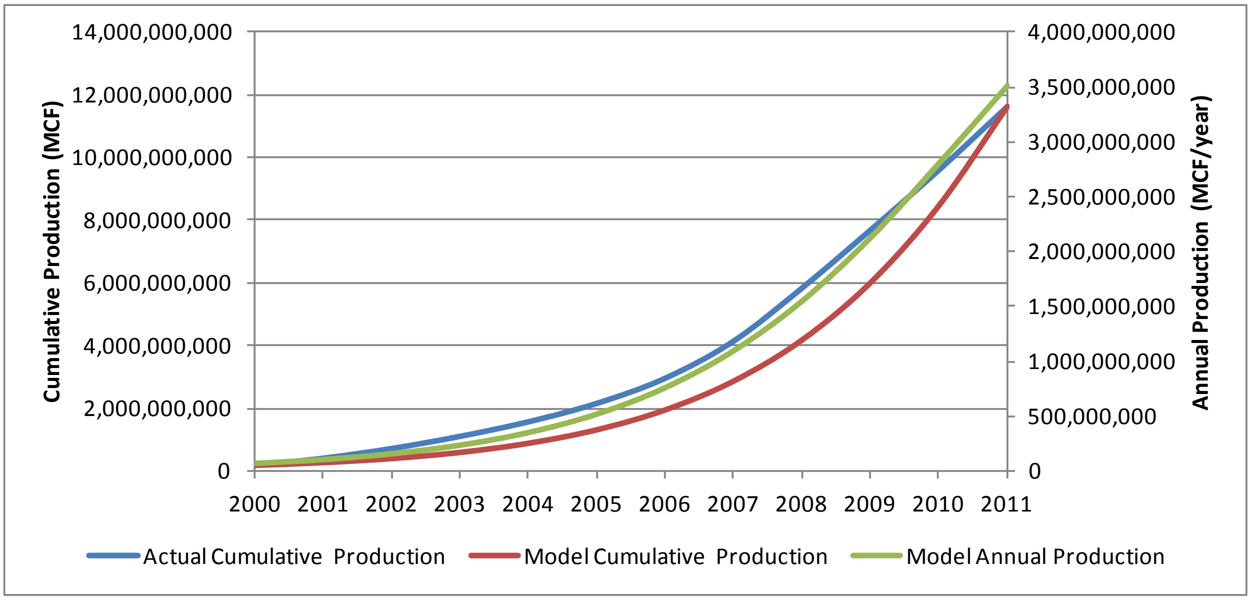


Figure 6-10. Methodology 3 Projected Cumulative and Annual Natural Gas Production from the Barnett Shale Play Region (2012-2035)

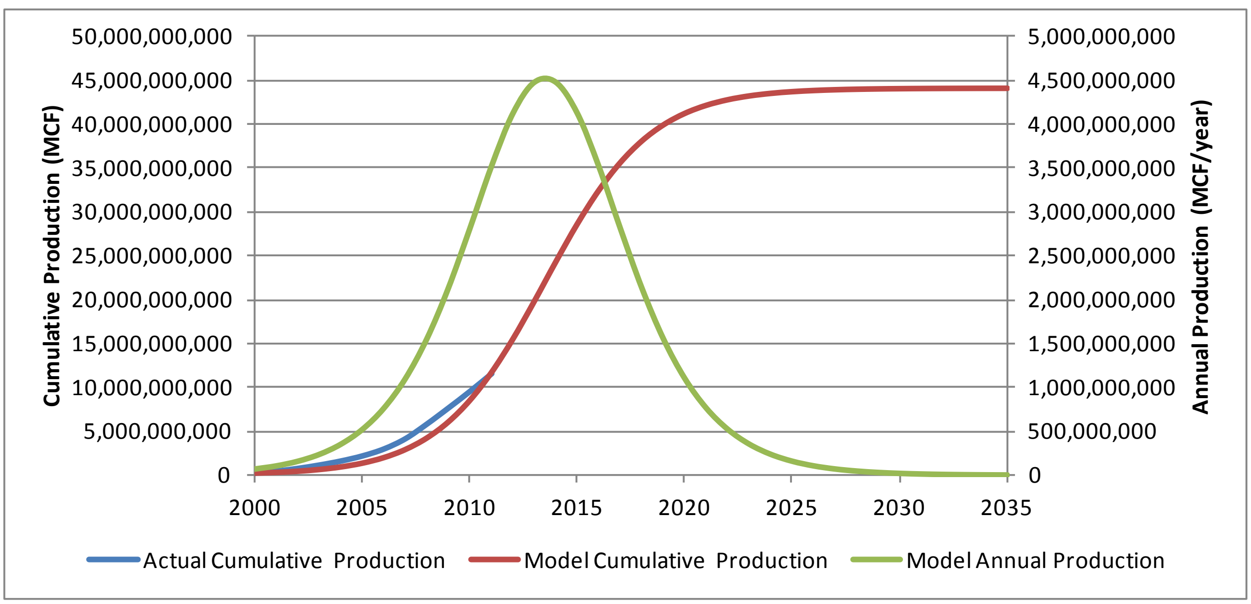


Figure 6-11. Methodology 3 Model Fit to Historic Condensate Production from the Barnett Shale Play Region (2000-2011)

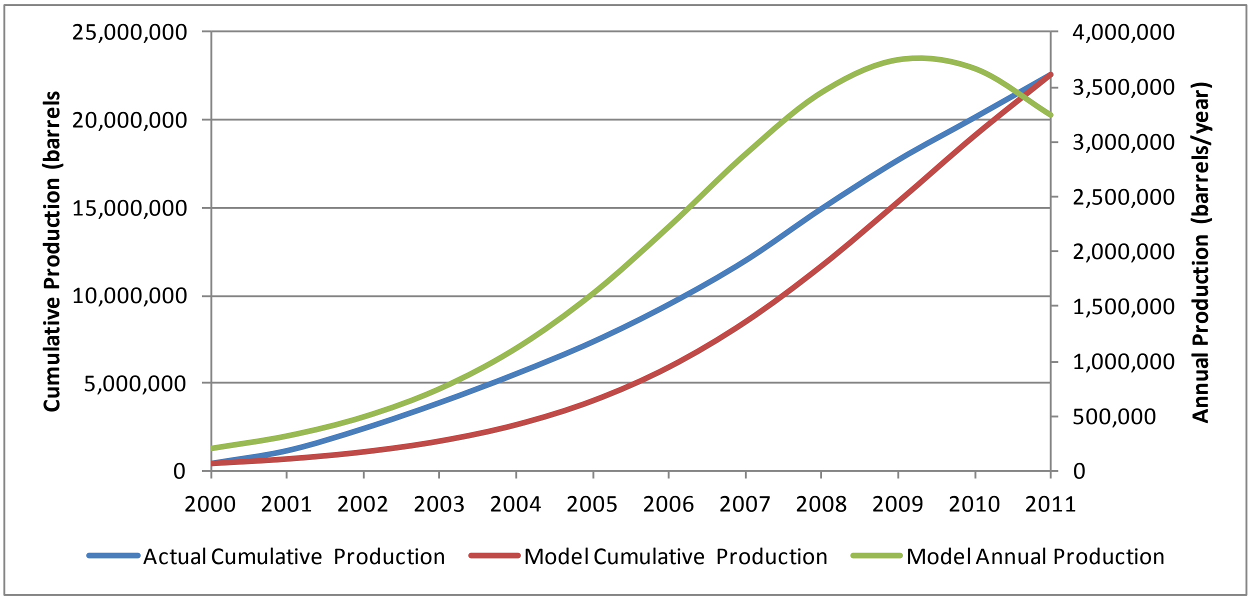


Figure 6-12. Methodology 3 Projected Cumulative and Annual Condensate Production from the Barnett Shale Play Region (2012-2035)

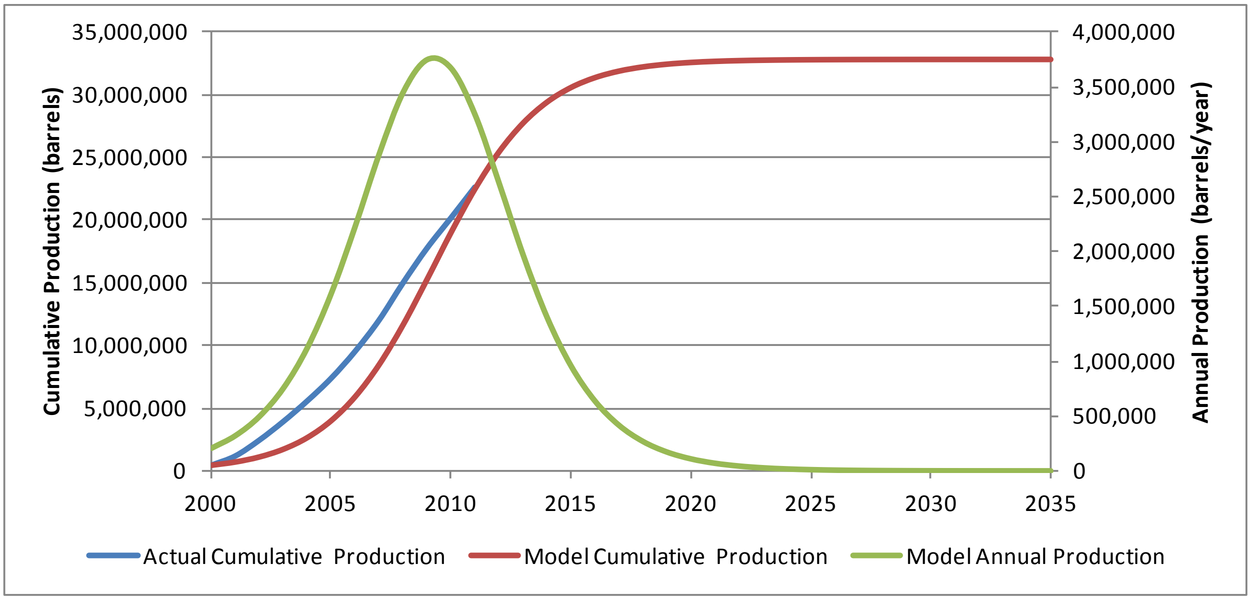


Table 6-4. Summary of Production Growth Factors for Barnett Shale Play Region for Methodologies 1 – 5

	Oil					Gas					Condensate				
	Methodology					Methodology					Methodology				
Year	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5
2012	1.000	1.000	0.998	NA	1.020	1.000	1.099	1.173	NA	0.892	1.000	1.063	0.808	NA	1.020
2013	1.000	1.000	0.961	NA	1.105	1.000	1.198	1.275	NA	0.979	1.000	1.125	0.607	NA	1.105
2014	1.000	1.000	0.894	NA	1.185	1.000	1.297	1.275	NA	1.005	1.000	1.188	0.431	NA	1.185
2015	1.000	1.000	0.805	NA	1.248	1.000	1.396	1.175	NA	1.034	1.000	1.250	0.295	NA	1.248
2016	1.000	1.000	0.704	NA	1.270	1.000	1.495	1.002	NA	1.026	1.000	1.313	0.196	NA	1.270
2017	1.000	1.000	0.600	NA	1.293	1.000	1.594	0.801	NA	1.034	1.000	1.375	0.128	NA	1.293
2018	1.000	1.000	0.501	NA	1.298	1.000	1.693	0.608	NA	1.045	1.000	1.438	0.083	NA	1.298
2019	1.000	1.000	0.410	NA	1.307	1.000	1.792	0.443	NA	1.073	1.000	1.500	0.053	NA	1.307
2020	1.000	1.000	0.331	NA	1.317	1.000	1.891	0.314	NA	1.100	1.000	1.563	0.034	NA	1.317
2021	1.000	1.000	0.264	NA	1.331	1.000	1.990	0.218	NA	1.157	1.000	1.625	0.021	NA	1.331
2022	1.000	1.000	0.209	NA	1.348	1.000	2.089	0.149	NA	1.223	1.000	1.688	0.014	NA	1.348
2023	1.000	1.000	0.164	NA	1.359	1.000	2.188	0.101	NA	1.273	1.000	1.751	0.009	NA	1.359
2024	1.000	1.000	0.127	NA	1.370	1.000	2.287	0.068	NA	1.304	1.000	1.813	0.005	NA	1.370
2025	1.000	1.000	0.099	NA	1.379	1.000	2.386	0.045	NA	1.344	1.000	1.876	0.003	NA	1.379
2026	1.000	1.000	0.076	NA	1.388	1.000	2.484	0.030	NA	1.375	1.000	1.938	0.002	NA	1.388
2027	1.000	1.000	0.059	NA	1.394	1.000	2.583	0.020	NA	1.415	1.000	2.001	0.001	NA	1.394
2028	1.000	1.000	0.045	NA	1.396	1.000	2.682	0.013	NA	1.436	1.000	2.063	0.001	NA	1.396
2029	1.000	1.000	0.035	NA	1.403	1.000	2.781	0.009	NA	1.462	1.000	2.126	0.001	NA	1.403
2030	1.000	1.000	0.027	NA	1.384	1.000	2.880	0.006	NA	1.493	1.000	2.188	0.000	NA	1.384
2031	1.000	1.000	0.020	NA	1.392	1.000	2.979	0.004	NA	1.525	1.000	2.251	0.000	NA	1.392
2032	1.000	1.000	0.016	NA	1.407	1.000	3.078	0.003	NA	1.562	1.000	2.314	0.000	NA	1.407
2033	1.000	1.000	0.012	NA	1.423	1.000	3.177	0.002	NA	1.591	1.000	2.376	0.000	NA	1.423
2034	1.000	1.000	0.009	NA	1.439	1.000	3.276	0.001	NA	1.669	1.000	2.439	0.000	NA	1.439
2035	1.000	1.000	0.007	NA	1.456	1.000	3.375	0.001	NA	1.743	1.000	2.501	0.000	NA	1.456

NA – not applicable

Figure 6-13. Oil Production Annual Growth Factors for Barnett Shale Play Region (2012-2035)

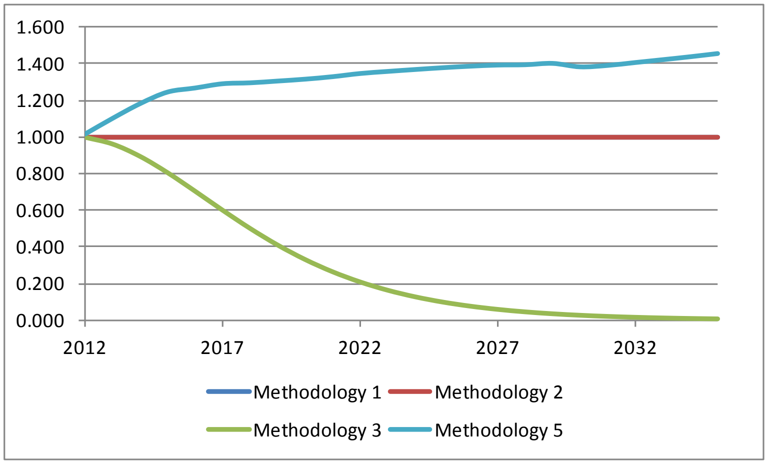


Figure 6-14. Gas Production Annual Growth Factors for Barnett Shale Play Region (2012-2035)

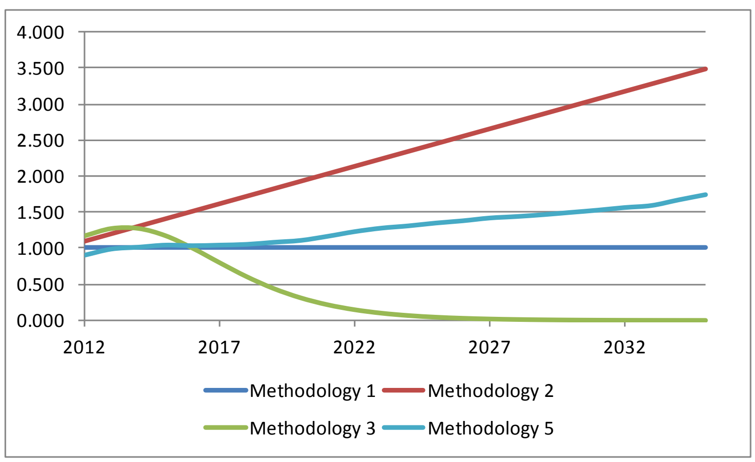
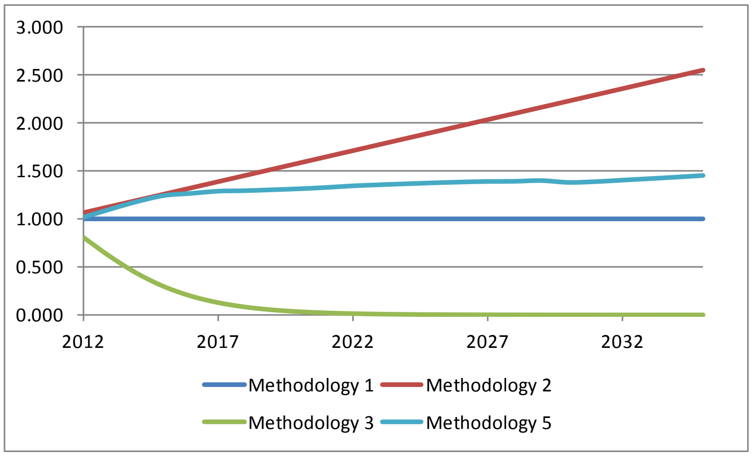


Figure 6-15. Condensate Annual Growth Factors for Barnett Shale Play Region (2012-2035)



Using the annual growth rates presented in Table 6-4 for each of the five projection methodologies, the projected annual production of oil, gas, and condensate as well as total cumulative production for 2012 through 2035 can be estimated. From those estimates, high growth rate, moderate growth rate, and low growth rate scenarios can be identified (Table 6-5).

Table 6-5. Identification of High, Moderate, and Low Growth Scenarios Based on Projected Cumulative Production for the Barnett Shale Play Region

Product	Methodology[b]	Projected Cumulative Production (2012-2035)	Growth Scenario
Oil (barrels)	5 (EIA)	427,424,566	High
	1 (Constant)	321,482,016	Moderate[c]
	2 (Curve Fit)	321,482,016	
	3 (Hubbert)	98,757,971	Low
	4 (Barnett)	NA	
Gas[a] (MCF)	2 (Curve Fit)	112,291,173,260	High
	5 (EIA)	64,336,215,175	Moderate[c]
	1 (Constant)	50,195,422,488	
	3 (Hubbert)	18,270,442,813	Low
	4 (Barnett)	NA	
Condensate (barrels)	2 (Curve Fit)	104,726,625	High
	5 (EIA)	78,142,293	Moderate[c]
	1 (Constant)	58,773,744	
	3 (Hubbert)	6,595,039	Low
	4 (Barnett)	NA	

NA – not applicable
[a] Includes both gas well gas and casinghead gas.
[b] *Methodology 1* – 2011 annual production assumed constant through 2035
Methodology 2 – cumulative production model developed based on fitting historical cumulative production data to a second or third order polynomial function
Methodology 3 – cumulative production model based on Hubbert's logistic growth model
Methodology 4 – Historic annual production data from the Barnett shale play region used as a surrogate for the Eagle Ford and Haynesville shale play regions.
Methodology 5 – EIA natural gas wellhead price projections through 2035 used as a surrogate for production.
[c] Either methodology could be used as the moderate growth rate.

6.2 Eagle Ford Shale Play Region

6.2.1 Methodology 2

Curve fitting under methodology 2 for the Eagle Ford shale play region resulted in the models for cumulative production and annual production as shown in Table 6-6.

Table 6-6. Methodology 2 Production Models for Eagle Ford Shale Play Region

Product	Cumulative Production	Annual Production
Oil	$Q_{Oil,EF-2}(barrels) = 174{,}142(t^3) - 1{,}047{,}423{,}000(t^2) + 2{,}100{,}012{,}736{,}153(t) - 1{,}403{,}471{,}303{,}059{,}310$	$P(t)_{Oil,EF-2} = \frac{dQ}{dt}_{Oil,EF-2}\left(\frac{barrels}{yr}\right) = 522{,}427(t^2) - 2{,}094{,}846{,}001(t) + 2{,}100{,}012{,}736{,}153$
Gas	$Q_{G,EF-2}(MCF) = 16{,}123{,}009(t^2) - 63{,}867{,}639{,}351(t) + 63{,}244{,}089{,}597{,}252$	$P(t)_{G,EF-2} = \frac{dQ}{dt}_{G,EF-2}\left(\frac{MCF}{yr}\right) = 32{,}246{,}018(t) - 63{,}867{,}639{,}351$
Condensate	$Q_{C,EF-2}(barrels) = 114{,}408(t^3) - 687{,}935{,}776(t^2) + 1{,}378{,}858{,}989{,}202(t) - 921{,}236{,}878{,}299{,}155$	$P(t)_{C,EF-2} = \frac{dQ}{dt}_{C,EF-2}\left(\frac{barrels}{yr}\right) = 343{,}233(t^2) - 1{,}375{,}871{,}553(t) + 1{,}378{,}858{,}989{,}202$

Figures 6-16 and 6-17 present actual and modeled historic oil production, and projected oil production, respectively. Figures 6-18 and 6-19 present actual and modeled historic natural gas production, and projected natural gas production, respectively. Figures 6-20 and 6-21 present actual and modeled historic condensate production, and projected condensate production, respectively.

Figure 6-16. Methodology 2 Model Fit to Historic Oil Production from the Eagle Ford Shale Play Region (2000-2011)

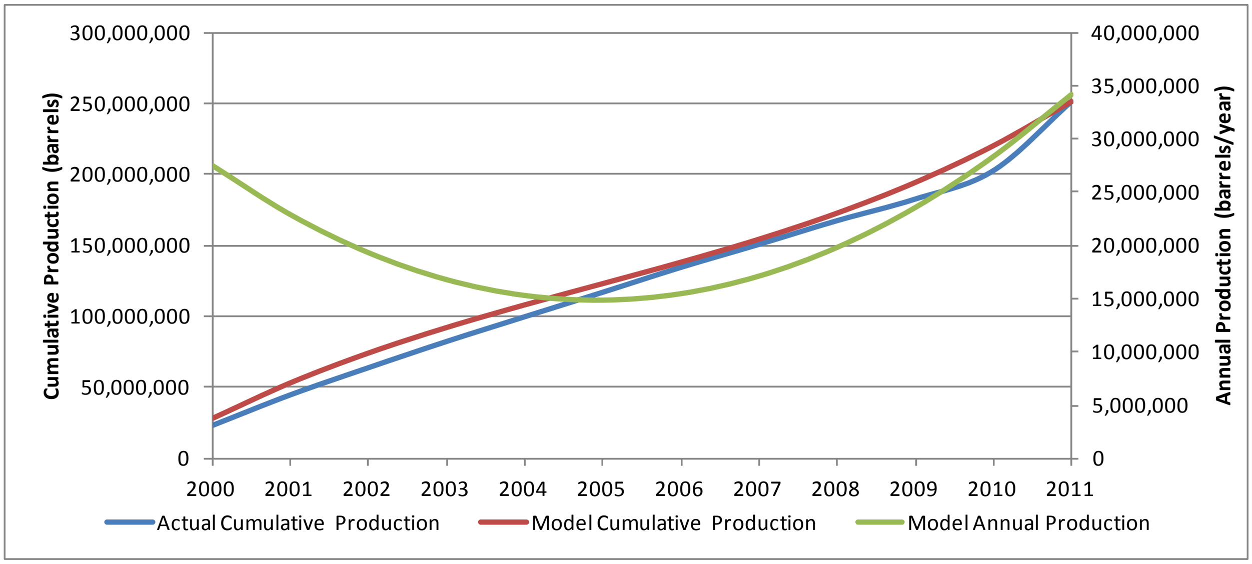


Figure 6-17. Methodology 2 Projected Cumulative and Annual Oil Production from the Eagle Ford Shale Play Region (2012-2035)

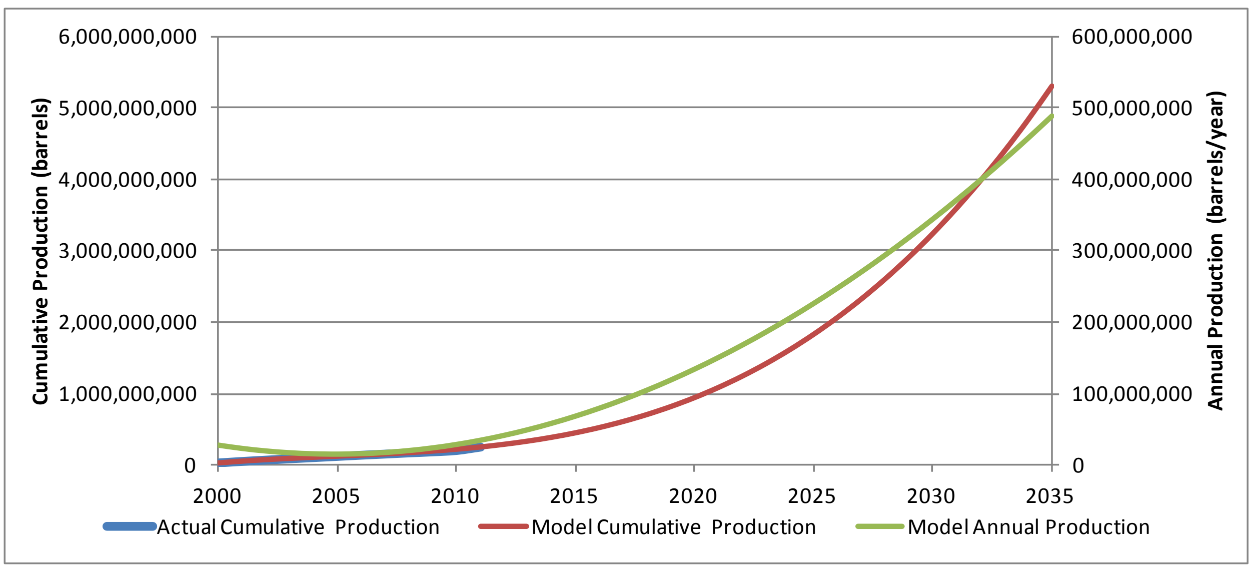


Figure 6-18. Methodology 2 Model Fit to Historic Natural Gas Production from the Eagle Ford Shale Play Region (2000-2011)

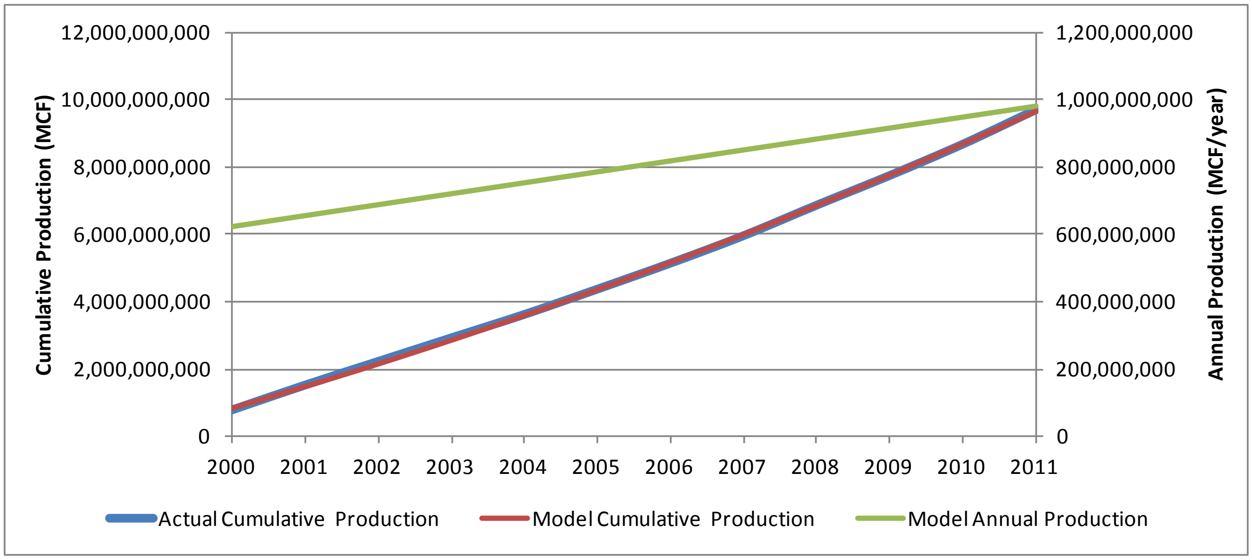


Figure 6-19. Methodology 2 Projected Cumulative and Annual Natural Gas Production from the Eagle Ford Shale Play Region (2012-2035)

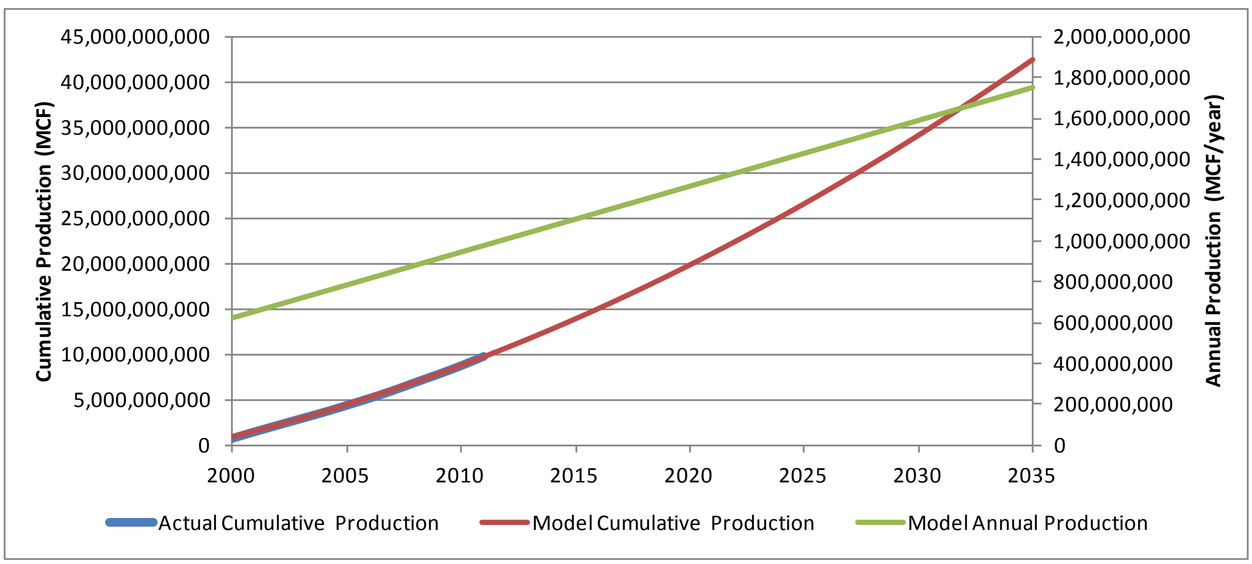


Figure 6-20. Methodology 2 Model Fit to Historic Condensate Production from the Eagle Ford Shale Play Region (2000-2011)

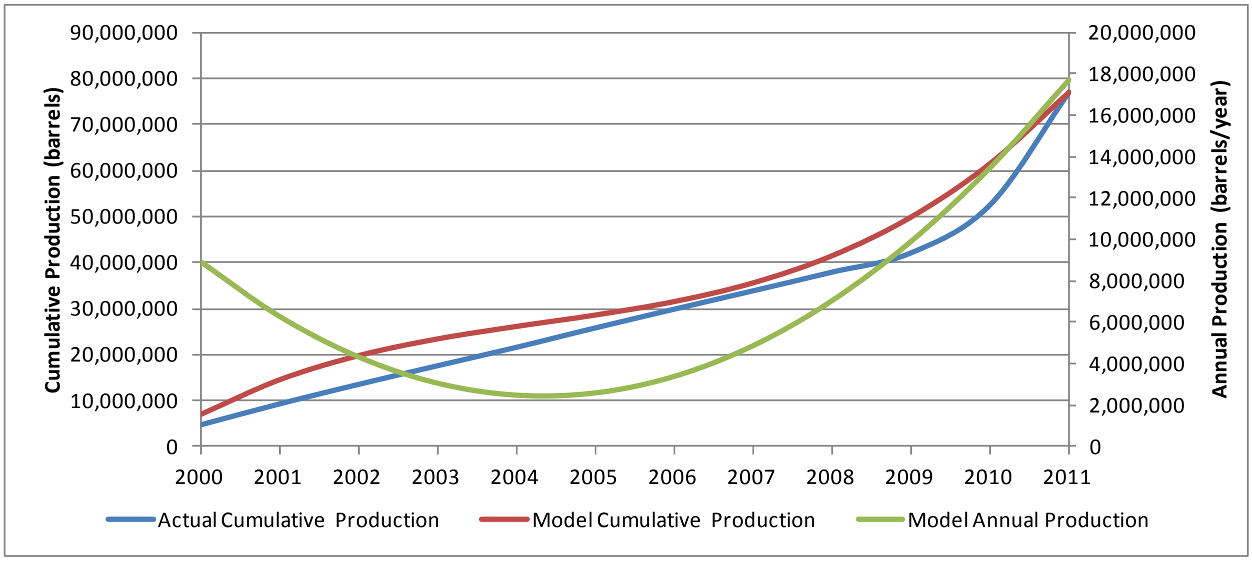
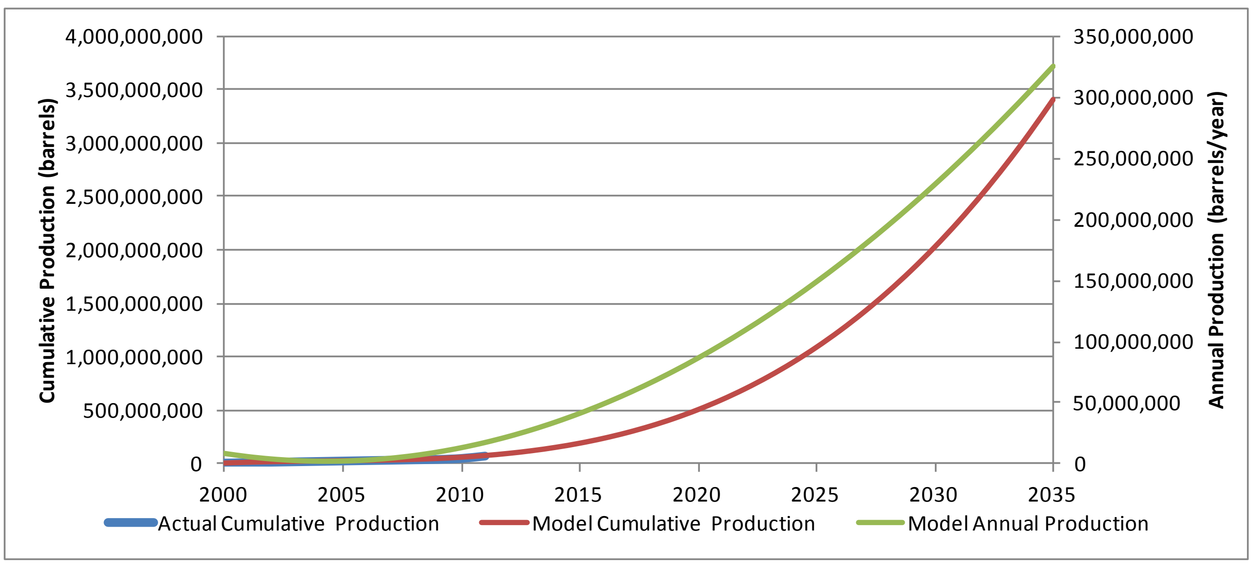


Figure 6-21. Methodology 2 Projected Cumulative and Annual Condensate Production from the Eagle Ford Shale Play Region (2012-2035)



6.2.2 Methodology 3

Model development under methodology 3 for the Eagle Ford shale play region resulted in the models for cumulative production and annual production as shown in Table 6-7.

Table 6-7. Methodology 3 Production Models for Eagle Ford Shale Play Region

Product	Cumulative Production	Annual Production
Oil	$Q_{Oil,EF-3}(barrels) = \frac{2{,}959{,}150{,}515}{1+(126.3)e^{-0.2239(t-2011)}}$	$P(t)_{Oil,EF-3}\left(\frac{barrels}{yr}\right) = \frac{dQ}{dt}_{Oil,EF-3} = \frac{(0.2239)(2{,}959{,}150{,}515)(126.3)e^{-0.2239(t-2011)}}{(1+(126.3)e^{-0.2239(t-2011)})^2}$
Gas	$Q_{G,EF-3}(MCF) = \frac{30{,}040{,}036{,}771}{1+(41.87)e^{-0.0.2626(t-2011)}}$	$P(t)_{G,EF-3}\left(\frac{MCF}{yr}\right) = \frac{dQ}{dt}_{G,EF-3} = \frac{(0.2626)(30{,}040{,}036{,}771)(41.87)e^{-0.2626(t-2011)}}{(1+(41.87)e^{-0.2626(t-2011)})^2}$
Condensate	$Q_{C,EF-3}(barrels) = \frac{766{,}596{,}670}{1+(156.4)e^{-0.2601(t-2011)}}$	$P(t)_{C,EF-3}\left(\frac{barrels}{yr}\right) = \frac{dQ}{dt}_{C,EF-3} = \frac{(0.2601)(766{,}696{,}670)(156.4)e^{-0.2601(t-2011)}}{(1+(156.4)e^{-0.2601(t-2011)})^2}$

The estimated model parameters are summarized in Table 6-8.

Table 6-8. Summary of Methodology 3 Production Model Parameters

Product	Q_∞	a	No
Oil	2,959,150,515	0.2239	126.3
Gas	30,040,036,771	0.2626	41.87
Condensate	766,596,670	0.2601	156.4

Figures 6-22 and 6-23 present actual and modeled historic oil production, and projected oil production, respectively. Figures 6-24 and 6-25 present actual and modeled historic natural gas production, and projected natural gas production, respectively. Figures 6-26 and 6-27 present actual and modeled historic condensate production, and projected condensate production, respectively.

A summary of the annual growth factors calculated for the Eagle Ford Shale play region under all five methodologies is presented in Table 6-9. Annual growth factors for 2012 through 2035 calculated for all five methodologies are presented in Figures 6-28 through 6-30 for oil production, gas production, and condensate production, respectively.

Figure 6-22. Methodology 3 Model Fit to Historic Oil Production from the Eagle Ford Shale Play Region (2000-2011)

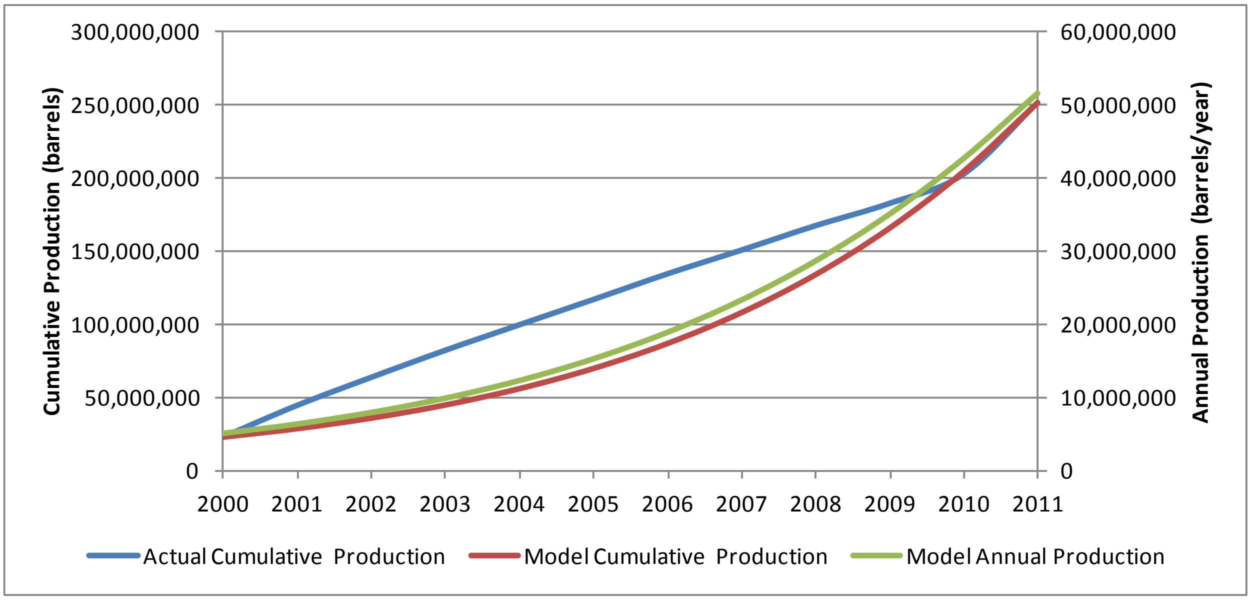


Figure 6-23. Methodology 3 Projected Cumulative and Annual Oil Production from the Eagle Ford Shale Play Region (2012-2035)

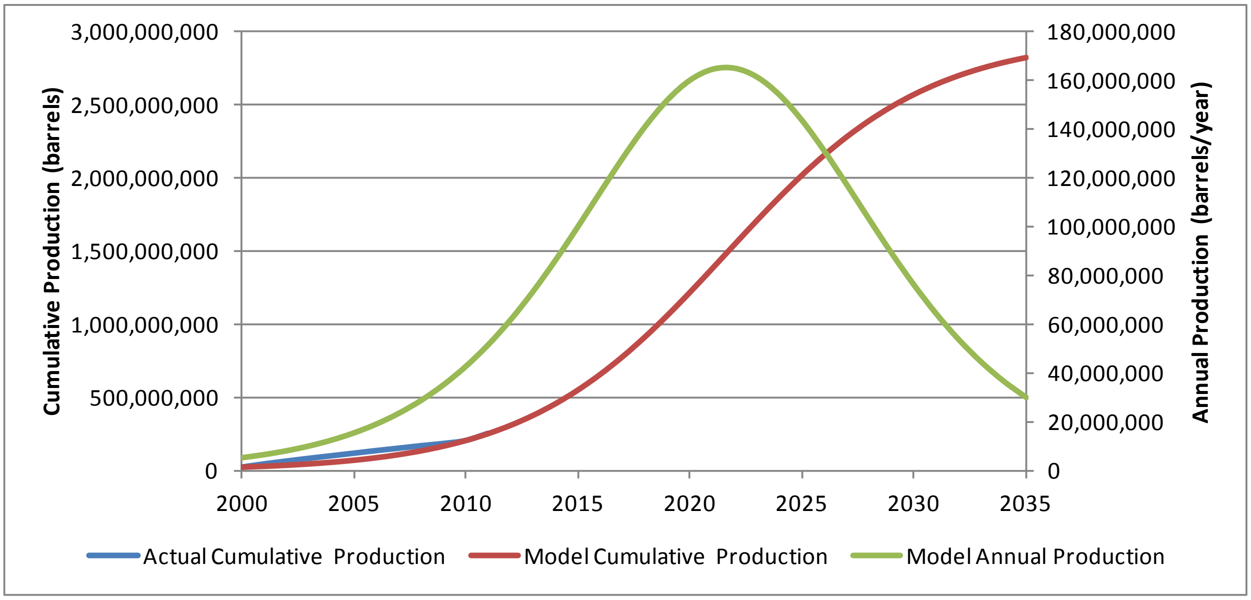


Figure 6-24. Methodology 3 Model Fit to Historic Natural Gas Production from the Eagle Ford Shale Play Region (2000-2011)

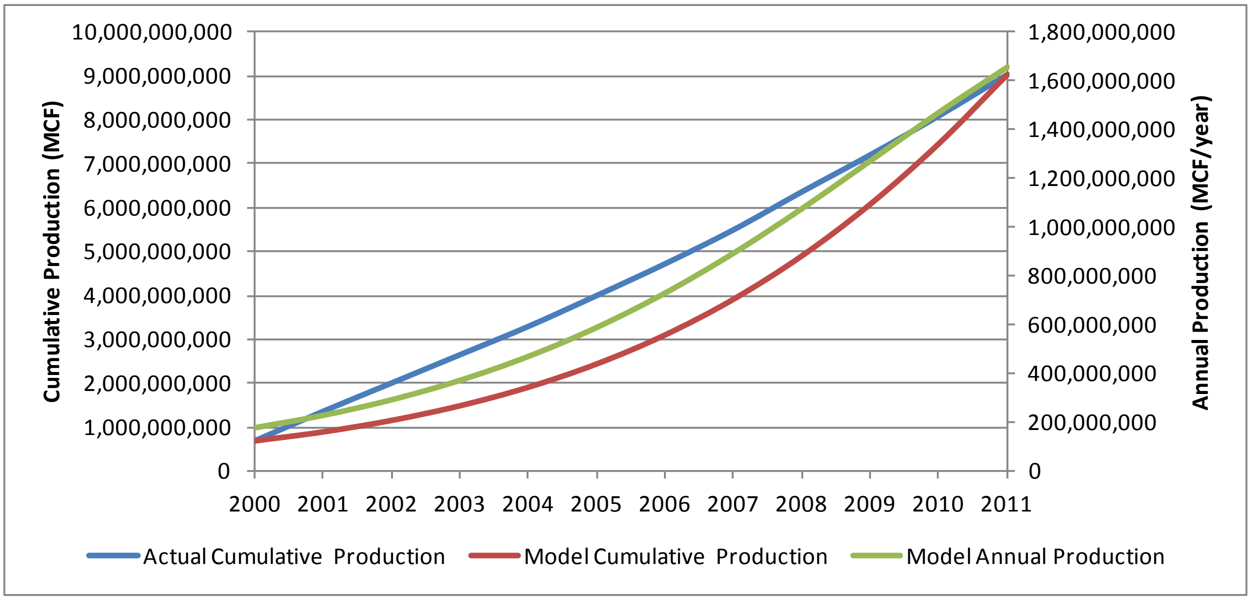


Figure 6-25. Methodology 3 Projected Cumulative and Annual Natural Gas Production from the Eagle Ford Shale Play Region (2012-2035)

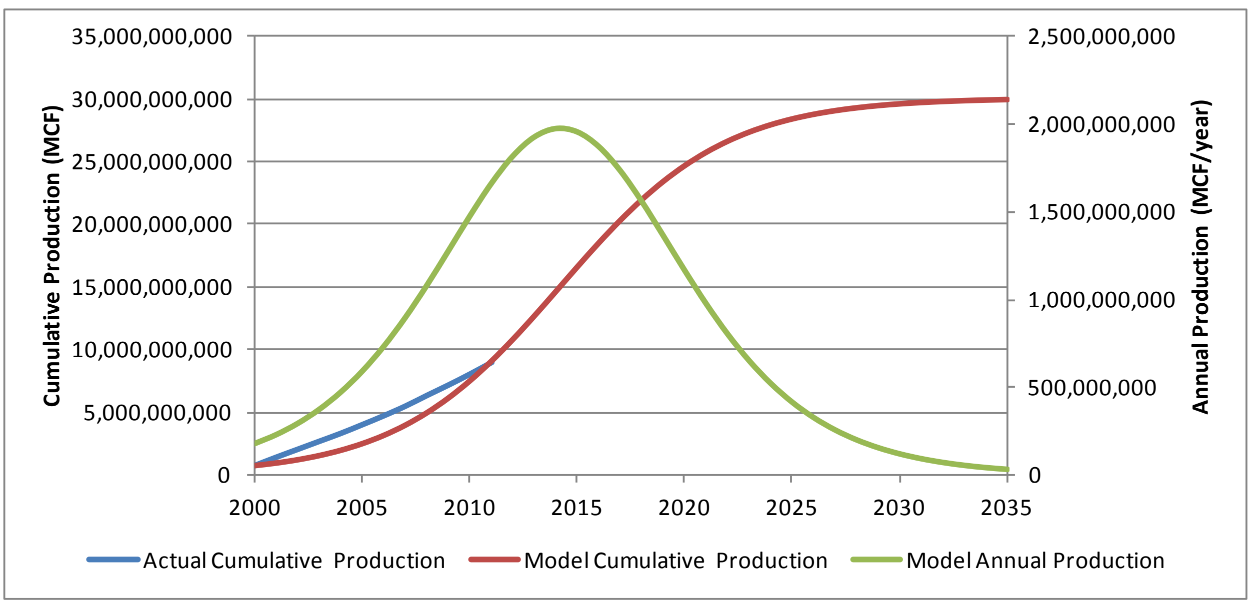


Figure 6-26. Methodology 3 Model Fit to Historic Condensate Production from the Eagle Ford Shale Play Region (2000-2011)

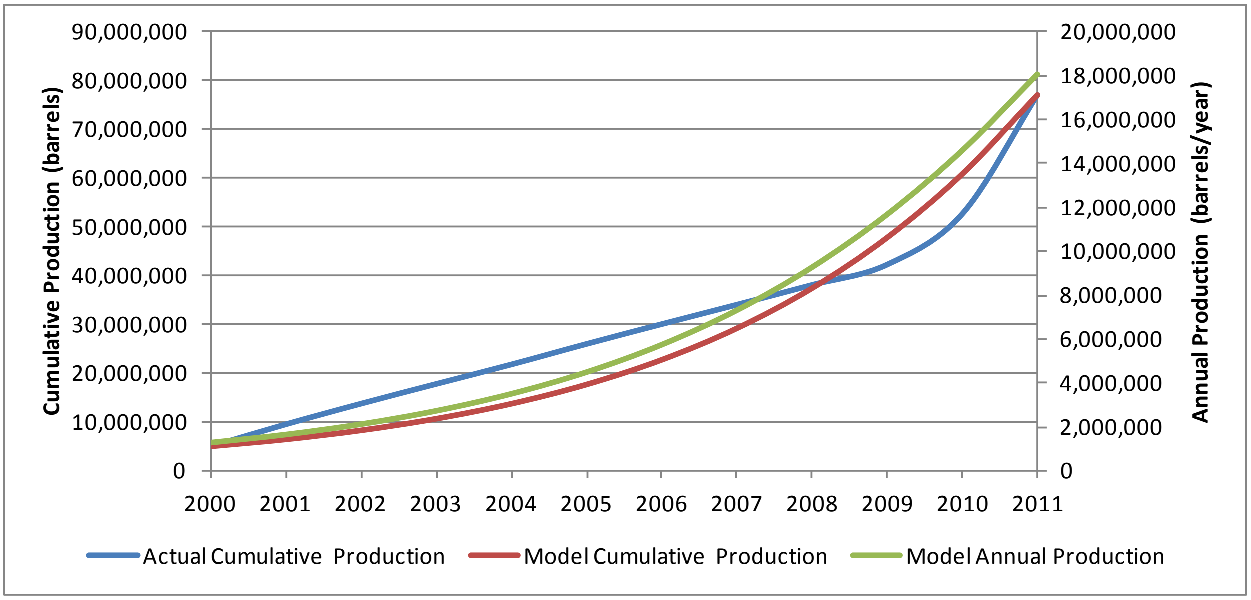


Figure 6-27. Methodology 3 Projected Cumulative and Annual Condensate Production from the Eagle Ford Shale Play Region (2012-2035)

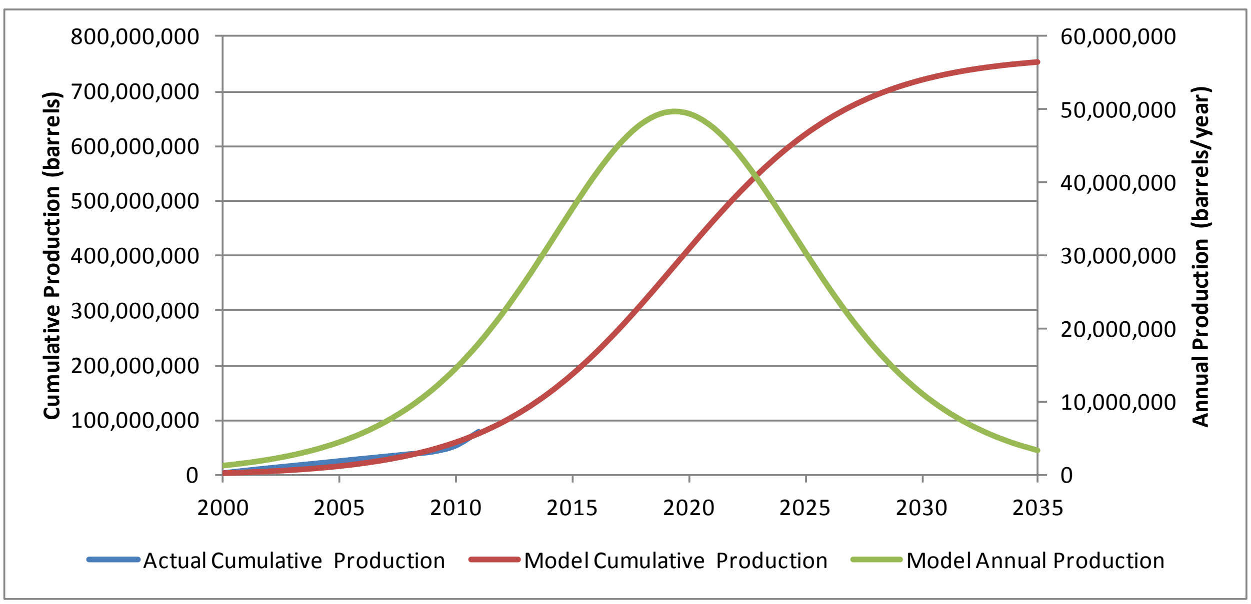


Table 6-9. Summary of Production Growth Factors for Eagle Ford Shale Play Region for Methodologies 1 – 5

Year	Oil					Gas					Condensate				
	Methodology					Methodology					Methodology				
	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5
2012	1.000	1.201	1.199	0.992	1.020	1.000	1.033	1.094	1.196	0.892	1.000	1.278	1.223	1.108	1.020
2013	1.000	1.433	1.425	0.947	1.105	1.000	1.066	1.160	1.513	0.979	1.000	1.595	1.473	1.224	1.105
2014	1.000	1.695	1.674	0.953	1.185	1.000	1.099	1.189	2.065	1.005	1.000	1.951	1.743	1.447	1.185
2015	1.000	1.987	1.941	0.997	1.248	1.000	1.132	1.177	3.050	1.034	1.000	2.346	2.019	1.678	1.248
2016	1.000	2.311	2.217	1.117	1.270	1.000	1.165	1.127	4.361	1.026	1.000	2.780	2.281	2.003	1.270
2017	1.000	2.664	2.489	1.084	1.293	1.000	1.198	1.044	4.762	1.034	1.000	3.252	2.507	1.864	1.293
2018	1.000	3.049	2.740	1.216	1.298	1.000	1.231	0.939	4.927	1.045	1.000	3.763	2.672	1.631	1.298
2019	1.000	3.463	2.953	1.359	1.307	1.000	1.263	0.821	5.212	1.073	1.000	4.313	2.756	1.658	1.307
2020	1.000	3.909	3.110	1.863	1.317	1.000	1.296	0.702	10.597	1.100	1.000	4.903	2.749	1.777	1.317
2021	1.000	4.385	3.197	1.794	1.331	1.000	1.329	0.587	11.516	1.157	1.000	5.530	2.651	1.335	1.331
2022	1.000	4.891	3.205	1.668	1.348	1.000	1.362	0.483	11.522	1.223	1.000	6.197	2.476	0.949	1.348
2023	1.000	5.428	3.135	1.502	1.359	1.000	1.395	0.392	10.613	1.273	1.000	6.903	2.243	0.648	1.359
2024	1.000	5.996	2.992	1.314	1.370	1.000	1.428	0.315	9.058	1.304	1.000	7.647	1.977	0.431	1.370
2025	1.000	6.594	2.789	1.120	1.379	1.000	1.461	0.250	7.241	1.344	1.000	8.430	1.701	0.282	1.379
2026	1.000	7.223	2.545	0.935	1.388	1.000	1.494	0.197	5.494	1.375	1.000	9.252	1.434	0.182	1.388
2027	1.000	7.882	2.276	0.766	1.394	1.000	1.527	0.155	4.005	1.415	1.000	10.113	1.187	0.116	1.394
2028	1.000	8.571	2.000	0.618	1.396	1.000	1.560	0.121	2.836	1.436	1.000	11.013	0.969	0.074	1.396
2029	1.000	9.292	1.730	0.493	1.403	1.000	1.593	0.094	1.967	1.462	1.000	11.952	0.781	0.047	1.403
2030	1.000	10.043	1.476	0.389	1.384	1.000	1.626	0.073	1.345	1.493	1.000	12.929	0.624	0.030	1.384
2031	1.000	10.824	1.246	0.305	1.392	1.000	1.659	0.057	0.911	1.525	1.000	13.946	0.494	0.019	1.392
2032	1.000	11.636	1.041	0.238	1.407	1.000	1.692	0.044	0.612	1.562	1.000	15.001	0.390	0.012	1.407
2033	1.000	12.478	0.862	0.184	1.423	1.000	1.725	0.034	0.410	1.591	1.000	16.095	0.305	0.008	1.423
2034	1.000	13.351	0.710	0.143	1.439	1.000	1.757	0.026	0.274	1.669	1.000	17.228	0.239	0.005	1.439
2035	1.000	14.255	0.581	0.110	1.456	1.000	1.790	0.020	0.182	1.743	1.000	18.400	0.186	0.003	1.456

Figure 6-28. Oil Production Annual Growth Factors for Eagle Ford Shale Play Region (2012-2035)

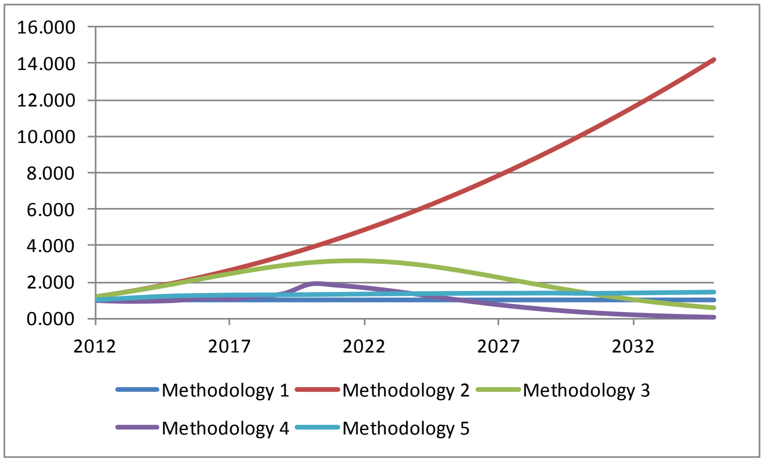


Figure 6-29. Gas Production Annual Growth Factors for Eagle Ford Shale Play Region (2012-2035)

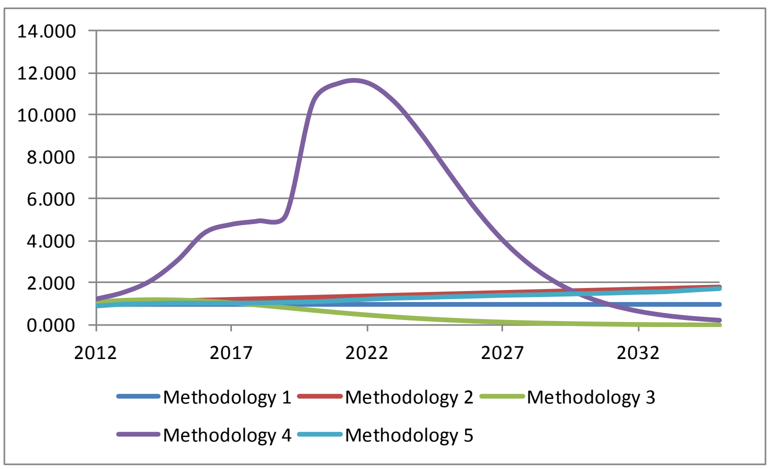
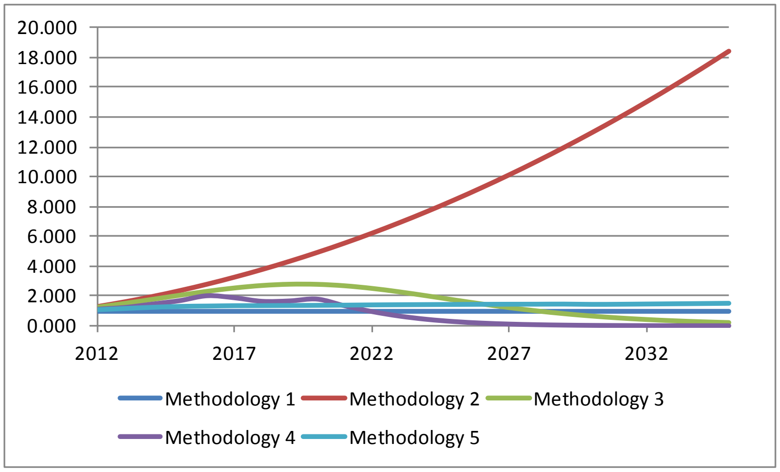


Figure 6-30. Condensate Production Annual Growth Factors for Eagle Ford Shale Play Region (2012-2035)



Using the annual growth rates presented in Table 6-9 for each of the five projection methodologies, the projected annual production of oil, gas, and condensate as well as total cumulative production for 2012 through 2035 can be estimated. From those estimates, high growth rate, moderate growth rate, and low growth rate scenarios can be identified (Table 6-10).

Table 6-10. Identification of High, Moderate, and Low Growth Scenarios Based on Projected Cumulative Production for the Eagle Ford Shale Play Region

Product	Methodology[b]	Projected Cumulative Production (2012-2035)	Growth Scenario
Oil (barrels)	2 (Curve Fit)	7,539,535,206	High
	3 (Hubbert)	2,416,144,809	
	5 (EIA)	1,556,547,786	Moderate
	1 (Constant)	1,170,737,856	
	4 (Barnett)	1,078,421,766	Low
Gas[a] (MCF)	4 (Barnett)	108,284,178,086	High
	2 (Curve Fit)	34,718,908,519	
	5 (EIA)	31,522,578,185	Moderate
	1 (Constant)	24,594,066,120	
	3 (Hubbert)	12,401,616,838	Low
Condensate (barrels)	2 (Curve Fit)	4,812,233,610	High
	3 (Hubbert)	906,610,576	
	5 (EIA)	780,176,918	Moderate
	1 (Constant)	586,800,264	
	4 (Barnett)	453,076,958	Low

[a] Includes both gas well gas and casinghead gas.
[b] *Methodology 1* – 2011 annual production assumed constant through 2035
Methodology 2 – cumulative production model developed based on fitting historical cumulative production data to a second or third order polynomial function
Methodology 3 – cumulative production model based on Hubbert's logistic growth model
Methodology 4 – Historic annual production data from the Barnett shale play region used as a surrogate for the Eagle Ford and Haynesville shale play regions.
Methodology 5 – EIA natural gas wellhead price projections through 2035 used as a surrogate for production.

6.3 Haynesville Shale Play Region

6.3.1 Methodology 2

Curve fitting under methodology 2 for the Haynesville shale play region resulted in the models for cumulative production and annual production as shown in Table 6-11.

Table 6-11. Methodology 2 Production Models for Haynesville Shale Play Region

Product	Cumulative Production	Annual Production
Oil	$Q_{Oil,H-2}(barrels) = 10{,}364(t^3) - 62{,}498{,}790(t^2) + 125{,}630{,}463{,}250(t) - 84{,}181{,}182{,}315{,}346$	$P(t)_{Oil,H-2} = \frac{dQ}{dt}_{Oil,H-2}\left(\frac{barrels}{yr}\right) = 31{,}093(t^2) - 124{,}997{,}581(t) + 125{,}630{,}463{,}250$
Gas	$Q_{G,H-2}(MCF) = 28{,}859{,}712(t^2) - 115{,}046{,}366{,}724(t) + 114{,}654{,}424{,}767{,}998$	$P(t)_{G,H-2} = \frac{dQ}{dt}_{G,H-2}\left(\frac{MCF}{yr}\right) = 57{,}719{,}425(t) - 115{,}046{,}366{,}724$
Condensate	$Q_{C,H-2}(barrels) = 146{,}730(t^2) + 584{,}635{,}536(t) - 582{,}351{,}298{,}854$	$P(t)_{C,H-2} = \frac{dQ}{dt}_{C,H-2}\left(\frac{barrels}{yr}\right) = 293{,}460(t) + 584{,}635{,}536$

Figures 6-31 and 6-32 present actual and modeled historic oil production, and projected oil production, respectively. Figures 6-33 and 6-34 present actual and modeled historic natural gas production, and projected natural gas production, respectively. Figures 6-35 and 6-36 present actual and modeled historic condensate production, and projected condensate production, respectively.

Figure 6-31. Methodology 2 Model Fit to Historic Oil Production from the Haynesville Shale Play Region (2000-2011)

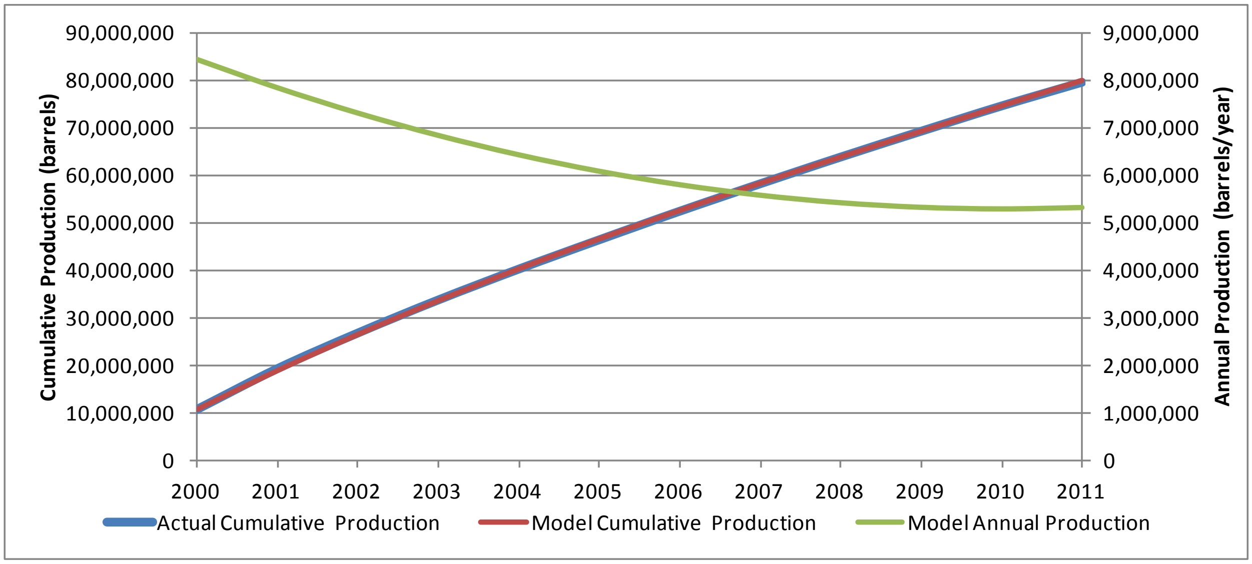


Figure 6-32. Methodology 2 Projected Cumulative and Annual Oil Production from the Haynesville Shale Play Region (2012-2035)

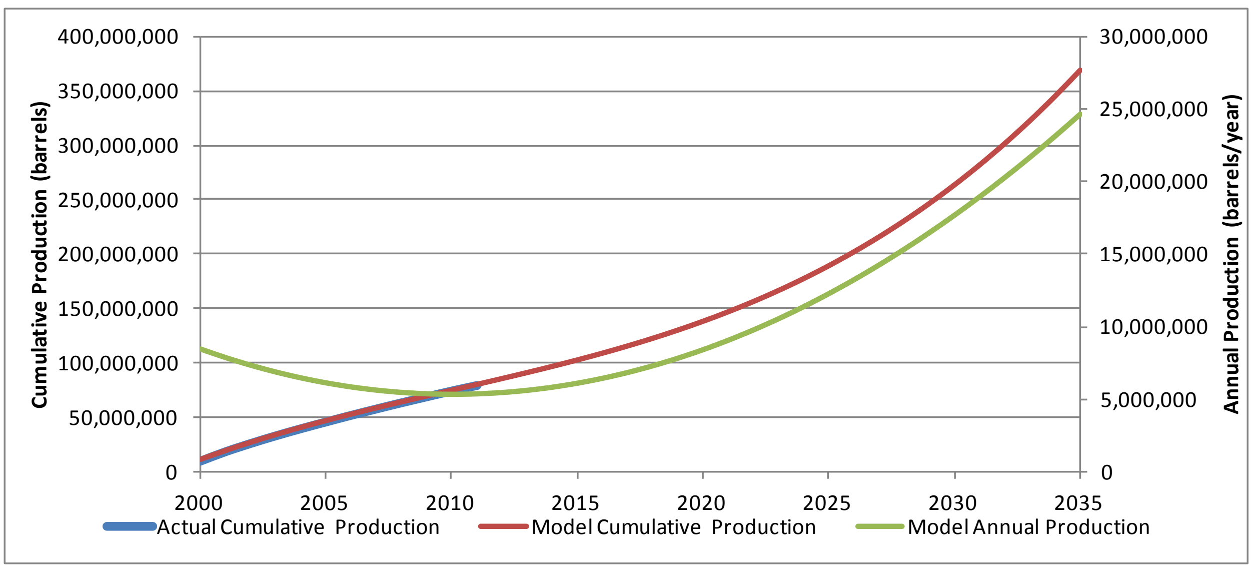


Figure 6-33. Methodology 2 Model Fit to Historic Natural Gas Production from the Haynesville Shale Play Region (2000-2011)

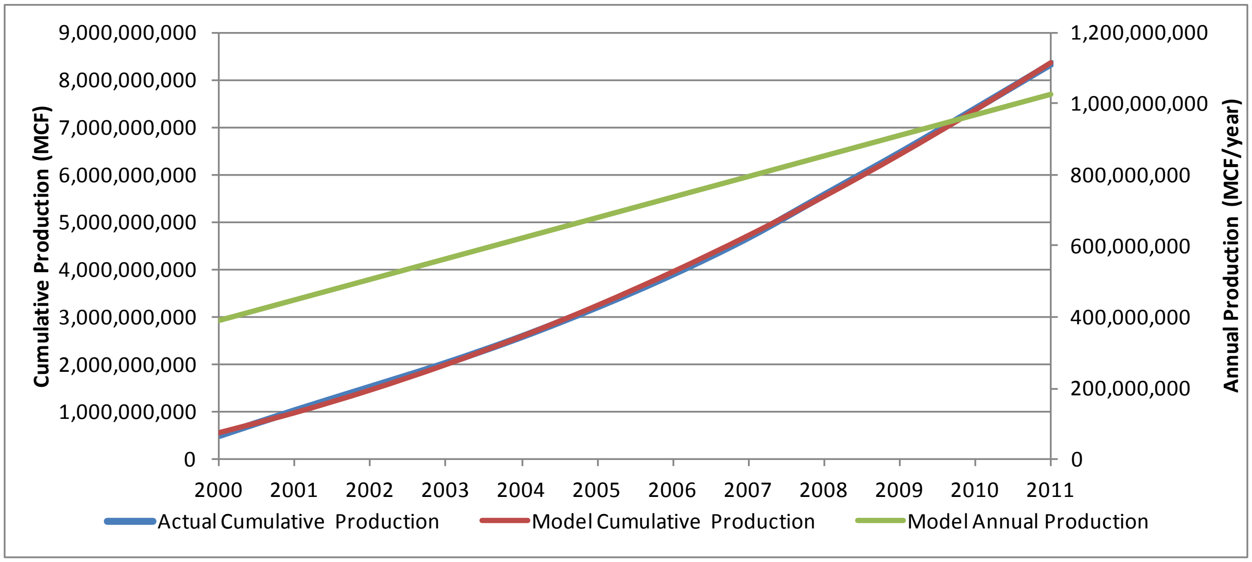


Figure 6-34. Methodology 2 Projected Cumulative and Annual Natural Gas Production from the Haynesville Shale Play Region (2012-2035)

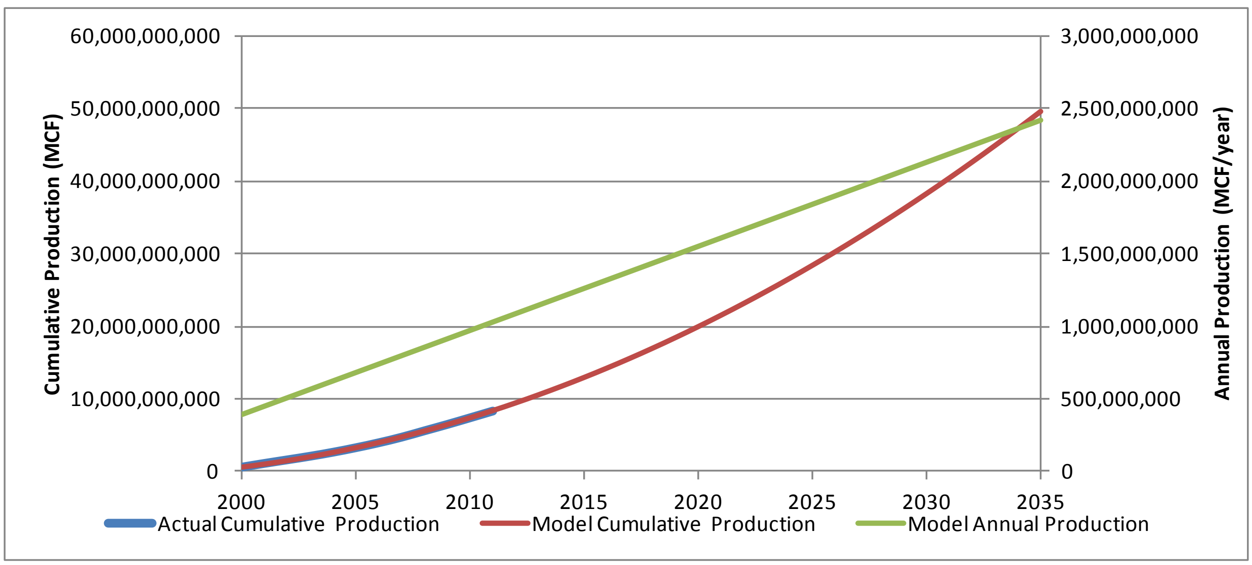


Figure 6-35. Methodology 2 Model Fit to Historic Condensate Production from the Haynesville Shale Play Region (2000-2011)

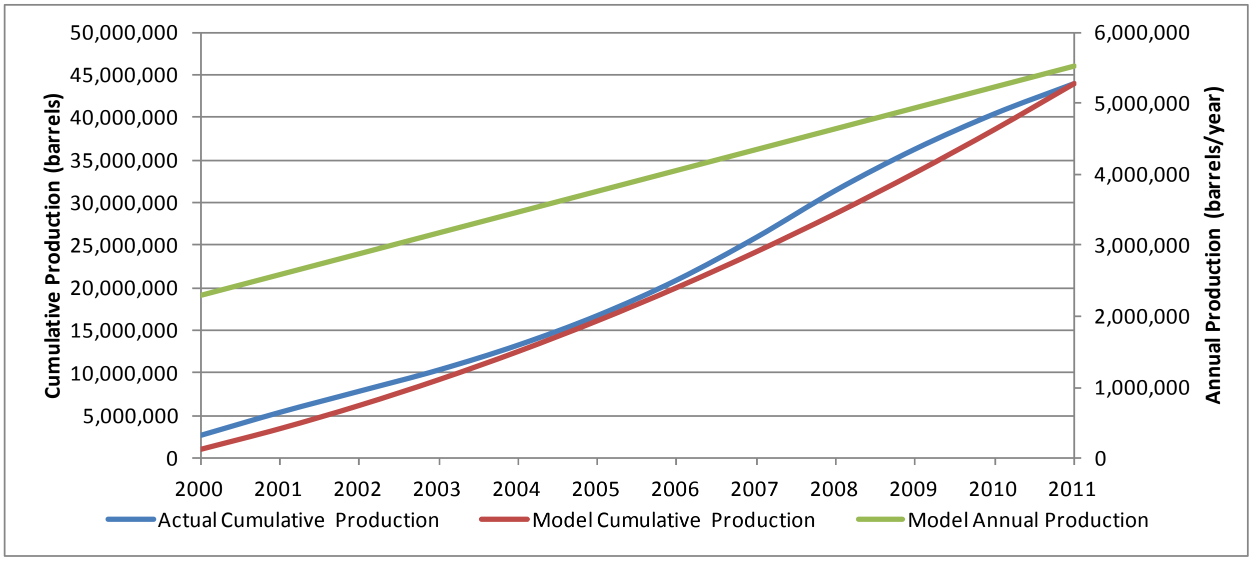
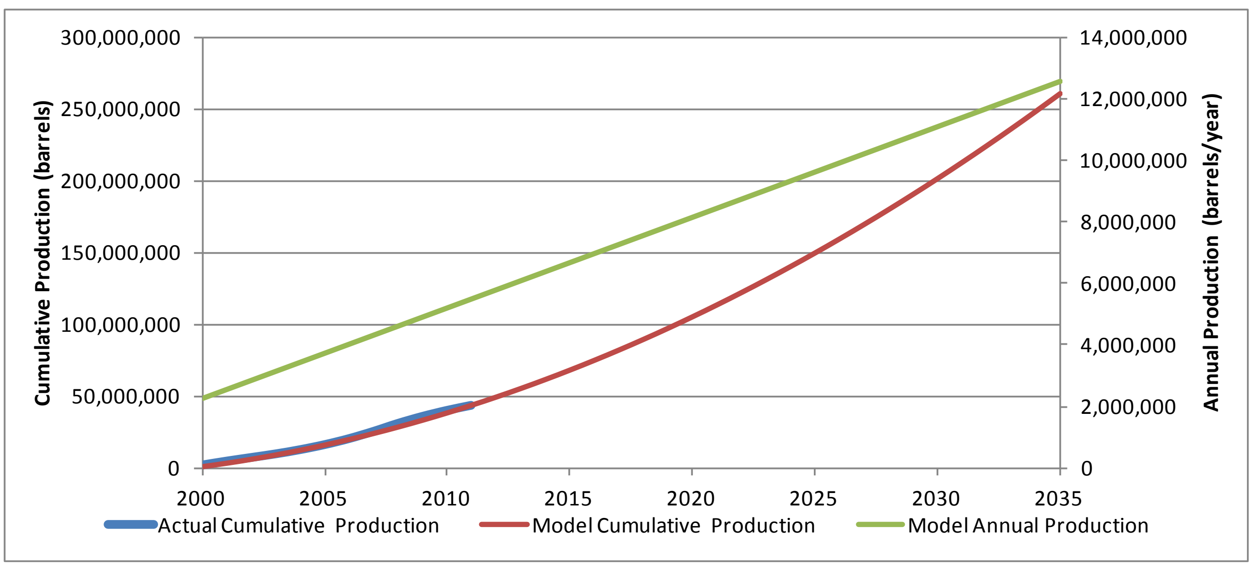


Figure 6-36. Methodology 2 Projected Cumulative and Annual Condensate Production from the Haynesville Shale Play Region (2012-2035)



6.3.2 Methodology 3

Model development under methodology 3 for the Haynesville shale play region resulted in the models for cumulative production and annual production as shown in Table 6-12.

Table 6-12. Methodology 3 Production Models for Haynesville Shale Play Region

Product	Cumulative Production	Annual Production
Oil	$Q_{Oil,H-3}(barrels) = \frac{108{,}453{,}587}{1+(9.148)e^{-0.2936(t-2011)}}$	$P(t)_{Oil,H-3}\left(\frac{barrels}{yr}\right) = \frac{dQ}{dt}_{Oil,H-3} = \frac{(0.2936)(108{,}453{,}587)(9.148)e^{-0.2936(t-2011)}}{(1+(9.148)e^{-0.2936(t-2011)})^2}$
Gas	$Q_{G,H-3}(MCF) = \frac{15{,}290{,}767{,}024}{1+(30.26)e^{-0.3229(t-2011)}}$	$P(t)_{G,H-3}\left(\frac{MCF}{yr}\right) = \frac{dQ}{dt}_{G,H-3} = \frac{(0.3229)(15{,}290{,}767{,}024)(30.26)e^{-0.3229(t-2011)}}{(1+(30.26)e^{-0.3229(t-2011)})^2}$
Condensate	$Q_{C,H-3}(barrels) = \frac{78{,}711{,}336}{1+(28.46)e^{-0.3256(t-2011)}}$	$P(t)_{C,H-3}\left(\frac{barrels}{yr}\right) = \frac{dQ}{dt}_{C,H-3} = \frac{(0.3256)(78{,}711{,}336)(28.46)e^{-0.3256(t-2011)}}{(1+(28.46)e^{-0.3256(t-2011)})^2}$

The estimated model parameters are summarized in Table 6-13.

Table 6-13. Summary of Methodology 3 Production Model Parameters

Product	Q_∞	a	No
Oil	108,453,587	0.2936	9.148
Gas	15,290,767,024	0.3229	30.26
Condensate	78,711,336	0.3256	28.46

Figures 6-37 and 6-38 present actual and modeled historic oil production, and projected oil production, respectively. Figures 6-39 and 6-40 present actual and modeled historic natural gas production, and projected natural gas production, respectively. Figures 6-41 and 6-42 present actual and modeled historic condensate production, and projected condensate production, respectively.

A summary of the annual growth factors calculated for the Haynesville Shale play region under all five methodologies is presented in Table 6-14. Annual growth factors for 2012 through 2035 calculated for all five methodologies are presented in Figures 6-43 through 6-45 for oil production, gas production, and condensate production, respectively.

Figure 6-37. Methodology 3 Model Fit to Historic Oil Production from the Haynesville Shale Play Region (2000-2011)

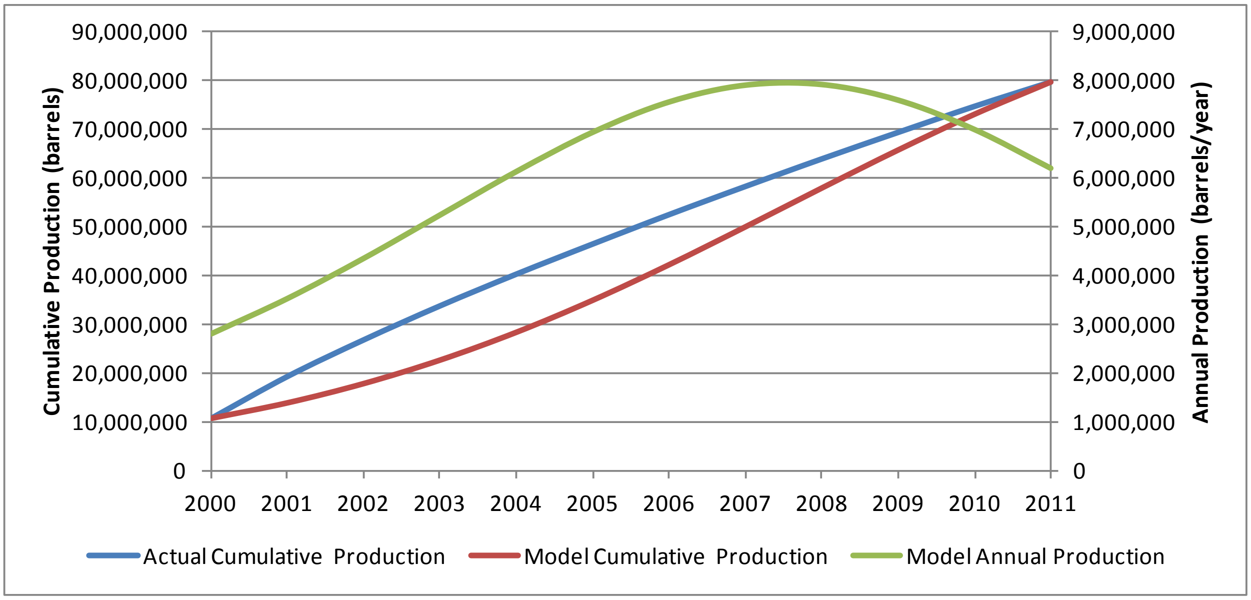


Figure 6-38. Methodology 3 Projected Cumulative and Annual Oil Production from the Haynesville Shale Play Region (2012-2035)

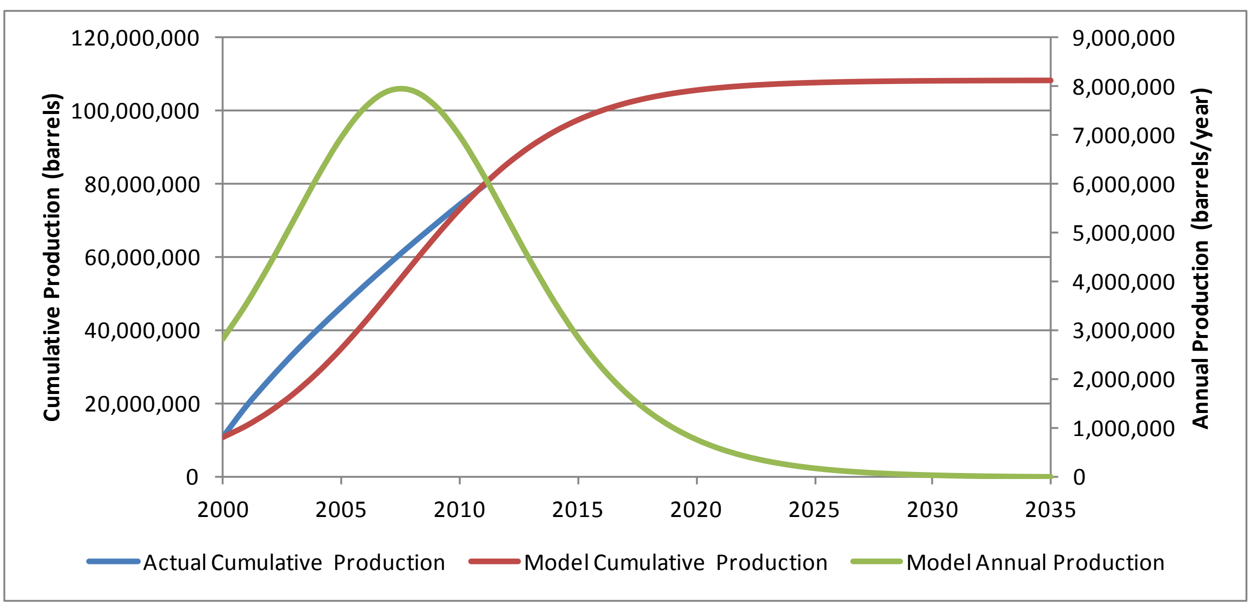


Figure 6-39. Methodology 3 Model Fit to Historic Natural Gas Production from the Haynesville Shale Play Region (2000-2011)

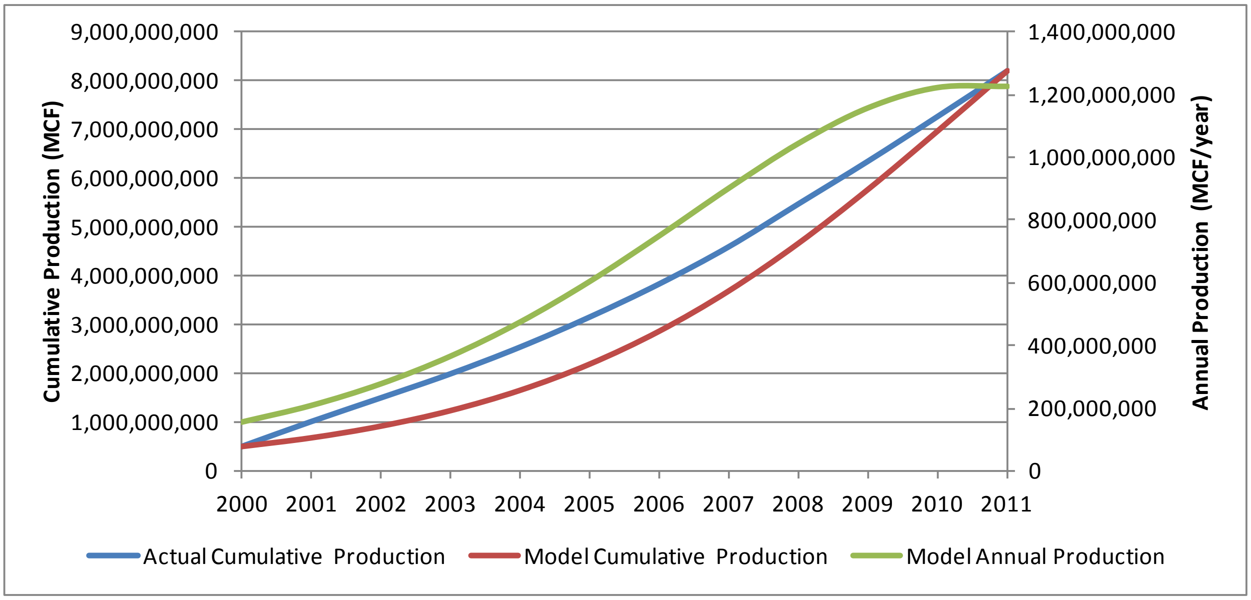


Figure 6-40. Methodology 3 Projected Cumulative and Annual Natural Gas Production from the Haynesville Shale Play Region (2012-2035)

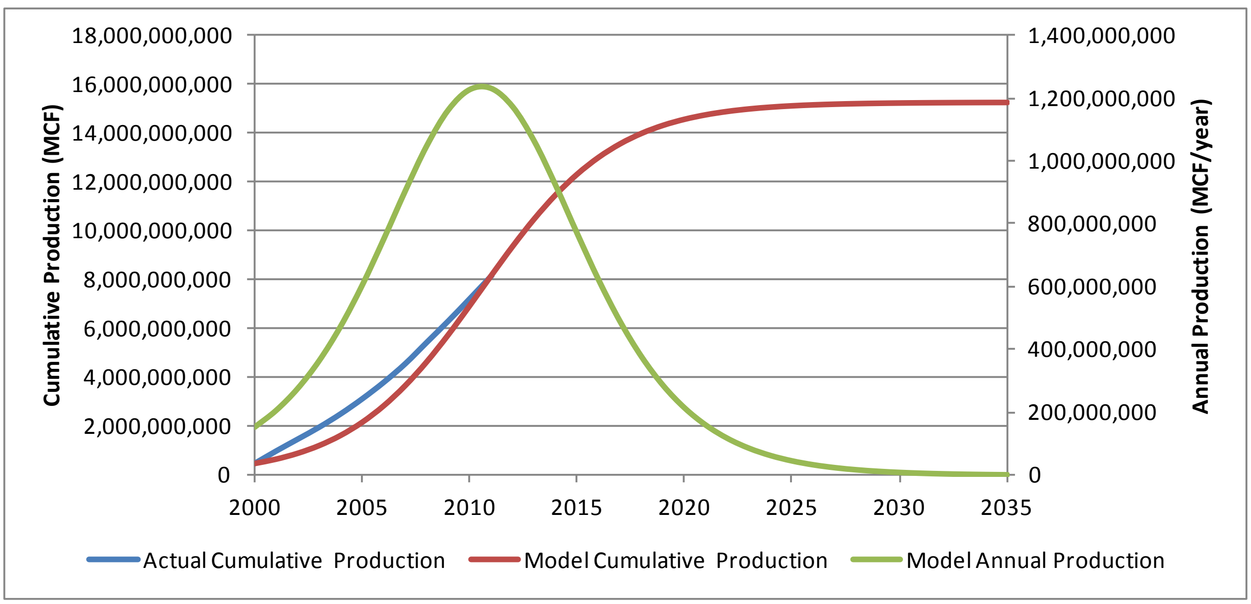


Figure 6-41. Methodology 3 Model Fit to Historic Condensate Production from the Haynesville Shale Play Region (2000-2011)

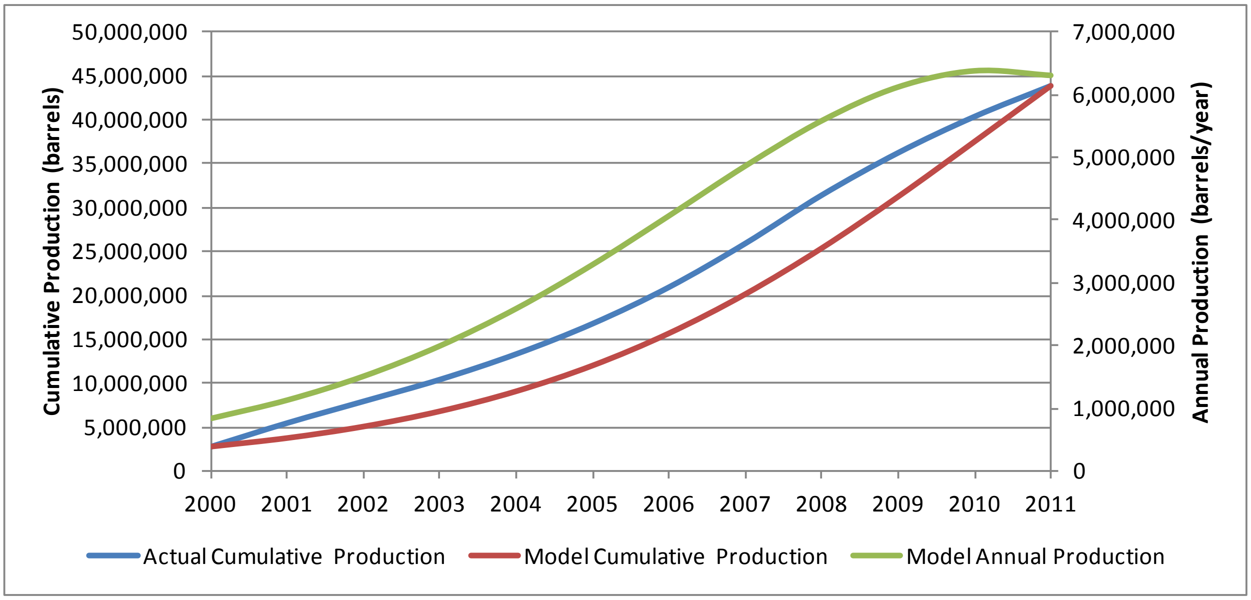


Figure 6-42. Methodology 3 Projected Cumulative and Annual Condensate Production from the Haynesville Shale Play Region (2012-2035)

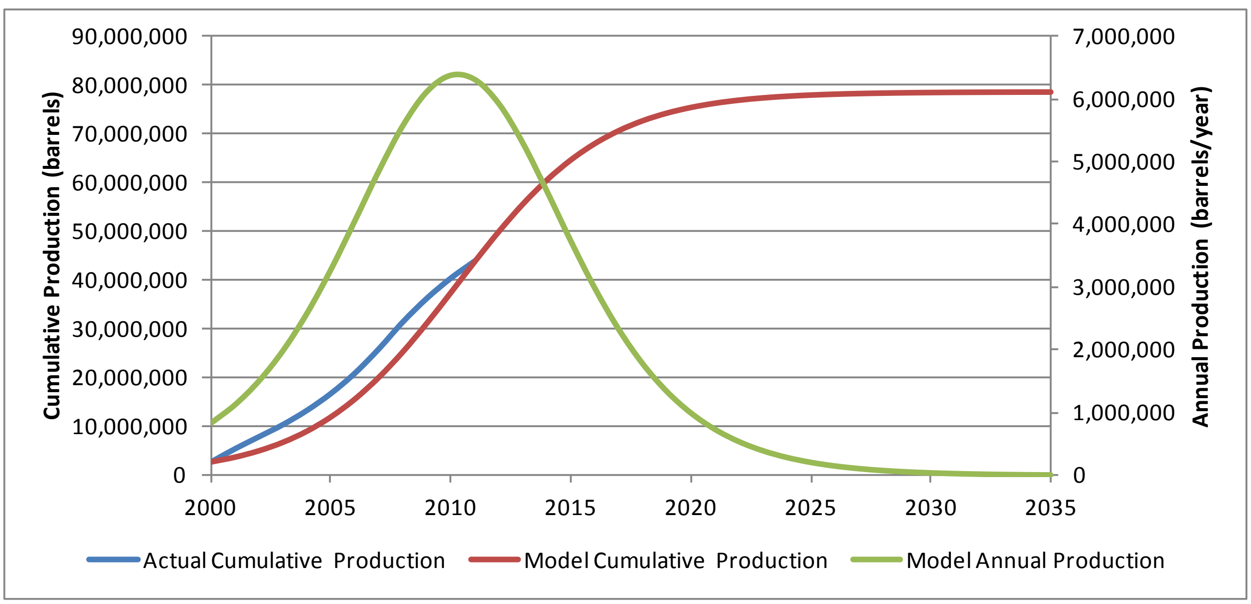


Table 6-14. Summary of Production Growth Factors for Haynesville Shale Play Region for Methodologies 1 – 5

Year	Oil					Gas					Condensate				
	Methodology					Methodology					Methodology				
	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5
2012	1.000	1.017	0.858	0.992	1.020	1.000	1.056	0.953	1.196	0.892	1.000	1.053	0.939	1.108	1.020
2013	1.000	1.046	0.715	0.947	1.105	1.000	1.112	0.864	1.513	0.979	1.000	1.106	0.839	1.224	1.105
2014	1.000	1.086	0.581	0.953	1.185	1.000	1.169	0.749	2.065	1.005	1.000	1.160	0.718	1.447	1.185
2015	1.000	1.138	0.464	0.997	1.248	1.000	1.225	0.625	3.050	1.034	1.000	1.213	0.591	1.678	1.248
2016	1.000	1.201	0.364	1.117	1.270	1.000	1.281	0.505	4.361	1.026	1.000	1.266	0.472	2.003	1.270
2017	1.000	1.277	0.282	1.084	1.293	1.000	1.337	0.397	4.762	1.034	1.000	1.319	0.368	1.864	1.293
2018	1.000	1.364	0.217	1.216	1.298	1.000	1.393	0.306	4.927	1.045	1.000	1.373	0.281	1.631	1.298
2019	1.000	1.462	0.165	1.359	1.307	1.000	1.449	0.232	5.212	1.073	1.000	1.426	0.212	1.658	1.307
2020	1.000	1.572	0.125	1.863	1.317	1.000	1.506	0.174	10.597	1.100	1.000	1.479	0.158	1.777	1.317
2021	1.000	1.694	0.095	1.794	1.331	1.000	1.562	0.129	11.516	1.157	1.000	1.532	0.117	1.335	1.331
2022	1.000	1.828	0.071	1.668	1.348	1.000	1.618	0.095	11.522	1.223	1.000	1.586	0.086	0.949	1.348
2023	1.000	1.973	0.054	1.502	1.359	1.000	1.674	0.070	10.613	1.273	1.000	1.639	0.063	0.648	1.359
2024	1.000	2.130	0.040	1.314	1.370	1.000	1.730	0.051	9.058	1.304	1.000	1.692	0.046	0.431	1.370
2025	1.000	2.298	0.030	1.120	1.379	1.000	1.787	0.037	7.241	1.344	1.000	1.745	0.033	0.282	1.379
2026	1.000	2.478	0.022	0.935	1.388	1.000	1.843	0.027	5.494	1.375	1.000	1.798	0.024	0.182	1.388
2027	1.000	2.670	0.017	0.766	1.394	1.000	1.899	0.020	4.005	1.415	1.000	1.852	0.017	0.116	1.394
2028	1.000	2.873	0.013	0.618	1.396	1.000	1.955	0.014	2.836	1.436	1.000	1.905	0.013	0.074	1.396
2029	1.000	3.088	0.009	0.493	1.403	1.000	2.011	0.010	1.967	1.462	1.000	1.958	0.009	0.047	1.403
2030	1.000	3.315	0.007	0.389	1.384	1.000	2.067	0.008	1.345	1.493	1.000	2.011	0.007	0.030	1.384
2031	1.000	3.554	0.005	0.305	1.392	1.000	2.124	0.005	0.911	1.525	1.000	2.065	0.005	0.019	1.392
2032	1.000	3.804	0.004	0.238	1.407	1.000	2.180	0.004	0.612	1.562	1.000	2.118	0.003	0.012	1.407
2033	1.000	4.065	0.003	0.184	1.423	1.000	2.236	0.003	0.410	1.591	1.000	2.171	0.002	0.008	1.423
2034	1.000	4.339	0.002	0.143	1.439	1.000	2.292	0.002	0.274	1.669	1.000	2.224	0.002	0.005	1.439
2035	1.000	4.624	0.002	0.110	1.456	1.000	2.348	0.001	0.182	1.743	1.000	2.277	0.001	0.003	1.456

Figure 6-43. Oil Production Annual Growth Factors for Haynesville Shale Play Region (2012-2035)

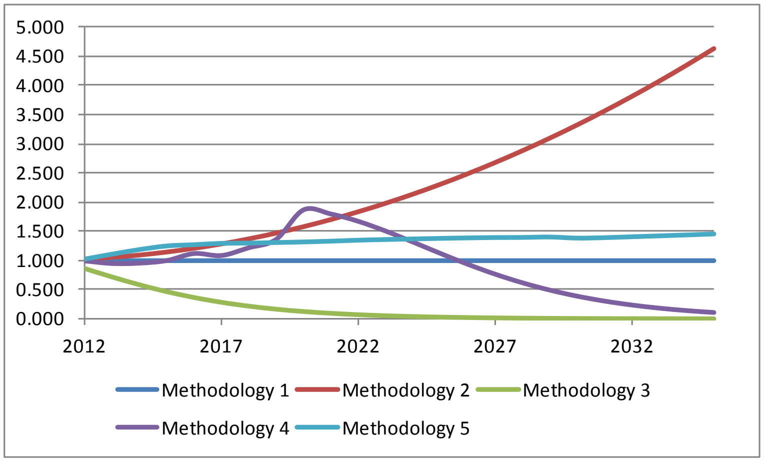


Figure 6-44. Gas Production Annual Growth Factors for Haynesville Shale Play Region (2012-2035)

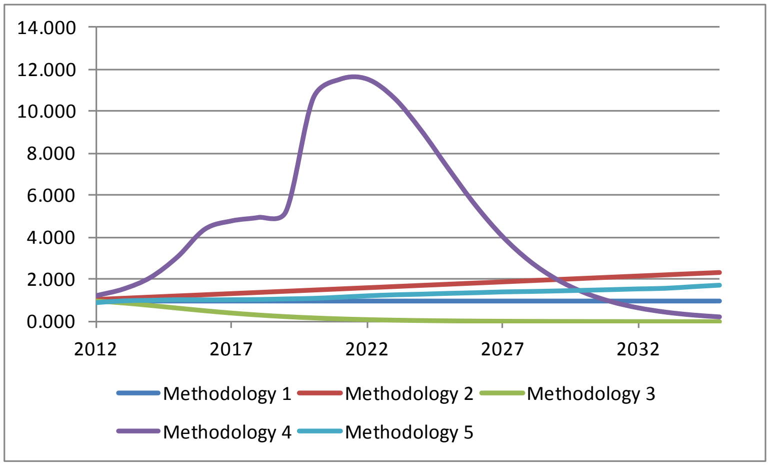
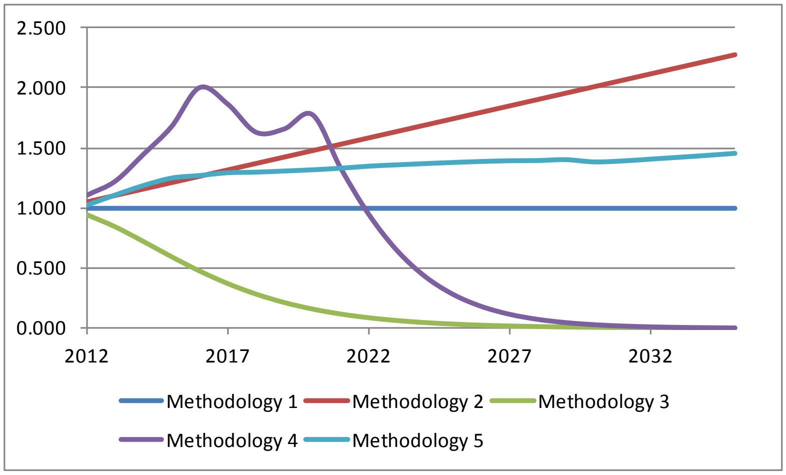


Figure 6-45. Condensate Production Annual Growth Factors for Haynesville Shale Play Region (2012-2035)



Using the annual growth rates presented in Table 6-14 for each of the five projection methodologies, the projected annual production of oil, gas, and condensate as well as total cumulative production for 2012 through 2035 can be estimated. From those estimates, high growth rate, moderate growth rate, and low growth rate scenarios can be identified (Table 6-15).

Table 6-15. Identification of High, Moderate, and Low Growth Scenarios Based on Projected Cumulative Production for the Haynesville Shale Play Region

Product	Methodology[b]	Projected Cumulative Production (2012-2035)	Growth Scenario
Oil (barrels)	2 (Curve Fit)	279,391,766	High
	5 (EIA)	159,496,904	
	1 (Constant)	119,963,592	Moderate
	4 (Barnett)	110,504,113	
	3 (Hubbert)	20,716,805	Low
Gas[a] (MCF)	4 (Barnett)	100,013,677,020	High
	2 (Curve Fit)	38,667,754,634	
	5 (EIA)	29,114,954,827	Moderate
	1 (Constant)	22,715,626,872	
	3 (Hubbert)	4,997,314,941	Low
Condensate (barrels)	2 (Curve Fit)	140,872,870	High
	5 (EIA)	112,467,350	
	1 (Constant)	84,590,904	Moderate
	4 (Barnett)	65,313,859	
	3 (Hubbert)	17,638,460	Low

[a] Includes both gas well gas and casinghead gas.
[b] *Methodology 1* – 2011 annual production assumed constant through 2035
Methodology 2 – cumulative production model developed based on fitting historical cumulative production data to a second or third order polynomial function
Methodology 3 – cumulative production model based on Hubbert's logistic growth model
Methodology 4 – Historic annual production data from the Barnett shale play region used as a surrogate for the Eagle Ford and Haynesville shale play regions.
Methodology 5 – EIA natural gas wellhead price projections through 2035 used as a surrogate for production.

7.0 Area Source Growth Factors and Associated Data for TexAER Upload

As described in previous sections, five different methodologies were employed to develop growth factors for oil production, natural gas production, and condensate production for each of the three shale play regions in Texas (Barnett, Eagle Ford, and Haynesville). The growth factor development and calculation spreadsheet is included as Appendix A. The final growth factors for each shale play for each methodology are shown in Tables 7-1 through 7-3 below.

The growth factors in Tables 7-1 through 7-3 were then applied to oil and gas-related Source Classification Codes (SCCs) based on using the projected growth in oil, gas, or condensate production as a scaling variable. For example, projected growth in oil production was used as the scaling variable for SCC 2310011020 "On-Shore Oil Production /Storage Tanks: Crude Oil". Table 7-4 below identifies the scaling variable (oil, gas, or condensate production) used to assign the growth factors to each SCC.

Six of the area source oil and gas SCCs are generic in the sense that they are not specific to a product (oil, gas, or condensate). For example, SCC 2310000000 is for "Oil & Gas Expl & Prod /All Processes /Total: All Processes". The scaling variable for those generic SCCs is identified as "Oil and Gas Production Forecasts" in Table 7-4. For those six SCC's, the growth factor is based on a weighted average of the oil and gas well counts in each county as compared to the total well counts. Table 7-5 presents the oil and gas well counts for each county and shows the percentage of each type of well in each county. These percentages were then multiplied by the oil and gas production growth factors to derive a weighted growth factor for each of the six SCCs:

$$GF_{o+g} = [GF_o \times (\%\ \text{Oil Wells}/100)] + [GF_g \times (\%\ \text{Gas Wells}/100)]$$

Where:

GF_{o+g} = oil and gas growth factor
GF_o = oil growth factor
GF_g = gas growth factor

The growth factor development and calculation spreadsheet is included as Attachment A. Individual growth factors at the county level for each of the five methodologies are provided for each SCC for each forecast year in Attachment B. Growth factor sets compatible with TexAER are included as Attachment C.

Table 7-1. Summary of Production Growth Factors for Barnett Shale Play Region for Methodologies 1 – 5

Year	Oil					Gas					Condensate				
	Methodology					Methodology					Methodology				
	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5
2012	1.000	1.000	0.998	NA	1.020	1.000	1.099	1.173	NA	0.892	1.000	1.063	0.808	NA	1.020
2013	1.000	1.000	0.961	NA	1.105	1.000	1.198	1.275	NA	0.979	1.000	1.125	0.607	NA	1.105
2014	1.000	1.000	0.894	NA	1.185	1.000	1.297	1.275	NA	1.005	1.000	1.188	0.431	NA	1.185
2015	1.000	1.000	0.805	NA	1.248	1.000	1.396	1.175	NA	1.034	1.000	1.250	0.295	NA	1.248
2016	1.000	1.000	0.704	NA	1.270	1.000	1.495	1.002	NA	1.026	1.000	1.313	0.196	NA	1.270
2017	1.000	1.000	0.600	NA	1.293	1.000	1.594	0.801	NA	1.034	1.000	1.375	0.128	NA	1.293
2018	1.000	1.000	0.501	NA	1.298	1.000	1.693	0.608	NA	1.045	1.000	1.438	0.083	NA	1.298
2019	1.000	1.000	0.410	NA	1.307	1.000	1.792	0.443	NA	1.073	1.000	1.500	0.053	NA	1.307
2020	1.000	1.000	0.331	NA	1.317	1.000	1.891	0.314	NA	1.100	1.000	1.563	0.034	NA	1.317
2021	1.000	1.000	0.264	NA	1.331	1.000	1.990	0.218	NA	1.157	1.000	1.625	0.021	NA	1.331
2022	1.000	1.000	0.209	NA	1.348	1.000	2.089	0.149	NA	1.223	1.000	1.688	0.014	NA	1.348
2023	1.000	1.000	0.164	NA	1.359	1.000	2.188	0.101	NA	1.273	1.000	1.751	0.009	NA	1.359
2024	1.000	1.000	0.127	NA	1.370	1.000	2.287	0.068	NA	1.304	1.000	1.813	0.005	NA	1.370
2025	1.000	1.000	0.099	NA	1.379	1.000	2.386	0.045	NA	1.344	1.000	1.876	0.003	NA	1.379
2026	1.000	1.000	0.076	NA	1.388	1.000	2.484	0.030	NA	1.375	1.000	1.938	0.002	NA	1.388
2027	1.000	1.000	0.059	NA	1.394	1.000	2.583	0.020	NA	1.415	1.000	2.001	0.001	NA	1.394
2028	1.000	1.000	0.045	NA	1.396	1.000	2.682	0.013	NA	1.436	1.000	2.063	0.001	NA	1.396
2029	1.000	1.000	0.035	NA	1.403	1.000	2.781	0.009	NA	1.462	1.000	2.126	0.001	NA	1.403
2030	1.000	1.000	0.027	NA	1.384	1.000	2.880	0.006	NA	1.493	1.000	2.188	0.000	NA	1.384
2031	1.000	1.000	0.020	NA	1.392	1.000	2.979	0.004	NA	1.525	1.000	2.251	0.000	NA	1.392
2032	1.000	1.000	0.016	NA	1.407	1.000	3.078	0.003	NA	1.562	1.000	2.314	0.000	NA	1.407
2033	1.000	1.000	0.012	NA	1.423	1.000	3.177	0.002	NA	1.591	1.000	2.376	0.000	NA	1.423
2034	1.000	1.000	0.009	NA	1.439	1.000	3.276	0.001	NA	1.669	1.000	2.439	0.000	NA	1.439
2035	1.000	1.000	0.007	NA	1.456	1.000	3.375	0.001	NA	1.743	1.000	2.501	0.000	NA	1.456

NA – not applicable

Table 7-2. Summary of Production Growth Factors for Eagle Ford Shale Play Region for Methodologies 1 – 5

Year	Oil					Gas					Condensate				
	Methodology					Methodology					Methodology				
	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5
2012	1.000	1.201	1.199	0.992	1.020	1.000	1.033	1.094	1.196	0.892	1.000	1.278	1.223	1.108	1.020
2013	1.000	1.433	1.425	0.947	1.105	1.000	1.066	1.160	1.513	0.979	1.000	1.595	1.473	1.224	1.105
2014	1.000	1.695	1.674	0.953	1.185	1.000	1.099	1.189	2.065	1.005	1.000	1.951	1.743	1.447	1.185
2015	1.000	1.987	1.941	0.997	1.248	1.000	1.132	1.177	3.050	1.034	1.000	2.346	2.019	1.678	1.248
2016	1.000	2.311	2.217	1.117	1.270	1.000	1.165	1.127	4.361	1.026	1.000	2.780	2.281	2.003	1.270
2017	1.000	2.664	2.489	1.084	1.293	1.000	1.198	1.044	4.762	1.034	1.000	3.252	2.507	1.864	1.293
2018	1.000	3.049	2.740	1.216	1.298	1.000	1.231	0.939	4.927	1.045	1.000	3.763	2.672	1.631	1.298
2019	1.000	3.463	2.953	1.359	1.307	1.000	1.263	0.821	5.212	1.073	1.000	4.313	2.756	1.658	1.307
2020	1.000	3.909	3.110	1.863	1.317	1.000	1.296	0.702	10.597	1.100	1.000	4.903	2.749	1.777	1.317
2021	1.000	4.385	3.197	1.794	1.331	1.000	1.329	0.587	11.516	1.157	1.000	5.530	2.651	1.335	1.331
2022	1.000	4.891	3.205	1.668	1.348	1.000	1.362	0.483	11.522	1.223	1.000	6.197	2.476	0.949	1.348
2023	1.000	5.428	3.135	1.502	1.359	1.000	1.395	0.392	10.613	1.273	1.000	6.903	2.243	0.648	1.359
2024	1.000	5.996	2.992	1.314	1.370	1.000	1.428	0.315	9.058	1.304	1.000	7.647	1.977	0.431	1.370
2025	1.000	6.594	2.789	1.120	1.379	1.000	1.461	0.250	7.241	1.344	1.000	8.430	1.701	0.282	1.379
2026	1.000	7.223	2.545	0.935	1.388	1.000	1.494	0.197	5.494	1.375	1.000	9.252	1.434	0.182	1.388
2027	1.000	7.882	2.276	0.766	1.394	1.000	1.527	0.155	4.005	1.415	1.000	10.113	1.187	0.116	1.394
2028	1.000	8.571	2.000	0.618	1.396	1.000	1.560	0.121	2.836	1.436	1.000	11.013	0.969	0.074	1.396
2029	1.000	9.292	1.730	0.493	1.403	1.000	1.593	0.094	1.967	1.462	1.000	11.952	0.781	0.047	1.403
2030	1.000	10.043	1.476	0.389	1.384	1.000	1.626	0.073	1.345	1.493	1.000	12.929	0.624	0.030	1.384
2031	1.000	10.824	1.246	0.305	1.392	1.000	1.659	0.057	0.911	1.525	1.000	13.946	0.494	0.019	1.392
2032	1.000	11.636	1.041	0.238	1.407	1.000	1.692	0.044	0.612	1.562	1.000	15.001	0.390	0.012	1.407
2033	1.000	12.478	0.862	0.184	1.423	1.000	1.725	0.034	0.410	1.591	1.000	16.095	0.305	0.008	1.423
2034	1.000	13.351	0.710	0.143	1.439	1.000	1.757	0.026	0.274	1.669	1.000	17.228	0.239	0.005	1.439
2035	1.000	14.255	0.581	0.110	1.456	1.000	1.790	0.020	0.182	1.743	1.000	18.400	0.186	0.003	1.456

Table 7-3. Summary of Production Growth Factors for Haynesville Shale Play Region for Methodologies 1 – 5

Year	Oil					Gas					Condensate				
	Methodology					Methodology					Methodology				
	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5
2012	1.000	1.017	0.858	0.992	1.020	1.000	1.056	0.953	1.196	0.892	1.000	1.053	0.939	1.108	1.020
2013	1.000	1.046	0.715	0.947	1.105	1.000	1.112	0.864	1.513	0.979	1.000	1.106	0.839	1.224	1.105
2014	1.000	1.086	0.581	0.953	1.185	1.000	1.169	0.749	2.065	1.005	1.000	1.160	0.718	1.447	1.185
2015	1.000	1.138	0.464	0.997	1.248	1.000	1.225	0.625	3.050	1.034	1.000	1.213	0.591	1.678	1.248
2016	1.000	1.201	0.364	1.117	1.270	1.000	1.281	0.505	4.361	1.026	1.000	1.266	0.472	2.003	1.270
2017	1.000	1.277	0.282	1.084	1.293	1.000	1.337	0.397	4.762	1.034	1.000	1.319	0.368	1.864	1.293
2018	1.000	1.364	0.217	1.216	1.298	1.000	1.393	0.306	4.927	1.045	1.000	1.373	0.281	1.631	1.298
2019	1.000	1.462	0.165	1.359	1.307	1.000	1.449	0.232	5.212	1.073	1.000	1.426	0.212	1.658	1.307
2020	1.000	1.572	0.125	1.863	1.317	1.000	1.506	0.174	10.597	1.100	1.000	1.479	0.158	1.777	1.317
2021	1.000	1.694	0.095	1.794	1.331	1.000	1.562	0.129	11.516	1.157	1.000	1.532	0.117	1.335	1.331
2022	1.000	1.828	0.071	1.668	1.348	1.000	1.618	0.095	11.522	1.223	1.000	1.586	0.086	0.949	1.348
2023	1.000	1.973	0.054	1.502	1.359	1.000	1.674	0.070	10.613	1.273	1.000	1.639	0.063	0.648	1.359
2024	1.000	2.130	0.040	1.314	1.370	1.000	1.730	0.051	9.058	1.304	1.000	1.692	0.046	0.431	1.370
2025	1.000	2.298	0.030	1.120	1.379	1.000	1.787	0.037	7.241	1.344	1.000	1.745	0.033	0.282	1.379
2026	1.000	2.478	0.022	0.935	1.388	1.000	1.843	0.027	5.494	1.375	1.000	1.798	0.024	0.182	1.388
2027	1.000	2.670	0.017	0.766	1.394	1.000	1.899	0.020	4.005	1.415	1.000	1.852	0.017	0.116	1.394
2028	1.000	2.873	0.013	0.618	1.396	1.000	1.955	0.014	2.836	1.436	1.000	1.905	0.013	0.074	1.396
2029	1.000	3.088	0.009	0.493	1.403	1.000	2.011	0.010	1.967	1.462	1.000	1.958	0.009	0.047	1.403
2030	1.000	3.315	0.007	0.389	1.384	1.000	2.067	0.008	1.345	1.493	1.000	2.011	0.007	0.030	1.384
2031	1.000	3.554	0.005	0.305	1.392	1.000	2.124	0.005	0.911	1.525	1.000	2.065	0.005	0.019	1.392
2032	1.000	3.804	0.004	0.238	1.407	1.000	2.180	0.004	0.612	1.562	1.000	2.118	0.003	0.012	1.407
2033	1.000	4.065	0.003	0.184	1.423	1.000	2.236	0.003	0.410	1.591	1.000	2.171	0.002	0.008	1.423
2034	1.000	4.339	0.002	0.143	1.439	1.000	2.292	0.002	0.274	1.669	1.000	2.224	0.002	0.005	1.439
2035	1.000	4.624	0.002	0.110	1.456	1.000	2.348	0.001	0.182	1.743	1.000	2.277	0.001	0.003	1.456

Table 7-4. Growth Factor Scaling Variables by SCC

SCC	SCC Description	Scaling Variable
2310020800	Oil & Gas Expl & Prod /Natural Gas /Gas Well Truck Loading	Condensate Production
2310021011	On-Shore Gas Production / Condensate Tank Flaring	Condensate Production
2310021030	On-Shore Gas Production /Tank Truck/Railcar Loading: Condensate	Condensate Production
2310030000	Oil & Gas Expl & Prod /Natural Gas Liquids /Total: All Processes	Condensate Production
2310030210	Oil & Gas Expl & Prod /Natural Gas Liquids /Gas Well Tanks - Flashing & Standing/Working/Breathing, Uncontrolled	Condensate Production
2310030220	Oil & Gas Expl & Prod /Natural Gas Liquids /Gas Well Tanks - Flashing & Standing/Working/Breathing, Controlled	Condensate Production
2310031000	Oil & Gas Expl & Prod /Natural Gas Liquids : On-shore /Total: All Processes	Condensate Production
2310020000	Oil & Gas Expl & Prod /Natural Gas /Total: All Processes	Gas Production
2310020600	Oil & Gas Expl & Prod /Natural Gas /Compressor Engines	Gas Production
2310020700	Oil & Gas Expl & Prod /Natural Gas /Gas Well Fugitives	Gas Production
2310021000	On-Shore Gas Production /Total: All Processes	Gas Production
2310021010	On-Shore Gas Production /Storage Tanks: Condensate	Gas Production
2310021100	On-Shore Gas Production /Gas Well Heaters	Gas Production
2310021101	On-Shore Gas Production /Natural Gas Fired 2Cycle Lean Burn Compressor Engines < 50 HP	Gas Production
2310021102	On-Shore Gas Production /Natural Gas Fired 2Cycle Lean Burn Compressor Engines 50 To 499 HP	Gas Production
2310021103	On-Shore Gas Production /Natural Gas Fired 2Cycle Lean Burn Compressor Engines 500+ HP	Gas Production
2310021109	On-Shore Gas Production /Total: All Natural Gas Fired 2Cycle Lean Burn Compressor Engines	Gas Production
2310021201	On-Shore Gas Production /Natural Gas Fired 4Cycle Lean Burn Compressor Engines <50 HP	Gas Production
2310021202	On-Shore Gas Production /Natural Gas Fired 4Cycle Lean Burn Compressor Engines 50 To 499 HP	Gas Production
2310021203	On-Shore Gas Production /Natural Gas Fired 4Cycle Lean Burn Compressor Engines 500+ HP	Gas Production
2310021209	On-Shore Gas Production /Total: All Natural Gas Fired 4Cycle Lean Burn Compressor Engines	Gas Production
2310021300	On-Shore Gas Production /Gas Well Pneumatic Devices	Gas Production
2310021301	On-Shore Gas Production /Natural Gas Fired 4Cycle Rich Burn Compressor Engines <50 HP	Gas Production

Table 7-4. Growth Factor Scaling Variables by SCC

SCC	SCC Description	Scaling Variable
2310021302	On-Shore Gas Production /Natural Gas Fired 4Cycle Rich Burn Compressor Engines 50 To 499 HP	Gas Production
2310021303	On-Shore Gas Production /Natural Gas Fired 4Cycle Rich Burn Compressor Engines 500+ HP	Gas Production
2310021309	On-Shore Gas Production /Total: All Natural Gas Fired 4Cycle Rich Burn Compressor Engines	Gas Production
2310021310	On-Shore Gas Production / Gas Well Pneumatic Pumps	Gas Production
2310021400	On-Shore Gas Production /Gas Well Dehydrators	Gas Production
2310021401	On-Shore Gas Production /Nat Gas Fired 4Cycle Rich Burn Compressor Engines <50 HP w/NSCR	Gas Production
2310021402	On-Shore Gas Production /Nat Gas Fired 4Cycle Rich Burn Compressor Engines 50 To 499 HP w/NSCR	Gas Production
2310021403	On-Shore Gas Production /Nat Gas Fired 4Cycle Rich Burn Compressor Engines 500+ HP w/NSCR	Gas Production
2310021409	On-Shore Gas Production /Total: All Nat Gas Fired 4Cycle Rich Burn Compressor Engines w/NSCR	Gas Production
2310021410	On-Shore Gas Production /Amine Unit	Gas Production
2310021411	On-Shore Gas Production / Gas Well Dehydrators - Flaring	Gas Production
2310021450	On-Shore Gas Production /Wellhead	Gas Production
2310021501	On-Shore Gas Production /Fugitives: Connectors	Gas Production
2310021502	On-Shore Gas Production /Fugitives: Flanges	Gas Production
2310021503	On-Shore Gas Production /Fugitives: Open Ended Lines	Gas Production
2310021504	On-Shore Gas Production /Fugitives: Pumps	Gas Production
2310021505	On-Shore Gas Production /Fugitives: Valves	Gas Production
2310021506	On-Shore Gas Production /Fugitives: Other	Gas Production
2310021509	On-Shore Gas Production /Fugitives: All Processes	Gas Production
2310021600	On-Shore Gas Production /Gas Well Venting	Gas Production
2310021602	On-Shore Gas Production / Gas Well Venting - Recompletions	Gas Production
2310021603	On-Shore Gas Production / Gas Well Venting - Blowdowns	Gas Production
2310021604	On-Shore Gas Production / Gas Well Venting - Compressor Startups	Gas Production
2310021605	On-Shore Gas Production / Gas Well Venting - Compressor Shutdowns	Gas Production
2310021700	On-Shore Gas Production / Miscellaneous Engines	Gas Production
2310030230	Natural Gas Liquids / Gas Well Tanks - Flaring	Gas Production

Table 7-4. Growth Factor Scaling Variables by SCC

SCC	SCC Description	Scaling Variable
2310030300	Natural Gas Liquids / Gas Well Water Tank Losses	Gas Production
2310030400	Natural Gas Liquids / Truck Loading	Gas Production
2310030401	Natural Gas Liquids / Gas Plant Truck Loading	Gas Production
2310121000	On-Shore Gas Exploration /All Processes	Gas Production
2310121401	On-Shore Gas Exploration /Gas Well Pneumatic Pumps	Gas Production
2310021500	On-Shore Gas Production /Gas Well Completion - Flaring	Gas Production
2310021601	On-Shore Gas Production / Gas Well Venting - Initial Completions	Gas Production
2310121100	On-Shore Gas Exploration /Mud Degassing	Gas Production
2310121700	On-Shore Gas Exploration /Gas Well Completion: All Processes	Gas Production
2310121701	On-Shore Gas Exploration /Gas Well Completion: Flaring	Gas Production
2310121702	On-Shore Gas Exploration /Gas Well Completion: Venting	Gas Production
2310000220	Oil & Gas Expl & Prod /All Processes /Drill Rigs	Oil and Gas Production Forecasts
2310000230	Oil & Gas Expl & Prod /All Processes /Workover Rigs	Oil and Gas Production Forecasts
2310000000	Oil & Gas Expl & Prod /All Processes /Total: All Processes	Oil and Gas Production Forecasts
2310000440	Oil & Gas Expl & Prod /All Processes /Saltwater Disposal Engines	Oil and Gas Production Forecasts
2310000550	Oil & Gas Expl & Prod /All Processes /Produced Water	Oil and Gas Production Forecasts
2310001000	Oil & Gas Expl & Prod /All Processes : On-shore /Total: All Processes	Oil and Gas Production Forecasts
2310000330	Oil & Gas Expl & Prod /All Processes /Artificial Lift	Oil Production
2310010000	Oil & Gas Expl & Prod /Crude Petroleum /Total: All Processes	Oil Production
2310010100	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Heaters	Oil Production
2310010200	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Tanks - Flashing & Standing/Working/Breathing	Oil Production
2310010300	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Pneumatic Devices	Oil Production
2310010700	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Fugitives	Oil Production
2310010800	Oil & Gas Expl & Prod /Crude Petroleum /Oil Well Truck Loading	Oil Production
2310011000	On-Shore Oil Production /Total: All Processes	Oil Production
2310011020	On-Shore Oil Production /Storage Tanks: Crude Oil	Oil Production

Table 7-4. Growth Factor Scaling Variables by SCC

SCC	SCC Description	Scaling Variable
2310011100	On-Shore Oil Production /Heater Treater	Oil Production
2310011201	On-Shore Oil Production /Tank Truck/Railcar Loading: Crude Oil	Oil Production
2310011450	On-Shore Oil Production /Wellhead	Oil Production
2310011500	On-Shore Oil Production /Fugitives: All Processes	Oil Production
2310011501	On-Shore Oil Production /Fugitives: Connectors	Oil Production
2310011502	On-Shore Oil Production /Fugitives: Flanges	Oil Production
2310011503	On-Shore Oil Production /Fugitives: Open Ended Lines	Oil Production
2310011504	On-Shore Oil Production /Fugitives: Pumps	Oil Production
2310011505	On-Shore Oil Production /Fugitives: Valves	Oil Production
2310011506	On-Shore Oil Production /Fugitives: Other	Oil Production
2310011600	On-Shore Oil Production /Artificial Lift Engines	Oil Production
2310111000	On-Shore Oil Exploration /All Processes	Oil Production
2310111401	On-Shore Oil Exploration /Oil Well Pneumatic Pumps	Oil Production
2310111100	On-Shore Oil Exploration /Mud Degassing	Oil Production
2310111700	On-Shore Oil Exploration /Oil Well Completion: All Processes	Oil Production
2310111701	On-Shore Oil Exploration /Oil Well Completion: Flaring	Oil Production
2310111702	On-Shore Oil Exploration /Oil Well Completion: Venting	Oil Production

Table 7-5. Growth Factor Weighting Percentages

County	Shale Play	Oil Well Count	Gas Well Count	Total Well Count	% Oil	% Gas
ATASCOSA	Eagle Ford	1,131	82	1,213	93%	7%
BEE	Eagle Ford	197	427	624	32%	68%
BRAZOS	Eagle Ford	480	104	584	82%	18%
BURLESON	Eagle Ford	1,000	115	1,115	90%	10%
DE WITT	Eagle Ford	45	301	346	13%	87%
DIMMIT	Eagle Ford	647	237	884	73%	27%
FAYETTE	Eagle Ford	553	236	789	70%	30%
FRIO	Eagle Ford	581	87	668	87%	13%
GONZALES	Eagle Ford	254	12	266	95%	5%
GRIMES	Eagle Ford	31	210	241	13%	87%
KARNES	Eagle Ford	230	161	391	59%	41%
LA SALLE	Eagle Ford	222	589	811	27%	73%
LAVACA	Eagle Ford	41	507	548	7%	93%
LEE	Eagle Ford	792	76	868	91%	9%
LIVE OAK	Eagle Ford	193	356	549	35%	65%
LEON	Eagle Ford	233	538	771	30%	70%
MAVERICK	Eagle Ford	698	127	825	85%	15%
MCMULLEN	Eagle Ford	684	666	1,350	51%	49%
MILAM	Eagle Ford	1,014	10	1,024	99%	1%
ROBERTSON	Eagle Ford	171	941	1,112	15%	85%
WEBB	Eagle Ford	111	5,025	5,136	2%	98%
WILSON	Eagle Ford	570	2	572	100%	0%
ZAVALA	Eagle Ford	173	80	253	68%	32%
ANGELINA	Haynesville	3	106	109	3%	97%
GREGG	Haynesville	3,117	986	4,103	76%	24%
HARRISON	Haynesville	308	2,600	2,908	11%	89%
MARION	Haynesville	215	112	327	66%	34%
NACOGDOCHES	Haynesville	102	1,446	1,548	7%	93%
PANOLA	Haynesville	226	5,237	5,463	4%	96%
RUSK	Haynesville	1,911	2,660	4,571	42%	58%
SABINE	Haynesville	9	4	13	69%	31%
SAN AUGUSTINE	Haynesville	18	140	158	11%	89%

Table 7-5. Growth Factor Weighting Percentages

County	Shale Play	Oil Well Count	Gas Well Count	Total Well Count	% Oil	% Gas
SHELBY	Haynesville	54	658	712	8%	92%
ARCHER	Barnett	3,068	5	3,073	100%	0%
BOSQUE	Barnett		4	4	0%	100%
CLAY	Barnett	1,107	28	1,135	98%	2%
COMANCHE	Barnett	71	184	255	28%	72%
COOKE	Barnett	2,212	43	2,255	98%	2%
CORYELL	Barnett	5	12	17	29%	71%
DALLAS	Barnett		25	25	0%	100%
DENTON	Barnett	49	2,857	2,906	2%	98%
EASTLAND	Barnett	626	848	1,474	42%	58%
ELLIS	Barnett		50	50	0%	100%
ERATH	Barnett	11	345	356	3%	97%
HAMILTON	Barnett	2	12	14	14%	86%
HILL	Barnett	2	238	240	1%	99%
HOOD	Barnett	2	795	797	0%	100%
JACK	Barnett	1,485	1,266	2,751	54%	46%
JOHNSON	Barnett		2,955	2,955	0%	100%
MONTAGUE	Barnett	2,458	46	2,504	98%	2%
PALO PINTO	Barnett	417	1,453	1,870	22%	78%
PARKER	Barnett	11	1,764	1,775	1%	99%
SHACKELFORD	Barnett	1,794	236	2,030	88%	12%
SOMERVELL	Barnett		99	99	0%	100%
STEPHENS	Barnett	1,348	1,039	2,387	56%	44%
TARRANT	Barnett		3,078	3,078	0%	100%
WISE	Barnett	532	4,290	4,822	11%	89%

8.0 Summary and Conclusions

Growth factors were calculated for the Barnett, Eagle Ford, and Haynesville shale play regions in Texas for annual oil production, annual natural gas production, and annual condensate production using five different methodologies. The growth factors are the change in annual production in years 2012 through 2035 relative to the annual production in the base year of 2011. Once the growth factors were calculated, the factors were applied to the 2011 annual production for each product in each shale play region to estimate annual production in each year 2012 through 2035. The estimated annual production values were then summed across the years 2012 through 2035 resulting in an estimated cumulative production for the same time period. Three growth scenarios (high growth, moderate growth, and low growth) were then identified from the estimated cumulative production values.

The annual production growth factors will also be used as the annual drilling growth factors. It is assumed that the relative change in the number of producing oil or gas wells in any future year relative to a base year will correspond to the relative change in oil or gas production. Furthermore, the growth factors calculated for each product in each shale play region will be applied to each county in that region.

For the purposes of projecting emissions from oil and gas production activities in each of the three shale play regions, the high growth rate scenario would result in "worst-case" total emissions estimates as this scenario produces the greatest total cumulative production through 2035. Since it is assumed there is a one-to-one (1:1) relationship between the relative change in production and the resultant emissions from production activities, then the highest cumulative production from 2012 through 2035 under the high growth rate scenario would correspond to the highest amount of cumulative emissions over the same time period.

While several methods of forecasting have been employed, there is a high degree of uncertainty and variability in production forecasting as future economic and geopolitical influences are impossible to predict. However, it is useful to contemplate which calculation methodology might result in a more "reasonable" production profile through 2035. While methodologies 1 and 2 are useful for comparison purposes and in the identification of growth scenarios, they are simplistic and based only on historic production data. Methodology 5 is based on natural gas price projections from EIA which result from complex modeling, but may be optimistic. Further, we assume that changes in production will follow changes in price immediately with no time delay, which historically has rarely been the case. Methodology 4 is instructive as it is based on a large body of historical data, but also reflects historical changes in the economy, oil and gas prices, and other factors that tend to affect trends in production. We are cautious about applying methodology 4 for the purposes of projecting future production as those historical impacts on production will effectively be "duplicated" in the future. A production projection simply based on historical data and total resource estimates is preferred as it does not involve trying to predict future economic or political events that may affect production.

It is our conclusion that Methodology 3 (Hubbert's model) is the preferred forecasting methodology under this effort. The model is developed for each shale play region based on historical data for the region, but also takes into account changes in production rates due to the size of reserves and estimated ultimate recovery. While there is a great amount of uncertainty in reserve estimation and even published Technically Recoverable Resources (TRR) values (and those values continue to change over time due to advances in technology and estimation methods), the Hubbert model accounts for estimated maximum cumulative production. The gradual leveling of total cumulative production as resources near depletion is reflected in the production rate curve when the cumulative production curve is differentiated. The result is a clear peak in the annual production curve indicating when maximum annual production is estimated to occur. For emissions modeling and estimation purposes, this peak would also correspond to the period of peak emissions resulting from production activities. Except under methodology 4, the other projection methodologies do not produce a distinct production peak which results in production either increasing (at a constant or variable rate) or remaining constant indefinitely, which are likely very unrealistic or improbable scenarios.

Attachment A
“Production Modeling and Growth Factor Calculation.zip”

Attachment B
“Area Source Growth Factors.zip”

Attachment C
“TexAER Area Source Growth Factors.zip”