EXAMINING UNCERTAINTY IN RESERVES ESTIMATION FOR OIL AND NATURAL GAS WELLS COMPLETED WITH HYDRAULIC FRACTURING

by
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Abstract

The recent innovations in horizontal drilling technology, paired with hydraulic fracturing (HF), have opened up vast reserves of petroleum across the world, particularly the United States. This recent surge in oil and gas production has numerous implications for energy security and international relations and will weigh heavily on future US energy policy decisions. However, wells in HF-stimulated reservoirs behave differently than their conventional counterparts, estimating recoverable resources difficult and often highly uncertain. Historically, recoverable reserves have been estimated using decline curve analysis, a method utilizing empirical curve fits production data to predict long-term good production. This analysis sought to understand the degree of uncertainty in unconventional reserve estimates using standard decline curve analysis through a comparison of representative well estimated ultimate recovery (EUR) in four tight oil plays and two tight gas plays. Mean EUR data from the US Energy Information Administration (EIA) and industry were compared directly with modeled representative well EURs. The high variability seen in the resulting comparison indicated significant uncertainty in mean EUR estimates for the same plays. More comprehensive reservoir modeling techniques like rate-transient analysis (RTA), which incorporates geologic data, fracture geometry, and flow regime analysis, have been demonstrated in conventional reservoirs to yield more accurate estimates of recoverable reserves and reduce uncertainty. As HF-stimulated oil and gas production in the United States continues to play a larger role in future energy policy decisions, reducing uncertainty, including by utilizing RTA, in future estimations of recoverable reserves will be critical to developing sustainable and effective policies.

Contents

1.0 Introduction and Background

The recent boom in United States oil and gas production, primarily driven by innovations in horizontal drilling and hydraulic fracturing (HF) stimulation, propelled the US for the first time in decades to the position as the world's top oil producer in 2014.[1] Among other things, the surge in production in the preceding 10 years transformed the world oil market and spurred widespread conversions to natural gas turbines for electricity production.[2] This surge in production led to aspirations among politicians and industry officials of "energy independence," after decades of US reliance on foreign oil imports, often from politically volatile regions of the world. However, when oil prices collapsed in late 2014 due to global oversupply, US production declined extraordinarily as drillers slowed down, raising questions regarding the long-term sustainability of high production rates from HF-stimulated wells.

The uncertainty surrounding the sustainability of long-term US oil production lies in reservoir behavior. Reservoirs stimulated by HF exhibit significantly different behaviors than their conventional counterparts throughout their producing lives. High initial decline rates, coupled with complex permeability and flow regimes, increase the difficulty of estimating proved reserves in these reservoirs. The Energy Information Administration (EIA) releases estimates of proved reserves, or the petroleum resources remaining in a given field that are estimated to be recoverable under current economic conditions, every year in its Annual Energy Outlook (AEO).[3] Policymakers and industry officials often use this publication for future decisions. The predictive portion of the

[1] Smith, Grant. *US Seen as Biggest Oil Producer After Overtaking Saudi Arabia*. Bloomberg, July 4 (2014).
[2] Crooks, Ed. *Cheap gas has hurt coal and nuclear plants, says US grid study*. Financial Times, August 24 (2017)
[3] EIA, US. *Annual Energy Outlook 2018*. US Energy Information Administration, Washington, DC (2018).

AEO, which uses reserve estimates to make projections of future production, is often criticized for optimistic predictions of production growth. Hughes (2014) predicts significant underperformance of US oil and gas reserves in comparison to the EIA estimates over the coming decades.[4] Previously, AEO publications between 2008 and 2010 failed to predict the future viability of various tight oil[5] and gas plays, which hampered the ability of government officials to prepare for a dramatic increase in domestic production adequately.[6] Now that significant oil and gas resources are available within the US, the reliability of estimating how HF-stimulated wells will behave over the coming decades is critical to the economy and national security of the US. As the US government considers its petroleum reserves when evaluating energy security and independence, accurate reserve estimates are critical to future policy decisions, trade partnerships, and military action. This analysis sought to examine the uncertainty of decline curve analysis as a method for reserves estimation in reservoirs stimulated using HF, by comparing reserve estimates from industry and the EIA to models based on production data using decline curve analysis.

1.1 Hydraulic Fracturing Stimulation and Unconventional Reservoir Behavior

In formations with low permeability where petroleum resources are contained in isolated pore spaces, hydraulic fracturing (HF) is utilized to connect these pore spaces and artificially enhance permeability, bringing the greatest surface area of a given formation possible into contact with the wellbore. This ensures larger production volumes and

[4] Hughes, J. David. *Drilling deeper: a reality check on US government forecasts for a lasting tight oil & shale gas boom.* Post Carbon Institute, Santa Rosa, California (2014).
[5] Oil or gas found in relatively impermeable rock which often requires hydraulic fracturing to induce permeability
[6] Ibid, Hughes.

longer well life. In higher-permeability conventional plays, estimation of recoverable reserves is usually accurate and predictable, since reservoir behavior and geology are relatively uniform and consistent data has been collected over decades. For many emerging low-permeability unconventional plays, especially those where HF techniques are used to induce permeability, traditional analysis methods often fail to characterize well behavior adequately. Much of the failure of traditional analysis methods to describe HF-stimulated reservoir behavior lies in the significant difference in the behavior of wells in conventional, higher permeability (10-100 mD)[7] plays vs. those in low-permeability (0.1 µD to 1mD) unconventional plays stimulated with HF.[8] When comparing conventional and unconventional plays in terms of decline rate, the difference is significant (See Figure 1.1.1).

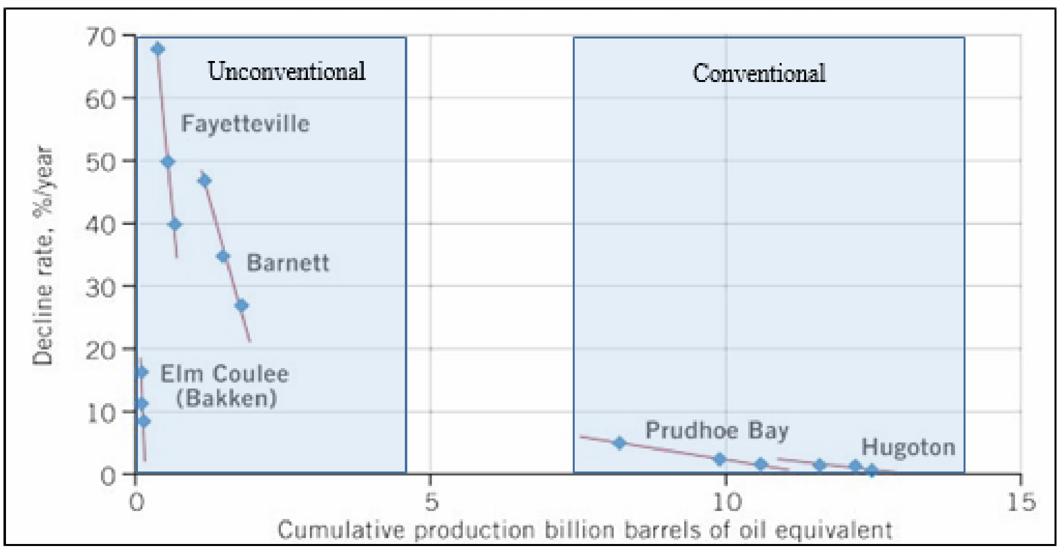

Figure 1.1.1: A plot of decline rates in both unconventional and conventional plays[9]

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[7] Reservoir permeability is measured in microdarcy (µD) and millidarcy (mD) with lower values corresponding to lower permeability.
[8] Hough, E., and Thomas McClurg. *Impact of Geological Variation and Completion Type in the US Bakken Oil Shale Play Using Decline Curve Analysis and Transient Flow Character.* In Presentation at AAPG International Conference and Exhibition, Milan, Italy, Oct, pp. 23-26. 2011.
[9] Sandrea, Rafael. *Evaluating production potential of mature US oil, gas shale plays.* Oil & Gas Journal 110, no. 12 (2012): 58.

In conventional fields like Prudhoe Bay in Alaska or Hugoton in Kansas, where oil is extracted without HF from conventional reservoirs, the decline rates are below 10% per year, whereas in plays like the Barnett, a low-permeability shale that needs HF stimulation, the average decline rates are roughly 25-50% per year, though the high rate is largely due to a steep initial decline.[10] Even the Bakken, with an average decline rate comparable to conventional plays, exhibits an initial decline rate of 65-80% per year on average, in comparison to conventional plays, which typically have initial decline rates of 5-10% per year.[11] On average, 50% of the estimated ultimate recovery (EUR) of a well in the Bakken has been produced within the first five years of the well's life, with the remaining 50% produced over the next 25 years.[12] Despite the enormous growth in domestic producing reserves for the United States due to HF stimulation of tight gas and oil plays, the growth is artificially inflated due to initial high production rates, and drillers must continually bring wells into production to maintain production growth.

1.2 Geological and HF Stimulation Design Factors Contributing to Reservoir Behavior

Factors related to the underlying geology and choices made by operators for the completion of the reservoir are primarily responsible for the uncertainties associated with reserves estimation for HF-stimulated reservoirs. Factors include the interaction between HF and the producing formation, and the effects of geology and type of stimulation on reservoir behavior.

Though there is a high degree of variance in pressures, pumping rates, and chemical/fluids used, the modern HF process primarily involves the injection of water,

[10] Sandrea, Rafael. *Evaluating production potential of mature US oil, gas shale plays.* 58
[11] Ibid, 58
[12] Ibid, 58

proppant, gel, and other chemicals at a high pressure to fracture the formation and induce secondary permeability. Proppant is a natural or engineered sand intended to "prop" open fractures after HF stimulation is complete so that flow through the induced permeability network may continue throughout the life of the well. The fracture network induced allows unconventional reservoirs, where the petroleum resources are stored in isolated pore spaces, to produce at commercially viable volumes.[13] Initially, due to in-situ stress conditions, the formation fractures vertically, perpendicular to the principal overburden stress. These vertical fractures are the initial, planar growth, and ideally, microfractures will branch out from the main planar fracture, expanding horizontally and creating fracture complexity.[14]

While geological characteristics of the formation are important to production, fracture complexity has been attributed to higher cumulative production across plays of varying geology.[15] The HF process, specifically what fluids and proppants are used, can significantly alter the fracture network extent (propagation) and complexity. In the past five years, the industry has shifted to focus on inducing fracture complexity using "slickwater," which is a blend of water, friction reducing chemicals, and in some cases, acid.[16] Slickwater, though an older fluid system, has largely replaced more modern and heavily-researched crosslink gel systems in several plays. The crosslink method, while successful at delivering proppant into the formation and reducing the potential for

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[13] King, George E. *Hydraulic fracturing 101: What every representative, environmentalist, regulator, reporter, investor, university researcher, neighbor, and engineer should know about hydraulic fracturing risk*. Journal of Petroleum Technology 64, no. 04 (2012): 34-42.
[14] Ibid, 34-42
[15] Britt, Larry K., Michael B. Smith, Henry H. Klein, and J. Y. Deng. *Production Benefits from Complexity–Effects of Rock Fabric, Managed Drawdown, and Propped Fracture Conductivity.* In SPE Hydraulic Fracturing Technology Conference. Society of Petroleum Engineers, 2016.
[16] Palisch, Terrence T., Michael Vincent, and Patrick J. Handren. S*lickwater fracturing: food for thought.* SPE Production & Operations 25, no. 03 (2010): 327-344.

proppant to accumulate in the wellbore, only seems to improve the propagation of planar fractures and induce higher fracture conductivity, rather than complexity.[17] Typically, operators prefer a “hybrid” stimulation, which combines a slickwater and crosslink gel fluid system to create near-wellbore fracture conductivity and a complex fracture network further out in the formation.[18] In hybrid fluid system HF stimulations, proppant also plays an important role, with smaller mesh-size proppant pumped into the outermost fracture network, and larger mesh-size proppant pumped into the near-wellbore zone. In the initial months and years after an HF stimulation, the production surges, as thousands of barrels of oil inside the now-connected pore space flow freely through the induced fracture network. Additionally, the initial pressures are typically high in these formations, increasing the production rate. However, because the network of fractures are so permeable, that initial network is rapidly depleted, and production quickly declines.[19] After 2-3 years, the production rate stabilizes, and continues at this rate for decades, albeit a much lower rate than the initial years of production. Ultra-low permeability matrix drives this initially rapid decline followed by a stable production rate near long, planar fractures.[20] Over time, these fractures draw out a greater amount of petroleum from the surrounding rock matrix due to their higher pore volumes. Increasing surface area contact with the producing formation, and inducing maximum permeability and pore volume through the fracture network, are critical to ensuring the longevity of wells and minimizing rapid initial decline. In response, the oil and gas

[17] Ibid, 327-344

[18] Geiver, L. *The Slickwater Story.* The Bakken Magazine. Retrieved from (2014).

[19] Clarkson, Christopher R. *Production data analysis of unconventional gas wells: Review of theory and best practices.* International Journal of Coal Geology 109 (2013): 101-146.

[20] Hough, E., and Thomas McClurg. *Impact of Geological Variation and Completion Type in the US Bakken Oil Shale Play Using Decline Curve Analysis and Transient Flow Character*. 23-26

industry has increased proppant and water volumes in unconventional plays across the United States. Between 2010 and 2014, the average proppant used for an HF stimulation in the United States more than doubled.[21] More proppant, along with an equivalent increase in water volume per stimulation, has led to longer producing lives for wells.

1.3 Techniques for Estimation of Recoverable Reserves

The various characteristics of both conventional and unconventional reservoirs discussed above can be modeled using a variety of tools. The oil industry has principally used decline curve analysis to predict ultimate resource recovery and proved reserves in fields they develop. Decline curve analysis uses exponential and hyperbolic equations, which are empirically adjusted throughout the life of the well as needed to provide a better fit to production data.

Decline curve analysis can be further refined using reservoir characterization including pressure, flow, and permeability data, so-called rate-transient analysis (RTA). Combining RTA with the empirical modeling of decline curve analysis typically leads to a better understanding of well performance and reservoir behavior over time. While decline curve analysis continues to be refined for unconventional reservoirs, RTA methods are still being developed for unconventional reservoirs, due to the high complexity of flow and permeability regimes discussed above.[22]

In conventional fields – such as those in Alaska, Kansas, Venezuela, Saudi Arabia, and the North Sea – exhibit constant decline rates of around 3-5% annually. Permeability remains relatively consistent and is defined solely by the permeability of the geologic

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[21] Bleiwas, Don. *Estimates of hydraulic fracturing (Frac) sand production, consumption, and reserves in the United States.* Rock Prod. Newslett. (2015).

[22] Clarkson, Christopher R. *Production data analysis of unconventional gas wells: Review of theory and best practices.* 102

formation in which the reservoir lies. Depending on the geology, permeability in conventional reservoirs can range from 0.1-1000 mD.[23] This continuous permeability means the whole-reservoir extent and initial pressure dominate the long-term decline behavior of conventional reservoirs. Conventional reservoirs are typically dominated by two flow regimes: radial flow and boundary-dominated flow.[24] In the initial radial flow period, pressure declines at a constant rate around the wellbore until the radial decline reaches the extent of the reservoir, where it transitions to boundary-dominated flow, where the rate of pressure decline begins to increase and the entire reservoir volume declines at a constant rate. Boundary-dominated flow is typically observed for the majority of reservoir life.[25]

Unconventional reservoirs exhibit far lower and more variable permeability, which contributes to more complex flow-regime characteristics throughout the life of the reservoir. Permeability in unconventional reservoirs can range from 15 μD - 0.1 mD.[26] Typically, multiple permeability regimes will define the flow regimes of an unconventional reservoir, since a combination of in-situ permeability of the formation (matrix), naturally induced fracture permeability, and induced fracture permeability (from HF) may all exist in a single reservoir. Flow regimes are highly variable depending on location and production characteristics, but multiple linear and boundary-dominated flow regimes typically dominate unconventional reservoirs.[27] Bilinear flow regimes, where

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[23] Hough, E., and Thomas McClurg. *Impact of Geological Variation and Completion Type in the US Bakken Oil Shale Play Using Decline Curve Analysis and Transient Flow Character*. 23-26

[24] Clarkson, Christopher R. *Production data analysis of unconventional gas wells: Review of theory and best practices*. 101-146.

[25] Ibid, 101-146

[26] Hough, E., and Thomas McClurg. *Impact of Geological Variation and Completion Type in the US Bakken Oil Shale Play Using Decline Curve Analysis and Transient Flow Character*. 23-26

[27] Clarkson, Christopher R., and J. J. Beierle. *Integration of microseismic and other post-fracture surveillance with production analysis: a tight gas study*. Journal of Natural Gas Science and Engineering 3,

the fluid is simultaneously flowing out of the formation matrix and the fractures, typically exhibits a rapid increase in the rate of pressure decline initially, until the transition to boundary-dominated flow for the entire stimulated network of fractures and matrix occurs.[28] Put differently, unconventional reservoirs exhibit rapid depletions in pressure and volume in the initial months after production begins, due to the higher induced permeability of the fracture network in comparison to the matrix permeability.[29] Later in the life of the well, depletion of pressure is dominated by the flow of the matrix itself, exhibiting a much slower decline in pressure for the majority of the reservoir's life. Decline curve analysis was initially proposed in "Analysis of Decline Curves" by J.J. Arps (1945), and demonstrated that decline curves could be fit to production data to model the decline parameters of a given reservoir and calculate the reservoir's estimated ultimate recovery.[30] The estimated ultimate recovery (EUR) is a calculation of the total amount of recoverable petroleum resource from the reservoir over its commercially viable lifetime. Conventional and unconventional reservoirs are modeled using different decline parameters, characterized by the variables displayed in Equations (1.3.1), (1.3.2), and (1.3.3) below using hyperbolic decline parameters initially developed by Arps (1945)[31]:

(1.3.1) $$D_0 = \frac{\frac{p_2 - p_1}{t_2 - t_1}}{t_1}\text{ ; where:}$$

D_0 = initial decline rate
t_x = time in months
p_x = production rate, bbls/day

no. 2 (2011): 382-401.
[28] Clarkson, Christopher R. *Production data analysis of unconventional gas wells: Review of theory and best practices.* 102
[29] Ibid, 102.
[30] Arps, Jan J. *Analysis of decline curves*. Transactions of the AIME 160, no. 01 (1945): 228-247.
[31] Arps, Jan J. Analysis of decline curves. 228-247

(1.3.2) $$q(t) = p_0[1 + D_0 b(t - t_0)]^{-\frac{1}{b}};$$ where:

$q(t)$ = modeled production rate, bbls/day
t = time in months
p_0 = measured production rate at time t_0, bbls/day
D_0 = initial decline rate
b = decline exponent constant

(1.3.3) $$EUR = p_0 + \sum_{t_0}^{t_f} q(t);$$ where:

EUR = estimated ultimate recovery, bbls
t_0 = initial time
t_f = final time
p_0 = measured initial production rate, bbls/day
$q(t)$ = modeled production rate, bbls/day

Perhaps the most important variable in the decline curve equation is *b*, or the decline exponent constant, which in addition to the initial decline rate defines the slope of decline curves. In conventional reservoirs, *b* is often set equal to zero to model exponential decline. In conventional reservoirs, exponential decline curves are well-suited to production behavior that exhibits a constant decline rate over an extended period. Unconventional reservoir decline curves, because of high initial decline early in the life of the well followed by an extended period of low decline rates, are best modeled by decline curves with *b* values above zero. For wells in the Bakken, *b* values were found to correlate with permeability regime, and whether or not long-term, ultra- low permeability matrix flow would dominate in the wells.[32] Typically, higher *b* values, or lower decline rates, related to greater surface area contact with the low-permeability matrix, and lower *b* values correlated with higher decline rates and contact with natural and induced fracture networks.[33] Wells with higher *b* values exhibited slower decline rates, and

[32] Hough, E., and Thomas McClurg. *Impact of Geological Variation and Completion Type in the US Bakken Oil Shale Play Using Decline Curve Analysis and Transient Flow Character*. 23-26
[33] Ibid, 23-26

higher long-term production rates, extending the commercially viable well life and increasing well rate-of-return. Ultra-low permeability (0.1-15 µD) reservoirs which have been stimulated with HF are generally modeled using a curve with higher *b* values (between 1 and 2),[34] whereas moderately low permeability (15 µD-0.1 mD) reservoirs which flow naturally in addition to HF stimulation are generally best modeled with lower *b* values, (between 0 and 0.5).[35] The incremental change in EUR for a small change in the *b* value can be substantial. This variability introduces wide margins of uncertainty in the estimation of future production, especially in emerging unconventional plays where less than a decade of reliable production data exists. As it is developed further, RTA methods may be useful for better constraining *b* in unconventional reservoirs and producing more accurate estimates of recoverable reserves.

2.0 Methods and Analysis

2.1 Data Gathering

To perform the decline curve analysis and calculate representative EURs, production data were obtained from S*haleProfile.com*, which aggregates and organizes these data from state oil and gas commissions.[36] The production data, expressed in barrels per day (bbls/day), presented a monthly average daily production for the well sample's average. This permitted the sample of hundreds of wells to be analyzed as a single "representative" well for each play. The organization of the data in this manner permitted decline curve analysis to be performed for a representative well, which exhibited characteristics of average well decline behavior in each play.

[34] Hough, E., and Thomas McClurg. *Impact of Geological Variation and Completion Type in the US Bakken Oil Shale Play Using Decline Curve Analysis and Transient Flow Character*. 23-26
[35] Ibid, 23
[36] Peters, Enno. *Visualizing US shale oil & gas production*. ShaleProfile.com. (2018)

Data were obtained for four tight oil plays: the Bakken, Eagle Ford, Permian, and the Niobrara, as well as two tight gas plays: the Haynesville and Marcellus shale, all for the years 2011-2015. These plays are some of the most productive and well-developed plays in the US, and possess variable geologic characteristics.

Mean EUR data were also obtained from the EIA for comparison with the modeled EURs. The EIA determines mean play/subplay EURs using distributions of well-level EURs by play and subplay for its prediction assumptions every year.[37] The data were obtained from the EIA for the same plays: the Bakken, Eagle Ford, Permian, and the Niobrara, as well as two tight gas plays: the Haynesville and Marcellus shale, all for the years 2011-2015.

Finally, EUR data were obtained from industry for major firms and independent industry assessors active in each play for comparison with modeled estimates. Firms often display average well EUR data in investor presentations, and these data were gathered and averaged for each play.[38] Additionally, independent assessors will often consult with investment firms and generate reports estimating recoverable reserves by play.[39]

This data is subject to several limitations, principally a lack of consistency in reporting and estimation. Data displayed by firms for investors often portray optimistic estimates of reserves and productivity. For official filings with the Securities and Exchange Commission (SEC), firms are subject to strict regulations and independent assessments of reserves, to ensure estimates are not artificially heightened to increase firm valuation.[40]

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[37] Energy Information Administration. *Assumptions to the Annual Energy Outlook.* Annual Energy Outlook 2013-2017. (2013-2017).

[38] Investor Presentations, 2011-2015. *Occidental Petroleum, EOG Resources, Continental Resources, Anadarko Petroleum, and Chesapeake Energy.*

[39] Independent Assessments: 2011-2015 *Jeffries, Strata Advisors.*

[40] Securities, U. S., and Exchange Commission. *Modernization of Oil and Gas Reporting. Final Rule, 17 CFR Parts 210, 211, 229, and 249,[Release Nos. 33–8995; 34–59192; FR–78; File No. S7–15–08], RIN*

However, SEC filings only require reserve estimates for entire corporate portfolios, and not individual wells, making investor presentations the only source of data for well-level industry EURs. Independent assessors like Jeffries and Strata Advisors were also used where available to introduce greater conservatism in the analysis. The variability of these data makes the industry EURs the least reliable for comparison with data from EIA and model simulations. However, industry EURs were considered valuable enough to include in the comparison.

2.2 Analysis Methods

Recoverable reserves for each play's representative well were estimated using standard decline curve analysis methods initially developed by Arps (1945).[41] The "representative" well is an average of the monthly production for the well sample in each play. The monthly production data for each representative well were populated in Microsoft Excel for each play and each of the years 2011-2015, and an initial decline rate D_0 was calculated for each representative well using Equation (2.2.1) below:

(2.2.1) $$D_0 = \frac{\frac{p_2 - p_1}{t_2 - t_1}}{t_1}$$; where:

D_0 = initial decline rate
t_x = time in months
p_x = production rate, bbls/day

Using D_0, production rate $q(t)$ in bbls/day was calculated for each of 360 months to simulate a 30-year economic well life using two different models; a reference case and a high case representative well. The reference case used Equation (2.2.2) initially and Equation (2.2.3) after the monthly decline rate dropped below 0.8% to simulate a flow

3235–AK00, US SEC, Washington, DC (14 January 2009). Federal Register 74, no. 9 (2009): 2157-2197.

[41] Arps, Jan J. Analysis of decline curves. 228-247

transition to exponential decline, consistent with the model used by the EIA[42] and a simplified version of flow models used by Clarkson (2013).[43] The high case used Equation 2.2.2 to model production for the life of the well, simulating well behavior with no exponential decline.

(2.2.2) $$q(t) = p_0[1 + D_0 b(t - t_0)]^{-\frac{1}{b}};$$ where:

$q(t)$ = modeled production rate, bbls/day
t = time in months
p_0 = measured production rate at time t_0, bbls/day
D_0 = initial decline rate
b = decline exponent constant

(2.2.3) $$q(t) = p_0 * [D_0(t - t_0)];$$ where:

$q(t)$ = modeled production rate, bbls/day
t = time in months
p_0 = measured production rate at time t_0, bbls/day
D_0 = initial decline rate

Finally, using Equation (2.2.4), the EUR was calculated for each representative well. Since the time unit for the data obtained is monthly and the production rate is expressed in bbls/day, the EUR calculation was multiplied by the average number of days in a month, 30.5, as shown below:

(2.2.4) $$EUR = [p_0 + \sum_{t_1}^{t_{360}} q(t)] * 30.5;$$ where:

EUR = estimated ultimate recovery, bbls
t_1 = time of first modeled production month
t_{360} = time at end of 30-year modeled well life
p_0 = measured initial production rate, bbls/day
$q(t)$ = modeled production rate, bbls/day

To ensure the curve provided an accurate representation of the production data, a

[42] EIA, US. *Oil and Gas Supply Module of the National Energy Modeling System: Model Documentation 2017*. (2017).
[43] Clarkson, Christopher R. *Production data analysis of unconventional gas wells: Review of theory and best practices.* 102

coefficient of determination was calculated to provide an estimation of the fitness of the modeled production data $q(t)$ to available measured production data $p(t)$. The equation used to calculate the coefficient of determination is shown in Equation (2.2.5):

$$R^2 = \frac{sum\ of\ squared\ residuals}{total\ sum\ of\ squares} \tag{2.2.5}$$

A minimum threshold was set at $R^2 = 0.99$ to ensure a high level of fitness for the predicted production rates. The modeled production rates were empirically fit by changing the decline exponent constant b until a minimum R^2 value of 0.99 was obtained. Both the measured and modeled production data for each representative well were plotted together to display the fitness of the modeled production rates visually, as shown in Figure 2.2.1.

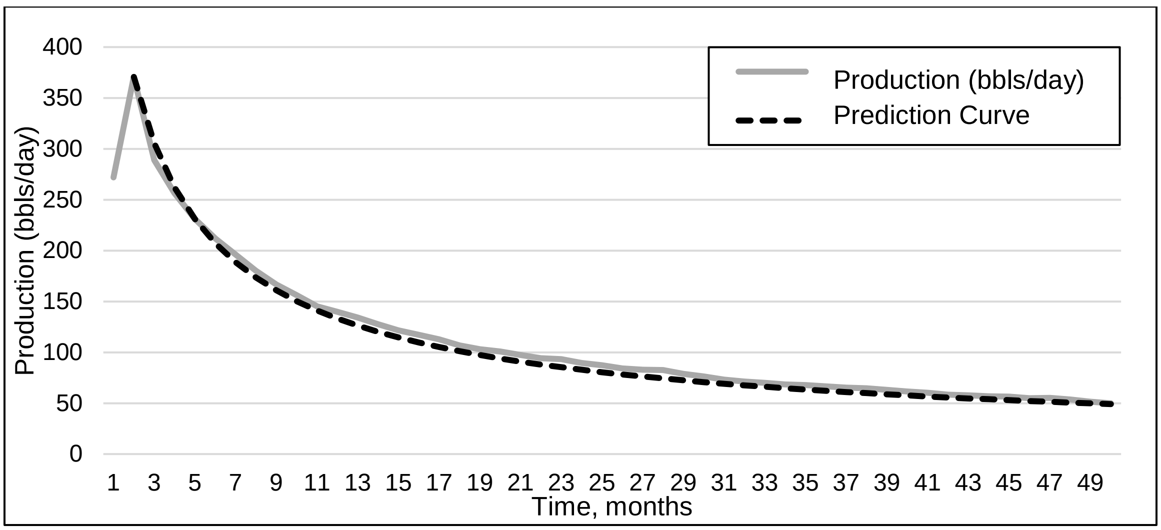

Figure 2.2.1: Example of decline curve fitted to 50 months of Bakken production data

To estimate proved and technically recoverable reserves for use in the AEO, the EIA obtains production data for plays nationwide using the proprietary database *DrillingInfo*, which gathers and aggregates industry data from plays and basins across the US. The EIA determines mean play EURs using distributions of well-level EURs by play and subplay.[44] The well-level EURs are determined using decline curve analysis similar to the methods described above. These play-level mean EUR data provide a baseline, consistent estimation of reserves for a given year, using the same framework to estimate EUR based on well production data. With data from major operators in each play, mean well EUR calculations from EIA were also gathered and compared directly with the modeled EURs.[45] Comparison of EUR based on the model, EIA, and industry estimates are displayed in Results.

3.0 Results

3.1 Model Results

Model results met the fitness threshold to the production data, with R^2 values all above 0.99. This fitness was also visually confirmed using graphs like Figure 2.2.1 to ensure the decline curve models fit production data appropriately. Detailed model results are included as an Appendix under section 7.1.

3.2 Comparison of Modeled Results with EIA and Industry Data

Generally, mean EIA EURs were lower than both the reference and high case modeled representative wells, while industry EUR estimates were generally higher than both modeled scenarios. Reference case model EURs tended to be more closely aligned with EIA EURs, while high case model EURs were better aligned with industry EURs. In particular, the Marcellus play modeled representative well EURs exhibited substantial differences from EIA EURs, with average EIA results 2.8 billion cubic feet (Bcf) lower than the reference case representative well and 5.7 Bcf lower than high case

[44] Energy Information Administration. *Assumptions to the Annual Energy Outlook.* Annual Energy Outlook 2013-2017. (2013-2017).
[45] Ibid.

representative well. Industry EUR estimates tended to be significantly higher than representative wells for both scenarios, with the exception of the Haynesville and Marcellus plays, where industry and modeled estimates were more closely aligned. However, for the various reasons discussed in section 2.1, the sample of EURs from industry is not considered as reliable as the sample of EIA EURs. A comparison of EIA and industry EURs with modeled EURs for each scenario is also displayed graphically below for all six plays. A detailed numerical comparison of results is included as an Appendix under section 7.2.

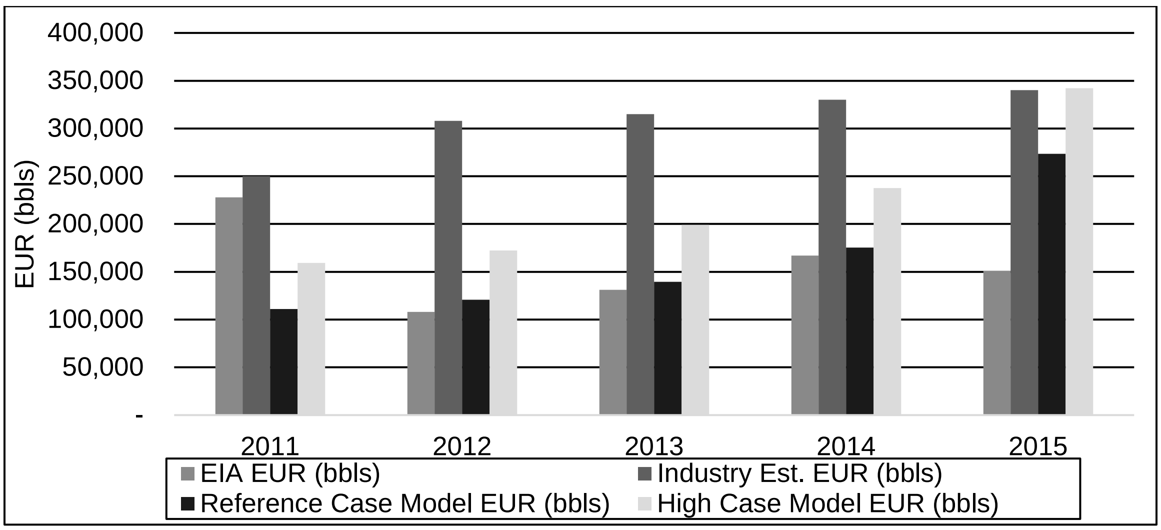

Figure 3.2.1: Comparison of modeled results, EIA, and industry data for the Permian play

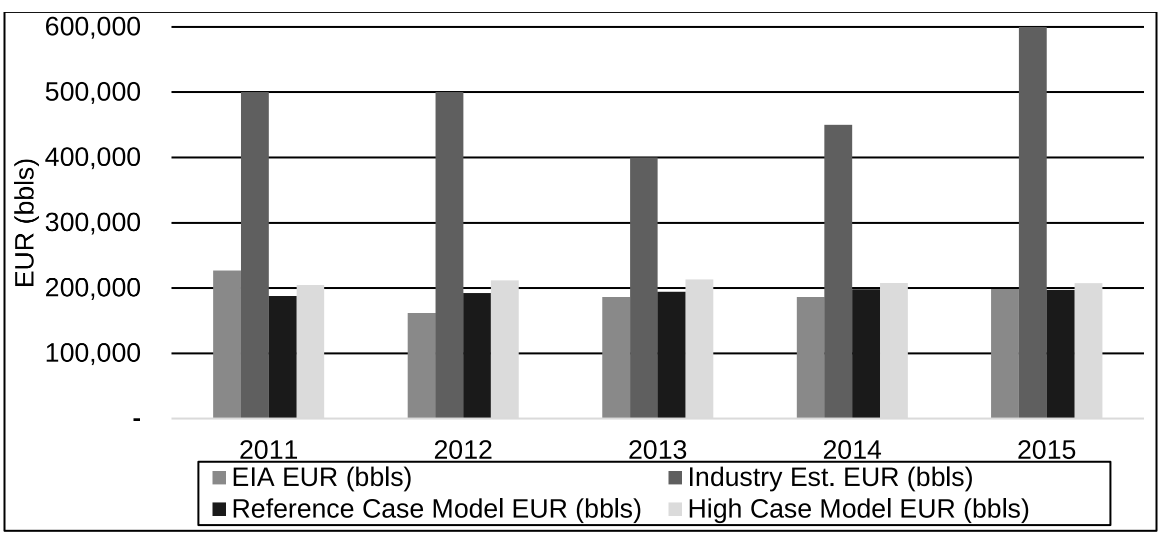

Figure 3.2.2: Comparison of modeled results, EIA, and industry data for the Eagle Ford play

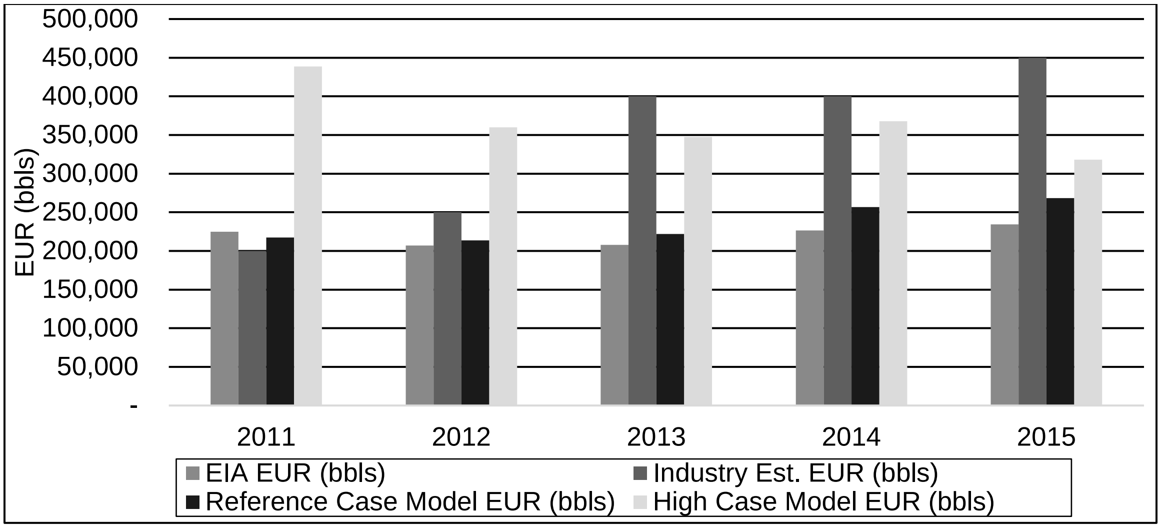

Figure 3.2.3: Comparison of modeled results, EIA, and industry data for the Bakken play

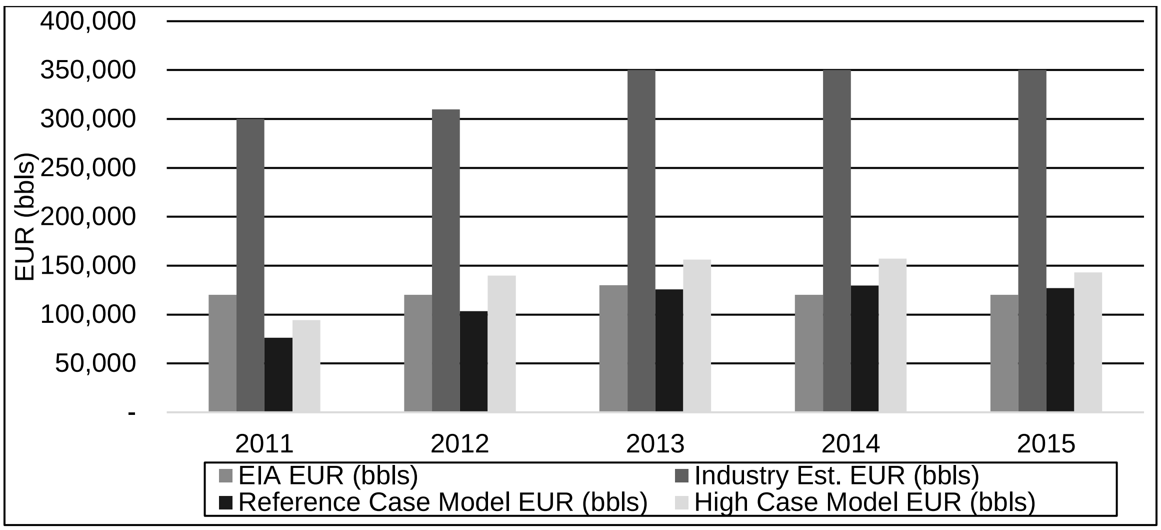

Figure 3.2.4: Comparison of modeled results, EIA, and industry data for the Niobrara play

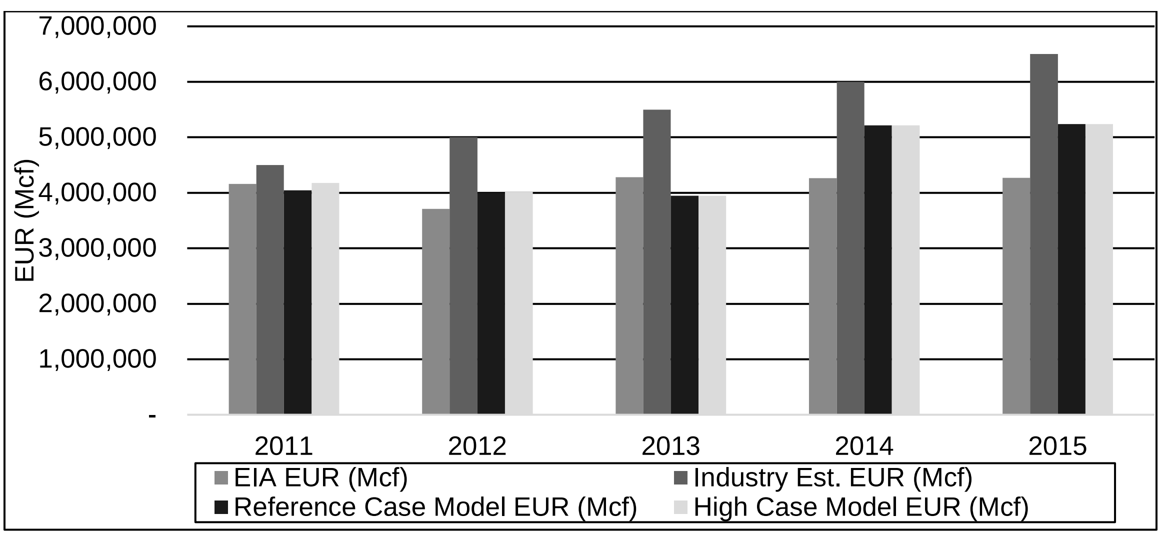

Figure 3.2.5: Comparison of modeled results, EIA, and industry data for the Haynesville play

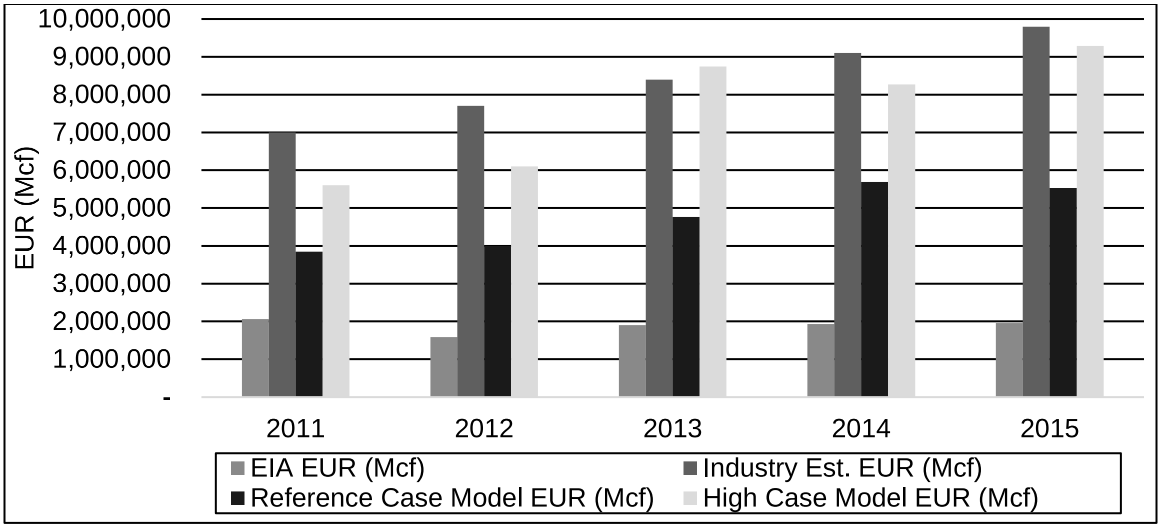

Figure 3.2.6: Comparison of modeled results, EIA, and industry data for the Marcellus play

4.0 Discussion

4.1 Implication of Results for Uncertainty in Reserves Estimation

Generally, modeled EURs for both the reference and high cases were higher than EIA estimates. The lower mean EURs calculated by the EIA indicated a high degree of conservatism in the agency's analysis. Even the reference case representative well EURs tended to be higher than EIA estimates for almost every play over the years 2011-2015, especially in the Marcellus shale, where reference case modeled EURs were more than twice the EIA-estimated EURs. In other plays, like the Eagle Ford and Niobrara, modeled EURs tended to align more closely with EIA EURs. Since the analysis methodology for the representative well models is nearly the same as that used by the EIA, alignment to some degree was expected. However, higher representative well EURs in relation to EIA EURs was not expected, since the agency is typically criticized for overestimating recoverable reserves in its analyses.[46] In general, the results of the analysis principally demonstrated the degree to which changes in decline curve variables,

[46] Hughes, J. David. *Drilling deeper: a reality check on US government forecasts for a lasting tight oil & shale gas boom.*

like decline rate D_0 and the decline exponent constant b, to fit production data can dramatically alter results, meaning use of this method involves significant uncertainty in estimating future production. In attempts to ensure conservatism in analysis, EIA likely used more aggressive decline variables, which in turn produced lower estimates. Since data on the fitness of EIA's models to production data are not available, it is difficult to ascertain the exact source of the agency's conservative recovery estimates.

The methodology used for aggregating production data was also thought to play a role in the major differences between modeled and EIA estimates. For example, the modeled EURs were calculated from the mean of a cohort of wells separated by year of first flow for years 2011-2015. The methodology used by EIA, however, takes an average EUR of all wells producing in a given area each year it performs the analysis, regardless of when the well started production.[47] The inclusion of legacy wells, or wells which had already been flowing for multiple years at the time of analysis, could have led to more conservative EURs.

However, the method used by EIA does not provide an assessment on whether long-term recovery of wells is changing every year, as technology and practices change in response to lessons learned by industry. The lower EIA EURs could indicate that inclusion of legacy wells in EIA's analysis was lowering mean EURs for individual plays, which if true could indicate EURs decline as more production data becomes available to fit decline curves. However, a correlation between the inclusion of legacy wells and lower EURs did not seem likely, since trends in EURs for both EIA and modeled estimates in tight oil plays generally increase with time (See Figure 4.1.1).

[47] EIA, US. *Assumptions to the Annual Energy Outlook*. (2013-2017).

Figure 4.1.1 also indicated EIA has become more conservative in calculating EUR with time, especially for the Bakken, Permian, and Niobrara plays. EIA EURs were higher than model reference case results in all tight oil plays in 2011, but dropped below model EURs in 2012 for the Permian and Bakken plays, and in 2014 for the Niobrara play.

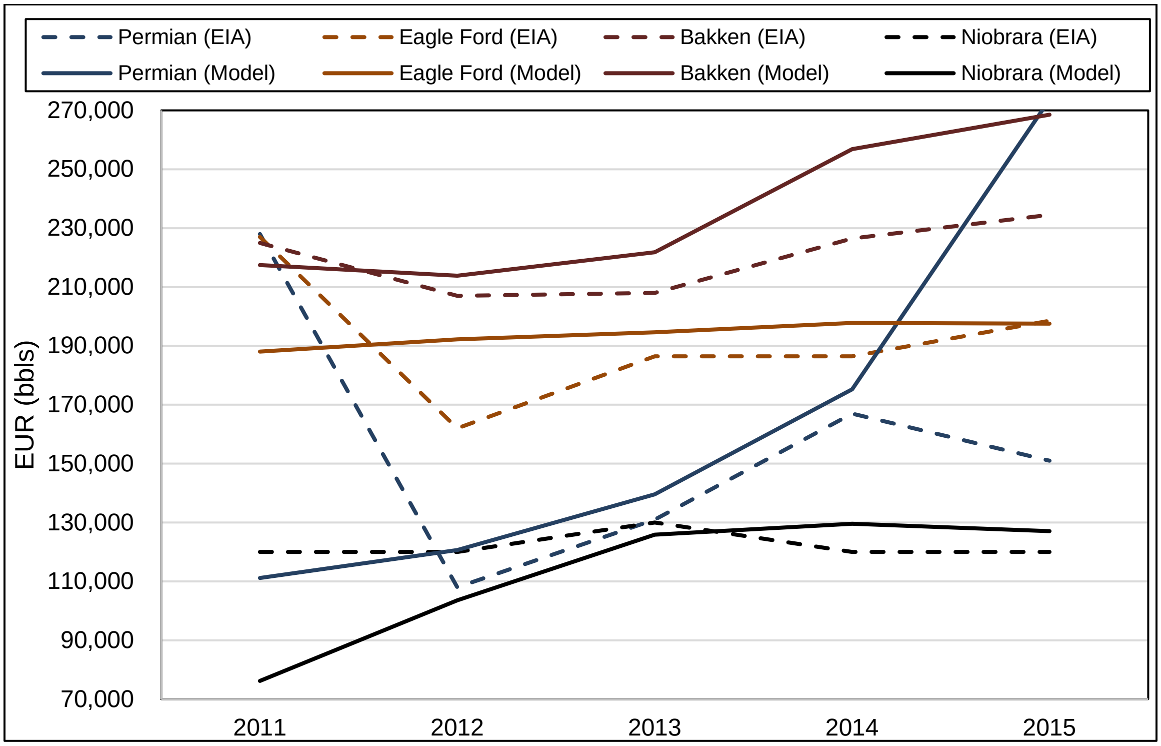

Figure 4.1.1: Comparison of trends in EUR estimated by the reference case model and EIA

One explanation for EIA's increasing conservatism could lie in the accelerating decline of legacy production, or production from wells with two or more months of production data.[48] The agency's March 2018 *Drilling Productivity Report* reported that monthly decline rate of legacy well production in the Bakken, Niobrara, and Permian plays increased between 2011 and 2015.[49] Even with the most recent numbers, production from new wells continues to exceed legacy decline, but if the trends indicated in EIA's

[48] EIA, US. *Drilling Productivity Report Background and Methodological Overview*. US Energy Information Administration (2018).
[49] EIA, US. *Drilling productivity report.* US Energy Information Administration (2018).

report continue, operators will encounter increasing difficulty in drilling enough new wells to exceed decline of old wells. Sustaining this pace requires substantial operating expenditures, and increase sensitivity to changes in the price of oil.[50] EIA has recognized the difficulty in sustaining production for plays with high decline rates, which may explain the agency's increasingly conservative EURs.

Industry EURs were higher than both the high and reference case modeled EURs, principally for two reasons. First, as discussed in the limitations of industry data in section 2.1, the motives of industry tend to differ significantly from government agencies like the EIA. Investor presentations typically display optimistic EURs and proved reserves estimates to attract investment and highlight firm accomplishments, and since data from independent assessors was limited, the data were still thought to contain inflated EURs.[51] Second, industry methodologies for calculating EURs are not publicly available, and likely vary from the methodology used by both the EIA and models in this analysis. For example, industry often includes all liquids and gas produced from a well in its EUR, whereas the EIA and the modeled analysis used separate oil or gas EURs. Additionally, decline variables and equations also differ among firms, which, as evidenced by the differences between the reference and high case modeled results, lead to significant differences in EUR.

Generally, the results indicate a significant degree of uncertainty in the estimation of reserves for wells completed with HF stimulations. The uncertainty appears to be fundamentally sourced from the inadequacy of decline curve analysis to predict the

[50] Smith, James L., and Thomas K. Lee. "*The price elasticity of US shale oil reserves*." Energy Economics 67 (2017): 121-135.
[51] DiLallo, Matthew. *This Oil Executive Thinks the Oil Market Is Way Too Optimistic (and That's Wildly Bullish for Oil Prices)* The Motley Fool. (2017)

behavior of unconventional reservoirs with induced permeability. As discussed in section 1.1, and drawing on work from Hough et al (2011)[52], and Clarkson (2013) [53], more consideration of the complex flow regimes and underlying matrix permeability are essential to understanding the behavior of unconventional reservoir behavior in the long term and yield more accurate calculations of EUR.

4.2 Greater Application of Rate-Transient Analysis to HF-Stimulated Reservoirs

Production data analysis (PDA) and more recently RTA have been widely used to characterize conventional reservoirs, based on workflows which use fundamental reservoir behavior to inform decline curve models.[54] Use of techniques based on reservoir pressure data and geologic formation characteristics to modify decline curves, rather than relying solely on empirical matches to production data, have allowed for improved prediction of long-term decline and better calculation of EUR. As discussed in sections 1.1 and 1.3, adapting RTA to the complex permeability and flow regimes present in HF-stimulated unconventional reservoirs has proven difficult. A better understanding of fracture geometry, matrix permeability, flow characteristics, and reservoir pressure are essential to better characterizing unconventional reservoirs and predicting production decline rates.[55] Industry has employed micro-seismic monitoring of HF operations to provide real time data on fracture propagation throughout the formation, which provides a better understanding of fracture geometry and reservoir flow regimes.[56] As well

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[52] Hough, E., and Thomas McClurg. *Impact of Geological Variation and Completion Type in the US Bakken Oil Shale Play Using Decline Curve Analysis and Transient Flow Character*. 23-26

[53] Clarkson, Christopher R *Production data analysis of unconventional gas wells: Review of theory and best practices.* 116

[54] Fetkovich, M. J., E. J. Fetkovich, and M. D. Fetkovich. *Useful concepts for decline curve forecasting, reserve estimation, and analysis.* SPE Reservoir Engineering 11, no. 01 (1996): 13-22.

[55] Clarkson, Christopher R *Production data analysis of unconventional gas wells: Review of theory and best practices*. 102

[56] Clarkson, Christopher R. *Integration of rate-transient and microseismic analysis for unconventional gas*

density has increased in many plays where HF stimulations are employed, gathering micro-seismic data has become more feasible and cost-effective. Improved coring techniques have also brought down costs to obtain accurate geologic cores, increasing understanding of underlying matrix porosity and permeability. Both of these factors allow for more accurate flow regime modeling, customized to the unique geologic and completion factors of each play. Use of RTA has demonstrated more accurate prediction of long-term reservoir behavior and production rates.[57] Increasing the accessibility of micro-seismic and geologic core data, coupled with better techniques for applying RTA to unconventional reservoirs has the potential to improve reserves estimation and reduce overall uncertainty greatly.

However, despite improvements in technology and RTA techniques for unconventional reservoirs, structural hurdles to widespread adoption of RTA remain. Decline curve analysis based solely on statistical well performance across the play is much simpler and more cost-effective than RTA, despite recent improvements in technology for obtaining the data necessary to performs the analysis more cost-effective. Domestic tight oil and gas production has primarily been driven by smaller firms which lack access to substantial research capital for analysis. Additionally, the rapid pace of drilling in many tight oil and gas plays does not provide sufficient time for more thorough reservoir analysis. A rapid drilling pace has led to several negative effects, including fracture interference, where the fracture network from one well combines with the fracture network from an adjacent well, leading to substantial decreases in well pressure and

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reservoirs: where reservoir engineering meets geophysics. CSEG Rec 36 (2011): 44-61.

[57] Clarkson, Christopher R *Production data analysis of unconventional gas wells: Review of theory and best practices*. 116

lower EURs.[58] The pace of drilling to keep production rates sustained has not left sufficient time for many firms to analyze the producing formation or characterize stimulated reservoirs adequately.

4.3 Implications for Future Energy Policy

While geologically, the technically recoverable reserves to sustain current consumption rates for a century are present, low recovery and high decline rates make this promise uncertain.[59] Similar statistics related to domestic oil supply are also typically uncertain, as reserves estimation and high decline in HF wells make supplying the entirety of the reserves infeasible. This comparative analysis of EURs demonstrated the uncertainty of reserves estimation from HF-stimulated wells, making the task of estimating the length of time domestic reserves will be able to supply consumption difficult, and in need of further evaluation before major policy decisions are made.

Reserves added through HF stimulation are and will continue to be a critical component of the US energy portfolio, and consequently US energy security. Future policy decisions must recognize, due to uncertainty in reserves estimation and high decline rates in HF wells, that domestic oil and gas is unlikely to sustain the energy demands of the US in the long term without the development of a diverse array of other energy sources. Currently, barriers to diversifying the energy sources of the US are numerous, derived from both social and economic considerations. Established relationships between traditional energy industries, government, and society mean that a shift in policy can often be difficult.

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[58] Jacobs, Trent. *Frac Hits Reveal Well Spacing May be Too Tight, Completion Volumes Too Large.* Journal of Petroleum Technology 69, no. 11 (2017): 35-38.
[59] EIA, US. *Annual Energy Outlook 2018*.

This makes current policy unfavorable to the development of emerging energy technologies, even if those technologies are superior to traditional energy sources. This has been referred to as “carbon lock-in,” where conventional energy sources remain dominant due to a number of feedback loops between government, industry, and society.[60] The energy return on energy investment (ERoEI), affordability, and structural advantages of fossil fuels make them attractive for elected officials, who would lose their offices if energy costs increased.

Elected officials also face pressure from the emerging concept of “energy independence.” This notion is popular since past reliance on foreign oil has brought economic hardship to the US, and because the dramatic increase in oil and gas production due to HF stimulated economic growth in many communities.[61] Elected officials opposed to furthering the development of domestic petroleum resources, or skeptical of the sustainability of the HF boom, would be considered unpopular with a significant portion of the American electorate. This pressure keeps existing energy policies in place, leaving industries researching emerging technologies reluctant to pursue the development of alternative energy sources until favorable policy is in place. This “policy uncertainty” is a major barrier to energy diversification in the United States.[62] Due to oil and gas being so closely tied to US energy policy, security, and economic development, the structural and policy mechanisms governing the current energy paradigm make diversification of energy sources and policy changes difficult. Uncertainty associated with the HF boom

[60] Brown, Marilyn A., and Benjamin K. Sovacool. *Climate change and global energy security: technology and policy options.* MIT Press, 2011.
[61] Desilver, Drew. *Oil and gas boom feeds greatest real wage growth in U.S., but will it last?* Pew Research Center, 2016
[62] Brown, Marilyn A., and Benjamin K. Sovacool. *Climate change and global energy security: technology and policy options.*

for both oil and natural gas resources in the US will become increasingly important in the coming decades. For presidential administrations and legislators on committees dealing with energy policy, an assessment of oil and gas resources in the United States based on the latest reservoir characterization techniques and best available data, conducted in collaboration with the oil industry, would be an important step toward reducing uncertainty in recoverable reserves. Better information on individual well performance, which could be reported confidentially to agencies like the EIA, would also lead to more accurate predictions of reserves and future production. For example, oil and gas leases on Federal lands could be accompanied with a reporting requirement for well performance describing specific reservoir characteristics and flow behavior. Additionally, policies that encourage the development of alternative energy technologies and increase energy efficiency serve as a hedge on the estimations of future oil and gas production. Use of policy mechanisms like production tax credits for alternative energy sources and energy efficiency standards for homes, appliances, and vehicles would diversify the US energy portfolio without posing a direct challenge to the fossil fuel industry and their associated constituencies.

5.0 Conclusion

The comparison of production data for the Permian, Eagle Ford, Bakken, and Niobrara tight oil plays and the Haynesville and Marcellus tight gas plays yielded varying results, ultimately indicating uncertainty in the estimation of reserves using decline curve analysis. This uncertainty confirms the necessity of the wider adoption by industry of more advanced reservoir analysis techniques like RTA for unconventional reservoirs, using better geologic data and new technologies like micro-seismic monitoring to better understand fracture networks and geologies. Further refining and reducing the uncertainty in reserves estimating using decline curves will require additional work and data. This analysis was limited by access to comprehensive production data to inform the models, along with a lack of reliable data on industry EUR estimates. Further work with access to more reliable and comprehensive data would greatly enhance the quality and significance of the results.

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7.0 Appendix

7.1 Detailed Model Results

Displayed below in Tables 7.1.1-7.1.6 are the modeled EUR results for the reference and best case scenarios, broken down into each play. The coefficient of determination (R^2) is also displayed to demonstrate the fitness of each decline curve model to the actual production data, and the sample size, or number of wells included in the mean daily production data to which the decline curve models were fit, is also included. While most sample sizes exceeded 1,000 wells, some samples, primarily for the Haynesville shale, were smaller than 500 wells, making the samples less representative of average well production for the play.

Year	Reference Case Model EUR (bbls)	Best Case Model EUR (bbls)	Fitness (R^2)	Sample Size (No. Wells)
2011	111,153	159,129	0.996	600
2012	120,649	172,463	0.999	1,187
2013	139,540	199,044	0.997	1,808
2014	175,273	237,734	0.997	2,681
2015	273,639	341,982	0.996	2,580

Table 7.1.1: Model Results for the Permian Basin play with accompanying fitness of results

Year	Reference Case Model EUR (bbls)	Best Case Model EUR (bbls)	Fitness (R^2)	Sample Size (No. Wells)
2011	188,059	204,858	0.993	1,629
2012	192,242	211,589	0.992	2,867
2013	194,611	212,952	0.994	3,657
2014	197,796	207,517	1.000	4,004
2015	197,524	207,023	0.998	2,709

Table 7.1.2: Model Results for the Eagle Ford shale play with accompanying fitness of results

Year	Reference Case Model EUR (bbls)	Best Case Model EUR (bbls)	Fitness (R^2)	Sample Size (No. Wells)
2011	217,476	438,856	0.990	1,235
2012	213,834	360,090	0.997	1,798
2013	221,850	347,543	0.994	1,985
2014	256,806	367,952	0.999	2,160
2015	268,534	317,933	0.995	1,493

Table 7.1.3: Model Results for the Bakken shale play with accompanying fitness of results

Year	Reference Case Model EUR (bbls)	Best Case Model EUR (bbls)	Fitness (R^2)	Sample Size (No. Wells)
2011	76,187	94,323	0.996	338
2012	103,552	139,961	0.995	706
2013	125,820	156,073	0.994	1,105
2014	129,576	157,072	0.994	1,640
2015	127,025	143,070	0.994	1,389

Table 7.1.4: Model Results for the Niobrara shale play with accompanying fitness of results

Year	Reference Case Model EUR (Mcf)	Best Case Model EUR (Mcf)	Fitness (R^2)	Sample Size (No. Wells)
2011	3,844,896	5,603,382	0.997	1,006
2012	3,995,522	6,100,552	0.994	1,334
2013	4,761,303	8,748,108	0.991	1,349
2014	5,687,129	8,268,238	0.990	1,188
2015	5,524,345	9,284,957	0.996	998

Table 7.1.5: Model Results for the Marcellus shale play with accompanying fitness of results

Year	Reference Case Model EUR (Mcf)	Best Case Model EUR (Mcf)	Fitness (R^2)	Sample Size (No. Wells)
2011	4,042,289	4,180,150	0.992	842
2012	4,001,091	4,017,615	0.995	299
2013	3,946,662	3,946,662	0.998	170
2014	5,215,425	5,215,425	0.996	160
2015	5,240,774	5,240,774	0.995	141

Table 7.1.6: Model Results for the Haynesville shale play with accompanying fitness of results

7.2 Comparison of Model Results with EIA and Industry Data

Model results are compared with EIA data in Tables 7.2.1-7.2.6 and industry data in Tables 7.2.7-7.2.12 below, organized by play.

Year	EIA EUR (bbls)	Reference Case Model EUR (bbls)	Best Case Model EUR (bbls)	EIA vs. Model Ref	EIA vs. Model Best
2011	228,000	111,153	159,129	116,847	68,871
2012	108,000	120,649	172,463	-12,649	-64,463
2013	131,000	139,540	199,044	-8,540	-68,044
2014	167,000	175,273	237,734	-8,273	-70,734
2015	151,000	273,639	341,982	-122,639	-190,982
			Average	**-7,051**	**-65,070**

Table 7.2.1: Comparison of modeled results and EIA data for the Permian basin play

Year	EIA EUR (bbls)	Reference Case Model EUR (bbls)	Best Case Model EUR (bbls)	EIA vs. Model Ref	EIA vs. Model Best
2011	227,000	188,059	204,858	38,941	22,142
2012	162,000	192,242	211,589	-30,242	-49,589
2013	186,500	194,611	212,952	-8,111	-26,452
2014	186,500	197,796	207,517	-11,296	-21,017
2015	198,500	197,524	207,023	976	-8,523
			Average	**-1,946**	**-16,688**

Table 7.2.2: Comparison of modeled results and EIA data for the Eagle Ford shale play

Year	EIA EUR (bbls)	Reference Case Model EUR (bbls)	Best Case Model EUR (bbls)	EIA vs. Model Ref	EIA vs. Model Best
2011	225,000	217,476	438,856	7,524	-213,856
2012	207,000	213,834	360,090	-6,834	-153,090
2013	208,000	221,850	347,543	-13,850	-139,543
2014	226,500	256,806	367,952	-30,306	-141,452
2015	234,500	268,534	317,933	-34,034	-83,433
			Average	**-15,500**	**-146,275**

Table 7.2.3: Comparison of modeled results and EIA data for the Bakken shale play

Year	EIA EUR (bbls)	Reference Case Model EUR (bbls)	Best Case Model EUR (bbls)	EIA vs. Model Ref	EIA vs. Model Best
2011	120,000	76,187	94,323	43,813	25,677
2012	120,000	103,552	139,961	16,448	-19,961
2013	130,000	125,820	156,073	4,180	-26,073
2014	120,000	129,576	157,072	-9,576	-37,072
2015	120,000	127,025	143,070	-7,025	-23,070
			Average	**9,568**	**-16,100**

Table 7.2.4: Comparison of modeled results and EIA data for the Niobrara shale play

Year	EIA EUR (Mcf)	Reference Case Model EUR (Mcf)	Best Case Model EUR (Mcf)	EIA vs. Model Ref	EIA vs. Model Best
2011	4,160,000	4,042,289	4,180,150	117,711	-20,150
2012	3,709,000	4,001,091	4,017,615	-292,091	-308,615
2013	4,279,000	3,946,662	3,946,662	332,338	332,338
2014	4,266,000	5,215,425	5,215,425	-949,425	-949,425
2015	4,269,000	5,240,774	5,240,774	-971,774	-971,774
			Average	**-352,648**	**-383,525**

Table 7.2.5: Comparison of modeled results and EIA data for the Haynesville shale play

Year	EIA EUR (Mcf)	Reference Case Model EUR (Mcf)	Best Case Model EUR (Mcf)	EIA vs. Model Ref	EIA vs. Model Best
2011	2,065,000	3,844,896	5,603,382	-1,779,896	-3,538,382
2012	1,589,000	3,995,522	6,100,552	-2,406,522	-4,511,552
2013	1,897,000	4,761,303	8,748,108	-2,864,303	-6,851,108
2014	1,934,000	5,687,129	8,268,238	-3,753,129	-6,334,238
2015	1,963,000	5,524,345	9,284,957	-3,561,345	-7,321,957
			Average	**-2,873,039**	**-5,711,447**

Table 7.2.6: Comparison of modeled results and EIA data for the Marcellus shale play

Year	Industry EUR (bbls)	Reference Case Model EUR (bbls)	Best Case Model EUR (bbls)	Industry vs. Model Ref	Industry vs. Model Best
2011	250,000	111,153	159,129	138,847	90,871
2012	308,000	120,649	172,463	187,351	135,537
2013	315,000	139,540	199,044	175,460	115,956
2014	330,000	175,273	237,734	154,727	92,266
2015	340,000	273,639	341,982	66,361	-1,982
			Average	**144,549**	**86,530**

Table 7.2.7: Comparison of modeled results and industry data for the Permian basin play

Year	Industry EUR (bbls)	Reference Case Model EUR (bbls)	Best Case Model EUR (bbls)	Industry vs. Model Ref	Industry vs. Model Best
2011	500,000	188,059	204,858	311,941	295,142
2012	500,000	192,242	211,589	307,758	288,411
2013	400,000	194,611	212,952	205,389	187,048
2014	450,000	197,796	207,517	252,204	242,483
2015	600,000	197,524	207,023	402,476	392,977
			Average	**295,954**	**281,212**

Table 7.2.8: Comparison of modeled results and industry data for the Eagle Ford shale play

Year	Industry EUR (bbls)	Reference Case Model EUR (bbls)	Best Case Model EUR (bbls)	Industry vs. Model Ref	Industry vs. Model Best
2011	200,000	217,476	438,856	-17,476	-238,856
2012	250,000	213,834	360,090	36,166	-110,090
2013	400,000	221,850	347,543	178,150	52,457
2014	400,000	256,806	367,952	143,194	32,048
2015	450,000	268,534	317,933	181,466	132,067
			Average	**104,300**	**-26,475**

Table 7.2.9: Comparison of modeled results and industry data for the Bakken shale play

Year	Industry EUR (bbls)	Reference Case Model EUR (bbls)	Best Case Model EUR (bbls)	Industry vs. Model Ref	Industry vs. Model Best
2011	300,000	76,187	94,323	223,813	205,677
2012	310,000	103,552	139,961	206,448	170,039
2013	350,000	125,820	156,073	224,180	193,927
2014	350,000	129,576	157,072	220,424	192,928
2015	350,000	127,025	143,070	222,975	206,930
			Average	**219,568**	**193,900**

Table 7.2.10: Comparison of modeled results and industry data for the Niobrara shale play

Year	Industry EUR (Mcf)	Reference Case Model EUR (Mcf)	Best Case Model EUR (Mcf)	Industry vs. Model Ref	Industry vs. Model Best
2011	4,500,000	4,042,289	4,180,150	457,711	319,850
2012	5,000,000	4,001,091	4,017,615	998,909	982,385
2013	5,500,000	3,946,662	3,946,662	1,553,338	1,553,338
2014	6,000,000	5,215,425	5,215,425	784,575	784,575
2015	6,500,000	5,240,774	5,240,774	1,259,226	1,259,226
			Average	**1,010,752**	**979,875**

Table 7.2.11: Comparison of modeled results and industry data for the Haynesville shale play

Year	Industry EUR (Mcf)	Reference Case Model EUR (Mcf)	Best Case Model EUR (Mcf)	Industry vs. Model Ref	Industry vs. Model Best
2011	7,000,000	3,844,896	5,603,382	3,155,104	1,396,618
2012	7,700,000	3,995,522	6,100,552	3,704,478	1,599,448
2013	8,400,000	4,761,303	8,748,108	3,638,697	-348,108
2014	9,100,000	5,687,129	8,268,238	3,412,871	831,762
2015	9,800,000	5,524,345	9,284,957	4,275,655	515,043
			Average	**3,637,361**	**798,953**

Table 7.2.12: Comparison of modeled results and industry data for the Marcellus shale play