RAILROAD COMMISSION OF TEXAS

HEARINGS DIVISION

AMENDED PROPOSAL FOR DECISION

OIL & GAS DOCKET NO. 02-0284942

THE APPLICATION OF PIONEER NATURAL RES. USA, INC., TO CONSIDER PERMANENT GAS WELL CLASSIFICATION FOR ALL WELLS ON THE RIDLEY 01 UNIT, SUGARKANE (EAGLE FORD) FIELD, KARNES COUNTY, TEXAS

HEARD BY: Paul Dubois – Technical Examiner
Marshall Enquist – Administrative Law Judge

APPEARANCES:	**REPRESENTING:**
APPLICANT:	
Brian Sullivan, P.E.	Pioneer Natural Res. USA, Inc.
Clark Jobe	
John Miller, P.E.	
Cary McGregor, P.E.	
Donna Chandler, P.E.	
Weldon Pierson	
Mark Murray	
David Simpson	
Kelly Ramey	
Katherine Gallagher	
OBSERVER:	
Jamie Nielson	Burlington Resources Oil and Gas Company LP

PROCEDURAL HISTORY

Application Filed:	October 2, 2013
Notice of Hearing:	October 23, 2013
Dates of Hearings:	November 13, 2013, April 29, 2015
Proposal For Decision Issued:	October 27, 2015
Conference Date and Remand:	December 15, 2015
Remanded Hearing:	April 8, 2016
Transcript Received:	April 25, 2016
Amended Proposal for Decision Issued:	September 6, 2016

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1. STATEMENT OF THE CASE

Pioneer Natural Resources USA, Inc. (Pioneer) seeks permanent gas well classification for all wells on its Ridley 01 Unit, in the Sugarkane (Eagle Ford) Field, Karnes County, Texas. The Commission has historically granted permanent gas well classification based on the following demonstration of evidence:

- At initial conditions, the hydrocarbon fluid in the reservoir exists as a single-phase gas (that is, there are no liquid hydrocarbons in the reservoir before production begins); and

- Liquid hydrocarbons that may form in the reservoir by retrograde condensatation are immobile and will not flow as liquids through the reservoir and into the production stream.

The preponderance of the evidence in the record does not indicate that a well drilled and completed on the Ridley 01 Unit will likely produce from a reservoir containing only single-phase gas at initial conditions, or that liquid hydrocarbons which may condense in the reservoir are immobile.

Eleven wells were completed in the Ridley 01 Unit between July 6, 2011, and October 8, 2013. Commission staff has administratively approved gas well classification for four of these wells (Nos. 1H, 3H, 7H and 9H) based on field rules and initial gas to liquid hydrocarbon ratios (GLR)[1] of 3,000 standard cubic feet per barrel (scf/bbl)[2] or greater. Pioneer argues, based on records of some wells on the lease and other wells in the area, that the Ridley 01 Unit wells produce retrograde gas, and therefore all wells on the Ridley 01 Unit should be eligible for permanent classification as gas wells. Pioneer's stated purpose for requesting the classification is to ease its present administrative burden; the Ridley 01 Unit was pooled and set up as a gas unit, and Pioneer prefers to manage all wells on the Ridley 01 Unit as gas wells. Although not a part of its argument, gas well classification will entitle Pioneer to certain significant tax benefits, which Pioneer has claimed for the wells already classified as gas wells. Such a tax benefit would not otherwise be available to operators of oil wells.[3]

A Proposal for Decision (PFD) in this case was issued on October 27, 2015. In that PFD the Administrative Law Judge and Technical Examiner (hereinafter, "Examiners") recommended Pioneer's application be denied. The Commission took up this matter in its public conference on

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[1] Generally speaking, the term "gas to liquid ratio", or GLR, is synonymous with "gas to oil ratio", or GOR. While GOR appears in statutory and statewide rule language, the term GLR tends to appear on Commission gas well classification forms. The "liquid" in GLR pertains to hydrocarbon liquids, and is inclusive of oil and condensate. However, 16 Tex. Admin. Code §3.79(11)(C) states that the term "crude petroleum oil" does not include hydrocarbon fluids that are gas in the reservoir but are removed from the reservoir in a liquid phase. The Examiners will predominantly use the term GLR, unless the context requires greater precision.

[2] In this PFD the term "scf/bbl" represents a GLR ratio, but the origin of the ratio, whether from a separator or the stock tank is either clear based on the context or uncertain based on the source reference. In contrast, the term "scf/stb", or standard cubic feet per stock tank barrel, will represent a GLR in the evidence that is specifically identified as such.

[3] *See* Tex. Tax Code §201.057, and 16 Tex. Admin. Code §3.101. All gas wells completed in the Sugarkane (Eagle Ford) Field are eligible for this severance tax reduction, whether or not they are classified as "permanent" gas wells.

December 15, 2015. At the applicant's request the Commission remanded the case back to the Hearings Division so Pioneer could present additional evidence to support its case. Specifically, Pioneer asked the Commission to consider evidence that was entered into the record in two other cases. In those cases, Devon Energy Production Co., LP ("Devon") sought to amend the field rules for the nearby Eagleville (Eagle Ford-1) and Eagleville (Eagle Ford-2) fields to provide for permanent gas well classification based on an initial producing GLR greater than 2,000 scf/bbl.[4] This remand dramatically expanded the scope of the present case. Whereas Pioneer initially sought gas well classification under existing rules and criteria, the Devon applications seek to justify and adopt a new standard within the existing regulatory framework.

The Examiners conclude the Eagle Ford Formation in this narrow transitional area is a hybrid reservoir type exhibiting characteristics of both volatile oil and retrograde gas—a finding which is entirely consistent with the Ridley 01 Unit's spatial location with the Eagle Ford Formation transition area between predominantly gas wells and predominantly oil wells, fully supported by the analytical evidence, and fully supported by recent research describing the complex phase behavior of unconventional shale reservoirs. Consequently, the Examiners conclude Pioneer's application—through the Devon evidence—to reduce the GLR criteria for gas well classification from 3,000 scf/bbl to 2,000 scf/bbl is not justified. However, the evidence suggests individual wells may be classified as gas wells on a temporary basis according to well-specific information reflecting the current phase-in-place characteristics of each well-specific reservoir area.

Therefore, the Examiners maintain their original recommendation that Pioneer's application be denied, with one adjustment. The Examiners conclude the preponderance of evidence in the record demonstrates that the Ridley Unit Well No. 6H was completed with an initial GLR of greater than 3,000 scf/bbl, and therefore meets the Commission's current field rule criterion for permanent gas well classification in the Sugarkane (Eagle Ford) Field. The Examiners conclude the evidence in the record demonstrates that Ridley Unit Well Nos. 2H, 4H, 5H, 8H, 10H and 11H are oil wells.

2. APPLICABLE LAW

The Natural Resources Code §86.002(5) defines gas well as one that:

> A. *Produces gas not associated or blended with oil at the time of production;*
>
> B. *Produces more than 100,000 cubic feet of gas to each barrel of oil from the same producing horizon; or*

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[4] Exh. No. 38. *See* Oil and Gas Docket Nos. 01-0297472 and 02-0297714: The Applications of Devon Energy Production Co., LP to Amend Field Rules for the Eagleville (Eagle Ford-1) and Eagleville (Eagle Ford-2) Fields, respectively. Final Orders pending.

> *C. Produces gas from a formation or producing horizon productive of gas only encountered in a well bore through which oil also is produced through the inside of another string of casing.*

Similarly, a gas well is defined in 16 Tex. Admin. Code § 3.79(11) ("Statewide Rule" 3.79[11]) as any well:

> *A. Which produces natural gas not associated or blended with crude petroleum oil at the time of production;*
>
> *B. Which produces more than 100,000 cubic feet of natural gas to each barrel of crude petroleum oil from the same producing horizon; or*
>
> *C. Which produces natural gas from a formation or producing horizon productive of gas only encountered in a wellbore through which crude petroleum oil also is produced through the inside of another string of casing or tubing. A well which produces hydrocarbon liquids, a part of which is formed by a condensation from a gas phase and a part of which is crude petroleum oil, shall be classified as a gas well unless there is produced one barrel or more of crude petroleum oil per 100,000 cubic feet of natural gas; <u>and that the term "crude petroleum oil" shall not be construed to mean any liquid hydrocarbon mixture or portion thereof which is not in the liquid phase in the reservoir, removed from the reservoir in such liquid phase, and obtained at the surface as such.</u>*[5]

In its Final Order for Oil & Gas Docket No. 02-0272551, dated January 10, 2012, the Commission established a permanent gas well classification criteria for all wells in the Sugarkane (Eagle Ford) Field.[6] Pioneer intervened in support of the application in that case. The adopted classification rule states:

> *Therefore, it is ordered by the Railroad Commission of Texas that all wells <u>completed with a gas-oil ratio of 3,000 cubic feet per barrel and above</u> in the Sugarkane (Eagle Ford) Field, Bee, De Witt, Karnes, and Live Oak, Counties, Texas, are permanently classified as gas wells without the need of further administrative review, effective the date of initial completion (emphasis added).*

This gas well classification rule has since been incorporated into the field rules for the Sugarkane (Eagle Ford) Field, which were most recently amended in Oil & Gas Docket 02-0295357, signed on April 28, 2015.

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[5] Emphasis added; the emphasized clause significantly bears on recent gas well classification cases, including the subject application.

[6] Oil & Gas Docket No. 02-0272551: The Application of Petrohawk Operating Company to Consider a Permanent Gas Well Classification for the Sugarkane (Eagle Ford) Field in Bee, De Witt, Karnes, and Live Oak Counties, Texas. Final Order dated January 10, 2012.

3. MATTERS OFFICIALLY NOTICED

In its request for the Commission to remand the matter back to the Hearings Division, Pioneer's counsel argued that the Devon evidence represents new data, and that "the Commission has historically been interested in the best and newest science available."[7] Consequently, the Examiners notified Pioneer of their intent to take official notice of a number of recently published learned papers relevant to the phase behavior of hydrocarbon fluids in unconventional shale reservoirs. In addition, the Examiners have taken official notice of PFDs in a number of docketed cases, and Pioneer has also requested the Examiners take official notice of certain materials. **Attachment A** contains a list of the materials for which the Examiners have taken official notice, either at their own initiative or upon the request of Pioneer.

4. PIONEER'S EVIDENCE

This case concerns (1) establishment of a new gas well classification criteria through the consideration of the Devon evidence, and (2) the evaluation of a large amount of data against both the existing and proposed gas well classification criteria. At the November 13, 2013 and April 29, 2015 hearings, expert testimony was offered on behalf of Pioneer by John Miller, P.E., a consulting petroleum engineer with FTI Platt Sparks. At the April 8, 2016 hearing Mr. Miller was joined by Cary McGregor, P.E., also of FTI Platt Sparks. Mr. McGregor also represented Devon in its applications for amended field rules in the two Eagleville field cases. Employees of Pioneer or Devon did not testify in either case. All told, Pioneer submitted the following evidence into the record of this matter:

- November 13, 2013: Exhibit Nos. 1 through 17 and Transcript Vol. 1.

- April 29, 2015: Exhibit Nos. 18 through 36 and Transcript Vol. 2.

- April 8, 2016: Exhibit Nos. 37 through 60 and Transcript Vol. 3, and including the following:

    - Exhibit No. 38 contained Devon Exhibit Nos. 1 through 41.
    - Exhibit No. 39 contained late-filed exhibits and other materials requested by the Examiners in the Devon matters and/or submitted by Devon for consideration.
    - Exhibit No. 40 is a transcript of the November 23, 2015 Devon hearing.

Pioneer's evidence will be summarized as follows: First, data from the Ridley 01 Unit wells will be presented, including production data and reservoir fluid characteristics; Second, data from wells that offset or are nearby to the Ridley 01 Unit will be presented, specifically focusing on the reservoir fluid characteristics and well classification; Third, the Devon evidence that Pioneer offers to support a new 2,000 scf/bbl gas well classification criteria will be presented.

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[7] Pioneer's Motion to Reopen and to Supplement the Record, page 1. Oil & Gas Docket No. 02-0284942. November 12, 2015.

4.1 The Ridley 01 Unit

4.1.1 Unit Location and Description

Pioneer's Ridley 01 Unit is located about 4.5 miles west of Runge, in Karnes County, Texas. Pioneer has completed eleven wells on the 1,017.423 acre unit. The Ridley 01 Unit was created by pooling twelve tracts of land, most of which were too small in size, too irregular in shape, or not optimally oriented to be efficiently developed independently.[8] The current field rules set the standard proration unit size for a gas well at 320 acres, and an operator may chose optional 80-acre units. Pioneer stated the Ridley 01 Unit was pooled for development of the Sugarkane (Eagle Ford) Field with gas wells; Pioneer expected all wells on the Ridley 01 Unit would prove to be gas wells based on initial characteristics of individual wells.[9]

4.1.2 Eagle Ford Formation

The Eagle Ford Formation is widely considered to be an unconventional play. In this part of Texas it exhibits a unique gradation of reservoir fluid classification as one moves from up-dip in the northwest to down-dip in the southeast. Up-dip wells tend to classify as oil wells. Likewise, down-dip wells tend to classify as gas wells. The area in between may be referred to as "condensate-rich" or "liquids-rich." Wells completed in this transition zone produce large volumes of hydrocarbon liquids. Pioneer asserts that the produced liquids may be shown to be condensates at the surface that exist as a gas at reservoir conditions. As shown on **Attachment B**, the Ridley 01 Unit is located in this liminal transition zone between oil and gas. Pioneer submitted a substantial amount of evidence describing certain fluid characteristics (e.g., liquid gravity and color) and classification of wells adjacent to and near the Ridley 01 Unit. Those exhibits also illustrated the gradational fluid characteristics from northwest to southeast, as mentioned above.[10]

In a conventional reservoir a gas cap may be present on top of the oil zone. In the Eagle Ford Formation, however, this is not the case; gas wells are generally located downdip from oil wells. This phenomena occurs as a result of two primary factors. First, the formation matrix is impermeable and the pore spaces are very small—in the nanometer range. As a result, there are no significant means for hydrocarbon fluids to migrate within the formation, which would otherwise allow for the conventional gravity/density separation and distribution of gas on top of oil on top of water. Second, the gas window is downdip and at deeper depths. The deeper depths result in increased temperature and pressure over time, and consequently, create greater thermal maturity than the shallower formation bearing oil. Deeper, hotter reservoir conditions favor the formation of natural gas.[11] The Eagle Ford Formation in this area is considered to be a high pressure high temperature (HPHT) reservoir, as that term is generally defined by industry.

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[8] Exh. No. 36.
[9] Tr. vol. 2, 31:18-23.
[10] Exh. Nos. 2, 5, 6, 19, 23, 24, 28, 41, 46, 47, 48 & 53.

[11] Vol. 3 Tr. 29 – 30.

4.1.3 Hydrocarbon Production

All eleven wells have been drilled, completed, tested and were producing in January 2015. The eleven Ridley 01 Unit wells are all completed in the same Eagle Ford Formation interval, with total vertical depths of about 12,850 feet.[12] The cumulative production from the Ridley 01 Unit wells through January 2015 is presented on **Table 1**.

TABLE 1
CUMULATIVE WELL PRODUCTION THROUGH JANUARY 2015[13]

Well No.	API No.	Gas ID No.	Completion Date	Cumulative Gas Production (mcf)[14]	Cumulative Oil/Condensate Production (bbl)
1H	255-31871	263530	7/6/2011	1,106,007	404,985
2H	255-32196	268662	2/5/2012	764,343	301,403
3H	255-32753	269546	12/20/2012	459,526	160,763
4H	255-32821	269685	1/4/2013	651,521	226,325
5H	255-32959	n/a	10/8/2013	262,156	161,885
6H	255-32960	n/a	10/8/2013	350,293	193,091
7H	255-32961	271813	10/8/2013	752,660	254,147
8H	255-32976	n/a	10/4/2013	348,464	184,671
9H	255-32975	271605	10/4/2013	599,403	205,089
10H	255-32978	n/a	10/4/2013	347,559	194,975
11H	255-32977	n/a	10/4/2013	349,649	199,530
			Unit Cumulative	**5,991,581**	**2,486,864**

[12] Exh. No. 31.
[13] Exh. Nos. 12 & 21.
[14] The Cumulative Gas Production Data for Well Nos. 1H, 2H, 3H, 4H, 7H and 9H (that is, all wells for which Gas ID Nos. have been assigned) appears to include the well "separation extraction loss," which is an aspect of the Commission's gas proration system. In the Commission's historical statutory responsibility to prorate all production from gas wells—that is, both gas and condensate—as gas, the well separation extraction loss (i.e., an estimate of the gas volume equivalent of condensate production) is added back to the gas produced from the formation on the basis of 1,100 scf gas per barrel of condensate. For example, Production Reports filed by Pioneer indicate that Well No. 1H produced 660,521 mcf formation gas and 404,985 bbl condensate through January 2015. The reported production was converted by the Commission's proration system such that a production data query for Well No. 1H indicates 1,106,007 mcf gas, which is 660,521 mcf formation gas produced plus 1,100 scf of gas for each barrel of condensate produced. Separation extraction loss is not applied until after a Gas ID No. is assigned to a well; once applied, the separation extraction loss results in a higher gas volume being carried in Commission records than actually produced from the reservoir in the gas phase. *GLR values calculated based on production data that includes the separation extraction loss will be 1,100 scf/bbl higher than the GLR based on field production rate measurements. Therefore, using a GLR ratio that includes the separation extraction loss will overestimate the GLR by 1,100 scf/bbl.*

Pioneer reports that as of January 2016 only nine of the Ridley 01 Unit wells remain in production; the 2H and 5H wells are not producing. The 5H well has consistently underperformed due to mechanical issues. Through January 2016, Pioneer reports the total unit production to be 8,130,296 mcf gas and 2,839,665 bbl hydrocarbon liquids, for a unit-wide cumulative GLR of 2,863 scf/bbl.[15]

4.1.4 Administrative Gas Well Classification

Field rules in the Sugarkane (Eagle Ford) Field allow for permanent gas well classification when a well is completed with a GLR of 3,000 scf/bbl or greater. A gas well classification criterion based on GLR may save operators the expense of having to run more costly laboratory analysis, such as a recombined wellstream compositional analysis for heptanes-plus (C_7+) or pressure-volume-temperature (PVT) analysis, to secure gas well classification. A C_7+ analysis costs about $5,000 and takes two weeks for results. The cost to run a PVT test is about $25,000 to $30,000 and takes six months.[16] Lacking a 3,000 scf/bbl or greater GLR, an operator retains the option to seek gas well classification via an affirmative C_7+ or PVT analysis.

Commission staff has administratively granted gas well classification for four of the wells (Nos. 1H, 3H, 7H and 9H). The bases for these determinations are as follows:[17]

- Well No. 1H met two separate criteria for gas well classification, including an August 17, 2011 tested GLR of 3,032 scf/bbl on Forms G-1 and G-5, and a full wellstream recombination composition of 8.42 mole percent C_7+ for a sample collected on July 7, 2011.

- Well No. 3H demonstrated a GLR of 3,062 scf/bbl on Forms G-1 and G-5 based on a December 23, 2012 test.

- Well No. 7H demonstrated a GLR of 3,148 scf/bbl on Forms G-1 and G-5 based on a November 5, 2013 test.

- Well No. 9H demonstrated a GLR of 4,534 scf/bbl on Forms G-1 and G-5 based on a October 24, 2013 test.

Commission staff denied gas well classification for two of the wells (Nos. 2H and 4H) based on the field rules and current Commission policy requirements for permanent gas well classification (neither well demonstrated a GLR of greater than 3,000 scf/bbl nor a C_7+ of less

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[15] Exh. No. 54. The cumulative GLR of 2,863 scf/bbl appears to include a separation extraction loss for all 11 wells, and thus it ***overestimates*** the GLR by 1,100 scf/bbl. Production report (Form PR) queries indicate Pioneer reported the Ridley 01 Unit production to be 5,006,667 mcf gas and 2,839,655 bbl hydrocarbon liquids through January 2016, which results in a cumulative unit GLR of 1,763 scf/bbl without the separation extraction loss.

[16] Tr. vol. 1, 18:22 to 19:3. The Examiners note that for the 22 visual cell data on Exh. No. 38 (Devon Exh. No. 17) for which sample data and laboratory report date could be identified, the average time for a visual cell PVT analysis was 74 days. Three of those analyses took considerably longer—106, 233, and 326 days. Excepting those three longer turn-around times yielded an average turn around time for 20 visual cell PVT analysis of 52 days.

[17] Exh. No. 56.

than 11 mole percent). Pioneer subsequently requested a hearing that seeks a Commission Final Order granting permanent gas well classification to all wells on the Ridley 01 Unit. Commission records (as of June 14, 2016) indicate that Pioneer has not filed completion reports for the remaining five wells. Pioneer is waiting resolution of the present case before filing the remaining well completion reports.

4.1.5 GLR From Well Data

Pioneer's body of evidence contains GLR data obtained during a variety of events, including initial well testing, sampling for reservoir fluid studies (PVT, C_7+), and daily production data. **Table 2** summarizes GLR data for the Ridley 01 Unit wells. This data indicates that all of the Ridley 01 Unit wells report at least one stock tank GLR value that exceeds the proposed 2,000 scf/bbl gas well classification criteria.

TABLE 2
GLR DATA SUMMARY

	Initial Production Test		**Separator Sample for Laboratory Analysis**			**24-Hour Production Test**		
Well	**Date of Test**	**G-5 GLR cf/bbl**	**Date of Sample**	**Separator GLR scf/sep bbl**	**Stock Tank GLR scf/bbl**	**Date of Test**	**Stock Tank GLR scf/bbl**	**References (Exh. Nos.)**
1H	8/17/2011	**<u>3,032</u>**	7/7/2011		**<u>3,134</u>**			8, 12, 27, 56
2H	2/14/2012	**2,185**	2/13/2013	1,612	**2,093**	2/14/2012	**2,114**	9, 27, 35, 56, 59
			7/23/2013	1,472	1,911			9, 27, 56
3H	12/23/2012	**<u>3,062</u>**						12, 56
4H	1/7/2013	**2,138**	2/22/2013	1,570	1,940	1/7/2013	**2,263**	10, 12, 35,56, 59
			7/23/2013	1,727	**2,205**			56
			11/7/2013	1,753	**2,239**			27, 56
5H						11/17/2013	**2,085**	35, 59
6H			11/7/2013	1,656	**2,046**	10/28/2013	**2,792**	12, 27, 56
7H	11/5/2013	**<u>3,148</u>**				10/28/2013	**<u>3,276</u>**	12, 56
8H			11/7/2013	1,823	**2,216**	10/25/2013	1,618	12, 27, 56
9H	10/24/2013	**<u>4,534</u>**				10/25/2013	**<u>4,483</u>**	12, 56
10H			11/7/2013	1,738	**2,114**	10/25/2013	**2,560**	12, 27, 56
11H			11/7/2013	1,738	**2,114**	10/25/2013	**2,613**	2, 27, 56

Note: **Bold** values indicate the reported GLR exceeds the proposed gas well classification criteria of 2,000 scf/bbl, and **<u>underlined</u>** values indicate the reported GLR exceeds the current gas well classification criteria of 3,000 scf/bbl.

Pioneer asserts that the stock tank GLR values shown in **Table 2**, however, do not include any gas which may be produced by flashing to ambient or standard temperature and pressure in the secondary separator or stock tank. Pioneer argues (below) that the reduction of temperature and pressure from the separator to the liquid stock tank will result in additional gas being generated, or "flashed" from the liquid hydrocarbon stream and the additional gas should be included in GLR calculations.

4.1.6 GLR with Additional Gas Produced ("AGP")

Pioneer asserts that the GLR values derived from first stage separator measurements that were reported on Form G-5 for the Ridley 01 Unit wells do not account for or include all of the gas that evolves from a hydrocarbon fluid stream as it is processed to ambient surface conditions. Mr. Miller testified that "Additional gas can evolve… after the first-stage separator and the second-stage separator in the stock tank." Mr. Miller then began to identify correlations that may be used to fully account for all gas evolved through the surface processing.[18]

Produced fluids from the Ridley 01 Unit wells are surface-processed through a three-stage separation system, as affirmed by Mr. McGregor.[19] The full wellstream enters a high-pressure separator near the wellhead where the fluid components (gas, hydrocarbon liquid, and water) are separated, metered and then recombined. Pioneer collected fluid samples for testing and analysis from the high-pressure separators, which operate at temperature and pressure conditions ranging from 117 to 155°F and 626 to 925 psi, respectively.[20] Pioneer stated that production measurements are conducted based on first stage (high pressure) separator output, and that production reports are filed based on those measurements.[21] The recombined post-separator wellstream is piped to a central gathering point where it is processed through a low-pressure separator, and the three fluids (gas, hydrocarbon liquid, and water) are sent to respective sales points or storage vessels. Final separation may occur in the hydrocarbon liquid stock tank as the wellstream comes to ambient temperature and pressure conditions.

Fluid phase changes—and subsequent GLR changes—as the produced fluid moves from sampling (separator) conditions to ambient (stock tank) conditions will yield an increased GLR value (*i.e.*, $GLR_{Separator} < GLR_{Stock\ Tank}$). The increased GLR in the conversion from first stage separator, through second stage separator to stock tank conditions is derived from two mechanisms: (1) separator liquid shrinkage; and (2) secondary flash gas, which Pioneer referred to as AGP:[22]

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[18] Vol. 2 Tr. 48-49.

[19] Vol. 3 Tr. 15: 5-8.

[20] Exh. No. 56 (Tab A, for each well). The Examiners note that no separator conditions were listed on Exhibit No. 56 for Well Nos. 6H, 8H, 10H, and 11H.

[21] In a statement, Brian Sullivan, counsel for Pioneer, stated "In April of 2011, Pioneer's production audit staff came to the Commission and said, how do you want us to report this on form PR? Okay? And the Commission Staff said, report to us off your high-pressure separator. Well, for me, that's not what the PR says. Okay? But that is the instruction Pioneer got from the Commission Staff in 2011." Vol. 3 Tr. 11: 8-15.

[22] The Examiners note that there is no way to readily ascertain whether the GLR value reported on any given Form G-1 or G-5 accounts for shrinkage and/or AGP. However, the applicable statute, Statewide Rules, and Form G-5 instructions are clear that all evolved gas through to ambient surface conditions should be considered. Therefore, in the absence of evidence to the contrary, the GLR values reported on Forms G-1 and G-5 can be relied on to account for shrinkage and all evolved gas at standard surface conditions. In this case, Pioneer's witnesses have testified that the AGP was not included.

- Liquid Shrinkage: The separator liquid shrinks as pressure and temperature are reduced from separator operating to ambient surface conditions. This shrinkage reduces the denominator in the GLR calculation, increasing the GLR. Shrinkage factors are determined from laboratory tests of liquid samples, by use of available correlations, or based on experience in the field, and for the Ridley 01 Unit are reported to range from 0.77 to 0.82 (based on the data in **Table 2**). Shrinkage factors and the resultant changes between separator and stock tank GLR are typically identified on laboratory reports for PVT and C_7+ fluid studies.

- AGP: The shrinkage of the separator liquid is accompanied by a "flash" of gas from the liquid to the gas phase at stock tank (ambient) temperature and pressure conditions. This additional flash gas production increases the numerator in the GLR calculation, increasing the GLR. Pioneer testified that the additional gas produced is not accounted for by the shrinkage factor.[23] Instead, Pioneer identified a publication that provides a method for calculating the additional gas produced based on separator operating conditions and fluid properties.[24] Pioneer utilized the methodology presented by Gold, et al (1989) and McCain (1990) to account for AGP. This method uses other measured variables from the surface facilities of the individual wells, including gas gravity, liquid gravity, 1st stage separator pressure, and 1st and 2nd stage separator temperature.

Pioneer asserts that accurate GLR data should include the AGP when liquids are flashed from primary to secondary separator conditions and from secondary separator to a stock tank environment at ambient surface (or standard) conditions. Pioneer utilized the methodology presented by Gold, et al (1989) and McCain (1990) to account for AGP.[25] Pioneer's calculated GLR plus AGP values for the seven unclassified wells are shown in **Table 3**.

In addition, Pioneer calculated AGP for one other condition set using the methodology of Gold, et al., but using production GLR values from the first month of production from each well, not the well test GLR values. In this scenario, Pioneer adjusted all wells based on identical well fluid characteristics: a constant shrinkage factor (75%) and a constant additional gas produced (690 scf per stock tank barrel [stb]) for all wells. The differences in separator temperature and pressure conditions were not considered. Based on the calculations (which are *not* shown on **Table 3**), Well Nos. 6H and 8H had GLRs greater than 3,000 scf/bbl, and all currently unclassified wells exhibited adjusted GLRs greater than 2,000 scf/bbl.[26]

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[23] Vol. 3 Tr. 205: 10-23.

[24] Exh. Nos. 34 & 57. *See* "An Improved Method for the Determination of the Reservoir-Gas Specific Gravity for Retrograde Gases." Gold, J. K., McCain, W. D., and Jennings, J. W. *Journal of Petroleum Technology*. Society of Petroleum Engineers, July 1989. The same methodology is presented in McCain (1990).

[25] Exh. Nos. 34 & 57

[26] Exh. No. 37.

TABLE 3
ADDITIONAL GAS PRODUCED

Well	Stock Tank GLR* (scf/bbl)	Pressure Sep. 1 (psi)	Temperature Sep. 1 (°F)	Temperature Sep. 2** (°F)	Additional Gas Produced (scf/bbl)	Adjusted GLR (scf/bbl)
2H	2,114	872	148	104	288	**2,402**
4H	2,256	626	118	83	419	**2,682**
5H	2,085	1,060	155	115	841	**2,926**
6H	2,046	970	138	113	1,016	**3,062**
8H	2,216	850	156	101	775	**2,991**
10H	2,114	830	155	108	870	**2,984**
11H	2,114	865	162	107	783	**2,897**

Notes:
(1) The process parameters used in AGP determination are included on the table. For fluid parameters (gas gravity and liquid gravity) see Exh. Nos. 35 or 59.
(2) * Exhibit Nos. 35 and 59 identify the initial GLR data as "Separator1GLR (SCF/STB)." However, the numerical values appear to be the stock tank GLRs described in the evidence, which is technically consistent with the adjustment equation employed.
(3) ** From the Ridley 01 Unit surface process description affirmed by Mr. McGregor (Vol. 3, Tr. 15:5-8), it is not clear whether, after wellstream component metering and recombination at the high pressure separator, the fluids enter well-specific or common secondary separators.
(4) **Bold** values indicate the reported GLR exceeds the proposed gas well classification criteria of 2,000 scf/bbl, and **underlined** values indicate the reported GLR exceeds the current gas well classification criteria of 3,000 scf/bbl.

Finally, Pioneer considered one other methodology to estimate AGP. Pioneer identified 31 Eagle Ford Formation wells with visual cell PVT tests for which flash values were also reported. As an alternative means to account for AGP than described above, Pioneer applied the average, maximum and minimum tested flash rates from these other 31 wells to the Ridley 01 Unit wells. As a result, all Ridley 01 Unit wells demonstrated adjusted GLRs in excess of 3,000 scf/bbl when the maximum additional flash gas was added, and all wells demonstrated adjusted GLRs in excess of 2,000 scf/bbl when either the minimum, average or maximum additional flash gas was added.[27] In this scenario, Pioneer did not establish that the input parameters to the AGP calculations were the same for all wells.

4.1.7 PVT Analysis

Pioneer did not conduct visual cell PVT analyses on any samples from the Ridley 01 Unit wells, although Pioneer refers to these analyses as the "gold standard" for gas well classification.[28] However, Pioneer conducted simulated PVT analysis on recombined samples

[27] Exh. No. 59.

[28] Vol. 3 Tr. 10: 1-6 and 63: 1-2; With regard to a "gold standard," in Exh. No. 40 (Devon Tr. 15: 17-20), Pioneer's Counsel stated that if the PVT analysis indicates a dew point, then the well is a gas well. He made no distinction between temporary or permanent gas well classification.

from two Ridley 01 Unit wells (2H and 4H). Mr. McGregor testified that a simulated PVT analysis using equations of state, such as these, "is not a very reliable indicator" of fluid type determination in these reservoir conditions.[29]

The simulated PVT laboratory report for Well No. 2H, which was completed in February 2012 and sampled for testing on July 23, 2013 (17 months later), concluded the reservoir fluid exists as a saturated oil and free gas at static reservoir conditions of 3,915 psia. The simulated PVT laboratory report for Well No. 4H, which was completed in January 2013 and sampled for testing on July 23, 2013 (6 months later), concluded the reservoir fluid exists as an oil at static reservoir conditions of 6,415 psia.[30] However, Mr. Miller stated these results may not be valid because of a communication error between Pioneer and the laboratory: Pioneer stated it informed the laboratory of the separator GLR, which the laboratory misunderstood to be the stock tank GLR.[31] Mr. Miller stated he did not have sufficient information to recalculate the simulated PVT data based on the corrected GLR. Pioneer did not offer corrected reports from the laboratory corroborating the error.

In a letter to the Examiners dated April 10, 2014, five months after the initial hearing, Pioneer stated that it would be conducting a very detailed PVT analysis of fluids from the Ridley 01 Unit Well No. 8H. Pioneer stated the test would take about four months and cost $40,000. On Pioneer's request, the record was reopened for a second day of hearing on April 29, 2015. At the start of the reopened hearing, counsel for Pioneer stated that no additional PVT analysis was performed on the Ridley Unit wells. The production characteristics of the Ridley Unit wells had changed from "a stabilized flow regime to a flow regime where things are slugging,"[32] a phenomena that prevents representative reservoir samples from being collected.

4.1.8 C_7+ Compositional Analysis

Current Commission policy provides for gas well classification when recombined wellstream analysis indicates a C_7+ composition of less than 11 mole percent. In addition, the academic and industry research on which the 11 mole percent criteria is based indicates that a well produces from a retrograde gas reservoir when the full wellstream C_7+ composition is less than 12.5 to 12.9 mole percent.[33]

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[29] Vol. 3 Tr. 77:20 through 78:9.

[30] Exh. No. 56. The Examiners note Pioneer's testimony that the average initial reservoir pressure in Ridley 01 Unit wells was about 10,300 psi (Vol 3, Tr. 48:15). Therefore, after about 17 months of production the reservoir pressure in Well No. 2 declined about 6,385 psi, and after 8 months of production Well No. 2 declined about 3,885 psi. No other reservoir pressure history information was provided for wells on the Ridley 01 Unit.

[31] Vol. 3 Tr. 182: 1-5. Mr. Miller did not indicate whether or not Pioneer sought a corrected laboratory report from the laboratory after the error was discovered; no corrected reports were offered as evidence.

[32] Tr. Vol. 2, 19: 9-24. "Slugging" refers to a multi-phase fluid flow alternating between high-liquid slugs and high-gas pockets.

[33] T-Bar memorandum dated August 3, 2006. Change in administrative determination policy for gas well classification. From Richard Varela, Director, Oil and Gas Division, to the Commissioners' Offices and initialed by the Commissioners' aides.

Pioneer conducted full wellstream recombination compositional analysis on fluid samples from 7 of the Ridley 01 Unit wells. Multiple analyses were conducted on two of these wells. The results of these analyses are summarized on **Table 4**.

Although only one well demonstrated a C_7+ less than 11 mole percent (No. 1H) and one other well demonstrated a C_7+ less than 12.9 mole percent (No. 2H), Pioneer believes two additional C_7+ standards are appropriate for the Ridley 01 Unit wells. First, based on the Devon evidence, Pioneer asserts that wells with a 14.5 mole percent C_7+ composition meet criteria uniquely valid for the Eagle Ford Formation—as the Devon data is derived solely from Eagle Ford Formation wells. Applying the proposed Devon standard qualifies Well No. 4H for gas well classification. Second, Mr. McGregor cites Moses (1986) as stating that gas condensates have been observed with C_7+ values as high as 15.5 mole percent. On that basis, he testified, Well Nos. 8H and 11H should also be classified as gas wells.[34] There is no evidence in the record that the 14.5 mole percent and 15.5 mole percent arguments for gas well classification have been made in any case prior to the subject applications.

TABLE 4
C_7+ COMPOSITIONAL ANALYSIS

Well No.	Completion Date	Sampling Date	Separator GLR (scf/Sep bbl)	Stock Tank GLR (scf/stb)	C_7+ (mole %)
1H	7/6/2011	7/11/2011	3,134	Not reported	<u>***8.42***</u>
2H	2/5/2012	5/4/2012	1,296	Not reported	14.03
		2/13/2013	1,612	2,093	***11.73***
		7/23/2013 (suspect)	1,134	1,472	18.21
		7/23/2013 (corrected)	1,472	1,911	15.64
4H	1/4/2013	2/22/2013	1,570	1,940	14.18
		7/23/2013 (suspect)	1,353	1,727	17.57
		7/23/2013 (corrected)	1,727	2,205	15.19
		11/7/2013	1,753	2,239	13.59
6H	10/8/2013	11/7/2013	1,656	2,046	15.69
8H	10/4/2013	11/7/2013	1,823	2,216	15.02
10H	10/4/2013	11/7/2013	1,738	2,114	15.51
11H	10/4/2013	11/7/2013	1,738	2,114	15.48

Note: **Bold** values indicate the reported C_7+ composition is less than the Moses/McCain criteria of 12.9 mole percent, and <u>**underlined**</u> values indicate the C_7+ value to be less than the Commission's administrative criteria of 11.0 mole percent.

Mr. Miller testified that there was a miscommunication between Pioneer and the contract laboratory with regard to the sample GLR for Well Nos. 2H and 4H (mentioned above). As a result, Pioneer believes the wrong GLR was used for the recombination calculations. Mr. Miller

[34] Vol. 3 Tr. 24: 1-10. Conversely, Moses (1986, p. 717) also states that volatile oils can have C_7+ compositions as low as 10 mole percent.

applied the correct GLR to the compositional analysis for Well Nos. 2H and 4H, yielding lower C_7+ fractions (see the "corrected" values on **Table 2**, above).[35]

Well No. 2H demonstrated a C_7+ composition of 11.73 mole percent from a sample collected on February 13, 2013. The well was completed on February 5, 2012, one year earlier. It is not known whether the reservoir pressure at the time of the latter sampling event on February 13, 2013, had declined below the dew point or bubble point. However, the laboratory report for the July 23, 2013 C_7+ composition sample indicates reservoir pressure on that date to be 3,915 psi. Well No. 2H is 12,970 feet deep, which yields a reservoir pressure of 10,376 psi based on a pressure gradient of 0.8 psi/ft.[36] Thus the reservoir pressure had decreased significantly between February 2012 and July 2013.[37]

4.1.9 Other Fluid Characteristics in Support of Gas Well Classification

4.1.9.1 Stock Tank Liquid Color

The color of the produced stock tank liquid is one of the reportable fields on Form G-5 (Line K). The Commission's existing policy states that one of several criteria for gas well classification is that the "liquid color is not consistent with that of crude oil petroleum." Pioneer provided photographic evidence of liquid samples from 9 of the Ridley 01 Unit wells, which are included on **Attachment C** to this PFD. The liquid colors documented in Pioneer's evidence include: straw, light straw, and yellow.[38]

Pioneer asserts none of the observed colors are consistent with the color of crude oil, and that the observed colors are consistent with the color range expected for condensate. McCain (1990) states that stock tank liquid color for condensate may range from lightly colored, brown, orange, greenish, or water-white. Therefore, Pioneer believes that, on the basis of liquid color, all wells on the Ridley 01 Unit should be classified as gas wells.[39] Mr. McGregor stated that, to his knowledge, an industry standard for liquid color determination has not been established.[40]

4.1.9.2 Liquid Gravity

The API gravities of the separator and stock tank liquids are reportable fields on Form G-5 (Lines K and L, respectively). The Commission's existing policy states that one of several criteria for gas well classification is a liquid API gravity greater than 50. Pioneer's evidence documented liquid gravity values ranging from 51.5 to 57.4°API.

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[35] Vol. 3 Tr. 181-183.

[36] Vol. 3 Tr. 48: 14-19.

[37] Exh. No. 56. It appears likely, to the Examiners, that the reservoir pressure on February 13, 2013, was likely below the bubble point. The average bubble and dew points from the Devon data (Exh. No. 38, Devon Exh. No. 17) were about 4,200 psi.

[38] Exh. No. 56.

[39] Tr. Vol. 3, 17.

[40] Tr. Vol. 3, 18.

Pioneer asserts that, on the basis of liquid gravity, all wells on the Ridley 01 Unit should be classified as gas wells. The liquid gravities are all greater than 50° API. Moses (1986) and McCain (1990) state that stock tank liquid gravities derived from retrograde gas are usually between 40° and 60° API. McCain (2011) revised this range for retrograde gas to between 40° and 70° API. However, McCain also states that liquid gravity is not a valid indicator of fluid type (that is, liquid gravity is not sufficient to precisely distinguish between fluid types such as volatile oil or condensate).[41]

4.2 Nearby And Offsetting Gas Well Classifications

In addition to the individual well data described above, another basis for the assertion that all of the Ridley 01 Unit wells are gas wells is that there are other wells near and around the Ridley 01 Unit that have received permanent gas well classification, and that some of these wells were used to support the permanent gas well classification rule for the Sugarkane (Eagle Ford) Field based on a 3,000 scf/bbl GLR.[42]

In the earlier case adopting a 3,000 scf/bbl GLR for gas well classification, data from 19 wells completed in the Sugarkane (Eagle Ford) Field, and 18 wells completed in the adjacent Hawkville and DeWitt (Eagle Ford) Fields, were presented to establish that this part of the Eagle Ford Formation exhibits retrograde gas behavior when the GLR values are 3,000 scf/bbl or greater. All 37 of these wells–which were drilled by several different operators–were determined by Commission staff to be gas wells based on at least one of the following criteria:

- GOR greater than 100,000 scf/bbl;
- C_7+ composition less than 11 mole percent; or
- PVT analysis indicating the observation of a dew point.

Pioneer also points out that, of the data presented in Docket No. 02-0272551, six wells had C_7+ compositions greater than 12.54 mol percent but were still classified as gas wells based on the observation of a dew point during the PVT analysis (five of the six wells had GORs less than 3,000 scf/bbl).

Of the 19 Sugarkane (Eagle Ford) Field wells used in the Docket No. 02-0272551 analysis, six were within close proximity–three miles–of the Ridley 01 Unit. Pioneer identified a total of 10 nearby wells within 3 miles of the Ridley 01 Unit for which visual cell PVT reservoir fluid studies have been conducted and were available to Pioneer. Data from these wells is summarized in **Table 5**. The presentation of the wells on the table are oriented by their relative position in the Eagle Ford Formation (up dip, on strike, and down dip—see **Attachment B**).

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[41] Exh. No. 60, tab 10, pg. 191.

[42] Oil & Gas Docket No. 02-0272551, The Application of Petrohawk Operating Company to Consider a Permanent Gas Well Classification for the Sugarkane (Eagle Ford) Field in Bee, De Witt, Karnes, and Live Oak Counties, Texas. Final Order dated January 10, 2012.

TABLE 5
WELLS WITHIN 3 MILES OF THE RIDLEY 01 UNIT
WITH VISUAL CELL PVT DATA

Position	**Well**	**G-5 GLR (scf/bbl)**	**Heptanes-Plus Composition (mol %)**	**Visual Cell PVT Results**	**Classification**
Up dip	Spear Reynolds A Unit No. 1 (API 255-31714)	1,956	12.46	Dew Point	Gas Well
Up dip	Schendel Unit No. 1 (API 255-31691)	2,397	14.39	Dew Point	Gas Well
On strike	Reynolds Gas Unit No. 1H (API 255-31736)	**3,420**	13.89	Dew Point	Gas Well
On strike	Mangione 01 No. 04H (API 255-33200)	**4,003**	13.2	Dew Point	Gas Well
On strike	Mangione 01 No. 03H (API 255-33198)	2,959	14.6	Bubble Point	Pending
On strike	Mangione 01 No. 02H (API 255-32559)	**3,285**	13.6	Bubble Point	Gas Well[43]
Down dip	Douglas GU No. 1 (API 255-31679)	**4,536**	**4.64**	Dew Point	Gas Well
Down dip	Handy 02-01 No. 07H (API 255-32982)	**3,685**	12.6	Dew Point	Gas Well
Down dip	Handy 02-01 No. 06H (API 255-32983)	**3,618**	13.6	Dew Point	Gas Well
Down dip	Handy 01 No. 01H (API 255-31635)	**3,448**	11.58	Dew Point	Gas Well

Notes: **Bold** data values indicate the administrative criteria achieved for permanent gas well classification.
Sources: Exh. Nos. 5, 23 & 50.

Because the Commission has classified most of these nearby wells as gas wells, Pioneer contends the Ridley 01 Unit wells should also be classified as gas wells, as all of the Ridley wells exhibit comparable GLR data (ranging from 1,618 to 4,534 scf/bbl) and, when available, C_7+ data (ranging from 8.42 to 15.69 mol percent).

Pioneer also provided illustrations indicating the gradation of liquid gravity, liquid color, and GLR along the Eagle Ford Formation dip through the Ridley 01 Unit area, arguing that these regional properties also confirm the Ridley 01 Unit wells should be classified as gas wells.[44]

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[43] Pioneer Exh. No. 50 indicated the Mangione 01 No. 03H well classification was pending. However, the Commission online system (Tracking No. 63437) indicates the gas well classification was approved on August 30, 2013, likely on the basis of initial producing GLR greater than 3,000 scf/bbl.

4.3 Proposed Gas Well Classification Criteria

Pioneer and Devon assert that the Eagle Ford Formation is an HPHT reservoir. Pioneer reports the Ridley 01 Unit wells produce with average reservoir temperature and initial pressure of about 320 °F and 10,300 psi, respectively, above the generally accepted industry threshold for HPHT reservoirs. Therefore, Devon (adopted by Pioneer) undertook an examination of available reservoir fluid studies exclusive to the Eagle Ford Formation to identify reservoir fluid correlations that may be present in and unique to the Eagle Ford.

Devon performed a retrospective study of available compositional and PVT analyses from multiple wells within the Eagle Ford Formation development area. The compositional and PVT data utilized were derived from existing data sources available to Devon. Devon assembled 125 data points from Eagle Ford wells for which GLR, C_7+ or PVT data were available. The Devon study data points were from wells operated by a number of different operators, and are spatially distributed along the Eagle Ford trend. The data points do not, however, extend much beyond the narrow transition zone between oil and gas.[45]

In the Devon hearing, Mr. McGregor stated that typical surface processes and sampling in the Eagle Ford Formation included a single-stage separator (operating at about 120°F and 800 psi), at which point the wellstream fluids are measured and then sent directly into sales lines.[46] Devon used the data to establish correlation relationships between GLR, C_7+ and PVT data comparable to that published by McCain (1973, 1990 and 2011), but appropriate and applicable for the Eagle Ford Formation.

Devon's data was derived from two sources, one public (with some limitations on confidentiality) and the second proprietary, in which all data was confidential except for certain graphed results.

4.3.1 The Public Data Set

The "Public" dataset was compiled by Devon's consulting engineers after obtaining from Commission staff a list of wells for which PVT and/or C_7+ data have been submitted.[47] From this list, Mr. McGregor identified 76 individual test data points from 59 wells for consideration, including the following:

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[44] Exh. Nos. 48, 52 & 53.

[45] Exh. Nos. 38 (Devon Exh. No. 23) & 41.

[46] Exh. No. 40 (Devon Tr. 66: 21 through 67: 17). It is unclear from Mr. McGregor's testimony in the Devon cases whether the GLR values resulting from these sales measurements represent equilibrium at standard conditions, including shrinkage and/or AGP.

[47] Pioneer provided the Examiners with a copy of the spreadsheet after the April 8, 2016 hearing. The spreadsheet contained 1,508 statewide records and 257 records readily identifyable as being from wells in an Eagle Ford Formation field. However, Mr. McGregor stated that between the time of the Devon data collection effort in 2015 and preparation for the Pioneer remanded hearing, about 175 (Eagle Ford) wells had been added by Commission staff to the list (Vol 3 Tr.: 20-21). Thus the list he used in preparation of the Devon hearings was considerably shorter. The completeness of the list is uncertain.

- 8 well tests documenting bubble points in reservoir fluids (at least 2 were visual cell PVT data and 3 were simulated PVT data).[48]

- 54 tests documenting dew points (at least 24 were visual cell PVT data and at least 24 were simulated PVT data).

- 14 tests documenting C_7+ composition analysis results (without PVT analysis) in which the C_7+ compositions were all less than 10 mole percent.

Generally, the laboratory reports for these data were available on the Commission's online completion system for the individual wells. However, the full laboratory reports for 11 data points and partial laboratory reports for two data points were considered to be confidential by Devon or the other operators of those wells, and therefore the laboratory reports for those data were not available in whole or, in two instances, in part.[49]

4.3.2 The Proprietary Data Set

The "Proprietary" dataset—consisting of 26 data points representing bubble point observations and 23 data points representing dew point observations from multiple operators—was considered to be confidential by Devon and not made available for the public evidentiary record. Mr. McGregor testified that the priopretary dataset was assembled by Mr. Jairo Corredor of Devon, and that the Devon proprietary dataset consisted only of visual cell PVT data.[50] In addition, the raw data was not made available to Devon's nor Pioneer's expert witnesses, Mssrs. Miller and McGregor; Devon only provided them with plottable data points and, in some cases, prepared the graphical exhibits and provided them to its consultants.[51]

4.3.3 Findings of the Devon Study

Devon and Pioneer presented their study by a series of exhibits graphing cross-plotted fluid characteristics (GLR, C_7+, liquid gravity, etc.) and other data. **Attachment D** reproduces two of these exhibits from Pioneer Exh. No. 38 (Devon Exh. Nos. 19 and 21). The following graphs were among those entered into evidence:

- Devon Exh. No. 19: From the public data, the exhibit plots GLR (at the time of fluid sampling for PVT analysis) against C_7+. Devon interprets GLR values greater than 2,200

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[48] On these summations, the Examiners could not always determine whether a particular data point represented a visual cell PVT or simulated PVT analysis because not all of the original laboratory reports are in the evidentiary record.

[49] Pioneer Exh. No. 39 (Devon transmittal letter, pg. 3).

[50] The Examiners note that Mr. Corredor was not present and did not testify at either the November 23, 2015 Devon hearing or the Pioneer hearings. Mr. Corredor was present at Devon's brief November 2, 2015 hearing, but no evidentiary matters were taken up at that time.

[51] Vol. 3 Tr.: 61-63.

to 2,300 scf/bbl and C_7+ of less than 14.5 mole percent to be indicative of a dew point in the PVT sample, and thus dispositive of gas well classification.[52] The Examiners note that not all of the plotted points on that exhibit have corresponding visual cell or simulated PVT results, and Pioneer did not explain the data relevance in the absence of a PVT observation with regard to establishing a new correlation.

- Devon Exh. No. 21: From the public and proprietary data, the exhibit plots GLR (from Form G-5) against C_7+. Devon interprets GLR greater than 2,000 scf/bbl and C_7+ of less than 14.5 mole percent to be indicative of a dew point in the PVT sample, and thus dispositive of gas well classification. Mr. McGregor noted that 32 of the wells which exhibited dew points (and should be gas wells) would have been classified as oil wells based on current administrative policy.[53] The Examiners note that not all of the plotted points on that exhibit have corresponding visual cell or simulated PVT results. Also, the Form G-5 GLR data and the C_7+ compositional analyses were not obtained at the same time.[54]

- Devon Exh. No. 22: For each well in the public data set, the exhibit plots both GLR values used on Exhibit Nos. 19 and 21 (from PVT sampling and Form G-5 testing, respectively). The average Form G-5 GLR values are about 500 scf/bbl lower than the GLR values reported at the time of fluid sampling. Mr. McGregor stated "this is the GOR for the well that's filed on the G-5 and I think they are lower, generally, because of the normal operating conditions out there." In order to avoid mis-classifying wells, Mr. McGregor further stated that the Form G-5 GLR was a more appropriate GLR standard to use than the recombination GLR taken at the time of fluid sampling.[55]

Based on this information, Devon and Pioneer assert that for the Eagle Ford Formation a Form G-5 GLR of 2,000 scf/bbl represents a distinct transition from volatile oil (less than 2,000 scf/bbl) to gas condensate (greater than 2,000 scf/bbl). Further, Devon and Pioneer assert that a recombined wellstream composition of less than 14.5 mole percent C_7+ is demonstrative of a gas well in the Eagle Ford Formation. Therefore, Pioneer and Devon assert that Eagle Ford wells with GLR values of 2,000 scf/bbl or greater or with a C_7+ of 14.5 mole percent or less may be permanently classified as gas wells.

4.3.4 Publication Review

In the Devon cases, Mr. McGregor cited two scholarly papers in support of Devon's application. Moses (1986) indicates that condensates have been observed with C_7+ compositions

[52] Exh. No. 40 (Devon Tr. 65: 4-8).

[53] Exh. No. 40 (Devon Tr. 68: 4-11; 70: 3-6).

[54] According to Devon Exh. No. 17 an average of 65 days separates the Form G-5 GLR data from the GLR measured during the PVT fluid sampling events. Pioneer's (and Devon's) only argument in support of correlating analytical results from two temporally-unrelated sampling events was that the G-5 GLR yield a more favorable (lower) GLR value.

[55] Exh. No. 40 (Devon Tr. 70: 16 through 71: 22). Again, the argument appears to be that the G-5 GLR data is preferable because it exhibits a lower GLR value, even though the GLR measurement was not obtained at the same time as the C_7+ sample.

as high as 15.5 mole percent, and volatile oils with C_7+ compositions as low as 10 mole percent.[56] McCain, in his 1994 paper "Heavy Components Control Reservoir Fluid Behavior," cites the importance of initial producing GOR, stock tank liquid gravity and stock liquid color as indicators, or "rules of thumb," in determining reservoir fluid type. McCain also presents generalized "type curves" of gas condensate wells showing an initial period of stable GLR and API gravities followed by increases in both characteristics (**Attachment E**).[57]

Pioneer presented as evidence a collection of nine articles and one textbook chapter (from McCain, 2011) in part as a response to the recent scholarly papers of which the Examiners have taken official notice. Mr. Miller reviewed the articles and provided a summary of matters he found to be relevant to and supportive of Pioneer's application. In particular, Mr. Miller noted the following:[58]

- McCain, et al, 1991, (Exh. No. 60, Tab 8) presented a summary of reservoir fluid property correlations as state-of-the-art circa 1991. These correlations predated the Eagle Ford or other recent tight resource play developments. The paper did give some attention to estimating AGP.

- McCain, et al, 1992, (Exh. No. 60, Tab 6), which predates the recent Eagle Ford development, emphasized the importance of taking reservoir fluid samples early in the production life of a well.

- El-Banbi, et al, 2001, (Exh. No. 60, Tab 7), which predates the development of tight resource plays, emphasized the importance of taking reservoir fluid samples early in the production life of a well.

- McCain, et al, 2011, (Exh. No. 60, Tab 10), is Chapter 5, "Identification of Type of Reservoir Fluid," from McCain's 2011 book on reservoir fluid property correlations. Mr. Miller cited McCain's definition of an initial producing GLR, including all surface gas produced, as being an indicator of reservoir fluid type only if the average reservoir pressure is higher than the dew point or bubble point of the reservoir fluid. This time may be a matter of days, months or years.

- Ilk, et al, 2012, (Exh. No. 60, Tab 3) described a transition zone in which near-critical reservoir fluid behavior is observed.

- Whitson, et al, 2012, (Exh. No. 60, Tab 2) emphasized the importance of collecting fluid samples early in the life of a well.

- Didar, et al, 2013, (Exh. No. 60, Tab 1) noted a shift in the two-phase critical point as a result of the pore-size dependence. The study concluded that the phase shift, or critical

[56] Exh. No. 40 (Devon Exh. No. 27).

[57] Exh. No. 40 (Devon Exh. No. 28).

[58] Note: The Examinerss ordered the summary based on the date of publication, from oldest to most recent.

point suppression, would delay the formation of condensate in the reservoir and provide more time to produce gas without interference from in situ condensate blockage.

- Akutlu, 2013 (Exh. No. 60, Tab 9), not a research paper, per se, this Executive Summary to the the August 2013 issue of the SPE Journal, explores a number of recent developments in understanding the complexities of a newly created reservoir, such as in a tight shale formation. Mr. Miller noted the author's recitation of phase changes resulting from nano-pore confinement including critical point shifts in the two-phase region, and indicating there are instances in which a oil in a PVT cell may actually exist as a gas condensate or wet gas in a confined reservoir.

- Orangi, et al, 2015, (Exh. No. 60, Tab 4) described the leaning of produced fluids with pressure decline and the mobility or immobility of condensation formation in the reservoir, and the changes in observed bulk gas condensate dewpoint pressures.

- Pitakbunkate, et al, 2015, (Exh. No. 60, Tab 5) also describes the effect of pore size on reservoir fluid phase behavior, including shifts in the critical point locations. In addition, this paper suggests the equations of state used in simulated PVT analysis may not be valid for PVT calculations in shale reservoirs. Mr. Miller stated that Pioneer's (and, thereby, Devon's) analysis focused more on attending to the fluid critical point, not simulated PVT behavior. Mr. Miller affirmed that the simulated PVT analysis for Pioneer's Ridley 01 Unit Well Nos. 2H and 4H are consequently invalid.

Mr. Miller concludes that these publications support Pioneer's position that the Ridley 01 Unit wells, based on the evidence presented, are gas wells.

4.4 Summary Of Evidence

Pioneer asserts all wells on the Ridley 01 Unit are gas wells, and that these classifications are based on both the existing and proposed gas well classification criteria. A summary of the gas well classification criteria reported by Pioneer for the 11 Ridley 01 Unit wells is presented in **Table 6**.

TABLE 6
PROPOSED GAS WELL CLASSIFICATION SUMMARY

Criteria	1H	2H	3H	4H	5H	6H	7H	8H	9H	10H	11H
C_7+ < 11 mole %	**8.42**										
C_7+ < 12.9 mole %		**11.73**									
C_7+ < 14.5 mole %				**14.18**							
C_7+ < 15.5 mole %								**15.02**			**15.48**
$GLR_{G\text{-}1/G\text{-}5}$ > 3,000	**3,032**		**3,062**				**3,148**		**4,534**		
$GLR_{at\ sampling}$ > 3,000	**3,134**										
$GLR_{daily\ prod.}$ > 3,000							**3,276**		**4,483**		
$GLR_{with\ AGP}$ > 3,000						**3,062**					
$GLR_{G\text{-}1/G\text{-}5}$ > 2,000		**2,185**		**2,138**							
$GLR_{at\ sampling}$ > 2,000		**2,093**		**2,239**		**2,046**		**2,216**		**2,114**	**2,114**
$GLR_{daily\ prod.}$ > 2,000		**2,114**		**2,263**	**2,085**	**2,792**				**2,560**	**2,613**
$GLR_{with\ AGP}$ > 2,000		**2,402**		**2,682**	**2,926**	**3,062**		**2,991**		**2,984**	**2,897**
Gas well based on current criteria	**Yes**	**Yes**	**Yes**	No	No	**Yes**	**Yes**	No	**Yes**	No	No
Gas well based on proposed criteria	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

Note: All GLR values are stock tank ratios as reported in the evidence (scf/stb.)

5. EXAMINERS' ANALYSIS

Pioneer holds the burden of proof to show that wells drilled on the Ridley 01 Unit should be permanently classified as gas wells. The statute defines "gas well", but there is no explicit "permanent" gas well classification provided in statute or Rule. However, as will be shown, the Commission has permanently classified gas wells based on two demonstrations of evidence:

- At initial conditions, the hydrocarbon fluid in the reservoir exists as a single-phase gas (that is, there are no liquid hydrocarbons in the reservoir before production begins); and

- Liquid hydrocarbons that may form in the reservoir by retrograde condensatation are immobile and will not flow as liquids through the reservoir and into the production stream.

These criteria have been held as valid in about 79 contested but unprotested docketed cases before the Commission since about 1990. To the Examiners knowledge, these criteria for permanent gas well classification have never been subject to judicial review by the courts.

Therefore, to understand the origin of the criteria and how they apply in this case, it is necessary to begin with a preliminary exploration of the reservoir fluids and the statutory definition of a gas well. Following an establishment of this Background Analysis (Sec. 5.1), attention can be turned to an Evidentiary Analysis (Sec. 5.2).

5.1 Background Analysis

To establish a physical context for the legal and technical analyses that follows, a brief description of the relevant hydrocarbon reservoir fluids and the means of testing and classifying wells based on fluid characteristics will be described (Sec. 5.1.1). Then, the Examiners will describe the statutory definition of a gas well (Sec. 5.1.2), Commission processes for gas well classification (Sec. 5.1.3), and what is meant by a "permanent" gas well (Sec. 5.1.4).

5.1.1 Reservoir Fluids

A hydrocarbon reservoir fluid can generally be classified as one of five types: (1) black oil; (2) volatile oil; (3) retrograde gas; (4) wet gas; and (5) dry gas. The type of reservoir fluid should be determined early in the life of a well, and the type of fluid present in a reservoir will affect sampling methodology and production practices.

Hydrocarbon fluids are mixtures of hundreds or thousands of individual constituent substances. Every hydrocarbon mixture has a unique phase diagram—the combinations of pressure and temperature conditions at which the hydrocarbon mixture exists as a single-phase gas, a single-phase liquid, or in mixed phases. The phase diagram is a function of the unique hydrocarbon mixture of the fluid. That is, altering the composition changes the mixture itself and therefore the temperature and pressure conditions that prescribe phase behavior of the mixture. For example, and very generally speaking, increasing the composition of heavier hydrocarbons would tend to increase the range of liquid behavior on the phase diagram in terms of pressure and temperature. Reservoir pressure will decrease with production, but the reservoir temperature will remain constant. As the pressure condition changes, then the phase state of the fluid may change also.

As discussed, the Eagle Ford Formation in the Ridley 01 Unit area exists in a transition zone between oil and gas. Specifically, as one moves from the northwest to the southeast the reservoir fluid types in Eagle Ford Formation grade from black oil, to volatile oil, to retrograde gas, to wet gas, to dry gas. However, the Commission's statutory scheme for classifying wells is constrained to two options: gas or oil. The implication here is that the technical characteristics that a petroleum engineer will rely upon may not be consistent with the well classification pursuant to statutory definitions. Therefore the proper classification of a well depends on a preponderance of evidence that points toward the statutory definition of a gas well or oil well in an area that is grading from volatile oil to retrograde gas. In the Ridley 01 Unit area—as in the entire Eagle Ford Formation transitional frontier—this can present challenges in discerning between retrograde gas and volatile oil.

5.1.1.1 Retrograde Gases

Attachment F is an example phase diagram in evidence, and has been edited to show both retrograde gas and volatile oil reservoir conditions.[59] Reservoir temperature does not change during production, while reservoir pressure begins at an initial pressure and declines during production. If the reservoir temperature is greater than the critical point temperature as shown on the pressure decline from points 1-2-3-3A, then the reservoir fluid is a retrograde gas. At initial reservoir conditions (point 1) all of the fluid exists in the reservoir as a gas. As the pressure declines below the dew point (point 2) liquid begins to condense from the gas, which will be observed at the surface as an increase in GLR (see also the type curves in **Attachment E**). If the reservoir pressure declines below point 3, then the condensate liquid in the reservoir may begin to revaporize (point 3A).

A well producing at points 1 and 2 is a gas well; at point 3 it is indeterminant based on the information given. McCain (1990, page 156) states "An initial producing gas-oil ratio of 3,300 to 5,000 scf/STB indicates a very rich retrograde gas, one which will condense sufficient liquid to fill 35 percent or more of the reservoir volume. Even this quantity of liquid seldom will flow and normally cannot be produced." As will be discussed, if the retrograde condensate in the reservoir does flow as a liquid and is produced through the well, then the produced liquid will be considered crude petroleum oil for gas well classification purposes.

5.1.1.2 Volatile Oils

The same mixture in **Attachment F** (at points 4-5-6-7) will be a volatile oil if the reservoir temperature is lower (cooler) than the critical point temperature, and the production pressure decline will be indicated by the vertical line to the left of the critical point. As the pressure declines below the bubble point (point 5), the percent of gas in the reservoir fluid will increase, which will also be observed at the surface as an increase in GLR (see also the type curves in **Attachment E**). Such a well would be classified as an oil well. However, the figure identifies a gas phase area below the phase envelope. Thus, at some point in the future (point 7) this well may be reclassified as a gas well if the GOR increases above 100,000 scf/bbl pursuant to the statutory definition.

For volatile oils, McCain (1990, page 153) observes, "The gas associated with a volatile oil is very rich, usually a retrograde gas. This rich gas releases a large quantity of liquid as it moves to the surface." That is, the gas phase produced from a volatile oil, or even a gas cap, may exhibit retrograde gas behavior through PVT analysis. The subsequent condensate from the reservoir gas is produced at the surface and causes the GLR to decrease later in the life of the well, as shown on **Attachment E**.

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[59] Exh. No. 38 (Devon Exh. No. 18), from McCain 1973.

5.1.1.3 Reservoir Fluid Sampling

The degree to which reservoir fluid studies can reasonably predict the composition and behavior of hydrocarbon fluids in the reservoir is dependent upon whether or not the sampled fluid is *representative* of the *in situ* reservoir fluids. The degree to which a field-wide reservoir classification scheme can reasonably predict the composition and behavior of hydrocarbon fluids throughout a reservoir is also dependent upon whether or not the samples used to develop the proposed scheme are representative of the diversity or uniformity of *in situ* reservoir fluids throughout the field.

In their work with conventional, non-HPHT reservoirs, Moses and McCain both assert that representative samples of initial reservoir conditions can only be obtained when the reservoir pressure is higher than the bubble point or dew point. Moses states, "If wells are not conditioned properly and the samples are not representative of the reservoir fluid, then the resulting fluid study may yield invalid data… In separator sampling, it is imperative that the well be stabilized, then tested for a sufficiently long period to determine the GOR accurately." Moses goes on to say, "To obtain samples for reservoir fluid analysis from a gas-condensate well, the well should ideally be produced at a rate equal to or slightly above the minimum stable rate… The most important factor in a flow test is stabilization. This includes stable wellhead pressure, stable gas production, and stable liquid production."[60]

Moses' concern about sampling a well at the minimum stable rate for fluid studies may be operationally difficult. That is, an operator may have competing business or operational demands for how to produce a well early in its life. Whitson and Sunjerga state, "It is clear that sampling early with low drawdowns will provide a sample closer to in-situ reservoir fluid than samples collected after sustained larger drawdowns. This leads to our simple sampling recommendation—collect 'early' samples from (liquid rich shale) wells producing with minimal drawdown. This may be 'easier said that done', and operationally unpopular… Early and low-drawdown sampling is possible and should be considered—even if operationally difficult."[61]

5.1.1.4 Reservoir Fluid Studies

An operator's objective for a reservoir fluid study will likely focus on gathering data necessary for the profitable and efficient recovery of hydrocarbon resources—*an issue and data need that, for the operator, likely transcends the relatively pedestrian issue of well classification for regulatory purposes*. That is to say, the value of such studies for an operator extends far beyond regulatory requirements to classify a well. Further, an operator has no obligation to provide the findings of reservoir fluid studies to the Commision beyond what is necessary to meet a regulatory requirement or application, such as well classification. The data that is

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[60] Moses 1986.

[61] Whitson, C. H. and Sunjerga, S. "PVT in Liquid-Rich Shale Reservoirs." Society of Petroleum Engineers. SPE 155499. SPE Annual Technical Conference and Exhibition. San Antonio, Texas. 2012. What is meant by the phrase "operationally unpopular" is not clear. The Examiners believe it to mean that from an operational standpoint an operator would prefer to produce at higher fluid production rates (drawdowns) than lower rates that may be optimal for representative fluid sampling.

publically available in Commission well records, therefore, should not be construed to represent the universe of knowledge about the reservoir fluids in a particular field.

Reservoir fluid studies can include a variety of analyses at different price and quality points. As mentioned, a C_7+ analysis costs about $5,000 and takes two weeks for results. The cost to run a visual cell PVT test is about $25,000 to $30,000 and takes six months.[62] This case generally involves two types of laboratory analyses of reservoir fluid samples: Visual cell PVT and recombined wellstream compositional analysis (C_7+). In addition, simulated PVT analysis may be conducted based on the results of the recombined wellstream compositional analysis. Pioneer's arguments rely strongly on visual cell PVT analysis, even though it did not collect any such data from its eleven Ridley 01 Unit wells. But Pioneer does rely on visual cell PVT data (1) in its arguments that the Ridley 01 Unit wells should be permanently classified as gas wells because nearby offsetting wells used visual cell PVT data for gas well classification, and (2) insofar as the Devon evidence is built around visual cell PVT analysis. In addition, a brief discussion of the American Society of Testing Materials ("ASTM") distillation test, which is an even lower-cost method of analysis, is provided because it is relevant to the Commission's current gas well classification policy.

5.1.1.4.1 ASTM Distillation Test

An ASTM distillation test can be used to assess the likelihood that a hydrocarbon liquid at surface conditions exists in the reservoir in the gas phase. An ASTM distillation test is performed on a sample of produced liquid hydrocarbons collected from a separator or a stock tank. In a distillation test, the sample is heated and the constituent hydrocarbon liquids in the sample evaporate when their respective boiling temperatures are reached. Smaller, lighter molecules typically have lower boiling temperatures. The test concludes when there is no more liquid in the flask, although a semi-solid residue may remain. The ASTM distillation test is used to demonstrate the boiling point and volatility characteristics of the produced hydrocarbon liquid. A gas would be expected to have a greater proportion of lighter hydrocarbon molecules that volatilize early in the test, whereas an oil fluid would be expected to have a greater proportion of heavier hydrocarbon molecules that volatilize later in the test, if at all.

5.1.1.4.2 Visual Cell PVT Analysis

A Visual Cell PVT test begins with individual liquid and gas phase samples collected from the production equipment—usually a separator—at a known GLR. In a visual cell test, the test cell is charged with the liquid and gas fluid samples which are recombined at the sampled GLR. Test cell volumes vary, but typically range from 250 to 1,500 cubic centimeters (cm). Then, the fluid in the test cell is brought to reservoir temperature and stabilized, and the test cell pressure is increased to a pressure at or above the known reservoir pressure. The test cell temperature is kept constant at reservoir temperature, as the reservoir temperature does not change during production. Visual cell PVT analyses may include several components, including a constant composition expansion ("CCE") test, and a constant volume depletion ("CVD") test.

[62] Tr. vol. 1, 18:22 to 19:3.

A visual cell CCE test examines the pressure-volume relationship of a hydrocarbon fluid as the change in volume as a function of pressure. This change is determined by measuring the total volume of a sample of reservoir fluid at various pressures above and below the saturation (dew point or bubble point) pressure. The composition of the sample does not change during the test. At the initial pressure (greater than the reservoir pressure), the fluid may exist as a gas, liquid, or a two-phase mixture. In the case of a retrograde gas reservoir, the fluid will exist in a single gas phase. As the pressure is reduced, liquid droplets—retrograde condensate— appear in the cell indicating the dew point pressure below which some of the fluid will exist in a liquid phase, fluid that was originally in the gas phase. As pressure continues to decrease, more liquid may condense. At some lower pressure the condensate may re-vaporize into the gas phase. Thus the CCE test yields a picture of a constant hydrocarbon mixture and its bulk phase response to changes in pressure.

A visual cell CVD test imitates the production behavior of a well. The cell volume remains constant, and pressure is reduced by the incremental removal of fluid. Again, as the pressure declines some of the fluid, in the case of a retrograde gas reservoir, will begin to condense. The first components to condense as pressure declines will be the heavier hydrocarbon fractions, which will settle to the bottom of the test cell. Thus the next parcel of hydrocarbon removed from the test cell will be somewhat lighter, as the gas no longer includes the condensed heavier fractions. As the cell is depleted at a constant volume, the produced fluids get lighter, and the heavier fractions remain stranded in the cell. The CVD test can indicate the gas to liquid ratio in the reservoir after production has depleted pressure in the constant reservoir volume.

Neither CCE or CVD PVT analyses account for pore size influences; they are a measure of the bulk behavior of the fluid. Indeed, PVT analysis can only assess the phase behavior of a bulk sample (in, say 100 to 1,000 cubic centimeter sample sizes); PVT analyses do not assess how or whether fluid phase behavior is influenced by unique intrinsic reservoir properties such as pore size or minerology (which, recent research indicates, can have significant effects). Further, the tests are dependent upon accurate knowledge of reservoir pressure and temperature.

5.1.1.4.3 Recombined Wellstream Compositional Analysis (C_7+)

A recombined wellstream compositional analysis is the reservoir fluid study that yields a value for C_7+. In a recombined wellstream compositional analysis, individual liquid and gas phase samples are collected from the production equipment—usually a separator—at a known GLR. The individual fluid phase samples are subject to gas chromatograph analysis that assesses the variety and distribution of hydrocarbon compounds present in each fluid phase. The liquid and gas phase compositional results are mathematically recombined proportionally according to the producing GLR at the time of sampling, which yields a compositional profile of the full hydrocarbon wellstream. Generally, wellstream fluids that contain a higher composition of lighter hydrocarbon molecules are more likely to be gas than fluids that contain a greater proportion of heavier molecules. Visual cell PVT analysis usually includes recombined wellstream compositional analysis.

5.1.1.4.4 Simulated PVT Analysis

A simulated PVT analysis does not use a visual PVT cell; instead, it is a mathematical model based on the wellstream compositional analysis and equations of state that model phase behavior in the reservoir. That is, the various constituent compents (e.g., 20 percent methane, 10 percent ethane… 12 percent heptane, etc.) are inputs into a complex equation that factors in physical constants associated with each constituent at reservoir temperature and pressure conditions, producing a simulation of phase behavior.

Mr. McGregor affirmed there are big disparities between visual cell PVT data and simulated PVT data that relies of equations of state.[63] In Oil & Gas Docket No. 03-0244306, in which Dr. McCain testified on behalf of the applicant, an error between calculated (simulated) dew points and visual cell PVT dew points up to 30 percent was described. However, visual cell and simulated data can be used effectively in tandem when visual cell data is used to tune the simulation equation of state parameters.

5.1.1.4.5 The Works of Dr. William McCain and Dr. Phillip Moses

The works of Dr. William McCain of Texas A&M University and Dr. Phillip Moses of Core Laboratories have regularly been cited as evidence in docketed cases in the Commission's jurisdiction since at least 1990.[64] The importance of these persons and their works warrant some attention at this moment, in particular because their works are not simply industry publications—they have stood the test of time and continue to be relied upon by the industry.

Generally, Moses and McCain looked at a wide and deep range of reservoir fluid data from around the world and studied various fluid characteristics including dew points, bubble points, fluid compositional data, and initial producing GLR, among many others. Through their work, McCain and Moses identified correlations between fluid properties and characteristics that can be helpful in understanding fluid behavior. They also identify when and how reservoir fluid studies should be conducted with regard to obtaining useful quality data; both advise that wells be properly conditioned and stabilized and that samples be collected before significant pressure decline has occurred. The Examiners understand that their works are not the law, and Dr. McCain even cautions:

> *Do not attempt to compare fluid types as defined here with the reservoir descriptions as defined by the state regulatory agencies which have jurisdiction over the petroleum industry. The legal and regulatory definitions of oil, crude oil,*

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[63] Vol. 3 Tr. 9:25 – 10:6

[64] The Examiners note that Dr. Moses has appeared before the Commission as an expert witness in at least one gas well classification case (O&G Docket No. 3-94,678, Final Order dated September 1, 1990), and Dr. McCain has appeared before the Commission as an expert witness at least four times (Docket Nos.: 02-0227689, Final Order dated April 10, 2001; 03-0227691, Final Order dated April 24, 2001; 03-0227690, Final Order dated June 21, 2001; and 03-0244306, Final Order dated February 7, 2006.) Further, their works have been widely cited in a number of gas well classification cases over the years, including the relatively recent cases (since 2011) regarding gas well classification provisions in field rules.

> *gas, natural gas, condensate, etc., usually do not bear any relationship to the engineering definitions given here. In fact, the regulatory definitions are often contradictory.*[65]

But, as will be seen, the statutory definition of gas well may require one to know the reservoir phase state of a petroleum fluid that has been produced at the surface in a multi-phase state. For this purpose, their works have proven to be invaluable.

Relevant to the present case[66], Moses and McCain both conclude from visual cell PVT data that C_7+ composition and initial producing GLR can be reliable rules of thumb to differentiate reservoir fluid type between volatile oil and retrograde gas.[67] That is, while visual cell PVT data provides direct evidence of phase behavior, C_7+ and GLR data provide an indirect correlation to visual cell PVT observation. Moses and McCain point to a C_7+ composition of 12.5 to 12.9 mole percent as a distinct differentiator between retrograde gas (lower C_7+ compositions) and volatile oil reservoirs (higher C_7+ compositions). **Attachment G** illustrates McCain's differentiation.[68] In 2006 the Commission relied upon the works of Moses and McCain when it adopted a policy for the administrative classification of gas wells based on C_7+ compositional analysis. The Commission adopted a somewhat more conservative posture of C_7+ composition less than 11 mole percent for administrative gas well classification.[69] Moses and McCain also identified an initial producing GLR of about 3,000 to 3,300 scf/bbl as a differentiator between the two reservoir fluid types, but the Commission has not established a related GLR-based administrative classification rule.

The Introduction to McCain's 2011 book, <u>Petroleum Reservoir Fluid Property Correlations</u>, co-authored with John Spivey and Christopher Lenn, states:

> *Generally, the various sets of data covered the full range of conditions and properties that might be found in practice. Unfortunately, no data for naturally occurring petroleum fluids are currently available for high-pressure, high temperature (HPHT) conditions that have recently become of interest.*[70]

Pioneer asserts, and the Examiners agree, that the Ridley 01 Unit wells access an HPHT reservoir as that term is generally understood in the industry. Further, the Examiners note, that on a broader scale, many HPHT reservoirs worldwide are not unconventional shale reservoirs, but deep offshore reservoirs such as those in the Gulf of Mexico and the North Sea. That is, it is

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[65] McCain, 1990, p. 149.

[66] Record evidence from the relevant works of Moses and McCain in the present case include: Exh. No. 38 (Devon Exh. Nos. 18, 18A, 27, and 28); Exh. No. 40 (Devon Tr. 18 & 60); Exh. No. 57; and Vol. 3 Transcript page 111:2.

[67] Exh. No. 38 (Devon Exh. No. 27).

[68] McCain, et al, 2011, pages 195-197. From page 197: "The producing gas-liquid ratios reported on figures 5-3 through 5-7 are not normalized to any standard surface facilities, i.e., number of separators, and also are not normalized to any standard operating temperatures and pressures. This lack of standardization causes most of the scatter in the data."

[69] The 2006 T-Bar Memorandum relied upon Moses 1986 and McCain 1990.

[70] Exh. 60, tab 10.

quite likely that HPHT reservoirs are broadly divserse. Nonetheless, McCain raises the issue that HPHT reservoirs are not represented in his data, and, the Examiners believe, Devon and Pioneer were wise to explore the matter further.

The Examiners also note that there is no evidence Moses and McCain's correlations are derived from horizontal wells that require multi-stage hydraulic fracture treatments, such as those drilled in the Eagle Ford and other unconventional resource plays in recent years. This absence of data suggests further issues that also merit attention.

5.1.1.5 Fluid Behavior in Unconventional Reservoirs

The methodologies described above have been used to conduct reservoir fluid characterization studies for very many years, and the Commission has also relied on the results of these studies for well classification decisions. However, the recent development of unconventional shale resource plays, which requires horizontal wells completed with large multi-stage hydraulic fracture stimulation treatments, has not only revolutionized the industry, it has also challenged some conventional understandings of reservoir fluid behavior. While visual cell PVT analyses evaluate the phase behavior of a recombined fluid sample in a bulk volume of 250 to 1,500 cubic centimeters, hydrocarbons in unconventional shale reservoirs are confined to pore spaces with dimensions measured in nanometers. Recent research indicates that these nanometer-scale pores profoundly alter the phase behavior of the hydrocarbon fluids residing within them. The Examiners believe these changes will likely affect well classification decisions.

Further, for unconventional shale reservoirs, the evidence in the record indicates that the collection of representative samples of reservoir fluids is is much more easily said than done. Accordingly, Dr. Yucel Akkutlu anticipates a coming paradigm shift following the rapid changes in reservoir knowledge and production technology brought about through recent development of unconventional reservoirs. In this Executive Summary to the August, 2013, edition of the SPE Journal, Akkutlu writes:

> *"Characterizing shale fluids is also a challenging task. This is mainly because of the fact that the reservoir fluids are produced under a strong influence of the tight shale matrix. For these fluids, identifying the phases (liquid, gas, supercritical fluid, and sorbed) in the matrix and identifying their producibility limit is <u>currently not possible because the composition of the produced fluid is different than the composition of the in-situ phases</u>… In a sense, referring to as (sic) the 'oil window' or 'gas window' of the resource shale on the basis of the volume of produced fluids is almost meaningless… the rock could potentially hold all of these phases at the initial conditions, or it could yield these phases to the fractures in its own unique way as we begin production"(emphasis added).*

As examples of these complications, the recent papers by Pitakbunkate, et al (2015), Orangi, et al (2015), and Didar, et al (2015) explore the potential impacts of the matrix pore size on fluid phase behavior. Pitakbunkate, et al, conclude that "...the fluid composition of the produced hydrocarbon mixture may not be a good representation of original fluid in the reservoir... At the beginning of production, shale reservoirs tend to release lighter components (i.e., methane) and the heavier componenents are left behind" but are mobilized later.

Didar, et al, conclude that the critical point suppression (cited by Mr. Miller) gives the reservoir more time to produce gas without the interference of condensation, and "a simple reduction of the pore size to a 3 (nanometers) would lead the reservoir to fall under a retrograde gas type rather than previously assumed volatile oil type." To the Examiners, these papers suggest uncertainty about whether assertions that such a reservoir contains only single-phase gas at initial conditions, or that hydrocarbon liquids in the reservoir are immobile, *can be made or sustained*. Indeed, articularing their problem statement, Whitson and Sunjerga state, "What you produce at the surface is not what you have in the reservoir." [71]

In a retrograde gas reservoir heavier hydrocarbon constituents will condense into the reservoir after the reservoir pressure decreases below the dew point, altering the composition of the produced fluid. Altering the composition changes the phase behavior. If altering the composition changes the phase diagram, and if, as the current research suggests, it is currently not possible to collect samples of the reservoir fluid from a tight shale reservoir (see Akutlu, 2013, and Whitson, 2012), then the capability of a visual cell PVT analysis to describe the phase behavior of the *in situ* reservoir fluids is affected. At least, with current capabilities the reliability is less certain. This is not to say that the information obtained from such studies is not valuable to the petroleum engineer. But, there are limits to what can be said about the phase-in-place reservoir fluids from a regulatory perspective.

Finally, in an unconventional shale reservoir permeability is very limited. In the Eagle Ford Formation the oil zone is up-dip of the gas zone, the opposite of what would be expected in a conventional reservoir. The gas-bearing reservoir was subject to deeper burial and higher temperature and pressure; the reservoir is more mature, but the reservoir matrix did not allow for intra-reservoir migration and gravity/density separation of oil and gas fluids. As a result, an unconventional field in general (and the Eagle Ford Formation in particular) may not exhibt features commonly observed in multi-phase reservoirs, such as a gas cap, gas-water contact, or oil rim. Yet, in the Eagle Ford there is an obvious gradation from oil to gas as one moves from up dip in the northwest to down dip in the southeast. The horizontal wells in the Eagle Ford parallel this gradation, effectively averaging the production characteristics along the lateral length.

5.1.2 What Is A Gas Well?

The Texas Natural Resources Code §86.002 defines an oil well as "any well that produces one barrel or more of oil to each 100,000 cubic feet of gas." Similarly, a gas well is defined as a well that "produces gas not associated or blended with oil at the time of production," or one that "produces more than 100,000 cubic feet of gas to each barrel of oil from the same

[71] Whitson, C. H. and Sunjerga, S. "PVT in Liquid-Rich Shale Reservoirs." Society of Petroleum Engineers. SPE 155499. SPE Annual Technical Conference and Exhibition. San Antonio, Texas. 2012.

producing horizon."[72] Thus, under these definitions of oil and gas wells, the GOR of an individual producing well is, by statute, the determinant factor in its classification.

The hardline in the statute—a GOR of 100,000 cf/bbl—as a means of classification between oil and gas wells may be somewhat arbitrary from a technical perspective. The Examiners are not aware of a scientific basis for a GOR of 100,000 cf/bbl as being technically dispositive of the fluid type for well classification purposes. Further, the classification of a well may change over time as the GOR may change. As will be discussed, this phenomena gave rise to the concept of a permanent gas well in certain limited circumstances, even though no such concept explicitly exists in statute or rule.

Although not reflected in the statute, since at least 1939 the Commission has maintained and the courts have affirmed that a hydrocarbon fluid that exists as a liquid in the reservoir, and is produced at the surface as a liquid, is crude petroleum oil. Statewide Rule 79(11) repeats (nearly verbatim) the statutory gas well definition. However, Statewide Rule 79(11)(C) further refines how the GOR is to be considered, clarifying what is meant—or, more specifically not meant—by the term "crude petroleum oil" in language that was first adopted in General Order No. 20-550 on January 18, 1939, in what was known as the "liquid-liquid-liquid" rule:

> *... A well which produces hydrocarbon liquids, a part of which is formed by a condensation from a gas phase and a part of which is crude petroleum oil, shall be classified as a gas well unless there is produced one barrel or more of crude petroleum oil per 100,000 cubic feet of natural gas; and that the term "crude petroleum oil" shall not be construed to mean any **liquid** hydrocarbon mixture or portion thereof which is not in the **liquid** phase in the reservoir, removed from the reservoir in such **liquid** phase, and obtained at the surface as such (emphasis added).*

That is, gas-phase hydrocarbons in the reservoir that change to the liquid phase in the wellbore or at the surface, are gas condensate; consequently, those liquids are not crude petroleum oil. Liquid hydrocarbons in the reservoir that are produced as liquids are crude petroleum oil. Thus, when calculating the GOR of a well for statutory classification purposes, the volume of oil used in the denominator of the ratio ***shall not*** include liquid hydrocarbons that are ***not liquid*** in the reservoir; conversely, a hydrocarbon fluid that is a liquid in the reservoir, whether originally as a liquid or as a product of condensation subsequent to initial production of the reservoir, is considered to be crude oil.[73]

Therefore, if all of the produced hydrocarbon liquids are condensate that forms outside of the reservoir, then by Rule 79(11)(C) the well is a gas well because there is no associated oil production (the denominator is zero and the GOR approaches infinity). However, if some of the

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[72] These definitions were established by the Legislature in 1935 in House Bill 266 and House Bill 782. *See* 1935 Tex. Gen. Laws ch. 120, and 1935 Tex. Gen. Laws ch. 76.

[73] *See* Oil & Gas Docket No. 06-0249228: Proposal for Decision and Final Order Denying the Application of Samson Lone Star, L.P. for Gas Well Classification for the Taylor Estate Lease Well No. 1, in the Waskom (Cotton Valley) Field, Harrison County, Texas. May 30, 2007. Motion for Rehearing denied August 14, 2007.

produced liquids are condensate, then only the fraction of produced liquids that are not wellbore or surface condensates (that is, liquids that are crude petroleum oil, which includes condesate that forms in the reservoir) are to be factored into the GOR calculation as oil; it is necessary, therefore, to know what portion of the produced liquid may exist as liquid in the reservoir—as that portion is crude petroleum oil.

5.1.2.1 Appellate Case Law

There have been two significant historical episodes in which operators sought illegal production advantages through improper well classification, despite the actual producing characteristics of the wells at issue. In both episodes, the operators sought oil well classification for wells the Commission determined to be gas wells.

In the 1930s, some operators of wells in the Agua Dulce Field (in Nueces County, District 4) were producing hydrocarbon liquids from high-pressure gas condensate reservoirs and claiming the wells were oil wells. The wells in question produced gas that was separated at the surface into a condensate liquid phase, which was sold, and a tail gas that was vented or flared. Commission rules at the time prohibited gas wells from venting or flaring gas, but oil wells could legally do so. The Commission found that condensate was not crude petroleum oil because it was formed in a surface separation process and was not liquid in the reservoir. These operators were wasting resources both by releasing gas to the atmosphere and also by causing hydrocarbons to be stranded in the reservoir.

In *Clymore Production Co. v. Thompson* the federal court found:

> *We think it perfectly obvious that the statutory definition of an oil well was not intended to cover wells of this character which normally produce gas and can only be made to produce oil by the use of manufacturing processes, however crude, at the head of the well.*[74]

Similarly, in the 1980s operators in the Panhandle Field (in District 10) were producing gas and condensing it at the surface by refrigeration to produce "white oil." The Commission determined that existing statutes and field rules prohibited the use of white oil in GLR calculations for the purposes of gas well classification.[75] The Commission's determination was upheld in *Hufo Oils v. Railroad Commission*.[76] In regards to *Hufo*, Smith and Weaver go on to say:

> *Several other issues in the white oil dispute had been decided at the commission level but do not appear in the court opinion. These issues are as follows:*

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[74] 13 F. Supp. 470 (W.D. Tex. 1936), cited in Smith, E. E. & Weaver, J. L., Texas Law of Oil and Gas. Second Edition. Vol. 2. 1998. § 10: 26-27.

[75] Smith, E. E. & Weaver, J. L., Texas Law of Oil and Gas. Second Edition. Vol. 2. 1998. § 10: 29.

[76] 717 S.W.2d 405 (Tex. App.—Austin 1986, writ denied).

> 1. *The oil operators argued that the gas remaining in the reservoir and produced by their wells had once been crude oil. The crude oil had vaporized as the Panhandle field was produced and pressure declined. The Railroad Commission, like the Clymore court fifty years earlier, rejected the argument that wells should be classified on the basis of original reservoir conditions.*[77]

That is, well classification is dependent upon the present phase-in-place of the reservoir fluids, not the initial characteristics of production observed at the surface, or even the intial characteristics of the reservoir. The Commission may require an operator to reclassify a well from oil to gas or from gas to oil, based on GLR changes over time. This would also seem to suggest that the concept of a permanent gas well classification is inconsistent with the statute and Statewide Rules. However, as will be seen with the technical concept of fluid mobility in the reservoir, in some circumstances it can be shown that a reservoir has and always will produce gas, not oil, regardless of how much liquid is produced at the surface.

5.1.2.2 Administrative Law Cases

Since 1989 the Examiners are aware of at least 79 (77 since 2001) docketed cases in which well classification was an issue—and in all of those cases the applicants sought to classify wells as gas wells, not oil wells.[78] Discussion of several of these cases will be introduced as appropriate. None of these cases were protested contested cases and most—75—of the applications for gas well classification were granted by the Commission on the recommendation of the Examiners. In only 4 cases were the Examiners' recommendations considered to be adverse by the Applicant. In all 4 of those cases the Commission upheld the Examiners' recommendations to deny permanent gas well classification. Motions for Rehearing were sought in two of those, and both were denied.

5.1.3 How Are Gas Wells Classified?

Attachment H is a process flow diagram for gas well classification. The Commission's policy on administrative gas well classification was most recently amended in a T-bar memorandum between the Oil & Gas Division and the Commissioner's aides and is dated August 3, 2006.[79] The Commission requires an operator seeking a gas well classification to file Form G-5, "Gas Well Classification Report," documenting the basis for the classification, whether it be by GOR or other criteria.[80] Through Form G-5, the Commission acknowledges

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[77] Smith, E. E. & Weaver, J. L., Texas Law of Oil and Gas. Second Edition. Vol. 2. 1998. § 10: 29. *Emphasis added.*

[78] The 79 cases were readily identified by (1) querying the Commissions online Neubus archive with the subject field search strings "permanent" and "classif"; and (2) searching the Commission's website for miscellaneous gas well classification dockets. The Examiners consider the list to be representative, but not necessarily complete.

[79] *See* T-Bar memorandum dated August 3, 2006. Change in administrative determination policy for gas well classification. From Richard Varela, Director, Oil and Gas Division, to the Commissioners' Offices and initialed by the Commissioners' aides.

[80] Operators must also file Forms G-1 and G-10, which include other required gas well test data.

that, from a standpoint of technical practicality, GLR alone may not be the sole criterion for well classification; other fluid characteristics warrant attention in some situations, as these other characteristics have been shown to suggest gas well classification is appropriate. In the event the Form G-5 results are inconclusive, reservoir fluid studies may be conducted to assess the phase characteristics of a hydrocarbon sample at reservoir conditions.

Generally and historically a well may, from time to time, be reclassified from gas to oil or from oil to gas. The determinant factor in such relcasification is GLR. For example, a well producing volatile oil may, towards the end of its productive life, produce more gas as the oil is depleted. When the well produces more than 100,000 scf/bbl of oil, the Commission may require, per statute, that the well be reclassified as a gas well (see **Attachment F**, as the volatile oil line decreases towards point 7). Similarly, a well that produces from a retrograde gas reservoir may, over time, begin producing liquids from the reservoir. When the well produces more than 1 barrel of oil per 100,000 scf gas, the Commission may require, per statute, that the well be reclassified as an oil well. In addition, there is no prohibition for an operator, on its own initiative, to request a well be reclassified—at any time in the life of the well—based on the appropriate demonstration of evidence, either through an administrative or hearing process.

There is, however, a technical and legal basis for a permanent gas well classification, which may prevent compulsory reclassification of a gas well to an oil well. The concept of a permanent gas well will be discussed below (Sec. 5.1.4).

5.1.3.1 Form G-5 Gas Well Classification Report

Form G-5 organizes well and reservoir fluid evaluation into two sections. The first section is a production test representing current operating or stabilized well conditions. The production test requires reporting of 14 data elements including gas production, hydrocarbon liquid production, and GLR. If the production test demonstrates that the GLR is greater than 100,000 cf/bbl, then the well is classified as a gas well. Otherwise it is an oil well and an operator may elect to conduct further testing. The second part of Form G-5 requires an ASTM distillation test be performed on the produced liquid phase if the producing GLR is less than 100,000 cf/bbl. The ASTM distillation test requires 17 data elements be reported on Form G-5.

From the data elements reported on Form G-5 for both the production and distillation tests, the current Commission policy enumerates seven result thresholds for gas well classification. These result thresholds, collectively, prescribe a solution envelope within which the Commission may administratively assign a gas well classification. Collectively, the result thresholds Form G-5 can be thought of as "rules of thumb" that indicate whether the fluid phase in place in the reservoir is likely to be gas or oil. For wells with a producing GLR of less than 100,000 cf/bbl, current Commission policy provides for gas well classification when ***all*** of the following result thresholds are met:

Production Test Elements:

- GOR is greater than 12,500 cf/bbl;

- the American Petroleum Institute ("API") gravity of the liquid exceeds 50°;
- the liquid color is not consistent with that of crude petroleum oil;

ASTM Distillation Test Elements:

- the initial boiling point is less than 120°F;
- at 80% recovery the boiling point does not exceed 520°F;
- the end point does not exceed 720°F with at least 95% recovery;
- and the residue is less than 5% with no evidence of cracking.

The Commission's current policy requires all of these elements to be demonstrated affirmatively.[81] That is, while each element individually may suggest a gas well characteristic, no individual element or subset of these seven elements is dispositive for gas well classification pursuant to statute, Statewide Rule or written Commission policy.[82] The Examiners are generally aware that Commission staff may have some latitude in granting gas well classification if some of these thresholds are not met, but there is no evidence in the record with regards to the nature or degree of such policy flexibility.

When Form G-5 fails to secure gas well classification, operators may choose to conduct analytical studies to assess the phase-in-place of the reservoir fluid (that is, the *in situ* fluid phase in the reservoir at the time of assessment). Of particular interest in this case—and in many recent cases—has been whether or not the hydrocarbons exist in a retrograde gas reservoir.

5.1.3.2 Gas Well Classification Based on PVT Analysis

Pioneer considers visual cell PVT data to be the "gold standard" for reservoir fluid studies.[83] However, the Examiners find the role of PVT analysis—what it can indicate, and what it cannot, needs to be clarified. The statute and Statewide Rules are the standards for gas well classification, and those come back to a 100,000 GOR and how GOR is to be calculated. What PVT analysis can do is indicate the phase characteristics—liquid, gas or both—of a particular bulk fluid sample when subject to reservoir temperature and pressure conditions. This information can be important, but it is not necessarily, in and of itself, dispositive for a permanent gas well classification and, to the Examiners knowledge, has not been held as such by the Commission. In fact, administratively, a dew point observation on a visual cell PVT test will secure a one-year temporary gas well classification, which an operator may renew on a year-to-year basis upon the demonstration of appropriate evidence.

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[81] The Examiners are not aware of the origins or scientific basis for these result thresholds, except to say that the Commission has relied on them for many years.

[82] *See* **Oil & Gas Docket No. 06-0248813**, the Application of Samson Lone Star, L.P. for Gas Well Classification for the Vaughn Gas Unit 1 Well No. 3, in the Waskom (Cotton Valley) Field, Harrison County, Texas, Final Order signed May 30, 2007; and *see* **Oil & Gas Docket No. 06-0249228**, the Application of Samson Lone Star, L.P. for Gas Well Classification for the Taylor Estate Lease Well No. 1, in the Waskom (Cotton Valley) Field, Harrison County, Texas, Final Order signed May 30, 2007.

[83] Vol. 3 Tr. 62:24 – 63:2.

As an example of a gas well later reclassified as an oil well, a visual cell PVT test for Devon's Krause C Well No. 1 (API No. 123-32314, one of Devon's public data point wells) indicated a dew point pressure of 4,364 psi at a reservoir temperature of 319°F and reservoir pressure of 10,972 psi. On that basis the Commission granted a temporary gas well classification on August 7, 2012 for a period of one year. If Devon desired to continue the temporary classification, it was instructed to run a shut-in bottom hole pressure survey (Form W-7) on the well in and submit that survey to the Commission within 30 days of August 14, 2013. The Commission would then review the shut-in bottom hole pressure survey to determine whether the gas well classification will be extended for a period of time. Extension could be based on evidence that the bottom hole pressure is still above the dew point, or that the reservoir GLR was 100,000 scf/bbl or higher. Devon did not submit a shut-in bottom hole pressure survey, and Commission staff rescinded the gas well classification. The well was reclassified as an oil well effective November 1, 2013.[84]

Such a well is properly initially classified as a gas well, but not permanently so, without additional information. The liquids that condense in the reservoir may be produced through the well, in which case they would be considered crude petroleum oil for the regulatory purpose of calculating GOR for well classification.

It is not clear to the Examiners if the administrative gas well classification policy considers simulated and visual cell PVT analyses to be equivalent, or if Commission staff who perform this analysis are aware of the technical distinctions and limitations in accuracy between visual cell and simulated PVT analyses. The 2006 policy memorandum states a "(PVT) test can be run in a laboratory and submitted to prove a well is a gas well. This test simulates the phase characteristics of a hydrocarbon sample at existing reservoir conditions." The Examiners believe that the policy language contemplates a visual cell PVT analysis, but the record on this question has not been developed.

5.1.3.3 Gas Well Classification Based on C_7+ Analysis

The 2006 gas well classification policy memo adopted a criterion for administrative classification based on a C_7+ composition of less than 11.0 mole percent. The gas well classification policy memo makes no explicit reference to "permanent" gas well classification, nor does it restrict the applicability of a C_7+ composition analysis to a sample collected early in the life of the well and at stabilized conditions. However, the memo makes explicit reference to Moses (1986) and McCain (1990). It may be implied, therefore, that the Commission policy recognizes Moses and McCain's requisite conditions that C_7+ composition samples be collected early in the productive life of a stabilized well before significant depletion of reservoir pressure.

The Examiners understand that, in practice, the C_7+ composition-based policy is implemented as a permanent classification. From a technical standpoint, the Examiners believe that a permanent gas well classification based on C_7+ analysis can be appropriate given the requisite conditions of sampling articulated in the literature, and if any liquid hydrocarbons in the

[84] *See* Commission online completion reports, tracking nos. 20756 & 92298.

reservoir are immobile. Consequently, a C_7+ compositional analysis is not valid for gas well classification after the reservoir pressure has declined below the bubble point or dew point, or if other technical considerations are not met. Therefore, C_7+ compositional data collected after a period of time should be supported with bottom hole or reservoir pressure data.

5.1.4 What Is A Permanent Gas Well?

Neither the statute nor Statewide Rule make reference to "permanent" or "temporary" gas well classification. Indeed, the Commission may require an operator to reclassify a well from oil to gas or from gas to oil, based on GLR changes over time, and this happens quite often. For example, the Examiners found 34 temporary gas well classification letters issued by Commission staff for the 59 wells in Devon's public data set. Of those 34 temporary gas well classifications, Commission records indicate about seven were eventually reclassified as oil wells; six were reclassified as permanent gas wells based on GLR or C_7+ data at some time after intial production. The ultimate classifications of the other 21 temporary gas wells are uncertain.

Although the concept of a permanent gas well does not explicitly exist in the statute or Statewide Rule, it can be implied, and the Commission has determined that certain wells (and wells completed in certain fields) can be permanently classified as gas wells. Indeed, permanent gas wells likely arose from a desire to promote efficient operation and avoid unnecessary classification flip-flopping from gas to oil and back,[85] and the science behind fluid behavior in a formation can justify its application under statute and Statewide Rule. Originally a permanent gas well classification could only be obtained by a Final Order after a hearing. During those hearings, dozens of which were held between 2001 and 2008,[86] the Commission would grant a permanent gas well classification with the following demonstration of evidence and logical inference:

- At initial conditions the hydrocarbon fluids in the reservoir exist only in the gas phase (there are no liquid hydrocarbons in the reservoir at initial conditions).
- PVT analysis identifies a dew point, indicating the well produces from a retrograde gas reservoir in which the reservoir temperature is higher than the critical point temperature (see **Attachment F**).
- As the well is produced and the reservoir pressure falls below the dew point pressure, liquids condense in the reservoir. PVT analysis can indicate the percent of liquid volume in the reservoir as a function of pressure decline.

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[85] PFDs in such gas well classification cases often cite the direct and lost production costs of shutting in a well for testing, and the risks associated with potentially losing the well. The PFDs made no mention of advantages that otherwise might be secured from gas well classification.

[86] *See*, for example Oil & Gas Docket Nos. 3-92,678; 3-94,678; 02-0227689; 03-0227691; 03-0227690; 03-0230586; 03-0231562; 03-0244306; and 03-0240486.

- All of the hydrocarbon liquids in the reservoir are the product of condensation that has formed since the production started.

- The volume of hydrocarbon liquid in the reservoir never reaches the critical condensate saturation that is required to initiate and sustain liquid flow in the reservoir.

- Since no condensed liquids in the reservoir can flow, all of the liquids produced at the surface must have condensed after the fluid (gas) left the reservoir.

- The produced condensate is not crude petroleum oil and is not to be included in GOR calculations for well classification purposes.

More often than not the works of Moses and McCain were cited in these hearings as operators referred to the correlations between a C_7+ composition of less than about 12.5 to 12.9 mole percent as indicative of a dew point—and thus a retrograde condensate reservoir. Although the 2006 T-bar policy memo does not make reference to "permanent" gas well classification, the Examiners understand that a demonstration of less than 11 mole percent C_7+ is implemented as a permanent classification.

In Oil & Gas Docket No. 03-0242323, the Commission found that the subject well should not be permanently classified as a gas well because it was not completed in a retrograde gas reservoir. Instead, the well produced from an associated reservoir with a gas cap and oil rim. Therefore, liquid hydrocarbons produced from this reservoir at some time may meet the statutory definition of crude petroleum oil. That well could, the Commission concluded, be classified as a (non-permanent) associated gas well as long as it meets the standard gas well criteria and may be reclassified as an oil well in the future if it meets the standard oil well criteria.

5.1.4.1 Liquid Mobility in the Reservoir

For retrograde gas reservoirs it may be shown that liquid condensate in the reservoir is not mobile. If the liquid is not mobile in the reservoir, then it cannot flow through the reservoir to a well and be produced at the surface; it will "drop out" and remain stranded in the reservoir. Hydrocarbon liquid mobility in the reservoir has long been held as an important factor in gas well classification cases. In the PFDs for Oil & Gas Docket Nos. 06-0248813 and 06-0249228, the Examiner stated: [87]

> *The importance of movable hydrocarbon liquids in a reservoir that produces gas is recognized in the Commission's definition of a gas well which, in an admittedly tortured manner, indicates that liquids that exist in that (liquid) phase in the*

[87] *See* (1) Oil & Gas Docket No. 06-0249228: Final Order Denying the Application of Samson Lone Star, L.P. for Gas Well Classification for the Taylor Estate Lease Well No. 1, in the Waskom (Cotton Valley) Field, Harrison County, Texas. May 30, 2007. Motion for Rehearing denied August 14, 2007. *And* (2) Final Order Denying the Application of Samson Lone Star, L.P. for Gas Well Classification for the Vaughn Gas Unit 1 Well No. 3, in the Waskom (Cotton Valley) Field, Harrison County, Texas. May 30, 2007. Motion for Rehearing denied August 14, 2007.

reservoir and that can be produced at the surface as liquids are considered crude oil.

This has become a critical distinction in Commission gas well classification decisions, and many docketed cases have hinged on it: If studies indicate the reservoir fluid exists as a gas in the reservoir, and if the studies indicate that as pressure declines the liquid condensate forming in the reservoir is not mobile in the reservoir, then all liquids produced at the surface are the product of condensation after the hydrocarbon gas has left the reservoir and entered the wellbore. In such a case, all liquids produced at the surface shall not be construed to be crude petroleum oil for the purpose of calculating GLR (GOR) pursuant to statute and Statewide Rules.

For a retrograde gas, PVT analyses can be used to determine how much liquid is condensed (i.e., the liquid drop-out) at various reservoir pressures. The question, then, becomes, how much hydrocarbon liquid must be present in the reservoir for the liquid to flow? This question is generally not directly answered empirically. Instead, operators have historically cited literature sources, again, as rules of thumb. Many of the identified 75 docketed cases with uncontested outcomes included a Finding of Fact that the hydrocarbon liquids in the reservoir were immobile, and that such liquids would not become mobile until they achieved the critical condensation saturation—which ranged from 10 percent to 40 percent of the pore volume.[88] In a 2002 case, Kerr-McGee cited a widely accepted understanding that oil in a reservoir is essentially immobile until it reaches a saturation of 10 to 20 percent.[89] In another 2002 case, Ballard Exploration Company, citing McCain (1990, p. 156), stated that liquid hydrocarbon volumes up to 35 percent of reservoir volume "seldom will flow and normally cannot be produced."[90] These rules of thumb, which vary considerably, have therefore been applied to assessing liquid hydrocarbon mobility in reservoirs, and this is particularly the case for wells producing retrograde gas.[91] Recently, Orangi, et al (2015), affirmed that gas production rates can be affected by condensation mobilization in an unconventional shale reservoir, stating "As the condensate-accumulation exceeds (critical condensate saturation), condensate starts flowing. This brings a further step-decrease in the gas rate… as the liquid flow takes up part of the connected pore network. This effect is seen (sic) more pronounced at the higher (critical condensate saturation) of 35% as expected."[92]

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[88] *See*, for example, Oil & Gas Docket No. 03-0244306, Final Order Approving the Application of Smith Production, Inc. for Gas Classification of the Swilley Lease, Well No. 1, Hull * Field, Liberty County, Texas. February 7, 2006.

[89] *See* Oil & Gas Docket No. 03-0230586: The Application of Kerr-McGee Rocky Mountain Corporation to Adopt Rules and Permanently Classify the Port Acres (Hack. 9600) Field as a Gas Field, Jefferson County, Texas. Final Order signed April 9, 2002. Specifically, Kerr-McGee cites Craft, B.C. and Hawkins, M.F., <u>Applied Petroleum Reservoir Engineering</u>. Prentice-Hall, Inc. Englewood Cliffs, N.J. 1954.

[90] See Oil & Gas Docket No. 03-0231562: The Application of Ballard Exploration Company, Inc. for Permanent Gas Field Classification for Big Thicket (Upper Yegua EY) Field, Orange County, Texas. Final Order signed August 6, 2002.

[91] See Oil & Gas Docket No. 03-0236149: The Application of Masters Resources, LLC, to Permanently Classify Its State Tract 9-12B Lease, Well No. 1 in the Fishers Reef (9800) FB D) Field as a Gas Well, Chambers County, Texas. Finding of Fact No. 6 states: The liquid hydrocarbons will be present at a maximum volume of 36.4 percent of the hydrocarbon pore space in the reservoir but will be immobile."

[92] Exh. No. 60, Tab 4, page 17.

The Examiners note that the cited critical condensation saturation values and the findings of fact in various Commission PFDs are somewhat ambiguous. It is not clear if the referenced pore space volume necessary to initiate or sustain liquid flow pertains to (1) a percent of the total reservoir pore volume, or (2) a percent of the hydrocarbon-filled pore volume. This ambiguity can significantly affect the outcomes of applying such values as rules of thumb.

Conversely, the Commission has also found that wells should be classified as oil wells because the liquids are, in fact, mobile in the reservoir. In Oil & Gas Docket No. 03-0240486[93] the Commission found that the subject well should be classified as an oil well because hydrocarbon liquids that condense from the gas phase in the formation will occupy up to 48.62 percent of the hydrocarbon pore volume. This liquid is mobile in the reservoir and will be produced at the surface as a liquid. Thus those liquids are crude petroleum oil and should be included in GLR calculations.

In Oil & Gas Docket Nos. 06-0248813 and 06-0249228,[94] Samson Lone Star, L. P. asserted that the subject wells meet the administrative gas well classification criteria pursuant to the C_7+ being less than 11 mole percent, and therefore the wells should have been administratively approved as gas wells and all contrary data ignored. Samson argued that the subject applications turn on the Commission T-bar memo, which should be interpreted to mean that use of the C_7+ criteria in itself is sufficient for gas well classification. As evidence, Samson submitted excerpts from a C_7+ analysis report from Southern Petroleum Laboratories. Secondly, Samson argued that the A.S.T.M. Distillation test should not be required if a C_7+ analysis report is submitted. Finally, Samson argued that there should be no review by the Commission of other data or information (submitted or not) through the administrative review process or the hearing process for reconciliation purposes.

In the Samson cases, the Examiner recommended the application be denied because the applicant failed to prove by the preponderance of evidence that the hydrocarbon liquid in the reservoir is immobile and not produced at the surface. *Specifically, the demonstration of a C_7+ composition, by itself, was not sufficient to prove liquid immobility in the reservoir.* Secondly, the Examiner concluded the C_7+ analysis report does not take the place of Form G-5 and the A.S.T.M. Distillation test if the GOR is less than 100,000 scf/bbl. That is, the A.S.T.M Distillation test is still required. Thirdly, Commission administrative review and consideration (or in the hearing process) is not limited to a single item or form, but the collective consideration of data and, if necessary, the reconciliation of all data and information that is deemed necessary for an engineering gas well classification determination. The Commission upheld the

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[93] *See* Oil & Gas Docket No. 03-0240486: Final Order Denying the Application of Walter Oil & Gas Corporation for Gas Well Classification for the Smith-Bailey Lease Well No. 1, in the Rich Ranch (Yegua) Field, Liberty County, Texas. February 8, 2005.

[94] *See* (1) Oil & Gas Docket No. 06-0249228: Final Order Denying the Application of Samson Lone Star, L.P. for Gas Well Classification for the Taylor Estate Lease Well No. 1, in the Waskom (Cotton Valley) Field, Harrison County, Texas. May 30, 2007. Motion for Rehearing denied August 14, 2007. *And* (2) Final Order Denying the Application of Samson Lone Star, L.P. for Gas Well Classification for the Vaughn Gas Unit 1 Well No. 3, in the Waskom (Cotton Valley) Field, Harrison County, Texas. May 30, 2007. Motion for Rehearing denied August 14, 2007.

Examiner's recommendation denying permanent gas well classification, and subsequently denied Samson's Motions for Rehearing in both dockets.

The Commission has, on occasion, granted permanent gas well classification for all wells in a particular geographic area based on a limited sample set. For example, in Oil & Gas Docket No. 06-0243382, the Commission granted permanent gas well classification for all wells in the Brookeland (Austin Chalk 8800) Field in Tyler County.[95] The Brookeland (Austin Chalk 8800) Field extends across 6 counties and includes only a portion of Tyler County. At the time there were 33 wells in the field in Tyler County. Anadarko, the applicant in the case, found itself having to reclassify several of its wells from gas to oil, and back again on several occasions because of GLR changes. That case is fundamentally different, however, from Pioneer's present case. Wells in the Brookeland (Austin Chalk 8800) Field are open-hole completions in a chalk reservoir matrix. In Anadarko, the average producing GLR was about 21,000 scf/bbl. The initial reservoir pressure was greater than 10,000 psi, and PVT data from 18 of the wells indicated dew points ranging from 4,441 psi to 7,049 psi. The C_7+ composition for all 18 of the Anadarko data was less than 12.5 mole percent. Condensation formation in the reservoir was generally considered to be immobile. Thus, in the Brookeland (Austin Chalk 8800) Field case, the data were remarkably consistent: All the rules of thumb point to gas. The Brookeland (Austin Chalk 8800) Field data is fundamentally different from that of the Sugarkane (Eagle Ford) Field transition zone of the Ridley 01 Unit. At initial conditions the Brookeland (Austin Chalk 8800) Field in Tyler County was a single-phase, conventional retrograde gas reservoir producing at a GLR far above what would be considered to be a transitional range. The Ridley 01 Unit, however, is right in the middle of a transition.

However, the literature sources cited for the minimum liquid mobility limit ranging from 10 percent to 40 percent of reservoir pore volume predate the contemporary era of horizontal wells in shale reservoirs with multiple hydraulic fracture stimulation treatments. That is, the range of minimum liquid mobility (from 10 percent to 40 percent) represents the mobility in a reservoir matrix—and likely does not address mobility through an artificially created fracture network that alters the permeability of the reservoir. The question becomes: are the old rules of thumb for a minimum liquid mobility limit (10 percent to 40 percent) still valid in fields such as the Sugarkane (Eagle Ford) Field? Permeability through unstimulated shale would likely require significant liquid volumes; the same cannot necessarily be said for flow through a created (through hydraulic fracture stimulation) network of fractures.

5.1.4.2 3,000 scf/bbl as a Field Rule for Gas Well Classification

As mentioned, Moses and McCain identified an initial producing GLR of about 3,000 to 3,300 scf/bbl as a differentiator between volatile oil and retrograde gas reservoir fluid types, but the Commission did not establish a related administrative classification rule in its 2006 policy memorandum. Since 2011, however, a GLR-based permanent gas well classification criteria has been adopted for some fields. The first such field to receive a 3,000 scf/bbl field rule for gas well classification was the Briscoe Ranch (Eagleford) Field (Oil & Gas Docket No. 01- 0270024,

[95] Oil & Gas Docket No. 06-0243382: Approving Permanent Classification for All Wells in the Brookeland (Austin Chalk 8800) Field, Tyler County, Texas. Final Order signed February 7, 2006.

Final Order dated May 24, 2011).[96] The applicant in that case, Anadarko, did not request a 3,000 scf/bbl field rule; the manner in which the rule was developed is interesting and warrants attention.

Anadarko applied for permanent gas well classification for some of its various leases in the Briscoe Ranch (Eagleford) Field. In addition to Anadarko, the hearing was attended by representatives of five other operating companies, including Pioneer. Anadarko provided C_7+ compositional studies for 36 wells across its various leases that demonstrated the following:

- 34 of the 36 samples indicated C_7+ compositions less than 12.5 mole percent, and the average composition of methane was 70 mole percent. The condensate is light straw in color and the average API gravity of the liquid hydrocarbon is 60.0 degrees. The average initial producing gas oil ratio was about 4,000 to 5,000 scf/bbl.

- Two of the 36 wells indicated C_7+ compositions of more than 12.5 mole percent and an average initial GLR of about 2,400 cubic feet per barrel.

Again, in the Briscoe Ranch (Eagleford) Field, the C7+ and GLR rules of thumb for gas well classification were remarkably consistent.

Anadarko's evidence included a contoured oil yield map of the field in the area, which was annotated with a line demarcating the 3,000 scf/bbl GLR contour. The leases for which Anadarko sought gas well classification were within the area of GLR values higher than 3,000 scf/bbl. The Technical Examiner in that case offered a recommendation, *sua sponte*, that a 3,000 scf/bbl field rule was a more efficient resolution than a lease-by-lease classification. Instead of granting Anadarko's lease-specific application for gas well classification, which would likely be followed by additional similar applications by other operators in the field—including those observing the hearing—the Technical Examiner noted the 3,000 scf/bbl GLR line and suggested that 3,000 scf/bbl would be an appropriate criteria for gas well classification. Neither Anadarko nor the other operators present were opposed to this recommendation. The Examiner recommended and the Commission approved a Final Order granting permanent gas well classification to all wells in the Briscoe Ranch (Eagleford) Field completed with a GLR of 3,000 scf/bbl or greater.

The Examiners note that, in the present case, none of the public data (Exh. No. 38, Dev Exh. No. 17) are from the Briscoe Ranch (Eagleford) Field. There is no evidence in the record to indicate Briscoe Ranch (Eagleford) Field produces from an HPHT reservoir.

Sugarkane (Eagle Ford) Field rules provide for permanent gas well classification based on an initial GLR of 3,000 scf/bbl or greater.[97] Similar field rules have been adopted for at least six other fields in Texas, most of which are actively being developed with horizontal wells.[98]

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[96] Pioneer Exh. No. 38 (Devon Exh. No. 5).

[97] Exh. Nos. 4 & 22.

[98] Exh. No. 38 (Devon Exh. No. 5).

The Briscoe Ranch case, and all subsequent cases adopting a 3,000 scf/bbl gas well classification criterion, have cited and relied on the works of Moses and McCain. The Examiners are aware that other similar field-wide gas well classification dockets are pending.

Recently, the Commission approved a 3,000 scf/bbl gas well classification criteria for the in the Lipscomb, S. E. (Cleveland) and Lipscomb (Cleveland) fields.[99] The PFDs in both of those cases describe the Cleveland Formation reservoirs as consisting of a compartmentalized sandstone with some higher quality reservoir sands distributed horizontally and vertically. While the Cleveland Formation fields are being developed with horizontal wells, the PFDs in those cases did not describe the Cleveland Formation as having shale, HPHT or nano-porosity characteristics. Further, the evidence in the Lipscomb Field cases indicates a C_7+ and GLR relationship as described by McCain. Although there is a significant amount of scatter, by far most of the data (about 139 of 144 data points) indicates that C_7+ values of 12.5 mole percent or less are associated with GOR values of 3,000 scf/bbl or greater.

Finally, the Examiners note that there is no evidence in the record that the 3,000 scf/bbl GLR permanent gas well classification rule (for any field or well) was ever intended to apply to any point in time of the life of a well other than initial completion and the establishment of stabilized production. In reviewing well records for Devon's public data set, the Examiners found several instances in which a well received a one-year temporary gas well classification based on PVT analysis identifying a dew point, and at the end of the temporary period permanent gas well classification was granted on the basis of a retested well demonstration of GLR greater than 3,000 scf/bbl. Applying the field rule in this way is not consistent with the technical basis of a 3,000 scf/bbl GLR gas well classification rule, nor is it consistent with statutory and Rule definitions from which the criterion was derrived. With regard to permanent gas well classification in Texas, the Examiners conclude that the 3,000 scf/bbl criteria only applies as an initial production condition; the same holds for C_7+ analysis, and for the same reason.

5.2 Evidentiary Analysis

The Commission has historically granted permanent gas well classifications based on two demonstrations of evidence:

- At initial conditions, the hydrocarbon fluid in the reservoir exists as a single-phase gas (that is, there are no liquid hydrocarbons in the reservoir before production begins); and

- Liquid hydrocarbons that may form in the reservoir by retrograde condensatation are immobile and will not flow as liquids through the reservoir and into the production stream.

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[99] *See* Oil & Gas Docket No. 10-0298029, The Application of Mewbourne Oil Company to Amend the Permanent Field Rules for the Lipscomb, S. E. (Cleveland) Field in Hemphill, Lipscomb, Ochiltree and Roberts Counties, Texas; *and* Oil & Gas Docket No. 10-0298030, The Application of Mewbourne Oil Company to Amend the Permanent Field Rules for the Lipscomb (Cleveland) Field in Hemphill, Lipscomb, and Ochiltree Counties, Texas;

In the discussion that follows the Examiners will proceed from (1) the evidence on the Ridley 01 Unit, to (2) the evidence from the nearby offsetting wells, to (3) the Devon evidence in the greater Eagle Ford Formation development area.

5.2.1 Evidence from the Ridley 01 Unit

There is no direct evidence from the Ridley 01 Unit that the produced hydrocarbons exist as a single phase gas at reservoir conditions, or that liquid hydrocarbons in the reservoir are immobile. A visual cell PVT observation of a dew point at a pressure below the initial reservoir pressure is direct and affirmative evidence that the sampled fluid exists as a single-phase gas when subject to reservoir temperature and pressure conditions. A visual cell PVT observation of a dew point does not merit a permanent gas well classification without evidence of liquid immobility, but it would have secured a temporary gas well classification for at least one year. However, Pioneer conducted no visual cell PVT observations for any of the Ridley 01 Unit wells, so a determination that the initial phase-in-place was single phase gas cannot be made on the basis of direct evidence. As the gas well classification process flow diagram (**Attachment H**) indicates, an operator has multiple avenues to attempt gas well classification.

There is some indirect correlation evidence from the Ridley 01 Unit—in the form of C_7+ composition, initial producing GLR data, etc.—that may indicate the presence of a retrograde gas at initial reservoir conditions. But, there is also substantial indirect correlation evidence to suggest the reservoir fluids exist as a volatile oil, or some hybrid of the two, at initial reservoir conditions.

5.2.1.1 Initial Testing and Administrative Classification

Four of the Ridley 01 Unit wells (1H, 3H, 7H and 9H) have been granted permanent gas well classification based on the existing field rule criterion of an initial producing GLR of 3,000 scf/bbl or greater. One of these wells, No. 1H, exhibited a C_7+ composition of 8.42 mole percent, which meets the administrative policy criterion (C_7+ composition less than 11 mole percent). These four well classifications are a settled matter.

The Examiners note, however, that some of the individual well evidence is inconsistent and demonstrates the unreliability of some of the rules of thumb used for gas well classification in this area. For example, Well No. 1H presented a C_7+ of 8.52, which was considerably lower than all of the other Ridley 01 Unit wells tested for this characteristic; the other six wells (10 discrete samples) exhibited C_7+ compositions ranging from 11.73 mole percent in Well No. 2H (which, as will be discussed, is suspect because the sample was collected after one year of production) to 15.69 mole percent in Well No. 6H. Simply comparing the C_7+ compositions of the No. 1H well with those of the classification-pending wells (No. 2H, 4H, 5H, 6H, 8H, 10H and 11H) suggests the unclassified wells do not meet the gas well classification criteria. It is also possible that Well No. 1H is the outlier, and that its true C_7+ composition was somewhat higher.

Also, the record contains only one Form G-5 for a Ridley 01 Unit well (No. 1H) that includes an ASTM Distillation test; none of the five other Form G-5s in the record (Well Nos.

2H, 3H, 4H, 7H and 9H) report the results of a distillation test, and Pioneer reported no other distillation test results for the other five Ridley 01 Unit wells. The results of this one test indicate that a liquid sample from Well No. 1H exhibited a total recovery of 86.9 percent and a "residue" of 11.1 percent. An ASTM distillation test must result in at least 95 percent recovery and less than 5 percent residue at 720°F for gas well classification pursuant to Commission policy. In a distillation test, the sample is heated and the constituent hydrocarbon liquids in the sample evaporate when their respective boiling temperatures are reached. The test concludes when there is no more liquid in the flask, although a semi-solid residue may remain. The 11.1 percent residue and 86.9 percent recovery at a final temperature of 718°F suggests that the Well No. 1H liquid sample contained more heavy hydrocarbon constituents than anticipated by the 5 percent maximum residue criteria in Commission policy. The Well No. 1H data is not unequivocal with regard to gas well classification.

5.2.1.2 GLR and Adjustment for AGP

Commission Forms G-1 (line no. 20) and G-5 (line E) both require an operator to identify the GLR of a well as observed during an initial production test. The indicated GLR units on the forms are "Cf/Bbl", or cubic feet of gas per barrel of hydrocarbon liquid. Tex. Nat. Res. Code §86.002(12), states:

> *"Cubic foot of gas" or "standard cubic foot of gas" means the volume of gas, including natural and casinghead gas, contained in one cubic foot of space at a standard pressure base of 14.65 pounds per square inch absolute and at a standard temperature base of 60 degrees Fahrenheit, and if the conditions of pressure and temperature differ from this standard, conversion of the volume from the differing conditions to the standard conditions shall be made in accordance with the ideal gas laws, corrected for deviation.*

Statewide Rule 79(6) [16 Tex. Admin. Code §3.79(6)] contains a nearly identical definition of "cubic foot of gas or standard cubic foot of gas." Therefore the statute and Statewide Rules require reported gas volume measurements to be adjusted to standard surface temperature and pressure conditions, which is consistent with the instructions for Form G-5 for liquid samples, which state:

> *The liquid hydrocarbon sample must be a fresh sample of stock tank liquid or a separator sample which has been flashed to atmospheric pressure and allowed to stabilize at the ambient temperature. If a separator sample is transported to the laboratory in a pressurized container, the sample must be flashed to atmospheric pressure and allowed to stabilize at 60 degrees Fahrenheit before measuring the API Gravity or commencing the distillation test.*[100]

Thus, the pressure and temperature at the point of sampling (separator) are to be used to convert sample volumes to standard (stock tank) conditions.

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[100] Exh. Nos. 33 & 38 (Devon Exh. No. 20).

However, using the ideal gas laws to convert a volume of gas from separator to standard conditions does not account for phase changes that occur as a result of changes in the environmental conditions: what was gas or liquid in a separator may not be gas or liquid at standard (or stock tank conditions). Therefore, the Examiners agree with Pioneer that the GLR used for gas well classification pursuant to the Field Rules for the Sugarkane (Eagle Ford) Field should include all gas evolved from the whole wellstream through to stock tank conditions, as that appears to be what was contemplated by McCain.[101] That is, the AGP subsequent to the first-stage (high pressure) separator should be accounted for in the numerator of the GLR calculation. The Examiners conclude this is consistent with the instructions on Form G-5, Gas Well Classification, definitions in the Natural Resources Code, and the technical literature (McCain 1990, 2011) upon which the C_7+ and GLR correlations are based.

Consequently, the Examiners conclude that Well No. 6H has an initial producing GLR of 3,062 scf/bbl based on the AGP correlation and the well meets the current field rule criterion for permanent gas well classification.[102] The Examiners recommend Well No. 6H be permanently classified as a gas well.

Pioneer also presents a brief study of AGP based on the operating parameters and production characteristics of a number of non-Ridley 01 Unit wells in the area.[103] Through this study, adding a constant 690 scf/bbl AGP to all wells on the Ridley 01 Unit would increase the GLR of Well Nos. 2H and 8H above 3,000 scf/bbl (although the source of the 690 scf/bbl AGP is not readily apparent from any exhibit or the transcript). Based Pioneer's tabulation of 31 wells with visual cell PVT data, Pioneer calculates the average AGP to be 511 scf/bbl, and the range to be from 132 to 1,042 scf/bbl[104] (Pioneer did not disclose the locations or analytical data for these 31 wells, except to say that 9 of the wells offset the Ridley 01 Unit). Why Pioneer considers this approach is valid is unclear. Pioneer has already provided individual AGP calculations on Exhibit Nos. 35 and 59 based on actual operating conditions, and actual operating conditions of the wells in question should be more reliable than composite average conditions derived from another population of wells. The Examiners are not persuaded.

However, the Examiners make two observations. First, the correlation equation by Gold, et al, that Pioneer used was developed based on 234 gas condensate fluid samples from worldwide sources that may not be comparable to Eagle Ford Formation fluids at the Ridley 01 Unit. Specifically, the equation was developed with fluids demonstrating a C_7+ composition from 4 mole percent to 13 mole percent (mean = 6.6 mole percent)[105], which is on the low side of the C_7+ compositions observed at the Ridley 01 Unit (*see* **Table 4**). Second, the data upon which the AGP calculations are based predates the unconventional development efforts in shale formations like the Eagle Ford Formation, and the calculations may not be specificaly applicable.

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[101] McCain 2011, page 193.

[102] Exh. Nos. 35 & 59.

[103] Exh. Nos. 37 and 58.

[104] Exh. Nos. 58 and 59.

[105] Exh. No. 34.

Third, it is not clear whether the AGP calculation parameters were developed with HPHT reservoir fluids.

The Examiners caution, however, that application of an AGP correlation on Form G-5 without further documentation would likely lead to confusion and possibly loss of data integrity in Commission records. Consequently, this issue warrants further consideration by Commission staff and industry before being adopted on a broader scale. Ideally, the Form G-5 GLR (Line E) is calculated by dividing the Gas Volume (Line B) by the Oil or Condensate Volume (Line C). If an AGP correlation is applied, it is not clear how the integrity of the values and calculations on Form G-5 can be assured in a consistent manner. Indeed, the Examiners note that all of the Form G-5s filed by Pioneer for the Ridley 01 Unit report a Gas Volume (Line B) and a GLR (Line E), but none of those Form G-5s report an Oil or Condensate Volume (Line C); therefore, the GLR calculation is not internally verifiable. The Examiners refer to the Commission action in Oil and Gas Docket Nos. 06-0248813 and 06-0249228, in which the Commission found that Form G-5 must be completed in its entirety for all wells with a GOR of less than 100,000 scf/bbl.

The Examiners also caution that AGP is not equivalent to the separation extraction loss (see footnote no. 14) that is added to gas well production data received by the Commissoin. Although GLR data may be overstated by 1,100 scf/bbl from the insertion of the separation extraction loss, the GLR may also understated because, based on Pioneer's testimony, it does not include AGP from the secondary separator or stock tank flash gas. Still, the evidence in the record suggests that the AGP would likely be less than the 1,100 scf/bbl separation extraction loss in terms of its impact to GLR, at least for the Ridley 01 Unit wells. Pioneer's Exhibit Nos. 35 and 59 include calculations for AGP from seven Ridley 01 Unit wells. The AGP ranged from 288 scf/bbl to 1,016 scf/bbl and an average of 832 scf/bbl.[106]

The separation extraction loss, which results in a standard linear shift of 1,100 scf/stb increase in the GLR, is not a comparable surrogate for the AGP. The AGP is derived from moment-in-time separator and fluid conditions and is not appropriately applied as a static adjustment across the producing life of a well. As production conditions change, the GLR may change, too. For example, Pioneer calculates an AGP for Well No. 2H on February 14, 2012, to be 288 scf/bbl based on gas gravity of 0.65, liquid gravity of 56.2°API, first stage separator temperature of 148°F, second stage separator temperature of 104°F, and first stage separator pressure of 872 psi. Applying Pioneer's methodology, the Examiners find that: (1) decreasing only the first stage separator pressure by 10 percent results in a nearly 9.89 percent decrease in AGP; (2) decreasing only the first stage separator temperature by 10 percent results in a 13.43 percent increase in AGP; and (3) decreasing only the second stage separator temperature by 10 percent results in a 5.67 percent decline in AGP. Pioneer's Exhibit No. 56 indicate many variations in operating conditions across the different wells, but only one or two operating conditions per well over time. Exhibit No. 39 (Revised Devon Exh. No. 17) indicates changing first stage separator operating pressure over time.

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[106] Exh. Nos. 35 and 59.

Therefore, the Examiners conclude it is inappropriate to apply a static AGP correction across both wells and time; AGP corrections should only be applied when the discrete operating conditions are known, such as during test or sampling events. Consequently, if surface operating conditions can so affect the gross GLR, then the Examiners are concerned about the possibility of the GLR being manipulated to secure a GLR that meets a target threshold, for whatever purpose. Indeed, the GLR of oil wells has long been lawfully constrained by production parameters for conservation purposes.

5.2.1.3 Reported Production Data

The reported production data from the Ridley 01 Unit wells is not consistent with unit-wide gas well classification based on a 3,000 scf/bbl GLR, nor is it consistent with the anticipated GLR behavior with respect to time for a retrograde gas reservoir. Through the Devon data, Pioneer introduced generic "type curves" illustrating the GLR behavior of gas condensate, volatile oil and other reservoir fluid types over time (**Attachment E**).[107] For a retrograde gas, the GLR type curve is stable until the reservoir passes through the dew point, at which time the GLR increases. For a volatile oil, similar behavior is observed. As the reservoir passes through the bubble point the GLR increases as gas is liberated from solution. The liberated gas behaves like a retrograde gas, according to McCain. At a later time, however, the GLR of a volatile oil reservoir decreases as liquid production increases relative to gas production as reservoir condensate is produced.[108] The Examiners note, however, that the GLR type curves for unconventional shale reservoirs may, in theory, have a somewhat different shape, but none are in evidence.

The production history data from the Ridley 01 Unit wells does not follow the pattern established by McCain's type curves. **Attachment I** provides graphical presentation of the Ridley 01 Unit data, based on production reports filed by Pioneer with the Commission. The data does not include the separation extraction loss, nor does it include AGP. The unit-wide production of gas, liquid hydrocarbons and GLR is presented based on number of months in production. That is, the data shows the production history as if all wells entered production on the same month. The data shows production from all of the wells through January 2016, and the number of wells in production at any one time varies.

The Examiners offer several observations about the information on **Attachment I**:

- The data point for the first month likely represents partial production from some wells.
- The data point for the second month appears to represent stable production conditions.
- The intial stable GLR ranges between about 1,650 to 1,750 scf/bbl through the first twelve months.

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[107] Exh. No. 38 (Devon Exh. No. 28). McCain, William D. "Heavy Components Control Reservoir Fluid Behavior." Society of Petroleum Engineering. Journal of Petroleum Technology. September 1994. Page 749.

[108] Id. Pages 746-747.

- After twelve months, the GLR slightly but noticeably increases to about 1,975 scf/bbl at month 18. This may represent reservoir pressure decreasing below the dew point or bubble point, but very little reservoir pressure data is in evidence apart from testimony that Eagle Ford wells typically do not pass through the dew point until about 12 months of production.[109]

- After month 26, the Ridley 01 Unit wells enter a less stable production regime with erratic but generally declining GLR behavior.

As an aggregation of Ridley 01 Unit production data, **Attachment I** could be considered a type curve for the Ridley 01 Unit. The Examiners see nothing on this graph to suggest, as a rule, that any one well on the Ridley 01 Unit is entitled, *a priori*, to *permanent* gas well classification. **Attachment J** contains the individual production and GLR curves for each of the Ridley 01 Unit wells. Again, the monthly individual well production data does not indicate permanent gas well classification is appropriate, and Pioneer has not commented at all on the quality or characteristics of the production data with regard to its request for gas well classification.

And, it is noted that the four wells for which permanent gas well classification has been administratively granted (Nos. 1H, 3H, 7H and 9H), the production-based GLR is significantly lower than the G-5 test GLR upon which classification was based.

However, in at least one other shale resource play developed primarily with horizontal wells, the production characteristics of wells have been used to establish a retrograde gas production "type curve" that is consistent with other evidence and published literature. In Oil & Gas Docket No. 09-0277581, Pioneer applied for a gas well classification based on a GLR of 3,000 scf/bbl for the Newark, East (Barnett Shale) Field. In addition, Pioneer requested a six-month period for the wells to stabilize (to recover from stimulation flowback) to allow for an accurate initial producing GLR that is not influenced by the short-term after-affects of reservoir stimulation. Pioneer argued that the intial flowback period produced a tremendous amount of water that affected the reservoir flow of gas and condensate. Pioneer provided the first 500 days of production GLR for 72 wells in the Newark, East (Barnett Shale) Field. That evidence demonstrated a period of up to about 120 days of increasing GLR while the wells stabilized, after which the average of all wells settled in at a GLR of about 100,000 scf/bbl.[110] The evidence was compelling. The Examiners recognize there are surely petrophysical differences between the Barnett Shale and Eagle Ford Formations, and that production characteristics may differ. That is not the issue. The concern is that, in its Barnett Shale case, Pioneer clearly established the typical production characteristics of wells in the field to support a 3,000 scf/bbl GLR as a classification criterion in a liquids-rich gas condensate play; no such complementary evidence has been offered in this case.

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[109] Vol. 3 Tr. 128: 11-20.

[110] *See* Oil & Gas Docket No. 09-0277581: The Application of Pioneer Natural Resources USA, Inc. for Approval of Permanent Gas Classification in the Newark, East (Barnett Shale) Field, Montague, Wise, Clay, Cooke, Denton and Jack Counties, Texas.

Further, subsequent to Docket No. 09-0277581, EOG Resources applied to have a number of its Newark, East (Barnett Shale) wells reclassified from oil to gas based on the same standard used by Pioneer.[111] In that case (in which Pioneer was an observer), the Examiners (including the Technical Examiner in the present case) reviewed the production history graphs of each and every one of the 1,009 wells in EOG's application. The Examiner and EOG agreed to the criteria by which the wells were to be evaluated: The wells were to achieve stabilized production within 180 days with a sustained GLR of at least 3,000 scf/bbl. On that basis the Commission approved 924 of EOG's wells as gas wells.

5.2.1.4 Variance of Other Gas Well Characteristics

Well No. 2H demonstrated a C_7+ composition of 11.73 mole percent on a sample collected one year after the well entered production. While 11.73 mole percent is within the demarcated range established by Moses and McCain (less than 12.9 mole percent), the Examiners find the data point to be anomalous and unreliable. The well also demonstrated C_7+ values of 14.03 mole percent (after three months of production) and 15.64 mole percent (after eighteen months of production. Looking at all of the available data, the Examiners find the preponderance of evidence does not support permanent gas well classification for Well No. 2H.

While not as accurate as a visual cell PVT observation, Pioneer did conduct two simulated PVT analyses for Well Nos. 2H and 4H, but neither analyses indicated a single-phase gas at initial conditions. Well No. 2H indicated mixed oil and gas phases 17 months after completion, and well No. 4H indicated an oil phase six months after completion. Pioneer does not consider these results to be valid because of a communication error with the laboratory. Regardless, the Examiners find the simulated PVT analysis for Well No. 2H does not characterize initial reservoir fluid phase conditions as it was sampled 17 months after well completion.

Pioneer also cites Moses as stating retrograde gases have been observed with C_7+ compositions as high as 15.5 mole percent. Pioneer asserts that, based on the 15.5 mole percent standard, Well Nos. 2H, 4H, 8H and 11H can also be classified as gas wells. The Examiners disagree. Moses does not propose 15.5 mole percent as a determinant standard and the Commission has never considered it as such; it is simply within the known range of occurrence. Such a high C_7+ does not necessarily rule out potential gas well classification, which might be facilitated by other corroborating evidence such as a higher GLR, or substantial achievement of the ASTM distillation benchmarks.

Next, Pioneer turns to produced fluid characteristics, namely stock tank liquid color and stock tank liquid gravity. The stock tank liquid color display (**Attachment B**) indicates a lighter rather than a heavier liquid, but not to the point of persuasion with regard to well classification. Stock tank liquid color and gravity are not dispositive characteristics in themselves or even

[111] Exh. No. 39 (Devon late-filed Exh. No. 43): Oil & Gas Docket No. 09-0285425, The Application of EOG Resources, Inc. to Amend the Permanent Gas Well Classification Procedures for Wells in the Newark, East (Barnett Shale) Field, Clay, Cooke, Denton, Jack, Montague, Palo Pinto and Wise Counties, Texas.

together.[112] These characteristics are considered, as a group, part of the Form G-5 classification system. As such, the liquid color and gravity are only two of seven characteristics that have been historically considered by the Commission. Only one of the Ridley 01 Unit Wells (No. 1H) presented ASTM distillation test results, and those results indicated that the well failed with regard to total recovery (only 86.9 percent) and residue (11.1 percent), but the liquid color was reported as light straw. The odd coupling of a high residue with a light straw-colored liquid was not explored.

5.2.2 Evidence from Nearby Offset Wells

Pioneer asserts that the Ridley 01 Unit wells should be permanently classified as gas wells because the Commission granted the same classification to other nearby wells. Pioneer specifically identifies 10 offset wells, 8 of which exhibited dew points on the basis of visual cell PVT data; the other two exhibited bubble points. Pioneer also offers graphical evidence of the gradation of fluid characteristics (GLR, liquid color and liquid density) in the area, indicating oil to the northwest and gas to the southeast. This evidence is clear that the Ridley 01 Unit exists in a reservoir transition zone.

Looking at the adjacent wells Pioneer offers as evidence, one does not find a single consistent means by which the wells were permanently classified as gas wells.

- <u>Temporary Classification Followed by Permanent Classification Based on GLR Retest</u>: The Spear Reynolds Unit A 1, Schendel Unit 1, and Reynolds Gas Unit 1H wells (which are updip or on strike with the Ridley 01 Unit) were granted temporary gas well classification on the basis of a visual cell dew point observations. All three of these wells exhibited C_7+ compositions ranging from 12.5 mole percent to 14.4 mole percent. About one year later these three wells were reclassified based on a retested producing GLR exceeding 3,000 scf/bbl, but the field rule requires 3,000 scf/bbl to be achieved *at completion*, which the Examiners find to mean an *initial* stabilized producing GLR. The Examiners conclude these three wells were correctly classified as temporary gas wells, but were later granted permanent gas well status improperly. The Examiners are aware of no evidence or technical basis for 3,000 scf/bbl to be dispositive of permanent gas well classification except on initial testing as indicated by the Sugarkane (Eagle Ford) Field Rules. Therefore, these wells should not be a basis for permanent gas well classification.

- <u>Varying Characteristics of On-Strike Wells</u>: The Mangione 01 wells (02H, 03H and 04H, which are all on strike with the Ridley 01 Unit) have GLRs ranging from 2,959 to 4,003 scf/bbl and C_7+ compositions ranging from 13.2 to 14.6. One well (04H) exhibited a visual cell dew point observation, the other two exhibited bubble points, although Pioneer contends those data may be in error (and the Examiners find some evidence exists to suggest that possibility, but not wholly conclusively, nor can it be infered that the wells would otherwise exhibit a dew point). Similarly, two Ridley 01 Unit Wells

[112] McCain 1990, pg. 191, states: "…the scatter is too large for the use of stock-tank liquid gravities in determining reservoir fluid type."

(Nos. 2H and 4H) also presented bubble points on simulated PVT analysis, but Pioneer also discounted those results as inaccurate. The Examiners conclude the on-strike wells, like the Ridley 01 Unit wells, exhibit a variability indicative of the transition zone. None of the C_7+ compositions meet established criteria, one of the intial GLR values is below 3,000 scf/bbl, and two bubble points were observed. The Mangione 01 Well Nos. 02H and 04H meet the field rule criteria for permanent gas well classification; Well No. 03H does not, and its classification by Commission staff is pending. Therefore, these wells do not persuade.

- Down-Dip Wells: The Douglas 01 01H, Handy 02 0106H, and Handy 02 0107H were granted permanent gas well classification because of initial producing GLRs ranging from 3,448 to 4,536 scf/bbl. In addition, these wells exhibited C_7+ compositions ranging from 5.0 to 13.6 mole percent. Interestingly, the Douglas 01 01H, which is the most downdip well, and thus the well situated closest to the gas window of the Eagle Ford, exhibited the highest initial producing GLR (4,536 scf/bbl) and the lowest C_7+ composition (5.0 mole percent), which one would expect. The downdip wells meet the existing field rule criteria for permanent gas well classification. **Attachment K** presents production data from these three wells for comparison to the retrograde gas type curves on **Attachment E**. The production data in **Attachment K** indicates fairly constant GLR behavior over time, except for the Douglas GU No. 1, which declined after production began. Although the Douglas GU No. 1 well was granted permanent gas well classification, the production characteristics suggest the possibility of liquid flow in the reservoir.

The Examiners conclude that the adjacent wells were not themselves classified as gas wells on a consistent and uniformly representative technical basis, and therefore do not suggest a particular classification for any of the Ridley 01 Unit wells. Therefore, nearby well data is not sufficient to properly classify the Ridley 01 Unit wells. Indeed, three of the nearby wells may have been improperly granted permanent gas well classification on the basis of GLR retest some time after initial production. In addition, there are other wells immediately offsetting the Ridley 01 Unit that are classified as oil wells, too, and so there is significant reason to believe that some of the Ridley 01 Unit wells should be classified, properly, as oil wells. This does not mean the Ridley 01 Unit wells are not gas wells, but only that the nearby and adjacent gas wells do not persuade.

5.2.3 Analysis Of The Proposed Devon Criteria

5.2.3.1 Fully-Documented Visual Cell PVT Data Is Necessary to Establish Valid Correlations

Devon's body of evidence contains 125 data points. With this data, Devon attempted to develop an Eagle Ford Formation-specific correlation relating GLR and C_7+ with PVT results indicating a dew point or a bubble point, similar to the relationships established through the work that Moses and McCain. But the 125 data points are not all created equal, and the Examiners find that it is scientifically inappropriate to include them all in the same analysis.

First, the Examiners consider the inclusion of full analytical reports in the public record of this case to be unequivocally essential. Full analytical reports allow the Examiners, industry, the public and posterity to actually see the results and assess their quality, allowing the evidence to stand on its own through time. Devon's data not only attempts to adjust a field rule for permanent gas well classification, but it is also an attempt at a parallel reconstruction of a correlation à la Moses and McCain, but without having been relied upon for years by industry as authoritative. Greater scrutiny of the evidence is necessary.

Second, the record establishes that the best quality data were the visual cell PVT analyses. The Examiners agree, and therefore give other analyses no weight. In fact, it is surprising that a significant portion of the Devon public data (**Attachment D**) consisted of simulated PVT and C_7+ analysis without visual cell data. If Devon's objective was to create an Eagle Ford Formation-specific correlation similar to McCain's worldwide data (**Attachment G**), then three contemporaneous pieces of information are necessary: visual cell results (observation of a dew point or bubble point), GLR and C_7+. As McCain's data shows, the cross-plot graph of GLR and C7+ depicts a smooth and continuous curve. But it is the association of individual data points with either a dew point or a bubble point that allows McCain to make a quantitative distinction between volatile oil and retrograde gas (i.e., 3,200 scf/bbl GLR or 12.9 mole percent C7+, as shown on **Attachment G**.) Graphing a GLR and C_7+ pair without a visual cell observation onto such a correlation is meaningless; there is no associated dew point or bubble point outcome to correlate. Further, an ideal data set would include an even spatial distribution across the whole field; the Devon data generally is only confined to the narrow transition area between oil and gas; the whole Eagle Ford Formation is not represented.

These two issues are related. For example, Devon's Exhibit No. 17 tabulates the public data set containing 76 data point wells. But from Devon's Exhibit No. 17 it cannot be known which PVT determinations are based on visual cell or simulated data. Without access to the complete laboratory reports one's ability to assess the relative value and meaning of each data point is significantly reduced, and it is not possible to determine whether the tabulated results are derived from visual cell or simulated PVT analysis.

The availability of laboratory reports is especially important in single-party, unprotested, cases; in protested cases an opposing party has the opportunity to challenge the evidence, an opportunity not available to the Commission in this case. Further, and perhaps more importantly, a review of the visual cell laboratory reports with constant composition expansion analysis indicates that some of the wells which exhibited a dew point at reservoir conditions can also yield enough hydrocarbon liquids to fill up to 50 percent of the pore volume. This evidence, which seriously challenges any argument that may be made that liquids are immobile in the reservoir, was not entered into the record at the hearing but was made available by the Examiners' taking official notice of Commission well records. The inclusion of full analytical reports in the public record of this case is unequivocally essential.

Finally, neither of Pioneer's or Devon's expert witnesses were first-hand familiar with the Devon proprietary data and therefore could not testify first-hand to its quality, or even to the well locations and sampling conditions from which the data originated. The record indicates the data was assembled by Mr. Jairo Corredor of Devon, but he was not present at Devon's evidentiary hearing on November 23, 2015 nor at the Pioneer hearing on April 8, 2016. Pioneer's counsel offered the possibility of allowing the Examiners to see the Devon data *in camera*. The Examiners believe this would not have been useful. The Examiners understand Devon's desire to keep certain information confidential—and its contractual obligations to do so. However, Texas history indicates gas well classification is a public act by the Commission, one which should be supported by the best science available. Such best science, at an absolute minimum, includes the laboratory reports substantiating the facts asserted with regard to the phase behavior and mobility of hydrocarbon fluids in a reservoir.

5.2.3.2 The Publically Available Devon Data In Evidence Includes Complete Visual Cell PVT Laboratory Reports for 22 Data Points from 22 Wells

The entire Devon data – public and private – are graphed on **Attachment D**. The shape of these graphs indicates an inverse power relationship between the plotted points. Devon, and Pioneer, assert this evidence supports its application for a permanent gas well classification based on a GLR greater than 2,000 scf/bbl. Pioneer also requested that a C7+ composition of 14.5 mole percent or less also merits a permanent gas well classification.

The Examiners took Official Notice of all Commission records for the wells identified on Pioneer's Exhibit No. 38, Devon's Exh. No. 17. This information is readily available through the Commission's online completion and Neubus well record archive systems. Official notice included Forms W-2, G-1, G-5, G-10, laboratory reports attached to the completion packets, gas well classification determination letters issued by Commission staff, and well production data. This information enabled the Examiners to identify the visual cell and simulated PVT data and whether complete laboratory reports were available.

Therefore, the 125 data points offered in the Devon data are reduced as follows:

- The proprietary data set is given no weight. Indeed, the only proprietary data in the record are points plotted on several graphs that were offered into evidence, and on those graphs no data values were identified.

- Visual cell PVT data in the public data set for which complete laboratory reports are not available are given no weight.

- Simulated PVT data in the public data set is given no weight. Evidence in the record demonstrates simulated PVT data is not accurate compared to visual cell data.

- C_7+ data in the public data set that was not collected concomitant with visual cell PVT data is given no weight.

As a result, 23 data points from 22 wells remained. However, two visual cell data points were associated with Devon's Krause Gas Unit C No. 1H (API No. 123-32314). The well was completed on February 1, 2011. A sample collected on April 12, 2011 indicated a bubble point based on visual cell PVT analysis. A sample collected more than two years later, on June 5, 2013, indicated a dew point based on visual cell PVT analysis. Devon offered no basis for the validity of the June 5, 2013 sample for the purposes of gas well classification, and the Examiners assign it no weight. As a result, there are 22 data points from 22 wells that have sufficient documentary support and analytical quality (i.e., visual cell PVT analysis). These wells are identified on **Attachment L**.

Of the 22 data points, the Examiners note that one data point was sampled more than one year after the well's initial test date, and three other data points were sampled between nine months and one year of the initial test dates (see **Attachment L**). The Examiners consider these data points to be suspect without supporting contemporaneous reservoir pressure information demonstrating that the subject reservoirs were above the dew point when sampled; but the data were not excluded.

The Examiners plotted the 22 valid C_7+ and GLR data points (see **Attachment M**). **Attachment N** allows a comparison of the Devon data with McCain, et al's (2011) correlation. Although the amount of data was sparse, the general trend appeared to be consistent with McCain even though only two bubble points were available to plot (only one of these was within the range of McCain's data on **Attachment N**). However, the Devon data was somewhat clumped together; most of the data points were centered on the graph, and there were only two bubble points. This is unfortunate, but to be expected because there is no regulatory reason for an operator to submit a PVT report to the Commission outside of a gas well classification determination, and such questions are more likely arise in the transition zone. Nonetheless, this introduces a significant bias into the sample set, and the Examiners do not see a significant point of departure for classification purposes. We understand that Pioneer disagrees, and we understand the Devon proprietary data may fill in some of the gaps (see **Attachment D** for Devon's graphs). But, the Examiners maintain the essential need to have documented data, especially in a situation regarding the possible creation of a new rule or criteria that may be broadly applied beyond the present case.

The Examiners also graphed (**Attachment O**) the Devon data points that exhibited an ASTM distillation residue of greater than 10 percent (the Form G-5 criteria is less than 5 percent). Ten of the 22 data points had residues greater than 10 percent (15 of 22 had residues greater than 5 percent). This graph suggests a more muddled picture, not a clearer one, especially when compared to McCain's. A high residue does not prove the well cannot be a permanent gas well, but it is a piece of evidence that suggests the presence of heavier hydrocarbons which would decrease the likelihood of gas. In the Samson cases cited earlier (Oil & Gas Docket Nos. 06-0248813 and 06-0249228), the Commission held that the administrative review and hearing processes are not limited to a single item or form, but the collective consideration of all data and, if necessary, the reconciliation of all data and information that is deemed necessary for an engineering gas well classification determination. Keeping in mind that a visual cell PVT observation of a dew point does not by itself entitle an operator to a permanent gas well classification, an attempt to explain the high residues of heavy hydrocarbons should have been made.

5.2.3.3 Hydrocarbon Liquids in the Reservoir are Likely to Exceed the Critical Condensate Saturation and Become Mobile

Pioneer has not demonstrated that liquid hydrocarbons in the reservoir are immobile. In fact, the visual cell PVT data suggests the opposite. Visual cell constant composition expansion PVT analyses of Devon's 22 data points indicates that the retrograde gas may produce sufficient liquid volume to occupy from 5 to 50 percent of the reservoir pore volume (**Attachment K)**. Eight of the 22 visual cell observations indicate hydrocarbon liquid volumes in excess of 40 percent of the pore volume, and these data points are also indicated on **Attachment O**. The rules of thumb in other permanent gas well classification cases cited liquid volumes ranging from 10 percent to 40 percent of the pore volume being necessary for liquid flow to occur. The recent publication by Orangi, et al (2015) affirms that 35 percent condensate saturation may be sufficient to support liquid flow in an unconventional shale reservoir; Devon's visual cell PVT data indicates 11 of the 22 Devon data point wells (half) will condense at least that much (35 percent) liquid.

Further, for about 10 of the 22 Devon wells, the maximum liquid saturation occurs within 500 psi of the dew point pressure, indicating that liquid buildup in the reservoir would happen very quickly. Such a rapid condensation of liquid in the reservoir could affect the production characteristics of a well, a phenomena the Examiners suspect may be associated with the Ridley 01 Unit wells entering a "slugging" production regime, as reported by Pioneer, that prevented the collection of representative reservoir samples for PVT analysis.[113]

5.2.3.4 The Narrow Transition Zone in the Eagle Ford Formation from Volatile Oil to Gas Condensate Limits the Applicability of Correlations in Gas Well Classification Decisions

The GLR and C7+ correlations proposed by Pioneer and Devon for the Eagle Ford Formation, in contrast to the works of Moses and McCain, have not yet stood the test of time or been recognized as authoritative and relied upon by the industry. Indeed, at the location of the Ridley 01 Unit and along the narrow Eagle Ford Formation transitional frontier, the Examiners are unconvinced that there is any basis for a permanent gas well classification, based on the evidence and recent research that was considered in this case.

The correlations, or rules of thumb, that are commonly used for gas well classification—that is, C7+, GLR, and the various components of the ASTM distillation test—break down in the Eagle Ford transition zone. Ideally, the gas well classification rules of thumb will all point in one direction, jointly supporting one another. At the Ridley 01 Unit, they do not. In the Eagle Ford Formation transition zone, visual cell PVT observations do not agree with the rules of thumb for GLR, C_7+, or many of the ASTM distillation test indicators, and there is no "gold

[113] Tr. Vol. 2, 19: 9-24.

standard" PVT data from the Ridley 01 Unit on which to rely. Even then, a visual cell PVT analysis would have entitled a temporary gas well classification for a period of one year. Pioneer, through Devon, has attempted to develop a new characterization model of the reservoir with new rules of thumb. The new model fails, however, because the reservoir does not behave like the conventional reservoirs that were used to develop the existing rules of thumb. That is, the problem is more complex than simply establishing new thresholds. Recent research indicates the phase behavior of hydrocarbons in tight shale reservoirs is not easily categorized, and the phase behavior during production is equally complicated. The cited research indicates multiple phases may exist at one time within the nano-pores of a shale reservoir.

In addition, the reservoir itself is transitioning from volatile oil to retrograde gas. Down dip, the pore spaces are predominantly gas-filled, but some liquids may be present. Up dip, the pore spaces are predominantly liquid-filled, but some gas may be present. In between, there is a gradation of increasing hydrocarbon liquid as a percent of pore volume from southeast to northwest. There is no evidence of a gas cap, or a gas-oil contact in the reservoir. Indeed, the recent research suggests the gas-oil contact is distributed throughout the formation not as a planar boundary, but as a changing proportion of phases, likely also accompanied by a changing reservoir fluid composition. The Examiners visualize this not as a single-phase reservoir, but a reservoir with essentially an oil rim along the pore walls and a gas cap distributed within the individual pore spaces, a continuous and internally integrated two-phase system. This model is consistent with the cited literature.

The unconventional Eagle Ford Formation is tapped by horizontal wells that run northwest/southeast, perpendicular to the gradient of the transition zone. These wells are also not represented by the older rules of thumb. A horizontal 6,000 foot lateral penetrates the reservoir perpendicular to the fluid gradation, so that each perforation cluster accesses a part of the reservoir with varying composition and fluid phase proportions. At the surface, such a well averages the fluid characteristics of the reservoir volume it accesses; it does not yield from one discrete point in reservoir space. Consider also that some of the perforation clusters may contribute unequally to the overall well production, and another variable is factored into the classification equation which could explain why some wells on a unit should be classified as gas wells and others as oil wells.

In most permanent gas well classification cases, operators have been able to show that the reservoir exists as a single phase gas initially; over time, not enough liquid condenses into the reservoir to be mobile. But consider a scenario in which the pore spaces are originally occupied by, say 30 percent hydrocarbon liquid and the lower mobility limit is 35 percent liquid. As production begins the reservoir gas begins to produce condensate, which may occupy up to, say, 15 percent of the reservoir pore volume. In such a scenario the reservoir may easily produce enough liquid condensate in the formation to be mobile, and, in such a scenario, a permanent gas well classification would be inconsistent with the statute and Statewide Rule. Since the initial liquid saturation is immobile, it will not be produced, at first. But the hydraulic fracture stimulation treatments may cause some of the heavier hydrocarbon constituents to enter the early production stream, skewing some analyitical techniques and confusing some rules of thumb. It also represents a reasonably plausible scenario that the applicant must address (but has not) in order to establish a preponderance of evidence in its favor.

5.2.3.5 Unexplored Factors

Devon performed a retrospective study of available compositional and PVT analyses from multiple wells within the Eagle Ford Formation development area, and most of the data was narrowly located along the transitional frontier between volatile oil and gas condensate. There is no evidence the data was gathered "prospectively." That is, the evidence in the record indicates that Devon or other operators in the fields, including Pioneer, did not undertake a study that, from the beginning, was intended to quantify an appropriate GLR for gas well classification. There is no evidence that data quality objectives or a reservoir sampling plan was designed and implemented to illuminate answers to the questions: "What is an appropriate GLR for gas well classification?" or, "What can we learn about the phase behavior of hydrocarbon fluids in the field transition area for the purpose of well classification?" Instead, only the available data at hand was reviewed to explore these questions.

Devon's study is not, however, invalid because it was not implemented prospectively. But, reliance upon the use of available data may not readily allow for the normalization of results based on differences in well construction (toe up-dip or down-dip), reservoir conditions before stimulation (temperature, pressure, and the means used to measure both), hydraulic fracture stimulation (type and volume of liquid used, mass of proppant used, or other stimulation parameters), well flowback and conditioning, the timing of sampling in the life of the wells, and operating and separator conditions, to name a few. That is, such data, as used, could be expected to reveal a significant degree of scatter due to the associated variables in reservoir data collection, especially as the data was collected by different operators over time and that completion techniques have likely evolved during this time also.

5.3 Evidentiary Summary:

The Examiners find from the history of gas well classification dockets that the Commission has based permanent gas well classification on two demonstrations of evidence, neither of which Pioneer has met for a unit-wide designation:

- At initial conditions the hydrocarbon fluid in the reservoir exist as a single-phase gas (that is, there are no hydrocarbon liquids in the reservoir before production begins); and

- Liquid hydrocarbons in the reservoir, which may form by retrograde condensatation, are immobile and will not flow as liquids through the reservoir and into the production stream.

On the first point, in the Ridley 01 Unit in particular, and the along the Eagle Ford's gas-oil transition frontier in general, Pioneer has not shown that the fluids in the reservoir exist as a single-phase gas.

One the second point, in the Ridley 01 Unit in particular, and the along the Eagle Ford's gas-oil transition frontier in general, Pioneer has not shown that the liquid fluids in the reservoir are immobile. The reservoir likely contains an initial portion of liquid according to recent research and according to the fact of being in a transition zone from oil to gas. Further, Pioneer's and Devon's own data indicates retrograde condensation formation will occupy up to 50 percent of the reservoir pore volume.

Pioneer had ample opportunity to collect visual cell PVT samples early in the life of each of the Ridley 01 Unit wells, yet chose not to do so, for any of the 11 wells. All of the wells were completed before the November 2013 hearing, and seven of the wells (Nos. 5H through 11H) were completed in October 2013. Observation of a dew point on samples collected in the Fall of 2013 would have provided important evidence for Pioneer's case. At a sample cost of $30,000, a gas well classification, even a temporary one, would have enabled Pioneer an opportunity to apply for significant severance tax savings, if only for a year or so.

The Examiners conclude the statutory definition of gas well offers Pioneer no relief on a unit-wide basis, but only on a well-specific demonstration of fact, which has only been achieved for five of the wells.

FINDINGS OF FACT

1. Notice of the hearing was sent to all operators in the Sugarkane (Eagle Ford) Field more than 10 days before the hearing.

2. Pioneer Natural Resources, USA Inc. (Pioneer) is requesting all wells on its Ridley 01 Unit in Karnes County, Texas, be permanently classified as gas wells. Through permanent gas well classification, Pioneer seeks to ease its present administrative burden; the Ridley 01 Unit was pooled and set up as a gas unit, and Pioneer prefers to manage all wells on the Ridley 01 Unit as gas wells.

3. Eleven wells were completed on the 1,017.423 acre Ridley 01 Unit between July 6, 2011, and October 8, 2013, and all but two of the wells are currently producing.

   a. Reported cumulative production from wells on the Ridley 01 Unit through January 2016 is 5,006,667 mcf gas and 2,839,655 bbl hydrocarbon liquids, for a cumulative producing GLR of 1,763 scf/bbl.

   b. Commission staff has administratively approved permanent gas well classification for four of the Ridley 01 Unit wells (Nos. 1H, 3H, 7H and 9H) based on field rules and initial gas to liquid hydrocarbon ratios (GLR) of 3,000:1 standard cubic feet per barrel (scf/bbl) or greater. Well No. 1H also demonstrated a full wellstream recombination composition of 8.42 mole percent C_7+, which met the administrative standard of less than 11 mole percent.

   c. Commission staff denied administrative gas well classification for Well Nos. 2H and 4H because the initial GLRs were less than 3,000 scf/bbl. Pioneer has not filed gas or oil well completion forms for the other five wells (5H, 6H, 8H, 10H and 11H), pending the outcome of this hearing.

4. Gas well classification will entitle Pioneer to apply for a severance tax reduction pursuant to Tex. Tax Code §201.057 and 16 Tex. Admin. Code §3.101. Operators of oil wells are not entitled to this severance tax reduction.

5. Texas Natural Resources Code §86.002(5) defines gas well as one that:

   a. Produces gas not associated or blended with oil at the time of production;

   b. Produces more than 100,000 cubic feet of gas to each barrel of oil from the same producing horizon; or

6. Statewide Rule 79(11) states that a well which produces hydrocarbon liquids, a part of which is formed by a condensation from a gas phase and a part of which is crude petroleum oil, shall be classified as a gas well unless there is produced one barrel or more of crude petroleum oil per 100,000 cubic feet of natural gas; and that the term "crude petroleum oil" shall not be construed to mean any liquid hydrocarbon mixture or portion thereof which is not in the liquid phase in the reservoir, removed from the reservoir in such liquid phase, and obtained at the surface as such.

   a. A hydrocarbon fluid that exists as a liquid in the reservoir, whether initially or as the product of condensation in the reservoir, enters the wellbore as a liquid, and is produced at the surface as a liquid is crude petroleum oil for the purposes of GOR calculations and gas well classification.

7. The Commission has held that a well (or a wells in a field) may be permanently classified as a gas well when:

   a. At initial conditions the hydrocarbon fluid in the reservoir exist as a single-phase gas (that is, there are no hydrocarbon liquids in the reservoir before production begins); and

   b. Liquid hydrocarbons in the reservoir, which may form by retrograde condensation, are immobile and will not flow as liquids through the reservoir and into the production stream.

8. Current field rules for the Sugarkane (Eagle Ford) Field include a gas well classification provision stating, "all wells completed with a gas-oil ratio of 3,000 cubic feet per barrel and above … are permanently classified as gas wells without the need of further administrative review, effective the date of initial completion."

      a. With regard to permanent gas well classification, the 3,000 scf/bbl field rule and C_7+ composition analysis criteria only apply as initial production conditions early in the life of a well, at a stabilized flowrate, and at a low draw-down.

b. There is no evidence that the 3,000 scf/bbl GLR permanent gas well classification rule (for any field or well) or the C_7+ composition analysis criteria were ever intended to apply to any point in time of the life of a well other than initial completion and the establishment of stabilized production.

9. A visual cell constant composition expansion PVT analysis is a reservoir fluid study that can describe the phase behavior of a hydrocarbon sample under reservoir temperature and pressure conditions.

   a. A visual cell observation of a dew point demonstrates the sample exists as a retrograde gas at reservoir temperature and pressure conditions.

   b. A visual cell observation of a bubble point demonstrates the sample exists as a volatile oil at reservoir temperature and pressure conditions.

   c. Moses and McCain have established correlations indicating that C_7+ compositions less than 12.5 to 12.9 mole percent and initial producing GLR values greater than 3,000 to 3,200 scf/bbl are indicators of visual cell PVT dew point observations.

   d. Accurate reservoir fluid studies are dependent upon the fluid sample being representative of the in situ reservoir fluid.

   e. The technical foundation of hydrocarbon liquid sampling for GLR, C_7+ and PVT analyses as indicators of reservoir fluid phase behavior indicate the importance of sampling early in the life of a well before pressure has declined significantly, and at a stabilized and low drawdown rate.

   f. Fluid properties such as liquid color, liquid gravity, distillation temperatures, percent residue or other diagnostics are not individually dispositive for well classification.

   g. A visual cell PVT test is of superior data quality than a simulated PVT test.

10. No Visual cell PVT analyses were conducted on samples from any of the Ridley 01 Unit wells

11. Two Simulated PVT Analyses of Ridley Unit wells were conducted, both of which indicated volatile oil reservoirs (Well Nos. 2H and 4H). Pioneer disputes the quality of this data based on a communication error with the laboratory, but did not provide evidence the laboratory corrected the error.

12. As pressure declines below the dew point, a retrograde gas will begin to condense liquid into the reservoir pore spaces.

    a. Retrograde liquids that condense in the reservoir will generally not be mobile until the critical condensation saturation is reached, at which point the liquid hydrocarbons in the reservoir are mobile.

b. In many previous hearings the industry and scientific literature cited for the critical condensation saturation ranges from 10 to 40 percent of the reservoir pore volume.

13. The Eagle Ford Shale Formation in this area is an unconventional field characterized by essentially no natural permeability and nanometer-size pore spaces.

    a. The Eagle Ford Formation in this part of Texas exhibits a unique gradation of reservoir fluid characteristics as one moves from up-dip in the northwest, where oil wells are prevalent, to down-dip in the southeast, where gas wells are prevalent.

    b. The Eagle Ford Formation in the Ridley 01 Unit area is considered to be a high-pressure, high-temperature (HPHT) reservoir.

    c. Reservoir pressure in the Ridley 01 Unit area declines below the dew or bubble points after about 12 months of production.

    d. The Ridley 01 Unit is located in this transition zone; oil wells and gas wells surround the Ridley 01 Unit.

    e. Current research indicates that in unconventional shale reservoirs:

        i. The reservoir fluids are produced under a strong influence of the tight shale matrix.

        ii. The confinement of hydrocarbon fluids in nanometer-size pore spaces can result in complex phase behavior in which multiple phases exist simultaneously in the reservoir.

        iii. Identifying the phases of these fluids (liquid, gas, supercritical fluid, and sorbed) in the matrix and identifying their producibility limit is currently not possible because the composition of the produced fluid is different than the composition of the in-situ phases.

        iv. The confinement of hydrocarbon fluids in nanometer-size pore spaces can result in suppression of the critical point, which may delay the formation of condensate in the reservoir and provide more time to produce gas without interference from in situ condensate blockage.

        v. Critical condensation saturations of 35 percent and greater are capable of supporting liquid flow in the reservoir.

14. Two Ridley 01 Unit wells demonstrated C_7+ compositions less than 12.9 mole percent.

a. Well No. 1H had a C_7+ composition of 8.42 mole percent within the first month of production.

b. Well No. 2H had a C_7+ composition of 11.73 mole percent, but this sample was collected one year after the well entered production. Three other laboratory reports for Well No. 2H indicated C_7+ compositions of 14.03, 18.21, and 15.64 mole percent.

c. Without supporting reservoir pressure data, the 11.73 mole percent C7+ composition analysis for Well No. 2H is not representative of initial reservoir conditions and therefore not suitable as a basis for permanent gas well classification.

d. The preponderance of C_7+ composition evidence for Well No. 2H does not indicate permanent gas well classification is appropriate.

15. Nearby offset wells do not demonstrate that all wells on the Ridley 01 Unit are permanent gas wells or should be classified as such.

a. Three down dip wells (Douglas 01 01H, Handy 02 0106H, and Handy 02 0107H) were classified as permanent gas wells based on initial producing GLR values in excess of 3,000 scf/bbl, and the Douglas 01 01H well also had a C_7+ composition of 5.044 mole percent.

b. Three wells, two up dip (Spear Reynolds Unit A 1 and Schendel Unit 1), and one on strike (Reynolds Gas Unit 1H) were classified as temporary gas wells based on visual cell PVT analysis that indicated a dew point. About one year later these three wells were reclassified as permanent gas wells based on a re-tested GLR some time after the initial completion.

i. Reclassification of these three wells based on GLR tests one year after production are inconsistent with the technical considerations underlying the 3,000 scf/bbl gas well classification field rule.

ii. The Spear Reynolds Unit A 1, and Schendel Unit 1, and Reynolds Gas Unit 1H wells should not have been permanently reclassified as gas wells based on GLR.

c. Two on strike wells (Mangione 01 Well Nos. 02H and 04H) have been permanently classified as gas wells based on GLR values in excess of 3,000 scf/bbl. One on strike well (Mangione 01 Well No. 03H) has not yet been classified. Two of these three wells exhibited a bubble point during visual cell PVT analyses.

d. The nearby offset wells are not consistently and appropriately classified as permanent gas wells sufficient to demonstrate by a preponderance of the evidence that all wells on the Ridley 01 Unit should be permanently classified as gas wells.

16. Pioneer sponsored evidence of a study conducted by Devon Energy Production Co., LP (Oil & Gas Docket Nos. 01-0297472 and 02-0297714) that attempts to provide for gas well classification in the Eagleville (Eagle Ford-1) and Eagleville (Eagle Ford-2) Fields when the initial producing GLR is greater than 2,000 scf/bbl.

17. The Devon study included reservoir fluid study and well test data from 125 data points from about 113 wells. The fluid study and well test data included GLR, C7+ compositions, simulated PVT analysis and visual cell PVT analysis.

18. Of the 125 data points from the Devon study, only 22 of the data points were visual cell PVT analyses for which the complete laboratory reports are in the evidentiary record (i.e., publically available Commission records).

    a. Complete laboratory reports are essential for data review, analysis, and to develop correlations.

    b. Complete laboratory reports were necessary in this case to distinguish visual cell analyses from simulated analyses.

    c. Complete laboratory reports were necessary in this case to identify the volume of retrograde liquid that may be condensed in a reservoir as pressure declines below the dew point.

    d. The only data points that are suitable for development of a correlation are those for which contemporaneous observations or measurements of C_7+ composition, GLR, and a visual cell dew point.

    e. Only 22 of original 125 data points were of sufficient quality (by methodology and documentation) to attempt to construct a new correlation applicable to only the Eagle Ford Formation.

19. The Devon data is not sufficient to establish a reliable gas well classification criteria based on a correlation of GLR and C7+ composition with a visual cell PVT observation.

    a. Only two wells exhibited bubble points, and 20 wells exhibited dew points.

    b. The data do not present a sharp distinction between volatile oil bubble points and retrograde gas dew points so that a point of departure for gas/oil well classification can be made.

    c. Eight of the 20 dew point observations also indicated more than 10 percent residue on the ASTM distillation test (Form G-5), an indication that the sampled liquid contains heavier hydrocarbons than would be expected to be present in a gas condensate.

d. Eight of the 20 dew point observations would result in sufficient condensation to fill more than 40 percent of the reservoir pore space, and 11 of the 20 dew point observations would result in sufficient condensation to fill more than 35 percent of the reservoir pore space, indicating the liquid hydrocarbons are mobile in the reservoir.

e. The Devon data indicates half of the wells in the study will yield liquid condensate in the reservoir at volumes exceeding the critical condensate saturation for liquid mobility as that parameter has been routinely applied by the Commission in gas well classification cases.

f. The critical condensate volume does not include in-situ reservoir fluids that may exist as an immobile liquid phase at initial conditions; these initial liquid fluids will increase the onset and volume of liquid flow in the reservoir.

20. Pioneer has not demonstrated that the hydrocarbons underlying the Ridley 01 Unit exist only as a single phase gas at initial conditions, based on (1) their own merit, (2) nearby offset wells, or (3) the Devon data.

21. Pioneer has not demonstrated that liquid hydrocarbons in the reservoir are immobile.

22. There is no evidence that fluid accumulation in excess of 40 percent of the reservoir pore volume will be immobile and will not flow.

CONCLUSIONS OF LAW

1. Resolution of the subject application is a matter committed to the jurisdiction of the Railroad Commission of Texas. Tex. Nat. Res. Code § 81.051

2. All notice requirements have been satisfied. 16 Tex. Admin. Code §§ 1.43 & 1.45

3. Pioneer has not demonstrated that the Ridley 01 Unit wells are collectively as a unit entitled to permanent gas well classification:

   a. Pioneer has not demonstrated that, at initial conditions, the hydrocarbon fluid in the reservoir exist as a single-phase gas. Tex. Nat. Res. Code §86.002(5)

   b. Pioneer has not demonstrated that liquid hydrocarbons in the reservoir, which may form by retrograde condensation, are immobile and will not flow as liquids through the reservoir and into the production stream. 16 Tex. Admin. Code §79(11)(C)

4. Ridley 01 Unit Well Nos. 01H, 03H, 06H, 07H and 09H are permanent gas wells pursuant to the Field Rules for the Sugarkane (Eagle Ford) Field, as established in Oil & Gas Docket No. 02-0272551

RECOMMENDATION

Based on the record evidence, the Examiners recommend that the Commission deny Pioneer's application that all wells on the Ridley 01 Unit in Karnes County, Texas, be permanently classified as gas wells. The Examiners further recommend that Well No. 6H be classified as a permanent gas well as it has demonstrated a GLR of 3,062 scf/bbl on initial completion. Well Nos. 1H, 3H, 7H and 9H have already received permanent gas well classification by Commission staff. The Examiners conclude Well Nos. 2H, 4H, 5H, 8H, 10H and 11H are oil wells.

Respectfully,

Paul Dubois
Technical Examiner

Marshall F. Enquist
Administrative Law Judge