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CLAYTON WILLIAMS ENERGY, INC.

Michael L. POLLARD
SENIOR VICE PRESIDENT — FINANCE
AND CHIEF FINANCIAL OFFICER

March 17, 2016

Mr. H. Roger Schwall
Assistant Director
United States Securities and Exchange Commission
Division of Corporation Finance
100 F Street, N.E.
Washington, D.C. 20549-3561

Re: Clayton Williams Energy, Inc.
Form 10-K for the Fiscal Year Ended December 31, 2014
Filed February 27, 2015
Response letter dated October 23, 2015
File No. 1-10924

Ladies and Gentlemen:

Set forth below are the responses of Clayton Williams Energy, Inc. (the "***Company***", "***we***," "***us***" or "***our***"), to comments received from the staff of the Division of Corporation Finance (the "***Staff***") of the Securities and Exchange Commission (the "***Commission***") by letter dated December 15, 2015, with respect to Form 10-K for the Fiscal Year Ended December 31, 2014, File No. 1-10924, filed with the Commission on February 27, 2015 (the "***2014 10-K***").

For your convenience, each response is prefaced by the exact text of the Staff's corresponding comment in bold, italicized text.

Form 10-K for the Fiscal Year Ended December 31, 2014

Properties, page 30

Reserves, page 30

1. We note your response three refers to the reclassification as of December 31, 2014 to unproved of 4.1 MMBOE of PUD reserves initially booked as of December 31, 2010. Your 2010 Form 10-K disclosed the 2010 initial strata of PUD reserves booked (on page 29) as 14.4 MMBOE.

It appears 28% (=4.1MMBOE/14.4MMBOE) of these initial PUDs were not developed. This does not agree with your statement in response two, "We have historically viewed our commitment to develop booked proved undeveloped reserves, or PUDs, as a commitment to develop within the five year development horizon from the date of first booking." These results do not comply with the definition of proved oil and gas reserves (Rule 4-10(a)(22) of Regulation S-X) which requires/describes the project to recover proved reserves as "...The

project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time." In part, Rule 4-10(a)(24) describes Reasonable Certainty as "...reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not..." The ultimate development of 72% of the PUD reserves booked on 2010 does not appear to comply with Regulation S-X. Given these historical results and your 2013-2015 single digit percent conversion to proved developed status, please explain to us how you intend to develop the PUD reserves you will book as of December 31, 2015. Include annual schedules for the projected PUD volumes drilled, location count, drilling rig count, required PUD development capital and development capital to be incurred. Please address the sources you will employ for this capital.

RESPONSE:

By telephone conference between our counsel and Mr. Schwall in January 2016 and a telephone conference on February 2, 2015 among the undersigned, other officers of the Company, our counsel at Vinson & Elkins and members of the Staff, we informed the Staff that (i) in light of the impending filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2015 (the "***2015 10-K***") and (ii) the dependence upon completion of a financing transaction that would significantly impact the Company's liquidity and proved undeveloped reserve bookings, the Company intended to respond to the outstanding comments of the Staff in large part in disclosures proposed for the 2015 10-K.

Recently, the Company disclosed in filings on Form 8-K the completion and funding of a $350.0 million term loan. The Company also recently filed a Form 12b-25 to provide related notice of a delay in the filing of its 2015 10-K, which disclosed its intention to file its 2015 10-K within the 15 day extended time period prescribed by Rule 12b-25. Accordingly, the Company is responding to these outstanding comments of the Staff herein and by reference to reserves disclosures it proposes to include in its 2015 10-K, a draft of which is enclosed herewith (the "***Proposed Disclosure***").

With respect to Comment 1 of the Staff's December 15 letter, in connection with our February 2 telephone conference with the Staff, we provided the Staff with supplemental information concerning the requested details about the Company's proved undeveloped reserves it proposed to recognize as of December 31, 2015. These proved undeveloped reserve bookings were, however, dependent upon the completion and funding of the Company's $350.0 million term loan, which funds, together with future cash from operations, were to provide sufficient sources of development capital for such reserves.

The Company respectfully disagrees with the Staff's comment that proved undeveloped reserves booked in year-end 2010 do not appear to comply with Regulation S-X solely by hindsight reference to a 72% ultimate development percentage of those proved undeveloped reserves four years later. The Company has, however, taken the Staff's comments regarding its historically low annual development percentages into account, and improved its reporting and involvement of its board of directors in its development plans, including the development of its proved undeveloped reserves within the five year development window. Per the undersigned's additional telephone conference on February 17, 2015 with Mr. Mark Wojciechowski of the Staff, we confirm that (i) with the recent completion and funding of our $350.0 term loan, the Company believes it meets the reasonable expectation requirement set forth in Rule 4-10(a)(26) for financing required to fund development of our proved undeveloped reserves as of December 31, 2015 and (ii) all of our proved undeveloped reserves as of December 31, 2015 are scheduled for development within five years of the date of initial booking as proved.

2. Expand the disclosure regarding actual and planned development activities to describe, in reasonable detail, the reasons why actual development in a given year varied from previously-disclosed planned development for that year.

RESPONSE:

Please refer to the attached Proposed Disclosure under the heading "Proved Undeveloped Reserves - *Scheduled versus actual conversions of proved undeveloped reserves in 2015*" which we propose to include in our 2015 Form 10-K.

Reserve estimation procedures, page 33

<u>Processes and controls, page 34</u>

3. ***Information provided in response to prior comment number two from our letter dated September 16, 2015 describes a number of factors that contributed to low PUD conversion rates and a lack of adherence to previously adopted development plans in recent years. In view of these reoccurring factors, expand your disclosure regarding the internal controls used in estimating your reserves to describe the steps taken by management to ensure that there is reasonable certainty of proceeding with your development plans. As part of your revised disclosure, explain how changes in drilling plans factor into the management of your drilling program. Refer to Item 1202(a)(7) of Regulation S-K.***

<u>RESPONSE</u>:

Please refer to the attached Proposed Disclosure under the heading "Reserve estimation procedures - *Processes and controls*" which we propose to include in our 2015 Form 10-K.

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4. ***Describe for us the role of senior management and your board of directors in reviewing or approving your annual estimates of proved reserves. As part of your response, explain the extent to which they are made aware that proved reserve estimates for a given year include proved undeveloped reserves that had been scheduled for development in one or more earlier years but had not been developed in accordance with previously adopted development plans.***

<u>RESPONSE</u>:

Please refer to the last paragraph of the attached Proposed Disclosure under the heading "Reserve estimation procedures - *Processes and controls*" which we propose to include in our 2015 Form 10-K.

* * * * *

We advise the Staff that the Company is preparing to file its 2015 Form 10-K as early as Tuesday, March 22, 2016, which filing will include the Proposed Disclosures. Accordingly, while we recognize that the Staff may have further comments with respect to the Proposed Disclosure and our responses to the Staff's comments herein, any preliminary comments of the Staff on the Proposed Disclosure would be appreciated prior to the filing of our 2015 Form 10-K so that we might have the opportunity incorporate revisions in response to the Staff's further concerns in our filed 2015 Form 10-K.

Please direct any questions, preliminary comments or requests for any additional supplemental information, to our counsel, Jim Prince of Vinson & Elkins LLP, by telephone at (713) 758-3710.

Very truly yours,

CLAYTON WILLIAMS ENERGY, INC.

By: /s/ Michael L. Pollard
Michael L. Pollard
Senior Vice President & Chief Financial Officer

Attachment

cc: James M. Prince
Vinson & Elkins LLP

PROPOSED DISCLOSURE

PROPOSED RESERVES DISCLOSURES FOR 2015 FORM 10-K

Item 2 - Properties

Our properties consist primarily of oil and gas wells and our ownership in leasehold acreage, both developed and undeveloped. At December 31, 2015, we had interests in 3,169 gross (1,444.8 net) oil and gas wells and owned leasehold interests in approximately 629,000 gross (364,000 net) undeveloped acres.

Oil and Gas Reserves

Total Proved Reserves

The following table sets forth our estimated quantities of proved reserves as of December 31, 2015, all of which are located within the United States.

	Proved Reserves(a)			
Reserve Category	Oil (MBbls)	Natural Gas Liquids (MBbls)	Natural Gas (MMcf)	Total Oil Equivalents(b) (MBOE)
Developed	25,349	4,266	39,987	36,280
Undeveloped	7,727	1,202	8,160	10,289
Total Proved	33,076	5,468	48,147	46,569

(a) None of our oil and gas reserves are derived from non-traditional sources.
(b) Natural gas reserves have been converted to oil equivalents at the ratio of six Mcf of gas to one Bbl of oil.

The present value of our future net cash flows from proved reserves, before deductions for estimated future income taxes and asset retirement obligations, discounted at 10% ("PV-10"), totaled $442.8 million at December 31, 2015. The commodity prices used to estimate proved reserves and their related PV-10 at December 31, 2015 were based on the 12-month unweighted arithmetic average of the first-day-of-the-month prices for the period from January 2015 through December 2015. The benchmark average prices for 2015 were $50.28 per barrel of oil and $2.58 per MMBtu of natural gas. These benchmark average prices were further adjusted for quality, energy content, transportation fees and other price differentials specific to our properties, resulting in an average adjusted price of $45.75 per barrel of oil, $15.84 per barrel of NGL and $2.52 per Mcf of natural gas over the remaining life of our proved reserves. Operating costs were not escalated.

Adjustments to benchmark average prices, which are generally referred to as price differentials, were computed on a property-by-property basis by comparing historical first-day-of-the-month benchmark prices for oil and gas to the historical prices for oil, and gas to the historical prices for oil , NGL, and gas actually received by us. Historical price differentials vary by property based on each property's production and marketing situation and include:

- area-specific market adjustments, referred to as basis differentials, for oil, natural gas and NGL as discussed under *"Item 1 — Business — Marketing Arrangements;"*
- gravity, hydrogen sulfide content and other quality characteristics of produced oil;
- the volume of processed NGL derived from our natural gas production, including the mix of the NGL components between ethane, propane, butane and natural gasoline;
- the Btu content of natural gas production and the value of any imbedded NGL components that are reported as natural gas sales; and

- the amount of transportation and marketing fees levied on oil, gas and NGL production, which vary based on factors such as the distance of a property from its delivery point, available markets and other pricing adjustments that vary from contract to contract.

Price differentials per barrel of oil and NGL and per Mcf of natural gas are subject to change and may vary materially in the future from the computed price differentials at December 31, 2015. Adverse changes in our price differentials could reduce our cash flow from operations and the PV-10 of our proved reserves.

PV-10 is not a generally accepted accounting principle ("GAAP") financial measure, but we believe it is useful as a supplemental disclosure to the standardized measure of discounted future net cash flows presented in our consolidated financial statements. To compute our standardized measure of discounted future net cash flows at December 31, 2015, we began with the PV-10 of our proved reserves and deducted the present value of estimated future income taxes of $16.4 million and net abandonment costs of $35.4 million, discounted at 10%. At December 31, 2015, our standardized measure of discounted future net cash flows totaled $391 million. While the standardized measure of discounted future net cash flows is dependent on the unique tax situation of each company, the PV-10 of proved reserves is based on prices and discount factors that are consistent for all companies and can be used within the industry and by securities analysts to evaluate proved reserves on a more comparable basis.

The following table summarizes certain information as of December 31, 2015 regarding our estimated proved reserves in each of our principal producing areas.

	Proved Reserves						
	Oil (MBbls)	Natural Gas Liquids (MBbls)	Natural Gas (MMcf)	Total Oil Equivalents (a) (MBOE)	Percent of Total Oil Equivalents	PV-10 of Proved Reserves (In thousands)	PV-10 as a Percentage of Proved Reserves
Permian Basin Area:							
Delaware Basin	15,364	2,338	17,990	20,700	44.5%	$ 147,382	33.3%
Other	7,813	2,354	18,447	13,242	28.4%	115,361	26.1%
Austin Chalk	4,633	444	5,164	5,938	12.8%	77,225	17.4%
Eagle Ford Shale	4,951	296	1,242	5,454	11.7%	96,085	21.7%
Other	315	36	5,304	1,235	2.6%	6,722	1.5%
Total	33,076	5,468	48,147	46,569	100.0%	$ 442,775	100.0%

(a) Natural gas reserves have been converted to oil equivalents at the ratio of six Mcf of gas to one Bbl of oil.

The following table summarizes changes in our estimated proved reserves during 2015.

	Proved Reserves (MBOE)
As of December 31, 2014	75,430
Extensions and discoveries	3,542
Revisions	(26,158)
Sales of minerals-in-place	(472)
Production	(5,773)
As of December 31, 2015	46,569

Extensions and discoveries. Extensions and discoveries in 2015 added 3,542 MBOE of proved reserves, replacing 61% of our 2015 production. These additions resulted primarily from our Delaware Basin program. Of the total reserve additions, proved developed reserves accounted for 2,648 MBOE, while the remaining 894 MBOE were proved undeveloped reserves.

Revisions. The 26,158 MBOE of net downward revisions in proved reserves resulted from a combination of (1) reclassifications of 9,561 MBOE of proved undeveloped reserves to probable reserves due solely to the SEC 5-year development rule, (2) net upward revisions of 11,963 MBOE related primarily to performance in our Delaware Basin program and (3) downward revisions of 28,560 MBOE related to the effects of lower commodity prices on the estimated quantities of proved reserves.

Sales of minerals-in-place. We sold our interests in certain selected leases and wells in South Louisiana in September 2015 resulting in a decrease of 472 MBOE.

Proved Undeveloped Reserves

Summary of changes in proved undeveloped reserves

The following table summarizes changes in our estimated proved undeveloped reserves during 2015.

	Proved Undeveloped Reserves (MBOE)
As of December 31, 2014	33,191
Extensions and discoveries	894
Revisions	(21,610)
Reclassified to proved developed	(2,186)
As of December 31, 2015	10,289

We added 894 MBOE of proved undeveloped reserves from extensions and discoveries related to Delaware Basin drilling locations. Net downward revisions of 21,610 MBOE resulted primarily from the combination of (1) reclassification of 9,561 MBOE of proved undeveloped reserves to probable reserves due solely to the SEC 5-year development rule, (2) net upward revisions of 7,968 MBOE related to performance in our Delaware Basin program and (3) downward revisions of 20,017 MBOE related to the effects of lower commodity prices on the estimated quantities of proved reserves. We also converted 2,186 MBOE, or 6.6% of our proved undeveloped reserves at December 31, 2014 to proved developed reserves at a cost of approximately $45 million.

Scheduled versus actual conversions of proved undeveloped reserves in 2015

As a result of the significant downturn in commodity prices commencing in late 2014, we indefinitely suspended new drilling operations in both of our core resource plays in early 2015 until we could better evaluate profit margins and returns on capital through a combination of higher or stabilized oil prices and lower capital costs. In early 2015, we continued to expect that conditions would improve to a degree that would enable us to resume drilling, including development of our proved undeveloped reserves, during the latter part of 2015. Based on this expectation as reported in our 2014 Form 10-K, we scheduled 18 PUD locations in our core areas to be drilled in 2015, representing 4,128 MBOE of proved undeveloped reserves, or 12.4% of our year-end 2014 PUD reserves, at an aggregate estimated development cost of $94.8 million. In July 2015, we resumed core drilling based on a rally in commodity prices during the second quarter of 2015, but as the downturn resumed and continued into the latter half of 2015, we once again suspended this program after drilling only three wells. Ultimately in 2015, we drilled 9 of the 18 core area locations with PUD reserves aggregating 2,186 MBOE. The operators of an additional 18 non-operated PUD locations, representing 667 MBOE, or 2.0% of our year-end 2014 PUD reserves, chose to defer drilling these locations in 2015.

The principal factors that contributed to the lower than expected conversion of PUD locations in 2015 included:

- Commodity prices in 2015 did not stabilize at a level that allowed us to increase capital spending to include all of the scheduled PUD locations originally scheduled for 2015 drilling.
- Following the temporary resumption of our 2015 drilling operations as described above, we modified our drilling schedule based on prioritization factors such as field delineation, lease expirations and other factors, resulting in approximately half of our actual capital spending being allocated to unproved locations as opposed to PUD locations.

Scheduled PUD locations at year-end 2015

Under SEC rules, we may classify undrilled locations as having PUD reserves only if we have adopted a development plan indicating that those locations are scheduled to be drilled within five years, unless specific circumstances justify a longer time. We derive this development plan by first preparing a five-year projection of future sources and uses of funds as of each date of determination, giving consideration to many factors such as our expectations for commodity prices, oil and gas production, cash flow from operations, adequacy of liquidity and other financial resources, pre-drill well economics, and lease expirations, among others. Based on these financial projections, we classify those qualified undrilled locations that otherwise meet the criteria as PUD locations only to the extent we intend to develop those PUD reserves with expected available future capital sources within five years of first booking. Any other potential PUD locations that cannot be drilled within such five year period are classified as probable reserves. Accordingly, all of our proved undeveloped reserves as of December 31, 2015 are scheduled for development within five years of first booking.

Our outlook for future oil and gas prices at year-end 2015 negatively impacted expectations for future cash flow sufficient to finance capital spending on PUD locations in the near term, and our prior year PUD development plan was revised accordingly. As a part of our assessment, we took into consideration the recently funded $350 million five-year term loan credit facility and related equity financing as providing a meaningful source of liquidity to supplement our cash flow from operations over the next two to three years. However, in light of the potential for an extended low product price environment, we did not schedule any PUD locations for drilling in 2016 or 2017. Thereafter, based on our current long term outlook for improved commodity prices and our reasonable expectations for access to adequate financing required to fund future drilling, we scheduled estimated future capital spending for

PUD development and related PUD reserves at year-end 2015, as follows: 2018 - $57.3 million and 4,251 MBOE; 2019 - $71.3 million and 5,430 MBOE; and 2020 - $7.1 million and 515 MBOE. Substantially all of these PUD locations are located in our core Delaware Basin play in Reeves County. This assessment resulted in the downgrade of 9,561 MBOE of PUD reserves to probable reserves at year-end 2015. Almost half of these downgraded volumes related to the downgrade of all of our prior PUD locations in our Eagle Ford Shale properties.

Alternative pricing cases

In addition to the estimated proved reserves disclosed above in accordance with the commodities pricing required by the reserves rule (the “SEC Case”), the following table compares certain information regarding our SEC proved reserves to a Futures Pricing Case.

	Proved Reserves				
Pricing Cases	**Oil (MBbls)**	**Natural Gas Liquids (MBbls)**	**Natural Gas (MMcf)**	**Total Oil Equivalents (a) (MBOE)**	**PV-10 (In thousands)**
SEC Case	33,076	5,468	48,147	46,569	$ 442,775
Futures Pricing Case	31,576	5,201	46,602	44,544	$ 455,976

(a) Natural gas reserves have been converted to oil equivalents at the ratio of six Mcf of gas to one Bbl of oil.

The above Futures Pricing Case discloses our estimated proved reserves using future market-based commodities prices instead of the average historical prices used in the SEC Case. Under the Futures Pricing Case, we used monthly futures contract prices, as quoted on the NYMEX on December 31, 2015, as benchmark prices for 2016 through 2020, and escalated prices at 3% per year for all subsequent years beginning 2021. These benchmark prices were further adjusted for quality, energy content, transportation fees and other price differentials specific to our properties, resulting in weighted average adjusted prices of $56.17 per barrel of oil, $19.66 per barrel of NGL and $3.47 per Mcf of natural gas over the remaining life of the proved reserves. We escalated operating costs at 3% per year beginning 2016.

Reserve estimation procedures

Overview

We have established a system of internal controls over our reserve estimation process, which we believe provides us reasonable assurance that reserve estimates have been prepared in accordance with the SEC and Financial Accounting Standards Board (the "FASB") standards. These controls include oversight by trained technical personnel employed by us and by the use of qualified independent petroleum engineers to evaluate our proved reserves on an annual basis. Substantially all of our estimated proved reserves as of December 31, 2015 were derived from engineering evaluation reports prepared by Williamson Petroleum Consultants, Inc. ("Williamson") and Ryder Scott Company, L.P. ("Ryder Scott"). Of our total SEC Case estimated proved reserves, Williamson evaluated 76.3% and Ryder Scott evaluated 22.5% on a BOE basis. These procedures also include oversight by our senior management and board of directors in reviewing and approving our annual estimates of proved reserves.

Qualifications of technical manager and consultants

Ronald D. Gasser, our Vice President - Engineering, is the person within the Company who is primarily responsible for overseeing the preparation of the reserve estimates. Mr. Gasser joined the Company in 2002 as a

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Senior Engineer working on acquisitions/divestitures and special projects, became Engineering Manager in 2006 and was promoted to his current position as Vice President - Engineering in October 2012. Mr. Gasser has 33 years experience as a petroleum engineer, including 30 years directly involved in the estimation and evaluation of oil and gas reserves. Mr. Gasser holds a Bachelor of Science degree in Petroleum Engineering from Texas Tech University. He is a Registered Professional Engineer in the State of Texas and is a member of the Society of Petroleum Engineers.

Williamson is an independent petroleum engineering consulting firm registered in the State of Texas, and John D. Savage, Executive Vice President - Engineering Manager of Williamson, is the technical person primarily responsible for evaluating the proved reserves covered by its report. Mr. Savage has 34 years experience in evaluating oil and gas reserves, including 32 years experience as a consulting reservoir engineer. Mr. Savage holds a Bachelor of Science degree in Petroleum Engineering from Texas A&M University. He is a Registered Professional Engineer in the State of Texas and is a member of the Society of Petroleum Engineers and the Society of Independent Professional Earth Scientists.

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over 75 years. William K. Fry, Vice President of Ryder Scott, is the technical person primarily responsible for evaluating the proved reserves covered by its report. Mr. Fry has over 30 years of experience in the estimation and evaluation of petroleum reserves. Mr. Fry holds a Bachelor of Science degree in Mechanical Engineering from Kansas State University. He is a Registered Professional Engineer in the State of Texas.

Technology used to establish proved reserves

Under current SEC standards, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and governmental regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and/or natural gas will be recovered. Reasonable certainty can be established using techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. "Reliable technology" is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In order to establish reasonable certainty with respect to our estimated proved reserves, we employ technologies that have been demonstrated to yield results with consistency and repeatability. The technological data used in the estimation of our proved reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, seismic data and well test data. Generally, oil and gas reserves are estimated using, as appropriate, one or more of these available methods: production decline curve analysis, analogy to similar reservoirs or volumetric calculations. Reserves attributable to producing wells with sufficient production history are estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations are estimated using performance from analogous wells in the surrounding area and technological data to assess the reservoir continuity. In some instances, particularly in connection with exploratory discoveries, analogous performance data is not available, requiring us to rely primarily on volumetric calculations to determine reserve quantities. Volumetric calculations are primarily based on data derived from geologic-based seismic interpretation, open-hole logs and

completion flow data. When using production decline curve analysis or analogy to estimate proved reserves, we limit our estimates to the quantities of oil and gas derived through volumetric calculations.

Virtually all of our additions to proved reserves in 2015 were derived from wells drilled in the Permian Basin and the Giddings Area. A significant amount of technological data is available in these areas, which allows us to estimate with reasonable certainty the proved reserves and production decline rates attributable to most of our reserve additions through analogy to historical performance from wells in the same reservoirs. None of our additions to proved reserves for 2015 were estimated solely on volumetric calculations.

Processes and controls

Mr. Gasser and his engineering staff maintain a reserves database covering substantially all of our oil and gas properties utilizing Aries™, a widely used reserves and economics software package licensed by a unit of Halliburton Company. Some of our properties are not evaluated since they are individually and collectively insignificant to our total proved reserves and related PV-10. Our engineering staff assimilates all technological and operational data necessary to evaluate our reserves and updates the reserves database throughout the year. Technological data is described above under "-Technology used to establish proved reserves." Operational data include ownership interests, product prices, operating expenses and future development costs.

Using the most appropriate method available, Mr. Gasser applies his professional judgment, based on his training and experience, to project a production profile for each evaluated property. Mr. Gasser consults with other engineers and geoscientists within the Company as needed to validate the accuracy and completeness of his estimates and to determine if any of the technological data upon which his estimates were based are incorrect or outdated.

The engineering staff consults with our accounting department to validate the accuracy and completeness of certain operational data maintained in the reserves database, including ownership interests, average commodity prices, price differentials and operating costs.

Although we believe that the estimates of reserves prepared by our engineering staff have been prepared in accordance with professional engineering standards consistent with SEC and FASB guidelines, we engage independent petroleum engineering consultants to prepare annual evaluations of our estimated reserves. After Mr. Gasser and our engineering staff have made an internal evaluation of our estimated reserves, we provide copies of the Aries™ reserves database to Ryder Scott as it relates to properties owned by our wholly owned subsidiary, SWR and to Williamson as it relates to properties owned by CWEI and our wholly owned subsidiary, Warrior Gas Company. In addition, we provide to the consultants for their analysis all pertinent data needed to properly evaluate our reserves. The services provided by Williamson and Ryder Scott are not audits of our reserves but instead consist of complete engineering evaluations of the respective properties. For more information about the evaluations performed by Williamson and Ryder Scott, see copies of their respective reports filed as exhibits to this Form 10-K.

Both Williamson and Ryder Scott use the Aries™ reserves database that we provide to them as a starting point for their evaluations. This process reduces the risk of errors that can result from data input and also results in significant cost savings to us. The petroleum engineering consultants generally rely on the technical and operational data provided to them without independent verification; however, in the course of their evaluation, if any issue comes to their attention that questions the validity or sufficiency of that data, the consultants will not rely on the questionable data until they have resolved the issue to their satisfaction. The consultants analyze each production decline curve to determine if they agree with our interpretation of the underlying technical data. If they arrive at a different conclusion, the consultants revise the estimates in the database to reflect their own interpretations.

After Williamson and Ryder Scott complete their respective evaluations, they return a modified Aries™ reserves database to our engineering staff for review. Mr. Gasser identifies all material variances between our initial estimates and those of the consultants and discusses the variances with Williamson or Ryder Scott, as applicable, in order to resolve the discrepancies. If any variances relate to inaccurate or incomplete data, corrected or additional data is provided to the consultants and the related estimates are revised. When variances are caused solely by judgment differences between Mr. Gasser and the consultants, we accept the estimates of the consultants.

Prior to completion of the final reserve estimates, our financial accounting group under the direction of Michael L. Pollard, Senior Vice President and Chief Financial Officer, assess compliance with the SEC five-year development rule and make recommendations to Mr. Gasser regarding the scheduled timing and ultimately any required downgrade of undrilled locations previously booked as proved undeveloped to probable (see “Item 2. Properties - Proved Reserves - Proved Undeveloped Reserves”). During this process, the financial accounting group (1) reviews changes in our drilling plans during the recently completed year, (2) assesses the impact that such changes may have had on the scheduled PUD drilling program as reflected in the prior year reserve report and (3) makes recommendations to defer drilling if permitted within the SEC five-year development rule or to downgrade affected PUD locations to probable.

Upon delivery of the final reserve estimates, our financial accounting group reconciles changes in reserve estimates during the year by source, consisting of changes due to extensions and discoveries, purchases/sales of minerals-in-place, revisions of previous estimates and production. Revisions of previous estimates are further analyzed by changes related to pricing and changes related to performance. All material fluctuations in reserve quantities identified through this analysis are discussed with Mr. Gasser. Although unlikely, if a material error in the estimated reserves is discovered through this review process, Mr. Gasser will submit the facts related to the error to the appropriate consultant for correction prior to the public release of the estimated reserves.

Senior management has historically been involved in the process of estimating our proved reserves. Mr. Pollard has been involved in the review of pricing and ownership data maintained in reserves database, including ownership interests, average commodity prices, price differentials and operating costs. Mr. Pollard has also consulted with Mr. Mel Riggs, President, on matters involving significant assumptions to the five-year forecasts required to assure reasonable expectations for future financing of PUD development projects, as well as significant changes in reserve estimates from year to year. Beginning with the year-end 2015 reserves estimates, we have added processes designed to more closely monitor our performance in drilling PUD locations in accordance with scheduled development plans set forth in the prior year reserve report. These enhanced processes include a detailed review by our board of directors of actual versus scheduled PUD drilling in 2015, including a discussion by the board with management of the significant reasons for the material historical variances in year-to-year PUD development plans as reflected in our most recent year-end reserve reports.

Other information concerning our proved reserves

The accuracy of any reserve estimate is a function of the quality of available geological, geophysical, engineering and economic data, the precision of the engineering and geological interpretation and judgment. The estimates of reserves, future cash flows and PV-10 are based on various assumptions and are inherently imprecise. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates. Also, the use of a 10% discount factor for reporting purposes may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our business or the oil and natural gas industry in general are subject.