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PRESENTATION

Operator

Good day, ladies and gentlemen, and welcome to the Berry Petroleum Fourth Quarter and Full Year 2018 Earnings Call. (Operator Instructions)

As a reminder, today's call will be recorded.

I would now like to turn the call over to Todd Crabtree with Investor Relations. Sir, you may begin.

Todd Crabtree - *Berry Petroleum Corporation - Manager of IR*

Thank you, Sydney, and welcome to everyone. Speaking this morning will be Trem Smith, President, CEO and Board Chair; Gary Grove, Executive Vice President and COO; and Cary Baetz, Executive Vice President and CFO. Trem will review our objectives and strategies, our differentiators and a few fourth quarter and full year highlights. Gary and then Cary will discuss our key operational and financial results for the same periods. Trem will have a few concluding remarks mainly on governance before we open it up to questions.

As a reminder, today's call contains certain projections and other forward-looking statements in the meaning of federal securities laws. These statements are subject to risks and uncertainties that may cause actual results to differ from those expressed or implied in these statements. These include risks outlined in our public filings. We refer to non-GAAP financial measures, and we have provided a reconciliation to the GAAP with our financial statements.

Today, we will be referencing slides from the March 2019 Investor Presentation deck, which is posted on our Investor webpage. The replay link of this call and transcript will also be made available on our Investor page.

I will now turn the call over to Trem Smith, Berry President and CEO.

Arthur T. Smith - *Berry Petroleum Corporation - President, CEO & Direcctor*

Thank you, Todd. Welcome, and thank you for joining us for Berry Petroleum's Fourth Quarter and Year-end Earnings Call. The past year was monumental for Berry. In this call, we will describe the reasons why it was such a great year and why we are set up for an equally strong or even stronger 2019. Most importantly, I want to clearly and concisely communicate to you that all we have done, continue to do and will continue to do is absolutely consistent with our business model. We managed to value not just the production growth, we are basin agnostic, we have no long-term capital commitments, i.e we can turn capital off such as a drilling rig and back on within 30 days and always live within our definition of levered free cash flow, which as a reminder is we pay our expenses, OpEx, taxes, we pay our financial obligations including interests, we return capital to our shareholders in the form of dividends and we fund sufficient CapEx to maintain production. The remainder is our levered free cash flow, which we use to grow the value of the company for our shareholders.

In addition, we continue to keep our debt-to-EBITDA ratio well below our 2-time target. In other words, we are not increasing debt. We have been living this simple strategy since we took over leadership of the new Berry in March 2017 and will continue to do so into the future. This is our competitive advantage.

Now let's talk about what it means. The Berry, right now is all about California. Why? In 2018, California represented 94% of Berry's value at a PV-10 of slightly more than $2 billion. For this reason, we are recording our California and Rockies results separately for the first time, supporting our premise that we are basin agnostic and know that value creation is heavily influenced by capital efficiency. In the Rockies, we completed our evaluation of the new Berry's positions. And in Utah, we completed our reservoir management plans for our Uinta Basin acreage. We like what we see from a technical perspective. However, continuing marketing issues and the current price environment mean value creation is difficult at best. Therefore, in response to these conditions and because Berry has no long-term drilling commitments, we are able to make the prudent business decision not to invest new capital until we see improved value in the top line. Remember, I'm a firm believer that growing production by itself is not value creation. Growing production that can be sold at high-value returns is. Today, the market conditions in Utah are not conducive to significant value equation, and we will spend 2019 focused on alternative marketing solutions. This judicious approach is exactly what we did last year in the Piceance in Colorado for similar reasons.

In California, which is where we spent most of our capital in 2018, we realized all our production growth and the preponderance of our operating income, resulting in more than a $1 billion add to our PV-10 and a 275% reserve replacement ratio in the state. Further, 88% of our capital was spent in California, which represents 94% of Berry's value. Our 2018 results illustrate this well. We drilled 224 wells in California, resulting in a 15% growth rate for the year. The allocation of capital isn't changing in 2019. In fact, it's becoming even more focused in California, with almost all of our development capital going to the state, and we expect a mid- to high-teen production growth and continued reserve growth.

In 2019, we forecast approximately 94% of our capital, including 98% of our development capital, to be spent in California and planned to drill approximately 400 wells with an expectation of high teens to low 20s projected exit growth rate. Note that the growth in 2018 and 2019 is all organic from our existing assets and does not incorporate acquisitions.

We are very focused in the state because of its ability to create value for Berry. Our production is 100% oil. Geographically, approximately 70% of our total company production comes from our fields in the world-class super basin, the San Joaquin basin. And approximately 94% of that production in California is in Kern County, one county. Further, we are focused on the west side of the basin, in 3 large fields, Belridge, McKittrick and the largest field in California, based on estimated ultimate recovery, Midway-Sunset. In 2018, 80% of our production in California and 59% of our total production came from these 3 fields, and 54% of our California production came from Midway-Sunset alone. Technically, we are focused on the thermal stimulation of heavy oil in shallow reservoirs. This is one of our core strengths.

In addition, as I have mentioned previously, California is a market island, resulting in our price for oil being heavily influenced by Brent. Approximately 2/3 of California's energy needs are met by shipborne imports, and a significant majority of these are from foreign forces, mainly the Middle East and South America. California imports an ever-declining volume from Alaska, which is also shipborne. None of the lower 48 crude pipelines come into California. This means that the remaining 1/3 of California's demand is filled by production from within the state and goes to refineries designed preferentially to process California heavy crude, another competitive advantage for Berry.

What does this mean for 2019? In November of last year, we presented the 2019 outlook based on the economic forecast at the time. Since then, the price of Brent has declined approximately 13%. Recognizing changed market conditions, we refined and reduced our 2019 capital budget while maintaining a high teens to low 20s projected exit growth rate in California and a high double-digit exit growth rate for the company. Compared to our November guidance, this results in a reduction in capital of $35 million or 14%, which translates to only a 3% reduction in company-wide production. The increased focus on high-value California projects means that we have -- we'll have higher fixed cost, primarily due to the increase in steam for thermal recovery. However, this increase in cost is more than offset by the value generated. This shift emphasizes our ability to adapt quickly. Remember, we are basin agnostic with no long-term capital commitments, we control what we operate with working interest averaging 90% company-wide and 99% in California, and we live within levered free cash flow.

Further, we have made and will continue to make progress in identifying and maturing opportunities through reserve growth, including by the addition of low-risk acreage near our existing production and infrastructure, what we call bolt-ons. In 2018, we continued our portfolio realignment with the sale of our non-core East Texas natural gas asset in November 2018 for $7 million. The East Texas transaction removed approximately 700 BOE per day of 100% natural gas production and increased our oil mix to 87% from approximately 82%.

We now have access to 879 new acres through bolt-ons completed in 2018, all of it in the Midway-Sunset field, our largest field, increasing our acreage position in the field by about 20%. These new acres, which are either not developed at all or minimally developed at most, are on trend with our existing production and, therefore, extremely low risk, in line with our both-on strategy, and represent a huge opportunity for new drilling locations going forward. The strategy is simple. We look for opportunities along our known producing trends and near or adjacent to our existing surface infrastructure. Today, we have several more opportunities under negotiations, which if fully executed could grow our acreage position in Midway-Sunset by over 50%.

The impact on drilling inventory of the bolt-on effort is significant. Remember, the San Joaquin basin is such a rich and prominent petroleum super basin and the number of wells per acre in developed areas can be very tight. For example, in our oldest field, the 160-acre FOB field, the well density is approximately 2 active wells per acre. The bolt-on strategy has been and continues to be a very successful strategy for us and requires little to no upfront capital to acquire. We will continue to execute this, while at the same time working transformational strategic growth opportunities.

On reserves, Gary will provide the details of our 2018 proven reserve report, an independent analysis of our P1 reserves by DeGoyler and MacNaughton. The results are impressive as shown by California's 275% reserve replacement ratio. Internally, the company is working through its own analysis of probable and possible reserves and contingent resources. The work here is impressive as well and indicates our inventory of drilling opportunities on our existing acreage will continue to grow in a major way over time. I hope to report on the results of this analysis later this year.

Our shallow and conventional reservoirs in California produce only oil, most are less than 2,000 feet in depth. We drill, complete and produce wells often within a week or less. To ensure we can drill our high-value projects, we have implemented a two-year budget cycle so that we can have a readily drillable inventory of casing, tubing, wellheads and pump jacks as well as a large inventory of drilling permits on hand. This is working extremely well. We have 4 rigs running, all in California, and we have at least 2 months of permits already in hand for each of the 4 rigs.

On the regulatory front, we welcome our new California governor, Gavin Newsom, and look forward to a constructive working relationship with him and his administration. We continue to be focused on our relationships with regulators through our Berry-first approach, which strives to produce a win-win result allow Berry -- allowing both Berry and the states we do business in to achieve their objectives. In addition, we are working closely with the Western States Petroleum Association, the California Independent Petroleum Association and the Kern County Administration as well as other federal, state and local politicians. I will continue to report on these efforts throughout the year. As I mentioned at the beginning of the call, 2018 was a tremendous year for Berry. I have highlighted a number of the significant operational and value-generating results. Our financial results, such as our significant, unhedged adjusted EBITDA of $296 million, reflect the success of these efforts. Cary will review them in detail shortly.

To summarize 2018, in January, we had our first bond offering, and those bonds continue to trade around par. Then in July, we went public on the NASDAQ, reinforcing our strong position in the industry and value in the market. During that time, we also simplified our capital structure by converting the preferred shares to common. In December, we announced our share buyback program to mitigate any dilution due to finalizing our bankruptcy and to take advantage of the lower share price caused mainly by the significant downturn in worldwide oil prices. This has been a prudent and well-executed program.

Last week, the board gathered in Dallas and showed strong support for our strategy, including the budget reduction and the market-driven reasons for it. They also approved the first quarter dividend of $0.12 per share. Simply put, they continue to support our strong focus on total shareholder return, a founding principle of the new Berry.

Looking ahead, last year gave us a solid foundation and put us in a strong position for a successful 2019. We are in a great position for growth and continued improvement to maximize the value of our existing fields while continuously looking for growth through bolt-ons and strategic acquisitions.

The future looks very bright. In fact, our technical assessment of our current resource and original oil in place indicates that a simple 1% increase in recovery factor could result in the addition of over 20 million barrels of oil in our California assets, a remarkable opportunity and another competitive advantage for Berry.

It was just 2 years ago last week that we created the new Berry. A lot has happened, and we are grateful to everyone that has been involved to this point. I am confident we can and will sustain our efforts to improve and execute our plan with excellence.

We will continue to prosper. Now I'll turn it over to Gary Grove, Berry's COO.

Gary A. Grove - *Berry Petroleum Company, LLC - Executive VP & COO*

Thanks, Trem, and good morning, everyone. As Trem mentioned earlier, California is our focus for development and received a majority of our capital in 2018. My comments today will highlight the impact that California has on the company and our future growth.

So let me first discuss the numbers for the fourth quarter and then talk about full year 2018. Production sales for the fourth quarter were 28,000 barrels of oil equivalent per day, comprising 85% oil, 13% gas and 2% NGLs. This is sequentially up 2% from 27,400 BOE a day in the third quarter, primarily due to the results of our capital development activity and inclusive of both impacts from inventory changes in Utah and the sale of our East Texas gas properties at the end of November.

Oil inventory grew in Utah during the quarter at an average of 355 barrels of oil per day versus a decrease in the third quarter of 352 barrels of oil per day. As a reminder, some acute marketing conditions had impacted our sales and production since the second quarter of 2018. Those conditions caused us to sell less than we produced in the fourth quarter and more than we produced in the third quarter. Production was also impacted as we needed to shut in wells for short periods time to manage the field-level inventory. Adjusting for inventory sales changes, production averaged 28,300 BOE a day during the quarter versus 27,100 BOE a day in the third quarter, a sequential 4% increase. Further adjusting for the sale of the East Texas properties, pro forma production averaged 27,800 BOE a day in the fourth quarter versus 26,400 BOE a day in the third quarter, a sequential 5% increase.

Now focusing solely on California, where the bulk of our capital is employed. Production for the fourth quarter averaged 21,700 BOE a day versus 19,500 BOE a day in the third quarter, an 11% sequential increase.

Now out of the fourth quarter production I just mentioned, that sales rate of 28,000 BOE a day, 21,700 BOE a day came from California, 4,200 from Utah and 2,100 BOE a day from Colorado and Texas. We continued to have drill rigs running in California during the quarter and picked up one rig in Utah during the quarter, resulting in total company capital expenditures of $53 million compared to $40 million for the third quarter. Again, with approximately 90% of our capital being spent in California, production in the state increased 11% sequentially over the third quarter. Also note, California has 100% oil production and receives a very effective differential to Brent pricing.

We drilled 76 wells in the quarter, 69 in California and 7 in Utah, versus 68 wells in the third quarter all in California, bringing our year-to-date count to 232 wells drilled, 224 in California and 8 in Utah. Of those 232 wells drilled in 2018, 174 were online at year-end whilst 52 were waiting to be placed online in early 2019 for California and 6 additional in Utah. Of those 52 non-active wells in California, 40 of them are in our Hill Diatomite area, which I will discuss in more detail.

We added an additional rig in California in January of this year and plan to keep 4 rigs continually running in California throughout 2019.

Overall, well performance on all of our 2018 capital is as expected in both California and Utah. And since we drilled some newer wells in Utah, we haven't talked about results yet there that much. I'll discuss the Utah wells in more detail shortly.

Turning to operating expenses. We had OpEx of $48.3 million, or $18.77 per BOE for this quarter. This compares to $18.10 per BOE in the third quarter.

Fourth quarter OpEx is higher than the third quarter, mainly due to higher fuel gas prices, reductions in electricity capacity payments, changes in inventory cost in Utah and one month less of the lower-cost gas properties in East Texas, partially offset by having purchased a larger volume of fuel gas under our gas purchase risk mitigation program. We had 15,000 MMBtu per day more fuel gas under contract for purchase than in the third quarter.

As for the electricity revenue reduction, 3 of our cogeneration facilities sell excess electricity into the market under PPA contracts. As part of the PPA, a certain portion of our payments are for providing capacity into the market. By contrast, those payments are higher from June through September. Overall, we saw a reduction of $4.8 million quarter-over-quarter in electricity sales as a result of those lower capacity payments and slightly lower energy payments. We burned approximately 70,700 MMBtu per day versus 68,500 MMBtu per day in the third quarter.

Average prices for Kern delivered were $5.27 per MMBtu versus $4.11 per MMBtu, while SoCal Citygate was $7.73 per MMBtu versus $7.56 per MMBtu for the fourth and third quarters, respectively.

I'd now like to take a moment to report on full year 2018 and reconcile to our 2018 guidance. Starting with production, we averaged 27,000 BOE a day for the year. This is at the lower end of our guidance range. Timing delays were the main reason annual production was under the midpoint, most notably in our Hill Diatomite property, which we have discussed previously.

We ended the year with approximately 40 wells, including 30 producers waiting to be completed. The sale of East Texas had a smaller effect on the overall annual production. And lastly, we shifted capital throughout the year towards our oily properties, resulting in lower BOE volumes but a higher oil mix than original guidance. With all of that said, we ended the year 8% higher than we entered for the company while taking into consideration East Texas sale and Utah inventory.

And again, focusing in California, even with the timing delays, we ended the year 15% higher than we entered, showing the strength of our 2018 capital program.

For OpEx, we averaged $18.33 per BOE for the year 2018. This is slightly above the midpoint of our guidance of $17.88. With the bulk of our capital spent on oil-rich and steam-concentrated projects in California, we performed very well in OpEx. Trem mentioned our focus on heavy oil projects in California and the impact it will have on OpEx. As a reminder, steam generation is the #1 cost in our expenses.

It was quite an achievement to stay within our guidance range for the year, given the higher fuel prices and the lower overall volumes. As I discussed last quarter, the ability to limit our exposure to high fuel gas prices is a competitive advantage to Berry.

Taxes other than income taxes came in at $3.36 per BOE for the year. This was directly around the midpoint of guidance at $3.38 per BOE. Adjusted G&A was $4.13 per BOE, which was slightly above the high end of guidance. The biggest reason revolves around our lower volumes, but we also saw some increased costs associated with our transition to a public company. Cary will add some additional color on G&A in his discussion.

Capital for the year was $147.8 million, which was under the $115 million midpoint of our guidance. This is reflective of our lower drilling cost, California projects and also a result of some drilling and completion cost savings. For the year, we drilled 232 wells, which was above our original guidance but in the range that I mentioned during the last earnings call.

Year-end 2018 proved reserves, as prepared by GeGoyler and MacNaughton, were 143 million BOE. Our NPV-10 was $2.2 billion based on Brent and Henry Hub pricing of $71.54 per barrel of oil and $3.10 per Mcf of gas, respectively. Our reserve replacement was 114% for the company and 275% for California by itself. Using total 2018 production, our R-to-P ratio was 14.5. Removing the sold properties in East Texas from 2018 production, raises the R-to-P ratio to 14.9. Our year-end 2018 reserve mix is 80% oil, 19% gas and 1% NGL. The current PUD well count in the report is 1,071, including injectors and producers, a significant increase from our year-end 2017 count of 711.

Now two items of note from our 2018 year-end reserve report. First, the 275% reserve replacement in California is a direct result of our capital focus on the projects returning the most value to the company. We plan to continue this focus into 2019. Second, the total proved NPV-10 value of $2.2 billion represents a multiple of approximately 150% of our current implied enterprise value.

Now before I talk about the revised 2019 guidance, I'd like to comment on a couple of topics that might have an impact on our operations. First, as most of you are aware, PG&E filed for bankruptcy on January 29, 2019. We do have one PPA contract with them but do not see any material impact to our operations as a result of their filing. We do purchase electricity from them on some of our properties, and that has not been disruptive, and we do not expect it to be going forward.

Second, on IMO 2020, we continue to analyze the situation and have put in place a firm link to Brent in some of our sales contracts to mitigate potential downside. However, we feel that the impact, if any, to us, will be diminished from the first conversations on the topic because of market fundamentals. The world has short heavy/medium (inaudible) oil and is expected to remain short because of the declining heavy oil production, heavy oil supply disruptions and increasing demand from several mega refineries in Asia. Inevitable lightening of the global refining crude slate due to the bunker fuel spec change has also been more gradual than anticipated, which further lessens the impact.

Ultracheap, ultralight oil from U.S. resource plays has incentivized many refiners in the U.S. to lighten their slate already. We'll continue to monitor the situation and make adjustments in our risk mitigation plans as necessary.

Third, let me quickly touch on permitting in California. There are multiple types of permits required to operate in California, and some are necessary for us to conduct our development program. First, we need permits to drill wells. And as Trem mentioned, we have an inventory of over 2 months of these permits in hand for each of our 4 rigs. We plan to continue to have this amount of runway and look to increase it as the year progresses.

Second, we need WST or well stimulation permits for our Hill Diatomite hydraulic stimulation completions. We have commented previously that we have not received these permits as quickly as we expected in the context of forecasting our volumes. We are currently waiting on 30 WSTs for our 40-well 2018 development program after receiving 10 permits in February. The remainder are in the process of being approved.

Third, we need and aquifer exemption or AE permit for some of our fields. We have one remaining field, Midway-Sunset, that is awaiting final approval of the AE. This permit is a onetime permit required to expand certain development outside of the 1973 field boundaries. We now expect to receive this AE for Midway-Sunset in early to mid-summer based on all of the information we have available. Our 2019 thermal Diatomite program will require this approval. We have received this onetime permit, when necessary, for all of our other fields.

And lastly, on regulatory front in California, we have been monitoring several initiatives. One is [Synecdoche 46], which will impose as severance tax on oil and gas at a rate of 10% of the average price per barrel of oil in Houston, California or 10% of the average price per unit in natural gas. Now severence tax has been brought before the legislature or the voters more than a dozen times over the past 20 years, and has never passed, so this effort is not new.

As Trem mentioned earlier, 2018 was a very good year for Berry. We accomplished quite a few of our objectives for the year, which sets us up for a nice growth plan for 2019 and beyond. We focused the majority of our capital in California and saw excellent results with production rising 15% from January to December.

Now turning to do this year, as Trem mentioned, our 2019 capital plan is being revised to incorporate the commodity price changes in the market. This revision is a result of removing capital in Utah, rebalancing capital in California and accounting for the timing of regulatory approvals we learned about in late 2018. Remember, we are always reviewing market conditions and allocation of capital throughout the year to make sure we're funding our highest-value projects and have a realistic assessment of key regulatory approval schedules.

Our Utah asset is a good example of this philosophy. While we are happy with our results to date of the 8-well drilling program from 2018, the market conditions are not favorable at this time. And just to give a quick update on those 8 wells. The first well we drilled in Utah last July has performed very well with current cumulative oil production 33% higher than our internal type curve. The next 7 wells were drilled as a follow-up to confirm our reservoir analysis. Through the first part of 2019, these wells have started to come online after completion and are outperforming the type curves as well. While it is still early for this next set of wells, we are excited about the opportunity in this area once the market conditions improve.

Now let me turn to guidance. The change to capital will also result in some other changes in our guidance. And here is the updated guidance for 2019. Capital will now range from $195 million to $225 million, a reduction of $35 million or 14% at the midpoint of guidance. This will result in wells drilled ranging from 370 to 420 versus the previously stated 400 to 450. And as a result, production is now expected to range from 28,000 to 31,000 BOE a day, a 1,000 or 3% BOE a day reduction at the midpoint of guidance. Oil mix will move up slightly to approximately 87%. OpEx is expected to range between $18 to $19.50 per BOE, a $1 per BOE increase as a result of removing lower-cost nonthermal barrels from Utah and California and adding more thermal barrels in California. Taxes other than income taxes are expected to remain in the range of $4.25 to $4.75 per BOE. Adjusted G&A is expected to range between $4.25 to $4.75 per BOE, a $0.25 per BOE increase as a result of lower volumes at the midpoint.

Compared to 2018 and pro forma for the East Texas transaction, we expect to grow production for the company in the low double digits In California, we expect to grow production in the mid- to high teens as a result of this capital program. The 2019 capital program will let us continue to develop our core areas and also drill further delineation wells to unlock the potential in the unproven portion of our reserves and contingent resource base.

Our entire operating team prides itself on searching out value for our shareholders and will continue to do so in 2019 and beyond. We have a very good team in place to execute on our program and can be very responsive to market changes as shown in our revised guidance. As an example, we do not have any stranded capital as a result of our new development plan.

So on behalf of the entire operating team, we're looking forward to 2019 and what it means for Berry. With that, I'd like to turn the call to Cary to discuss our financial results.

Cary D. Baetz - *Berry Petroleum Corporation - Executive VP, CFO & Director*

Thank you, Gary. Before starting, I want to highlight a housecleaning item that Trem mentioned. Beginning this period, we will present our operating and financial results split between California and the Rockies to provide better visibility to their operating results and to show the significant value and growth of our California assets.

For the fourth quarter, we reported adjusted EBITDA of $82 million, the same as the third quarter. On an unhedged basis, adjusted EBITDA was $73 million in the fourth quarter compared to $83 million in the third quarter. This decrease was primarily due to lower oil prices, which was partially offset by increased oil production. As both Trem and Gary have highlighted, our results were all about California where we saw improved production results quarter-over-quarter and accounted for 78% of our overall production and 87% of our oil and gas revenues in the fourth quarter. For the year, California, which is 100% oil, made up 73% of our production, resulting in 85% of our oil and gas revenues. In 2018, our California assets earned operating income of $227 million, which includes the DD&A, for a margin of nearly 50% compared to $19 million operating income and 25% margin for the Rockies operations.

For the fourth quarter, California oil prices before hedges averaged $62.65 a barrel, which was 9% lower than the $69.13 per barrel realized in the third quarter. Realized oil prices for the company before hedges of $61.48 per barrel, also 9% lower than the third quarter. Our fourth quarter realized price represents 92% of Brent in California and 90% for Berry overall.

Gary walked through volume, so I won't rehash them. However, due to the previously discussed marketing challenges in Utah, we saw a 355 barrel per day oil inventory build that negatively impacted our volumes for the quarter in oil.

As Gary pointed out, our fourth quarter operating expenses or OpEx were $18.77 per BOE compared to $18.10 per BOE in the third quarter. Recall, that OpEx consisted LOE and expenses and third-party revenues from electricity generation, transportation and marketing activities and the effects of derivative settlements for gas purchases while excluding taxes and other -- taxes other than income taxes. For the fourth quarter, OpEx per -- per BOE increase compared to the third quarter was primarily driven by higher fuel gas prices, decreased electricity revenues from the lower seasonal capacity payments as well as the impact of selling our East Texas natural gas assets in November, which had a lower cost on a PBOE basis compared to our other operations. The natural gas purchase hedges and other fixed-price contracts offset a portion of the fourth quarter fuel costs. Taxes other than income taxes were $3.05 per BOE for the fourth quarter compared to $3.30 per BOE in the third quarter, mostly due to lower production in the Rockies and lower severance tax rates.

G&A expenses of $16.1 million for the fourth quarter compared to $13.4 million in the third quarter largely due to an increase in stock compensation associated with performance shares meeting target thresholds. In the fourth quarter and third quarters, G&A expenses also included non-reoccurring restructuring, and other costs and noncash stock compensation cost of approximately $4.6 million and $2.7 million, respectively. Adjusted G&A expenses were $4.49 per BOE in the fourth quarter compared to $4.25 per BOE in the third quarter. The quarter-over-quarter increase on a BOE basis was primarily due to the costs associated with supporting the company's public company status and continued system improvements.

Adjusted net income was $35 million for the fourth quarter compared to $41 million for the third quarter of 2018. The decrease in adjusted net income was primarily associated with an increase in our corporate tax rate from 17% in the third quarter to 23% in the fourth quarter due to timing impact of releasing our prior year valuation allowance and lower operating results for the quarter as previously discussed. We finished 2018 without having to pay cash income taxes for the year.

As of December the 31, 2018, our elected commitment under our reserve-based lending credit facility or RBL was $400 million with no outstanding borrowings. We had $393 million available for borrowings under the RBL facility due to $7 million in outstanding letters of credit. As of March 5, the company has current liquidity of $401 million, including a cash balance of $10 million.

For 2018, our cash flow from operations were $230 million, including the $127 million payment for early termination of the hedging contracts in the second quarter, and we generated levered free cash flow of $46 million or $84 million unhedged basis.

For 2018, our operating performance gave us the confidence to return meaningful capital to our shareholders in the form of dividends, which we began in the first quarter as -- our first quarter as a public company as well as through our share repurchase program, which we initiated in the fourth quarter with almost 450,000 shares acquired by year-end. Today, we have repurchased almost $2.4 million shares for approximately $25 million.

In connection with our closure of our bankruptcy case, we issued common shares for unsecured claims of only 2.8 million out of the 7.1 million shares initially reserved. The remaining 4.3 million shares were -- were never issued and retired. As a reminder, our outstanding share count in prior quarters did not include the 7.1 million reserved for general unsecured stock claims. However, this amount was included in our previous EPS calculations.

For our fourth quarter reporting, the share count now includes the 2.8 million shares issued for the general unsecured stock claims less 450,000 shares were repurchased during the quarter. The EPS numbers also reflect these changes. The shares repurchased since December 31 are not in our current -- are not in our current share count or EPS calculations.

For 2018, Berry reported adjusted EBITDA of $258 million compared to $178 million for 2017. Adjusted EBITDA on an unhedged basis was a $296 million in 2018 compared to $175 million in 2017, primarily due to increased oil production and higher price -- and higher oil prices and, not to be overlooked, increased percentage of oil as a portion of our overall production in 2018 due to the acquisitions of Hill oil assets, and the disposal of the Hugoton gas assets in 2017 and our focus on developing and growing our oil-rich California operations.

Adjusted net income was $100 million for 2018 compared to $28 million for 2017. The improved results of 2018 compared to 2017 reflect an improved operating results partially offset by increased corporate tax rate. For 2018, OpEx totaled $18.33 per BOE compared to $16.84 per BOE in 2017. This per BOE increase was primarily driven by the change in mix of our products from 64% oil to 82% oil, driven by the Hill and Hugoton transactions. Our oil production is costlier than gas production but also generates more margin per barrel.

LOE increased due to higher fuel gas cost, mainly increased volumes purchased, and increased facility maintenance and well servicing activity. The OpEx per BOE increase was partially offset by decrease in transportation expenses in 2018, primarily due to the disposition of the Hugoton in 2017, which required significant transportation costs. Taxes other than income taxes were $3.36 per BOE for 2018 compared to $3.40 per BOE in 2017 due to reduced greenhouse gas rates and a lower severance tax rates associated with production where those taxes apply.

G&A expenses were $54 million for 2018 compared to $64 million in 2017. The decrease in general administrative expenses were due to reduced restructuring and transaction costs, partially offset by higher costs associated with building out a public company, infrastructure including higher labor costs and related increased stock compensation. Adjusted G&A expenses were $14.13 per BOE in 2018 compared to $2.74 in 2017. The increase in adjusted G&A expenses per BOE were due to increased costs associated with supporting the company's growth and public company status as well as the impact of lower volumes noted above from the changes in production mix resulting from the 2017 asset transactions.

Capital expenditures totaled $148 million for 2018 compared to $73 million in 2017. As stated by Gary, the increase in capital was largely focused on increased drilling in California, which accounted for 88% of all our development capital spent in 2018. Due to improvement in our California operations and higher market prices, we saw total company PV-10 increased by just over $1 billion in 2018 to $2.2 billion, $2 billion of which was related to California, which more than doubled year-over-year.

As highlighted by Trem and Gary, considering the year-end oil price declines as well as continued challenging markets in Utah and our constant focus on value, we have realigned our 2019 plan to focus almost all of our capital in California. Within California, we have relocated the capital to areas, which are less likely to be impacted by regulatory permitting delays. We have reduced planned spending by $35 million or 14% while only losing a little more than 3% of the production from our previous guidance.

Accordingly, we have updated our 2019 guidance. We still see California production growth in the high teens. The new numbers are in our earnings release. As a reminder, Berry describes free cash flow as levered free cash flow, including interest, dividends and the cost to maintain our production. That said, our fully loaded breakeven CODs is in the upper $40 Brent. We manage our budget to a $0 levered free cash flow. That means every dollar over our fully loaded breakeven cost goes to growth. Our latest outlook is based upon the current strip and a breakeven levered free cash flow. If prices continue to improve, then we will have more cash to invest in our business or to return to our shareholders, which may include opportunistic share repurchases, increased dividend and special dividends or a combination thereof. And if prices drop, we will slow our growth plans. However, we will continue to protect our downside to ensure the payment of our fixed charges and to replace our production.

Thank you. And I'll turn it back over to you, Trem.

Arthur T. Smith - *Berry Petroleum Corporation - President, CEO & Direcctor*

Thank you, Gary. Now in closing, I'd like to address some changes in governance that have occurred during -- driven by our being newly public and reflecting the maturation of the company as a growing public entity. We've made a few changes to our board. We added Don Paul, a research professor of engineering, the University of Southern California. He will make an extremely valuable contribution by helping us supply practical and existing technologies utilized elsewhere in the world to improve the production efficiency of our heavy-oil reservoirs. He will also be beneficial in the political arena, representing our industry at the state and federal levels. He serves on the audit, and nominating and governance committees. Earlier in 2018, after we went public, we added Anne Marriuci and Kent Potter, who serve as chairs for the nominating and governance -- nominating and governance and audit committees, respectively. Brent Buckley has stepped down as Chairman. He was critical to the successful emergence of Berry from bankruptcy and led us through the period of growth and sustainability resulting in our going public last year. I want to thank him for all his efforts in this role. He remains on the board and serves on the audit and compensation committees. Finally, we have moved to a CEO, Chairman and Lead Independent Director model of governance. I'm the new Chairman, and Anne Marriuci is the newly elected Lead Director.

With that, I'd like to open the call to Q&A.

QUESTIONS AND ANSWERS

Operator

(Operator Instructions) And our first question comes from Leo Mariani with KeyBanc.

Leo Paul Mariani - *KeyBanc Capital Markets Inc., Research Division - Analyst*

Just a quick question around Utah. Clearly, you guys had a couple of issues in terms of the inventory in the fourth quarter. Just trying to get a sense, I mean, do you guys expect further issues in 2019 where you might see some of these fluctuations on sales quarter-to-quarter. Just trying to get a sense of how the marketing plan is going and you think you're going to be able to kind of stabilize some of the sales versus production there this year.

Gary A. Grove - *Berry Petroleum Company, LLC - Executive VP & COO*

Sure, Leo. This is Gary. So our plan right now, and it looks the way we have in this particular time frame, we think we'll be back to our operating levels of inventory in and around April this year and without any further (inaudible) throughout the year. Now obviously, we can't see every single month going forward exactly what may or may not happen in that particular market, but we are also looking for alternatives outside of that particular area as well. We have a couple of things that we're looking to test. It's too early for me to comment on that as far as a maturation change and how we would market our product there, but our goal is to, obviously, eliminate those kinds of fluctuations going forward.

Leo Paul Mariani - *KeyBanc Capital Markets Inc., Research Division - Analyst*

Okay. That's helpful. And a question on the stock buyback plan here. So clearly, in your prepared comments, you guys stated that part of the rationale was to offset some of these shares that had to be issued in some of these, I guess, bankruptcy claims here that we're getting resolved. Just wanted to kind of clarify. So at this point, have all the prior bankruptcy claims, is that sort of behind us? Would there no longer be any further potential for stock issuance, sort of, under that? Wanted to kind of clarify that. And you clearly made some comments as well that with free cash flow gives you guys the optionality of potentially spending a little bit more money, maybe boosting dividend, maybe adding to stock buyback. Can you maybe kind of talk about maybe what your preference would be these days kind of between those 3 options?

Cary D. Baetz - *Berry Petroleum Corporation - Executive VP, CFO & Director*

Yes. Leo, this is Cary. The bankruptcy is completely behind us, and the bankruptcy shares have all been resolved. So no more shares will be issued underneath that. So check another box and get the past behind us. So it's great. I think, again, looking at returning shareholder value, obviously, the dividend is extremely important to us. I think it shows our understanding of the life cycle and the cash flow-generation capability of the assets. So -- but the other thing is the share repurchase. We didn't just buy just because of the dilution coming out there. We bought it because we also knew the stock was extremely cheap through the cycle. And if we see another situation that happens, then we're going to do what's right for what we think the company and the greatest value to our shareholders are.

Leo Paul Mariani - *KeyBanc Capital Markets Inc., Research Division - Analyst*

Okay, that's helpful. I guess just with respect to the regulatory side, I guess you guys did mention that you may had a couple delays. It sounds like that more affected the Diatomite side of the business. You also talked about having 2 months of permits in hand per rig, wanting to sort of increase that. Clearly, there's a new governor in place over there in California. Can you maybe just give us a bit more color around the regulatory landscape? Is there a pathway to kind of build the months of permits there? Where there kind of any slowdowns, the result of any transitions in government or kind of things getting better? What can you kind of tell us about the regulations?

Gary A. Grove - *Berry Petroleum Company, LLC - Executive VP & COO*

Sure, Leo. This is Gary, again, and I'll let Trem follow up at -- at a higher level, if needed. So just, specifically, back on permits, again. The drilling permits have not been interrupted. There's -- the change of governor has not done anything there. We're 2 months in advance of each of our rigs, which is typically where we like to be, if not more. And quite frankly, we're looking to even gain some inventory there as well. So on that side, again, there's no issue. The only timing issue we had, specifically, was in and around some of the stimulation permits that we need for the Diatomite as you correctly mentioned. We're working with agencies there to understand the time frame necessary. And that's truly what the question comes down to so that we can plan accordingly. And I think we've mentioned before, once we understand that and feel comfortable with it, we'll be able to plan a little bit stronger in and around that particular development. Obviously, we like that area, and we'll continue to go down that path and, ultimately, get it to where we feel like we can forecast it within the range of everything else we in our inventory. And as far as the new governor coming in, Trem did mention we're looking to work with his administration But as of now, today, there's been no large change. And Trem, did you want to add anything to that?

Arthur T. Smith - *Berry Petroleum Corporation - President, CEO & Direcctor*

Sure, Leo. Thanks, Gary. I just want to reiterate that when we took over leadership in 2017, we've had a very strong focus, Leo, on, what we call, our Berry-first approach. So we have developed significant working relationships, personal working relationships, with all the regulators, trying to understand, making sure they knew who we were, what the new Berry was and making sure they knew how much we respected them and understood they're the drivers. I think that relationship is continuing to improve, and we're starting to see the results at all levels, from my level down through the working level. And we do that, obviously, in California. Spent a lot of time in Sacramento and downtown Bakersfield with the Kern county administration and all those stakeholders. We also do it, obviously, in Colorado and Utah. And it's a significant effort. So you're starting to see those improvements in -- the planning -- it goes to planning. So I think I'll add that. I didn't know if that was the -- was that all, Leo?

Leo Paul Mariani - *KeyBanc Capital Markets Inc., Research Division - Analyst*

Yes, no, I think that's very good color from you guys. I think that's certainly helpful for sure. And then again just lastly, sort of noticing that your production tax per BOE, your guidance is supposed to be up a little bit in '19 versus 2018. I think you guys have mentioned in the prepared comments you had a bit of a relief in '18 versus last year. I just want to get a sense what's kind of driving the increases in '19 there.

Gary A. Grove - *Berry Petroleum Company, LLC - Executive VP & COO*

So again, this is Gary. I think -- well, from previous guidance, our volumes are slightly down a little bit, so like we guided up from where we were. And then -- but as far as compared to 2018, it's just the mix more than anything else of where production is coming from and the associated result of that. As much as we can, we're always looking to safeguard against the tax cost in each particular state and take advantage of what's available to us in each particular state as well as far as reduction to that cost.

Operator

(Operator Instructions) And I'm not showing any further questions at this time. I would now like to turn the call back to Trem Smith for closing remarks.

Arthur T. Smith - *Berry Petroleum Corporation - President, CEO & Direcctor*

Thank you very much. I appreciate everybody being on this call. I hope it was clear. Look forward to future conversations. I would like to say that we are going to have an Investor Day, an Analyst Day Meeting in New York on May 16, and there will be invitation sent out for that, and look forward to deeper discussions at that time. We're very excited about Berry and then the story, and appreciate your time today. Thanks.

Operator

Ladies and gentlemen, thank you for participating in today's conference. This does conclude the program, and you may all disconnect. Everyone, have a great day.