

**GASCO ENERGY, INC.**

**Moderator: Mark Erickson  
March 1, 2007  
10:00 am CT**

Operator: Good morning. My name is (Sarina) and I will be your conference operator today. I would like to welcome everyone to the GASCO Energy Fourth Quarter 2006 Full-Year 2006 Earnings conference call. All lines have been placed on mute to prevent any background noise.

After the speakers' remarks, there will be a question and answer period. If you would like to ask a question, simply press star, then the number 1 on your telephone keypad. If you would like to withdraw your question, press star, then the number 2 on your telephone keypad.

Please be advised that the remarks that follow, including answers to your questions, include the statements that the company believes to be forward-looking statements, within the meanings of the Private Securities Litigation Reform Act. These forward-looking statements are subject to risks and uncertainties that could cause actual results to materially differ from those currently anticipated. Those words include, among others, matters that are described in GASCO earnings release issued yesterday in their full filing with the Securities and Exchange Commission.

The company disclaims other obligations to update these forward-looking statements. While the company believes that forward-looking statements are reasonable, they are subject to factors such as commodity prices, competition, technology, environmental, and regulatory compliances, other drilling securities, schedules, capital plans, and other factors may cause results to differ materially.

Now I would like to turn the matter over to Eric - Mark Erickson, (the company's) Chief Executive Officer of GASCO Energy. Please go ahead, sir.

Mark Erickson: Good morning. This is Mark Erickson. Thanks for taking the time to join us today. We have a lot to cover from an active 2006. Joining me on the call today are Mike Decker, Chief Operating Officer, and King Grant, Chief Financial Officer. Together, we'll recap the quarter and years by natural and operational results and discuss additional operational details which we would like to share with you today.

After the prepared remarks, we'll welcome questions from the conference call participants. Joining us for the questions and answers portion of the call will be Peggy Herald, Controller.

Once King covers the financial results, I will return with a detailed discussion of 2006 reserves and 2007 cap ex. Later, Mike will provide new developments and details on the progress of the Riverbend Project and our ongoing successful efforts to reduce per well investment which should assist you with your models. We will then turn the call over to questions and answers.

I would now like to turn the call over to King Grant to discuss some key financial results to help you assess our performance.

King Grant: Thanks, Mark. Good morning, everybody. Let's discuss selected results for the full year 2006 and the fourth quarter. Keep in mind that we're comparing 2006 to 2005 which was an unprecedented high-price environment for the natural gas industry. To that end, I'll first cover production; clearly, an important driver for GASCO in 2006 as we set a new record for annual and fourth quarter production as we announced in early January 2006 - 2007.

Equivalent production for 2006 was 3.8 Bcfe which is up 123% over 2005's 1.7 Bcfe. Estimated accumulative net production for the quarter-ended 12/31/06 was 1.1 Bcfe, an increase of 17% over third quarter '06 production of .9 Bcfe and 43% above fourth quarter 2005's production of .8 Bcfe.

Net production increases are attributed to the completion of new wells and a higher average working interest in those wells, partially offset by normal production to clients of the existing wells.

Total revenues for 2006 were \$25.7 million, a 52% increase over total revenue and \$16.9 million for the same period in 2005. The line item breakout is approximately \$1.9 million for gathering income and \$2.7 million for interest income.

Oil and gas sales were a company record \$21 million, a 29% increase over 2005's total of \$14.1 million. The increase in oil and gas sales is attributed to higher production, significantly offset by lower prices received for sales of our natural gas. The average realized price for gas for the full year was \$5.38 per Mcf versus \$8.16 per Mcf for 2005, a 34% decrease. For liquids, the average price received during 2006 was \$54.86 per barrel as compared to \$56.91 during 2005.

Total revenues for Q4 '06 were \$6.6 million, a 20% decrease over total revenue of \$8.3 million for the same period in 2005. The line item breakout for the quarter is approximately \$.3 million for gathering income and \$.4 million for interest income.

Oil and gas sales were \$5.6 million versus \$7.4 million in Q4 '05. The decrease in oil and gas sales is attributed to higher production, partially offset by lower commodity prices received. The average realized price for gas for the fourth quarter was \$4.96 per Mcf versus \$9.58 per Mcf for 2005. For liquids, the average price received during Q4 '06 was \$46.55 per barrel as compared to \$58.37 for the same period last year.

The \$2.1 million decline in oil and gas sales for Q4 '06 over Q4 '05 is comprised of an \$2.9 million increase from higher production which was more than offset by \$5.0 million reduction due to lower realized prices. GASCO remains unhedged as we do not control firm capacity on U.S. pipelines transporting our gas from a basin.

For the full year's earnings results, we posted a net loss attributable to common shareholders of \$55.8 million or 65 cents per share. This compares to breakeven results of a net loss of \$71,000 or breakeven per share in 2005.

Included in the full-year operating expense is a non-cash charge of \$51 million related to an impairment of the carrying value of oil and gas properties that we incurred in the second quarter of 2006. For the impairment charge, GASCO would have posted a net loss for the year of \$4.8 million or 6 cents per share.

Further, as required, we adopted FAS 123R effective 1/1/06. This accounting standard requires that we run stock-based compensation expense through the

income statement. In 2006, this reduced our earnings per share by 5 cents. This - thus, prior to the impairment charge and stock-based compensation, GASCO had a net loss of a penny per share.

For the first - fourth quarter of 2006, GASCO posted a net loss for the quarter of \$1.8 million or 2 cents per share, this compares to net income of \$2 million or 3 cents per share in the same period of '05. We reported record cash flow from operations for 2006 of \$9.4 million, this compares to cash flow in '05 of \$2.1 million.

In looking at selected unit cost analysis for the full-year '06, LOE was 92 cents per Mcfe versus 51 cents per Mcfe for 2005. Of the 41-cent per Mcfe increase year-over-year, 10 cents is the result of a severance tax relief on some of our older production and 11 cents is the result of the wellbore covers that occurred in the second and third quarters as discussed in earlier conference calls. The remaining 20 cents per Mcfe increased as the result of higher costs across all categories in the field and can certainly be traced to higher field costs.

DD&A expense was flat at \$2.85 per Mcfe versus \$2.83 per Mcfe in 2005. G&A expense on a per unit basis fell to \$2.15 per Mcfe from \$2.66 per Mcfe because we were better able to spread our overhead across the larger productions (basins).

Now let's look briefly at last year's capital expenditure program. During 2006, we invested approximately \$87.3 million for drilling completion, recompletion, infrastructure, operations, and geophysical data acquisitions. The detail is as follows.

Drilling completions and recompletions - \$63.3 million, development wells in progress over yearend - \$1.4 million, (play) and pipelines - \$3.4 million, the evaporation pit in Utah - \$2 million, exploration wells - \$6.4 million, and acquisitions - \$6.3 million; all other which includes G&G, seismic, and (not) oil and gas PP&E was \$4.5 million. Our balance sheet is strong with cash on hand at 12/31/06 of \$22.4 million.

We continue to maintain our revolving line of credit with JP Morgan. The borrowing base was redetermined to \$25 million early last fall as we previously reported. The bank has nearly completed the evaluation of our 12/31/06 Reserve Report and has indicated to us on a preliminary basis that the redetermination will result in an increase of \$12 million for a new borrowing base of \$37 million.

I'd now like to turn the call back over to Mark Erickson for a discussion of '06 reserves and 2007 cap ex.

Mark Erickson: Thank you, King. We have prepared remarks regarding our Reserve Report. GASCO employed Netherland Sewell & Associates to prepare a fully-engineered Reserve Report. I think it is important that investors understand how we look at reserves, especially as they apply to our Riverbend Project where all of GASCO's reserves are booked.

I will start with the overview of the report and then go into additional details. For 2006, GASCO's yearend reserves were 42.2 Bcf equivalent, down from 76.7 Bcf equivalent at yearend 2005. The net present value discounted at 10% was 63.2 million, down from 109 million at yearend 2005.

The PV-10 assumed net yearend commodity prices of \$4.47 per Mcfe and \$43.21 per barrel as compared to 2005 yearend prices of \$8.01 per Mcf and

\$59.87 per barrel. This represents a 44% decrease in gas prices and a 28% decrease in oil prices used to evaluate our reserves.

All reductions in reserves and present value are solely due to the dramatically lower commodity prices utilized in this report. There were no net performance-related revisions.

Our reserve mix is 97% natural gas; GASCO added 16.6 Bcf equivalent of proved developed reserves before production, revisions, and acquisitions, which represents a 70% increase. The price deck used essentially eliminated our proved undeveloped reserves and reclassified them as probables. At a Rockies price of \$7 per MMBtu, essentially 100% of reserves eligible to be classified as proved undeveloped would be included. In this scenario, proved reserves would total 124 Bcf equivalent representing a 62% increase year-on-year.

We'd like to share with you some statistics from our 2006 Reserve Report. One metric we like to look at is reserve finding costs calculated by dividing the development cap ex which consists of drilling and completion expenditures by the difference between ending and beginning reserves. Obviously, with the reserve writedown, this is an impossible calculation to make.

We have taken the following approach to calculate our finding costs for 2006. You take the net development cap ex of \$63.3 million for drilling and completion, less investment for wells in progress, the evaporation pit permitting, and property plant equipment, divided by the reserve additions from extensions and discoveries of 16.6 Bcf equivalent, we get a finding cost of \$3.81 per Mcf equivalent.

Another way to look at this is to focus on the results from our 28 new well additions to the 2006 Reserve Report. The results show that we added 19.8 Bcf equivalent of new proved developed producing and proved developed non-producing reserves and at an all-in development cost of \$65.4 million which includes \$7.1 million for future recompletions, yielding a finding cost of \$3.30 per Mcf equivalent.

In 2006, our lease operating expenses were 92 cents per Mcf equivalent, adding this to our finding cost yields, a fully produced finding cost for 2006 ranging from \$4.22 to \$4.73 per Mcf equivalent before general and administrative expenses.

We believe that this is similar to other unconventional resource plays in the Rocky Mountain region and elsewhere. We continue to focus on lowering these costs going forward. Our current internal goals are to lower developed finding costs to \$2.75 per Mcf equivalent and \$3.50 per Mcf equivalent fully produced.

In 2006, of the 28 wells outed to the Reserve Report, four were previously classified as proved undeveloped locations or PUDs in our 2005 report. In 2005, these PUDs were assigned average ultimate reserves of 1.6 Bcf equivalent each. Subsequent to drilling and completion, each well identified 1.9 Bcf equivalent of average ultimate reserves in this year's report which represents a 22% upward revision over the predrilling and undeveloped estimates.

This is similar to what we saw in 2005 when four PUDs were drilled showing a 19% increase over their predrilling estimates. This is an important point. We believe that this demonstrates the conservative nature of our Reserve Report.

Based on the 2006 new well additions, the best performing well is expected to make approximately 3 Bcf equivalent and the poorest well is expected to recover approximately .3 Bcf equivalent. Average for all these new well additions is 1.5 Bcf equivalent per well. This wide variance is not surprising to us given the fact that we still focus 85% of our Utah drilling efforts on step-out and extension wells. These statistics will tighten and averages should increase over time.

In the Spring Canyon area of the Riverbend area of our project, the new wells averaged 1.7 Bcf equivalent. We are projecting well costs reduced to \$2.5 to \$3 million in this area, resulting in current finding costs using a royalty burden of 20% from \$2.39 per Mcf equivalent, moving to \$1.75 to \$2.20 per Mcf equivalent. GASCO currently has an inventory of up to 250 net locations in this area.

In the Kenilworth trend area, we have identified a third Blackhawk marine trend, the Aberdeen Formation. We have only intercepted it with one well, it appears to have similar characteristics to both the Spring Canyon and Kenilworth marine sands.

The good news is that it is situated such that the new (payers) position so that it overlaps the Kenilworth formation in a portion of the western part of our acreage. This should yield us a much needed potential reserve uplift in this area from the current estimated 1.1 Bcf equivalent to something more in our typical average of 1.3 to 1.8 Bcf equivalent. We are seeing significant reduction in investment in this area, bringing projected well costs down to the \$2.5 to \$2.75 million range.

Current finding costs in this area using 1.1 Bcf equivalent and \$2.75 million for well investment with a 20% royalty burden, are \$3.13 per Mcf equivalent, and projected to be lowered to \$2.00 to \$2.75 per Mcf equivalent in 2007.

GASCO currently has an inventory of up to 1,000 net locations in this area with potential for up to 150 of these to have both the Kenilworth and Aberdeen marine Blackhawk (numbers) present.

The majority of our leasehold is potentially productive from the Mesaverde Desert and (Grace) members of the Blackhawk Formations. In these wells, our results have averaged 1.3 Bcf per well. Current well investment for these wells is projected to be from \$2 million to \$2.25 million per well. Current finding costs in these wells using 1.3 Bcf equivalent with a 20% royalty burden is projected to range from \$1.90 to \$2.20 per Mcf equivalent. Our location inventory in these areas exceeds 2,000 potential locations on 20-acre spacing.

Today we announced our preliminary capital budget of \$40 million for our 2007 program, subject to final Board of Director approval. The program is initially budgeted to cover the drilling and completion costs of approximately ten net wells to GASCO's Riverbend Project.

We also finished drilling the Billy Canyon well in Wyoming. The budget also includes expenditures for the installation of associated pipeline infrastructure, distribution facilities, and geophysical operations. This budget will be funded from cash on hand, cash flow from operations, and borrowings under the company's reserve base revolving line of credit.

I would like to take the - I would like to provide a little color on the Brek acquisition that we announced in the fall of 2006. This transaction is

proceeding. We hope to close prior to the end of the second quarter. It is taking longer than we anticipated. We anticipate filing the preliminary Joint Proxy Statement after Brek files its 2006 10-K and they give us further clarity on the structure of their spin - on the spin-off of their investment in Vallendar Energy.

Let's turn the call over to Mike to discuss operations.

Michael Decker: Thank you, Mark. Good morning, everybody. As many of you are aware, GASCO has placed great importance on driving costs out of the per well investment total. Some of our success in lowering per well investment comes from aggressively fitting out services. Additional savings are a direct result of our new Drilling Manager, Chuck Wilson, and his team's efforts to reduce drilling days.

I would like to note that the average time to reach DD to the Blackhawk Formation which ranges from 12,000 feet to 13,300 is currently about 25 days. This compares to an average time to Blackhawk, total depth last year of 37 days. Reduced drilling days are a result of specialized bit selection and more consistent crews who know - who now have more wells under their belt, better operating iron in the field is also benefiting our efforts to drill faster wells.

We can also breakdown a basic (AFE) for a typical Blackhawk well. For example, we have reduced the following components on the drilling side -- rig moves and rig-ups by \$61,000 or 24%, setting surface casing by \$40,000 or 24%, mud and chemicals by \$45,000 or 33%, drilling bits by \$30,000 or 24%, mud motors by \$20,000 or 33%, and wireline logging by more than \$35,000 or 65%.

Then on the completion side of the (AFE), we have reduced frac costs by \$270,000 on a two mobilization frac which equates to a 30% savings. Coupling these service cost reductions with reduced drilling days at \$40,000 per day, yields the lower (AFEs) that we're beginning to realize.

Therefore, in summary, this time last year, the average Blackhawk well cost \$4.25 million to drill and complete and now we are seeing a range from \$2.5 to \$3 million to drill and complete. Importantly, we feel strongly that we can push the costs even lower.

Another important development is that we recently drilled our first in-fill well in the Riverbend area to test the extended drainage in the Wasatch Mesaverde Formations and the Upper Fluvial members of the Blackhawk. The well was directionally drilled as a 20-acre offset in the Wasatch and the Upper Mesaverde and a 10-acre offset in the Lower Mesaverde and Fluvial Blackhawk. This well has not been completed yet but well logs show that only a few sands could possibly be correlated between this well and its offset.

To summarize in the drilling, completions, and recompletions, GASCO spudded 30 gross wells, 18.4 net, and reached total depth on 29 gross wells, 18 net, in the Riverbend Project. Other activity included initial completion operations on 26 wells, 16.5 net, and the reentry of 16 wells or 8 net to complete behind pipe pay zones. Exiting the year, GASCO operated 92 gross wells with two additional wells awaiting completion activities. Currently, three drilling rigs are operating in the Riverbend Project area and we expect the fourth rig to be delivered at the end of March 2007.

I would now like to discuss our permits. Currently, GASCO has 32 permits in hand. We are actively permitting for 2008 and beyond. The GASCO

Operations Team continues to work with the Vernal Office of the BLM to get permits and environmental assessment approvals as quickly as possible.

We should also remind you that we hold 20% state in (feland) which is not applicable to BLM regulatory hurdles and where permitting is not quite an onerous.

On a related permitting note, GASCO recently received approval of its Riverbend Environmental Assessment. The approved EA includes 45 proposed wells within Spring Canyon marine trend of the Blackhawk Formation. The EA should provide for accelerated permitting approvals from the Bureau of Land Management as environmental and cultural studies of the 45 proposed well sites have already been completed.

Moving on to our Riverbend gas gathering activities; GASCO recently completed the linking of the Wilkin Ridge and West Desert gathering systems to its existing 50 million cubic feet of gas per day gas processing facility which began operations in June of 2006.

Now up to 95% of produced volumes are processed in the plant, ensuring that production will meet pipeline specifications reducing the likelihood of any future curtailments due to hydrocarbon dew point issues. The company currently operates nearly 100 miles of gathering system along with the processing facility.

Let's talk about our recently spudded deep test in the Uinta Basin where we'll be testing the Manco Shale and Dakota Formation at depths of 16,650 feet. The well will test the productive potential of the Wasatch, Upper and Lower Mesaverde, and Blackhawk Formations, the Manco Shale, and Dakota

sandstones. The well, which is the Federal 14-31, is operated by GASCO with 100% working interest.

The preliminary well cost estimate to drill and complete the well is \$7.3 million. Estimated time to reach total depth is (98ths) spud, the well is currently drilling through 8,000 feet.

It is important to note that the location was selected because it is located in the core of the Riverbend Blackhawk Spring Canyon marine trend where GASCO has the most geological control and continues to have consistent and favorable results. Therefore, this well is a development well with an exploration lag. So we're anticipating encountering at least two billion cubic feet of gas of completable reserves from the Spring Canyon on upwards.

Recent announcements by industry players in the Basin indicate increased activity targeting deeper pay zones is ongoing in the Uinta Basin. The early wells are providing encouraging preliminary results. Geological modeling in cases like the Manco Shale and associated sandstones are prevalent under GASCO's leasehold.

I would now like to discuss Wyoming and the Cottonwood Ranch 24-21 well. We recently drilled and plugged the 24-21 on our Daniel Anticline prospect. While we encountered numerous gas shows within sands and natural fractures, there was not enough gas to warrant a completion.

GASCO is currently integrating a new geology and geophysical information into the models and we feel that this well does not condemn the entire prospect; in fact, we feel that approximately 25% has been compromised. Consequently, we are permitting another well to the North of the 24-21 and

the grindstone 41-8 wells. The soonest we can move on to the new location is in late summer due to lease stipulations.

Turning to Nevada, our partner, Plains Exploration, is nearing its spud date on an exploratory well in White Pine County, Nevada. The well is being operating by Plains and is being drilled as a tight hole. GASCO has carried on this well and does not contribute any capital to the drilling of the well. Depending on the results, Plains may also spud an additional well in Nevada in which GASCO is carried 100% as well.

Finally, I think it is important to summarize the highlights of our operational activities in 2006. I would like to emphasize that we are executing our operating plan as we had set forth in 2006 and that was to 1) reduce drilling days, and 2) aggressively bid services where possible. These are very important items that are greatly improving the economics of the play.

Importantly, we have reduced drilling days. Two years ago in mid-2005, we were drilling Blackhawk wells at an average time of 49 days. One year ago, we had reduced the drilling days to 37 with an average well cost of approximately \$4.25 million. Today, we have reduced the drilling days to an average 25 days and are currently targeting 20 days.

Our three best wells to be drilled through the Blackhawk are now 21, 17, and 14 days. Let me reemphasize that; our three best wells drilled are 7 - or 21, 17, and we just DD'd a 14-well day yesterday. This yields a fully completed well cost ranging from \$2.5 to \$3 million; all that savings goes to the bottom line and obviously reduces our finding and development costs.

While we did have higher LOE costs in 2006, we are aggressively working to reduce these costs as well. We saw four components that contributed to this

increase; first, increased water disposal costs; second, increased workovers; third, inflationary increases for manpower and supplies; and fourth, the increases in our severance and property taxes.

First, addressing our water disposal costs, we spent more than ten months of the year trucking our water more than 80 miles for disposal. Beginning in mid-October, our evaporational pit became operational and it is currently located in the center or in the heart of the field. Therefore, the full annual savings being realized were not evident in the 2006 numbers. We are experiencing a reduced water disposal cost of as much as 50%.

Second, we had a large number of workovers on our older wells. In our early wells, we had set our tubing above the perforation so as to run production logs and better understand the productivity of the different frac stages in sands within each stage.

The higher tubing led to more scale problems. So in 2006, we began to lower the tubing in many wells and in the process, had to also cleanout entry per scale. We are currently setting the tubing at a deeper and more efficient production depth and employing an aggressive scale prevention chemical treatment program. It should also be noted that expenses were incurred setting plunger lifts. The plunger lifts not only help increase our production but also help in minimizing the scale issues.

Third, as all operators experienced, we too saw inflationary increases in manpower and supplies. Many of our service suppliers increased wages above inflationary rates so as to retain their personnel. GASCO anticipates less percentage increases in 2007.

And finally, taxes. Utah grants a severance tax holiday on a well's first six months of production; as our wells age, more of our production falls outside of this window.

That covers operations. I will now turn the call back over to Mark.

Mark Erickson: Thanks, Mike. I would summarize 2006 as an excellent year for operations. We successfully reduced per well investment to approximately \$2.5 to \$3 million per well from the high's experience in mid-year 2006 that were approaching \$4.25 million per well, which is a 30% reduction in well investment.

We suffered the impact on our reserves, earnings, and balance sheet of dramatically lower commodity prices but exited the year with production increasing to record highs and strong proved developed reserve growth. We expect commodity prices and well investment to come more in line during 2007 as GASCO and other operators exercise more investment discipline.

We've strengthened our Talent Operating Team with the additional of an experienced Drilling Manager. We are starting to see the impact of the team's efforts with consistent reductions in drilling time and lower drilling investment through operational efficiencies.

Finally, we achieved a new record well for Spring Canyon, 14 days. We believe these results are repeatable and can be improved upon. Going forward, we have reduced our targeted well time to 20 days from 37 days one year ago and 25 days just a few months ago.

Operating costs will continue to be a focus this year as we seek opportunities similar to the evaporation pit that will reduce water disposal costs by 50% and

overall lease operating costs by 11%. We'll see increasing economies of scale as we expand production in well count.

We continue to expose the company to high upside projects. In 2007, we hope to get the results from new drilling in Wyoming, Nevada, and California. The Mancos Dakota play in the Uinta Basin is poised for meaningful growth and activity based on the results of other operators in the area and activity in adjacent basins. This is an opportunity where the play can be tested and exploited knowing that there are dependable up-hole pay zones.

We are currently drilling our first Mancos Dakota test, expecting it to reach total depth in the next 75 days. I must caution you that one successful well does not make a play nor does a dry whole condemn one. We have a lot to learn about the Mancos Dakota.

Our goals for 2007 include accept modest production growth in exchange for stretching our capital into 2008. Position our gas sales contracts to ensure our production flows and allows the option for hedging. Demonstrate continued reduction in fully produced finding costs with a target of \$3.50 per Mcf equivalent. Continue to delineate the Spring Canyon, Kenilworth, and Aberdeen Blackhawk marine trends. Expose the company to high upside projects.

In closing I still heartily believe we are in the right spot at the right time. We will continue to meet the challenges this industry - of this industry as we have demonstrated in the past.

Thank you again for joining us. Operator, I'd like to turn the call over for questions.

Operator: At this time, I would like to remind everyone, if you would like to ask a question, press star, then the number 1 on your telephone keypad. We'll pause just one moment to compile the Q&A roster.

Your first question comes from Chris Pikul with AG Edwards.

Chris Pikul: Hey, good morning, gentlemen.

Mark Erickson: Good morning, Chris.

Michael Decker: Hi, Chris.

Chris Pikul: I agree with you. I think you've made a lot of great progress on a lot of fronts, so congratulations from that end.

Mark Erickson: Thank you.

Chris Pikul: I wish the market would give you some credit for it. In light of what you said about LOE, Mark, I think you kind of touched on it, but could you just remind us of the bump in per unit LOE in fourth quarter and maybe give us a little suggestion as to what '07 might look like?

Mark Erickson: Sure. Since Mike has looked at that in detail, I'll have Mike answer that question, Chris.

Chris Pikul: Okay.

Michael Decker: You know, Chris, in the - I think if I got the question, I actually wasn't quite ready to respond to that like Mark was...

Chris Pikul: I was just talking - is the fourth quarter LOE seemed to jump quite a bit? In light of some of the cost savings you're talking about, could you just give us a reason for that? Was it workovers and then maybe a little outlook for '07? I'm calculating \$1.24 per unit...

Michael Decker: Okay.

Chris Pikul: ...versus roughly 80 cents in the third quarter?

Michael Decker: Yeah, and that - again, that goes back because of doing additional workovers.

Chris Pikul: Okay.

Michael Decker: Okay? And, you know, as I said, we - as many of you know that what we had wind on, we had run our production tubing up shallow. So we could always go ahead and have the option of running production logs. And using that information helped us to maximize our frac treatments and productivity. And now that we have begun to do that in - so now that we've recognized that issue, we are now lowering the tubing even on our initial wells because we have such a good set of production logs now.

Chris Pikul: Uh-huh.

Michael Decker: And so we won't have that cost incurred. And then we're working with a new chemical company that is now aggressively treating our scale.

The other item that we really focused on in the fourth quarter was getting a large number of our wells on plunger lifts. Okay? And plunger lifts are a means of lifting the water associated with the gas production and they have - they yield two results. First off, we have seen a nice upward tick in

production; it could be anywhere from 200 to 300, even as much as 500 Mcf a day with these plunger lifts utilizing more efficient water uplift.

But the other thing too is because this plunger lift is cycling within the wellbore, you know, many times a day, it's also helping keeping the wellbore clean so as to allow - or to reduce our scale issues. So coupling the plunger lifts along with the scale treatment programs should greatly reduce - or at least - I don't know about greatly but should have a significant impact on our LOEs in 2007.

The other item that went into our 2006 fourth quarter was also property taxes. And we had a large amount of that come due for Utah in the fourth quarter and that was reflected in the LOEs as well.

Chris Pikul: Okay. So there's a combination of some one-time events and some efficiencies going forward. So \$1.24 isn't representative of what you think on a per unit basis?

Michael Decker: That is correct, Chris.

Mark Erickson: If you look at what our target for 2007, you know, when you look at our fully produced costs, we're using 75 cents per Mcf as a target.

Chris Pikul: Okay. Mark, you gave us a lot of great information on wells and well costs. You know, on the surface, the economics look even more appealing. In light of your decision to pair back the budget, you know, which is understandable, can you just kind of take me forward about a year, you know, all things being equal, if you're not in a position to grow production, you know, dramatically and the play is not going to become self-funding over that time, you know, where do you see GASCO in a year, you know, if we get - if we have current

prices and you can book, you know, some incremental reserves, what do you see are the company's, you know, options at that point?

Mark Erickson: Well, the main thing a year from now, as we're going to have a lot more information on well costs and the performance of, you know, the potential of the Mancos, we'll have our seismic information in. So when I look at what are we going to be doing a year from now, that's a pretty hard question as far as funding our growth going forward because we are sitting in a position where we enjoy a lot of flexibility that we didn't have in the past.

Looking at our budget for 2007, this is a preliminary budget. And we want to - we put that out there. It's still subject to Board approval. But we want to demonstrate that we want to live within our means in 2007 and stretch our capital into 2008. We want to be able to bake in some of the results that we're currently seeing. And then as we go forward into, you know, 2007 and into 2008, we'll be looking at what our capital plans will be for 2008.

Chris Pikul: All right. Well, just playing devils advocate, if the equity never seems to respond and, you know, you managed to maybe grow production a little bit here and add some reserves, I mean you're - are you going to be in a position to want to accelerate this play through some - you know, be a partner or something like that? Or does - there has to be a point where more drilling has to take place, am I - is that correct or...?

Mark Erickson: Well, understand that we're still in the mode of proving up the play. And proving up the play means demonstrating lowering well costs, delineating the Blackhawk marine trends, testing the Mancos. And our real primary objective is we want to continue with the current level of activity. We've put a lot of time and effort and capital frankly into improving the performance of these rigs, getting the crews trained, and we'd like to keep them working.

Now to do that, what we've done in the past to stretch capital, is we've brought partners in with us to maintain the current level of activity. We've been able to make additional profits through the ownership of our gathering system, our processing plant, and our water disposal facilities. Those are actually starting to contribute real meaningful cash flow numbers.

So the real key for us is to continue with the high level of activity to delineate and prove-up the play. But we want to maintain production growth. But we also - we're going to demonstrate and we will exercise the financial discipline to stretch our capital and accept modest production growth in return for stretching our capital. We don't want to get caught in a situation where we have to go back to the market looking for capital and be at the mercy of the market.

Chris Pikul: All right, very good. I just have a couple more questions. Just so everybody is on the same page, could you make sure we're all up-to-speed on reconciling the \$4.51 Rocky Mountain price that you mentioned to the wellhead price of \$4.04?

Mark Erickson: Sure. Basically, Northwest was \$4.55 and CIG was \$4.46. That came to a wellhead price of \$4.04 and then adjusting for Btu brought it up the \$4.57 that you talked about.

Chris Pikul: Wait, I'm sorry.

Mark Erickson: Or \$4.47.

Michael Decker: \$4.51.

Mark Erickson: Or \$4.51.

Chris Pikul: How did you get to the wellhead price of \$4.04?

Mark Erickson: Okay. Northwest was \$4.55.

Chris Pikul: Right.

Mark Erickson: And CIG I think was \$4.46.

Chris Pikul: Okay.

Mark Erickson: Okay. Then going to the wellhead, at the wellhead, those prices after gathering expense processing marketing fees, was \$4.04.

Chris Pikul: Okay.

Mark Erickson: And then after adjusting for Btu, we got to \$4.51.

Chris Pikul: Okay. So \$4.51 is the revenue number essentially.

Mark Erickson: That's per Mcf, yes, that is the revenue number.

Chris Pikul: Okay. So on the next page where you say an assumed Rockies price of 7, that's the equivalent number?

Mark Erickson: That would be the equivalent of a CIG Northwest price.

Chris Pikul: So...

Mark Erickson: And then it was - well, I believe that went down to \$6.46 at the wellhead.

Chris Pikul: And then we - would we gross that back up again for the quality?

Mark Erickson: Then that would increase based on Btu. And the average was \$7.14 per Mcf in that run net at the wellhead.

Chris Pikul: Okay. And you wouldn't happen to have a PV-10 number for those, you know, prospective reserves there would you?

Mark Erickson: We don't have it with us.

Chris Pikul: Okay. Okay. That was helpful. I guess I'll just get off and let somebody else ask something. Thanks.

Mark Erickson: Thanks, Chris.

Operator: Your next question comes from the line of Rodney Clayton of JP Morgan.

Rodney Clayton: Good morning, gentlemen.

Mark Erickson: Good morning.

Rodney Clayton: First on your - the well you drilled here in 14 days, can you get - talk a little bit more about that? You know, was that from your best rig? What kinds of things did you do maybe differently in that well to get that type of success? And do you think this is something that can be replicated on a wider basis or is this more of a one-off type issue?

Michael Decker: Rodney, this is Mike. And to address that question, first also I'll say, no, it is not a one-offish well. Second, we do feel it is repetitive. Third, the well was in the Spring Canyon trend, drilled down to about 12,400 feet, so it is typical of what we see in the Spring Canyon trend. And the way it was done was utilizing and maximizing our bit selection.

As you know, since last summer, we have been working with different bits, working with the bit suppliers and so on to improve the quality of the bits, and we are now fully seeing the impact of what that is.

Our Drilling Manager, our new Drilling Manager, Chuck Wilson, has been actively working with our Drilling Superintendents in the field, monitoring what the different results we're getting from our bits, and has begun to employ consistency between the different rigs so that we should see the same impact throughout all of the rigs.

Mark Erickson: Rodney, this is Mark. I just want to reemphasize. We feel very strongly that those results are repeatable and, in fact, that we can improve upon them. And it's really the - I think the most important thing to note is in the past, we talked about one rig being better than the other, etc.; what we're seeing now with the employment of a Drilling Manager is we're getting consistency from rig to rig.

Rodney Clayton: Okay. And, obviously, you have the new build rig that's going to come on line with your other older rigs. Are those some rigs you are looking to maybe replace with new builds as well that might be more efficient?

Michael Decker: Well, at this point in time, we have - we invested a lot of money in capital and continue to upgrade those rigs. And so we are not looking at replacing those at this point in time. We've spent a lot of money to go ahead and make sure that

they continue to operate at better efficiency and we're not looking to replace those right now.

Mark Erickson: Rodney, if we're not successful - this is Mark - if we're not successful in bringing in a drilling partner, our preferred alternative would be to find a window for those rigs instead of laying them down.

Rodney Clayton: Okay. And going to the budget, again, you know, obviously, it looks like '07 you're going to spend about half of what you spent in '06 and understandably. But, you know, looking in the future in terms of the development of this play eventually, how do you balance your need to accelerate development and really ramp-up drilling with your capital constraints?

Mark Erickson: It's similar to what, you know, I viewed with - or reviewed with Chris, that what we see is important is maintaining our current level of activity in proving up the play. And I think GASCO - the story with GASCO is about demonstrating the profitability of the play and we can do that whether we're putting the dollars in directly or we're doing it with drilling partners.

And so we want to maintain the current level of activity and continue to delineate and prove up the play, demonstrate lower finding costs, which we think will translate into a higher net asset value for the company and also a higher share price.

Rodney Clayton: Okay. With the ten net wells that you're planning to drill in '07, what's that on a gross basis?

Mark Erickson: Well, if you look at the three rigs we have running out there right now, we believe those are capable of drilling approximately ten wells each for the year. So that will be 30 gross wells. And if we bring the fourth rig on at the end of

March, we've got nine months of drilling, that's going to translate roughly into six, maybe seven gross wells. So, you know, we're targeting something in the neighborhood of 35 to 38 gross wells, provided we find a drilling partner.

Rodney Clayton: Okay. And how would you allocate that between Spring Canyon, Kenilworth, and Desert (Grace)?

Mark Erickson: I think as the program sits right now, it's approximately 75% in the Spring Canyon area and 25% in the Kenilworth area.

Rodney Clayton: Okay. And just one last question, based on some of your latest drilling statistics where you're, you know, economics have obviously improved, what do you think right now is your breakeven gas price, would it be, you know, (MI/MAX) or Rockies or how ever you want to give it?

Mark Erickson: Well, if looking again at the fully developed finding cost, if - you know, if we hit our benchmark of \$3.50, you know, we're going to be breakeven in that range. And, you know, I'm looking at being, you know, breakeven at that \$3.25 to \$3.75 for a (MI/MAX) price.

Rodney Clayton: Okay.

Mark Erickson: When I'm looking at breakeven, I'm not talking about a PV-10 number; I'm just talking about returning our capital.

Rodney Clayton: Right. Right. Okay. I guess I'll stop here and let someone else jump on.  
Thanks.

Mark Erickson: Thanks, Rodney.

Operator: Your next question comes from David Cameron with Wachovia.

David Cameron: Hi, good morning.

Mark Erickson: Good morning, David.

David Cameron: A couple questions. You commented briefly, I guess, Mike, you did about the EA and you got approved permits out there. Can you talk - I mean is that the same EIS that we've been talking about for the last year? Is that just a sub - what's the difference there or am I comparing apples to oranges?

Michael Decker: A little bit apples to oranges there, David. We have the larger picture Environmental Impact Statement or EIS of over 1,500 locations...

David Cameron: Uh-huh.

Michael Decker: ...that we're currently working on. Okay? And then within that, we had some smaller environmental assessments which don't have quite the degree of scrutiny as an Environmental Impact Statement. And so at this point in time, we have - that's what the Riverbend EA was, was a smaller package of 45 wells within the Spring Canyon trend...

David Cameron: Okay.

Michael Decker: ...that we had, you know, applied for to go ahead and help expedite the permits in that area. We currently have - and then also, as you're well aware of, we're currently shooting our 2D seismic; that too required environmental assessment and we got approval of that. And currently in the works is about a 75-well environmental assessment within the Wilkin Ridge area that we're currently awaiting for approval.

David Cameron: Okay. Okay. And the EIS, we're still targeting '08 kind of timeframe or...?

Michael Decker: You know, what we're seeing right now and, obviously, you know, don't hold me exactly to it, but what I've seen from a tiny basis is it looks like about a February '08 event.

David Cameron: Okay. And then, Mark, you talked about PUDs and I think you led off initially with comments about some of the new drills you had, they were on the books at 1.6 so then you're getting 1.9. Are those reserve engineering numbers you're sighting or are those GASCO numbers? What exactly just to clarify?

Mark Erickson: Both in 2005 where we saw 19% increase and 2006 where we saw 22% increase were based off the Netherland Sewell numbers.

David Cameron: So the Netherland Sewell number at 1.9 Bcf that you said 1.6 to 1.9 increased. What do you think that 1.9 ends up being two years down the road? I mean is that a good number, should it be moving higher?

Mark Erickson: My feeling is that we're going to see the reserves move up another 10% or 15% with time. And we're just starting to see the increases associated with some of our plunger lift program. But you know the nature of reserve engineers that's show me before you get it and so they basically work off of decline curve analysis and they take your current wells at their rate and just basically decline amount from there. And even though engineering-wise you can demonstrate that they should flatten out more in their later lives, you don't get credit for it.

King Grant Later life would be after five years or so of production...

David Cameron: Production - okay.

King Grant: ...where you're in the terminal flattening out. So that would be the - where you pick up the reserves is in the tail-end when they decide that it's not a 4% decline rate terminal but more like 6% or 7% or whatever it turned out to be.

Mark Erickson: And kind of backing it up a little bit more is if you looked at our PDP forecast, I actually looked at the PDPs that we had for the 2005 report and compared the reserves to the 2006 for the same wells and they went up by approximately somewhere between 5% and 10%, I'm just - kind of in the back of my head I'm just trying to recalculate it. But I think it was about 8% or 9%.

David Cameron: Okay. All right. And then Mark, on the same - that same vein, in the Kenilworth, you mentioned you identified the Aberdeen, that it overlaps kind of in the western part of the acreage and then you gave some reserve numbers and you said it upped your (EUR) from 1.1 to 1.8, is that your number, is that a Netherland Sewell number?

Mark Erickson: That is a recent well and it was not included in the Reserve Report. But based on, you know, the early look at it is it's almost a doubling of the pay. It looks similar to the Kenilworth. So it's like making the Kenil - it's like taking and increasing the sound thickness by two-fold. So we're just comparing it to the results we're seeing in the Spring Canyon area where we've had some thicker sounds and, you know, increasing it to the 1.3-1.8 Bcf range and making it more typical with the wells we're seeing in Riverbend, we feel pretty comfortable with that.

Michael Decker: And David, that's strictly based on well logs.

David Cameron: Okay.

Michael Decker: Okay. That well is being completed as we speak today.

David Cameron: Okay. All right. And just to clarify to make sure - I want to make sure I'm looking at the right stuff here that if I go back to like the (preservation) you had maybe in the fourth quarter or something, I remember the Kenilworth trend you kind of targeted 1 to 1.5 Bs, you know, and then you added some uplift if you went to Lower Mesaverde, Wasatch-type uplift, they're adding another half a B to whatever those numbers were. Is that the same math that you're looking at here or is it just...?

Mark Erickson: The difference being in our presentation when you look at it, we've got the type curve and then we have a conceptual type curve.

David Cameron: Uh-huh.

Mark Erickson: The type curve ties more closely to MHA Netherland Sewell number, the conceptual looks at what we think we can get from one of those wells.

David Cameron: Okay. And there you're quoting like \$3.5 to \$4 million per well. That same number is now down to \$2.5 to \$2.75?

Mark Erickson: Yes, it is.

David Cameron: Okay.

Mark Erickson: A (minor) adjustment.

Michael Decker: Hey, David, I'd like to emphasize. You know, we talked about the 21, 17, and 14 days...

David Cameron: Yeah.

Michael Decker: ...one of the - the 21-day well was actually in the Wilkin Ridge area, the other two were within the Riverbend Spring Canyon trend. So we are seeing that - to kind of refer back to Rodney's question - we are seeing that at least in our two primaries of drilling that we're, you know, developing right now.

David Cameron: Okay. Yeah, that's good.

Mark Erickson: And the reasons for those - one of the reasons for the lower cost in the Wilkin Ridge area is we have fewer pay zones to complete and we're drilling them faster. So the completions in the Wilkin Ridge area would probably be like Kenilworth, Aberdeen, Lower Mesaverde. And then we've seen the upper Mesaverde Wasatch be more spotty in that area. It doesn't mean there won't be completions in those intervals; they just won't be as reliable.

David Cameron: All right. And then you mentioned - you know, the Dakota Mancos test you're drilling, it's going to cost you \$7 million, total cap ex for the year is \$40 million, you know, you're 100% working interest. Why not sell down part of that well? And I know you can take it and still complete it; I mean obviously, you completed it up hole and get a couple of Bs out of it. But why not - you know, that's - whatever that number is 7 over 40 of your drilling program for the year, why not lesson your risk there?

Mark Erickson: We are looking to do that, David. The idea would be that if we bring a drilling partner in - and we are in discussions with several parties - that we would make that deal retroactive to the first of the year.

David Cameron: Oh, okay. Okay. That takes care of that question. Modest production growth; was I think in your prepared remarks. What does that mean? How modest are we for '07? Do you care to give us any guess at it?

Mark Erickson: I wouldn't I mean I know that from previous conversations, we felt pretty comfortable saying with 10 net wells that we could keep our production flat. And we are very comfortable with that. We've got a large inventory of behind pipe recompletions.

David Cameron: Okay. Yeah, that gives me a range, so I appreciate that. And then finally, production, can you talk a little more about the freeze-ups, some of the stuff going on as far as the weather-related issues, freeze-up of the pipelines, and just how that's impacted the first quarter and if that's all back on line or where you're at today?

Michael Decker: Yeah, David, this is Mike again. It was about a two-week stretch out in the field where the entire field was experiencing anywhere from 30 to 40 below temperatures. That's not wind-chill, that's just standing temperatures out in the field. And our field systems, in fact, the majority of the systems out there are designed for about 10 below. So this was an abnormally cold period of time. And during that time, we were seeing well freeze-ups. Our rigs were having trouble keeping heat in the system. And we probably were down about 50% of our production over the two-week period.

I'm pleased to say that we are now back all up, everything is flowing. And in fact, we have begun our program of putting additional plunger lifts in a few wells that were timely and that we had wanted to do at the end of the fourth quarter and we had to move to the first. So we are back in the normal field operations but it was really cold, I was out there, it was bitter cold.

David Cameron: Okay. And - so it sounds like today, everything is kind of back up and...

Michael Decker: That is correct.

David Cameron: Okay, good.

King Grant: And that - it's King, David.

David Cameron: Yes.

King Grant: It's - quarter to date, we are back kind of even with the same date - or same day in the fourth quarter.

Michael Decker: And that's a good point.

David Cameron: But the same...

Michael Decker: Yeah, quarter-over-quarter, if you compare the same time period, (unintelligible) flat right now.

Man: (Unintelligible).

David Cameron: Okay. Okay. And then, King, just confirm for me, I mean you're lower - your credit facility, irregardless of what happened to the PUDs, remains the same. Is that correct? I mean there's no change to the credit facility because they look - it only gets PDPs, not PUDs?

King Grant: The bank runs its own base price deck and sensitivity price deck. There's nothing in the documentation or in their credit - in their underwriting standards that tells them to look at the SEC PV-10. So it's a completely

independent evaluation. And they have completed their engineering evaluation and the engineers - you know, and the credit people, the bankers have - are recommending to the underwriting committee the \$37 million. And that's not a stretch.

David Cameron: Okay.

King Grant: There's a little bit more potentially if we were to ask for it. But we'll get redetermined again in about six months. So, you know, \$30 - the bank did not - has not changed its price deck from last summer. I'm glad they do it in February rather than the end of the year; otherwise, they might have lowered it. But we feel like we're in pretty good shape.

David Cameron: All right. And then last question, I promise, cap ex funding, and I know, Mark, you walked through this before, but can you - or King - or somebody walk me through \$40 million, kind of what's that look like from your standpoint? How do you get to \$40 funding internally back of the envelope type numbers?

King Grant: Back of the envelope, we ended the year with \$20 million in cash. We were cash flow and, you know, a million dollars or more a month. And then, you know, got - connects us to \$30 million available on the credit facility.

David Cameron: Oh, okay. Thank you. Okay, thanks. It sounds like you guys are making good operational progress.

Mark Erickson: Thank you.

David Cameron: Thanks.

Operator: Your next question comes from Chris Pikul with AG Edwards.

Chris Pikul: Thanks. I just wanted to follow-up on a couple things. The downspacing wells that you mentioned, Mike.

Michael Decker: Yes.

Chris Pikul: Would the potential reserve effect the incremental to, you know, the initial 3-P Report and the follow-up this past year?

Michael Decker: Well, in the - if you'd refer back to the 2-P Report that we updated last year, there was some 20-acre in-fill wells that were - or locations that were given credit for in that report.

Mark Erickson: In the probable category.

Michael Decker: In - yeah, they were - exactly, they were in the probable category, Chris.

Chris Pikul: Well, what about the 10 acres in the Lower Mesaverde?

Michael Decker: Well, the 10 acres, no, there would be nothing in that report for 10 acres.

Chris Pikul: Okay. And you're saying you drilled a well there and you thought there was very little communications that you noticed?

Michael Decker: Well, when I say the lower communications, based on well logs and correlating the well logs from the in-fill and its offsets, we saw little sand correlations between the two wells.

Chris Pikul: Okay. Okay.

Michael Decker: Okay? And we have not completed that well yet, Chris.

Chris Pikul: Fair enough. Fair enough.

Mark Erickson: The objective of the 20-acre drilling program is to move reserves from the probable category to the proved category.

Chris Pikul: Right. Right. Understood. All right. Given the efficiencies you're making on the - for the drill bit there, there's a - the particle drilling, does that still have any potential impact on your operations here?

Michael Decker: You know, at this point in time, you know, we're moving ahead, Chris, without that and just doing it strictly based on conventional technology. And we'll see where things head with particle drilling.

Chris Pikul: Okay, fair enough. Mike, can you just go over briefly how you plan to drill and sort of complete this Mancos well? Are you going to - you know, are you going - what kind of frac you're going to use? Are you going to isolate all these different zones and run things independently or open everything up or, you know, there's different members there, the Mancos, and maybe just give us a little education on that?

Michael Decker: Yes, yes, and yes, and, you know, Chris, at this point in time, I'm being a little facetious here, we don't know. We don't know what we're going to see in the wellbore. Okay? We don't know how much natural fraction, what type of sands we're going to see, based on, you know, the other operators in the area that are drilling some of those wells, we'll get some ideas. But beyond that, I won't know until the next quarter when we actually have logs and can begin to evaluate our completion strategy.

Chris Pikul: Okay. So...

Mark Erickson: You can ask us that question next quarter, Chris.

Chris Pikul: Presumably, by the end of the second quarter, you'd have some hard data there?

Michael Decker: Yes. I mean from our - the different log suites we'll be running, yes, we will have more firm data. That will be a good question to lead with next quarter, Chris.

Chris Pikul: Fair enough. And lastly, I just wanted to run through on your potential reserve scenario here under the higher price, you sight 124 Bs, which would be a net increase of roughly 47, you know, call it 50 Bcf. Can you run through, you know, how many wells you're adding to that? If you drilled sort of 18 net, you know, how many offsets you're booking and sort of what that kind of on a per well basis what you're contributing to reserves?

Mark Erickson: It - I believe it comes out where we would have I think something in the neighborhood of 60 to 80 PUDs and the reserves on a per well basis would range from 1.3 to 1.8 Bcf per well.

Chris Pikul: That are contributing to the proved under that pricing?

Mark Erickson: Correct. And it would not include any 28 acres downspacing.

Chris Pikul: Okay. All right.

Mark Erickson: We took about...

Chris Pikul: Thank you, gentlemen.

Michael Decker: You bet. Thank you, Chris.

Operator: Your last question comes from Rodney Clayton with JP Morgan.

Rodney Clayton: Hi. Just one follow-up. You know, given your capital constraints, are you committed to go ahead with the additional Wyoming well or would you consider maybe taking a capital in drilling some additional wells at Riverbend instead?

Michael Decker: Which well are you talking about, Rodney? Would it be the Billy Canyon one that we're talking about in the budget?

Rodney Clayton: Right.

Michael Decker: You know, at this point in time, the well has been cased at an intermediary casing point. And so I guess to answer your question, no, we don't have to go ahead and move on to that wellbore.

Rodney Clayton: Oh, okay. That's helpful. Thanks.

Michael Decker: Okay.

Operator: At this time, there are no further questions.

Mark Erickson: Thanks, everyone, for taking time to join us this morning. Thank you, thank you all.

Operator: This concludes today's conference call. You may now disconnect.

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