Black Hills Corp

October 08, 2015
02:00 PM EDT

Jerome Nichols: Good afternoon, everyone. Welcome to Black Hills Corporation's 2015 Analyst Day, being held here at the Warwick New York Hotel in New York City. My name is Jerome Nichols and I am the Director of Investor Relations for Black Hills.

On behalf of our leadership team and everyone at Black Hills, I want to thank all of you -- those on the webcast, and particularly those here at the hotel -- for taking the time out of your busy schedules to spend the afternoon with us. We're really excited about today's event and hope you'll find our presentations informative and helpful.

Slide 2 of our presentation deck has our meeting agenda. Our leadership team will provide an introduction and strategic overview, business segment presentations, and a financial update. After the coal mining presentation today, we'll take a short break.

We will hold a question -- a quick question-and-answer session after each presenter. We will also have plenty of time at the end of the presentation for final questions. If you are participating by webcast today, you can ask questions through the chat feature of your web player.

Our presentation today includes forward-looking information and the use of non-GAAP financial measures. You should refer to slide 3 of the presentation, as well as our filings with the Securities and Exchange Commission, for some of the risk factors that could cause future events to differ from our forward-looking statements. A reconciliation of non-GAAP measures is available in the appendix of our presentation materials.

As a reminder, today's event is being recorded, and the transcript and an audio recording will be available after the event at our website at www.blackhillscorp.com under the Investor Relations tab.

Our first presenter this afternoon is David Emery, Chairman, President and Chief Executive Officer. Dave?

David Emery: Thanks, Jerome, and welcome, everybody. Also, thanks to all those of you who are participating by webcast. We appreciate your attendance as well. And thanks for being here. We've got a room full of people, it looks like, so we appreciate you being here today.

Couple of things we want to accomplish today. And, you know, we have these events every year. We kind of alternate where we have them. This particular one, I think, the last time we were in New York City -- we were talking about it earlier -- while we sat here this afternoon, two years ago, we had five feet of snow at home and a huge outage to go home to. So, we're glad that it's nice and not doing that at home this time.

But, similar to prior years, we'd like to go into a little more depth about our businesses at this meeting; hopefully share some new things with you, which if you saw our release yesterday, we -- we're going to share a few new things with you today, and we usually try to do that every year, and give you a chance to meet a little bit broader section of our management team rather than just the couple of us that you're stuck with for the rest of the year. So, hopefully give you a chance to ask some others questions, besides just the normal cast of characters here.

We've got an exciting -- you know, an exciting growth plan, and we're very excited about it. We've got good base growth. We add to that the SourceGas opportunity, and it's something we're really enthused about. Hopefully you'll get a better feel for what that entails today as we go through it. I think we've got an excellent track record of executing on these types of transactions, integrating them quickly and being successful with them, which I think bodes really well for the future.

Briefly, to introduce the group that's here -- and you probably know some of us but maybe not all. Rich Kinzley, our CFO. John Benton's our Vice President and General Manager of our oil and gas company. Mark Lux is our Vice President of Power Delivery. That includes responsibility for our coal mine and our generation fleet. Brian Iverson is -- a really long title, but let's call it Regulatory and Assistant General Counsel. And then Linn Evans, our Chief Operating Officer, Utilities. And then, of course, Jerome's here, and Kimberly Nooney, our VP-Treasurer, is here. She can answer questions as well.

Couple of things that you saw in the release yesterday, on what our topics were going to be for the day. Obviously the SourceGas acquisition -- we've made a lot of progress on a lot of fronts. I'll let Linn fill you in on all the details there, but we feel real good about where we're at, both integration planning and regulatory-wise.

Cost of service gas program is something we've been talking about for a couple of years -- really, more like three or four. You saw that in the last month we filed in five of our six states. We'll file in the sixth one soon, and we'll fill you in on that.

Obviously oil and gas is something that we've made a pretty major transition of what we're trying to accomplish there this year, and that is a much greater focus on utility cost of service gas and a pretty dramatic reduction in regular E&P spending. You know, at the end of the last quarter we announced we'd cut $200 million of normal E&P CapEx out of the two-year forward forecast, and we'll -- instead focused on cost of service gas.

The Peak View wind project is a project that's been working in Colorado for most of a year, with multiple iterations with the Commission. We have a settlement agreement reached there. It has not been approved, but we feel pretty good about where we sit, and we'll give you an update on that. That's a project that is not in our current capital forecast. So, that's an exciting new addition.

And then the Colorado IPP review -- we'll talk about that, but we've had some inbound offers and inquiries about that property, and we think we might be able to divest the minority interest for a very healthy number, and makes a lot of sense in the context of financing SourceGas and some of the other things we have going on right now.

I think most of you, if not all, are familiar with the company. But, you know, we're primarily now a utility. We do have coal operations and oil and gas; a little bit of non-utility power generation.

But, for all practical purposes, our power generation fleet and our coal mine are integral to our utilities. Oil and gas is the only non-utility business that I would consider we really have. And as I mentioned earlier, we're transitioning that to be a utility cost of service gas company primarily. So, we're really very utility-focused and have been working on that pretty hard for more than ten years now.

We talked about having four major goals and objectives from a strategy standpoint. And we've had these four for several years. Very straightforward. Everything we do revolves around these four objectives. And that's profitable growth; valued service; obviously, better every day, which is continuous improvement; and a great workplace. We think the energy industry workplace will continue to get more competitive for really good people as a lot of folks retire over the next few years, so that's high on our list, and keeping talent.

This slide speaks a little bit to what I talked about from an execution standpoint. But if you go back 11 years, basically, to early 2004, we really made a very conscious decision as a company to start focusing on what we thought we were the best at, of everything we do, and that is running utilities.

And we've done a whole series of transactions subsequent to that -- either acquisitions; generation build; some bigger projects on the transmission side; and a few other things. And then a series of divestitures that were all pretty well-timed in order to effectuate that strategy. And I think it's been very successful.

Some of the things we're going to talk about today kind of get to the end of that line there, when you see what the impact of the SourceGas transaction's going to be. But it's been a long, continuous process, but it's been very deliberate.

Several things. When we look at, you know, what's bright about the future here, and it's really all about the growth opportunity. And that's not just adding on SourceGas; that's talking post-SourceGas opportunities. We felt really good about our growth track record anyway. We have a very strong record of growing our utilities. We have pretty good service territories; very constructive regulatory environments, and have been successful in growing our base utilities.

We will continue to focus on acquisitions where they make sense. We've done a lot of small tuck-in acquisitions, if you will. We'll look for the big ones, but they have to make a lot of sense for us. When you have to pay the multiples that we paid for SourceGas, you have to see a lot of opportunity to improve the business jointly as you combine those entities to really make that work. That one, we saw that opportunity.

Some of the other big ones we'd looked at in the couple of years prior to that, we didn't see that much opportunity, and we didn't buy them for that reason. So, we'll continue to focus on that. And then our organic growth in our base utilities -- we're going to really work on that; continue to make that a focus.

Technology is something, and we've talked about it a little bit in the past, but we're doing everything we can to keep costs down for ratepayers. If we can utilize technology and decrease ongoing cost to customers, that's a win-win. We make the technology investment for the shareholders; we save money for customers. We've had a lot of focus on improving our operations through automation and things like that.

Generation and transmission are things that we do a lot of. You've seen our track record there, where Mark and his group are fantastic in building power plants on time, on budget; or usually, ahead of schedule and ahead of budget. Something that, as we have continued justification, and we will, we'll continue building projects and growing our business through that, and transmission as well.

And then finally, the cost of service gas program which I mentioned earlier. That's an opportunity we're really excited about. Having a portion of your gas portfolio come from a cost of service gas program provides an excellent long-term hedge for customers, certainly provides an investment opportunity for shareholders, and still leaves over half of the gas supply to be procured through regular means. But it really gives them a good stability to their ongoing fuel costs as customers.

The SourceGas transaction -- you know, I'll let Linn and others talk about the details of the transaction. But one of the things I mentioned earlier is that, you know, we think we're pretty darn good at integrating utilities.

When we did our Aquila transaction in 2008, we did seven major systems conversions in a little over two years. And we were very deliberate in what we did. We picked platforms that not only worked well for the combined Aquila/Black Hills entity, but also platforms that we knew we could easily add a lot more customers onto without having to go through that process again. So, the acquisitions that we've done subsequent to then, we've literally just bolted all of those directly on our systems and processes. It's been very efficient.

The last one we did is an example that's a little smaller than SourceGas, but the process is the same. We purchased Energy West Wyoming July 1st. Only about 7,000 customers, but we had them fully on our systems -- everything from payroll, to accounting, to human resources, to customer information services -- on day one of closing. Phenomenal accomplishment. Process is the same to do that whether it's 7,000 customers or 700,000 customers.

We probably won't be able to do SourceGas quite that fast, because we have four states to convert all the customer information and tariffs and everything else; but we think we can do it very quickly. So, it's a huge advantage for us.

But in this environment, I mean, there's been a lot of things kind of acting -- impacting our business, I guess, if you will. Certainly the interest rates have had an impact on the whole sector, us included. But oil and gas prices have had a pretty big negative impact on us.

And as I said, that being our one kind of market-exposed business, it's hit us pretty hard. You look at the operating losses at E&P this year, and they're not good. You know, we've had a non-cash impairment of our reserves, and likely we'll have more as the year goes on. But, from a strategy perspective, I think we've remedied that for a go-forward strategy, and really focusing on cost of service gas instead, and it really kind of gets us out of that very heavy dependence on product prices.

The repositioning here, I already spoke about. But it's an area where, with our Mancos shale gas play, we think we have a huge resource, way more than we will use even for cost of service gas. And we've got a lot of testing under our belt here, and John'll talk about that. But with a few years of drilling -- and we've learned a lot about that play, and we think we can really transfer it into a very successful program for gas procurement for utilities.

From a stock performance perspective, obviously the last year hasn't been too good to us. Prior to that we've done very, very well, and I think we've got a great long-term track record, and a very bright future. Certainly our dividend track record is one of the things we're very proud of -- I think the second-longest streak in the utility industry for consecutive dividend increases. So, all in all, overall returns still look pretty good despite the big downturn in oil and gas over the last few years.

I think all of these things, I've already spoken about, so I won't reiterate them again other than to just say, we have a lot of exciting things on the plate for the future here, and you'll get a lot more detail from everyone else, and I'll let them fill you in on what those are and add a little color to it that I have skipped over. So, with that, I'll introduce Linn Evans, the President and COO of our utilities. Linn?

Linn Evans: Thank you, David, and good afternoon. For those of you on the webcast who may have a printed document, I'm going to start on what I think is slide 19 in the deck, at least. And I will talk about the utilities at a more specific level than Dave did. And then, after I'm finished, Brian Iverson will step up and talk about cost of service gas now that we have those filings in place, and the regulatory lift that we have there.

As Dave indicated, we have four categories of goals: profitable growth; valued service; better every day; and a great workplace. Not only do -- does that help us communicate our strategy externally, but it's very important for how we communicate our strategy internally, ensuring that we have our employees aligned with us and everything that we do.

We have goals down to the individual throughout the organization. We use that as part of our annual performance management process, and it's also an important part of our incentive compensation to ensure that we're all aligned for shareholders and customers alike.

We have, of course, many growth opportunities, as Dave has already suggested. We'll drill into those more independently as we go through the presentation. But valued service is something -- maybe stop and talk about for a minute, before we go into the growth items. We really strive to be top-quartile in everything we do, particularly with respect to operations, customer service and reliability.

We think we are doing that, and we're focused on continuing to improve. We're very focused on our relationships. Relationships are important to us, particularly with our customers; our regulators; our government entities; and importantly, the communities that we serve every day.

And as an organization, we're very focused on having a strong compliance culture. That's really important to us as an organization in terms of our values, and our employees know to do the right thing every day. And that impacts our relationships, obviously, with our regulators and our customers.

A great workplace is very important to us, as Dave has already suggested too. We're retiring a lot of people from this industry, including our own company, and we're working very hard to make sure that we can attract the best and the brightest to our organization.

Engagement -- employee engagement's very critical to us. We measure it. We measure it on a consistent basis. We put plans in place each year to help us continue to maintain the high-level engagement that we currently enjoy, and continue to improve upon it.

And we want to be one of the safest energy companies in the country. We're very serious about that goal. We've made great progress with respect to our safety performance over the last number of years. We have about 2,000 employees. We said today about 9 reportable incidents out of 2,000 employees. We're not world-class yet, but we're sneaking up on it and getting there as quickly as we can.

You've seen this slide before if you're familiar with our organization. It gives you an idea of our footprint for our electric utilities and our gas utilities, and the number of customers that we have in each.

If you look at the map for the natural gas utilities, you see new jurisdictions that we've already talked about a little bit: MGTC and Energy West. So, you see a little bit larger footprint in Wyoming. And of course SourceGas is going to add to that, and we'll talk about that in a few moments.

But I'm very proud of the team and how they performed with respect to integrating these this year. We are fully integrated on day one on our systems of billing, taking customer calls, et cetera. So, our team's done a phenomenal job of incorporating and integrating those two new utilities.

We thought this might be helpful to show you at least an economic indicator of the jurisdictions that we have the privilege to serve. Four of our seven states are in the top ten with respect to the lowest unemployment, and all seven of our current states that we serve happen to be in the top 20. So, good, decent growth within our -- the territories that we serve.

We work to give you more clarity and more detail, if you will, with respect to our capital investment. You can see that we've given capital investment back from 2011 through 2017 forecast. We've divided those into generation, transmission, and distribution, and other category.

We've also worked to give you an idea of what kind of riders we have with respect to capital investment, that essentially allows us to have a immediate return, eliminating regulatory lag as best as we can with respect to those investments. Now, this chart -- table does not include SourceGas; nor does it include our recently-announced Peak View wind project.

Growth through acquisitions. Very important to us. Obviously I'll drill into the SourceGas acquisition in a few -- in a couple more slides. We're also focused on what we call organic growth -- growth within our own utility, encouraging customers to use natural gas who may not; or convert from propane, et cetera; compressed natural gas stations -- things of that nature.

We have three different horizons that we look at: the near term, the mid term, and the long term. And then we have very specific goals that we have within the organization with respect to adding what we call Residential Meter Equivalents. That's essentially the amount of annual margin that we get from a typical residential customer in a given year.

And we don't just look to add revenue or margin. We put all of our investments in all of those customers that we seek through a financial analysis, to ensure that we're not just adding revenue but we're adding value for shareholders, and holding ourselves accountable to those models. And really, what we want to do is grow faster and more aggressively than the average utility in the US.

And we've had some track record with respect to that. This gives you an indication of our customer count and the volumes of usage. These usage -- these volumes are not weather-normalized. So, you can see in 2012 we had a pretty mild winter -- you might recall that -- with usage kind of rebounding from that point.

We're seeing our customer growth approaching 1%. And we're also seeing volumes at about 2%. And we're seeing an increase, as the chart indicates, in our electricity demand. I know there are some parts of the country that it seems to be a challenge, but for us it's not. In fact, we enjoy trying to keep up with it, to be frank.

SourceGas. A very exciting transaction for us -- one that we have looked at, frankly, for -- over the last five years. When the opportunity came, we took advantage of the opportunity to acquire SourceGas. We announced the transaction on July 12. It was for $1.89 billion. We do have $150 million of tax benefits which effectively lowers that price to $1.74 billion. And included in that is a $200 million, roughly, reimbursement for capital that SourceGas will spend by the time that it is closed. And the transaction, of course, also forecasts that we will absorb $720 million of debt.

The strategy -- this acquisition fits extremely well with our strategy. Later on I'll show you a slide of the footprint. You see how it fills in, very nicely, three of the four states that we serve, including the addition of Arkansas.

We're adding -- I don't know if it's (ph) 55% growth in our customer count. About 60% of those customers are in states that we already serve and territories that we already serve. And we believe this transaction -- we're working very hard to make sure it is meaningfully accretive to EPS in the first calendar year after we close.

Regulatory approvals are moving well. We have received Hart-Scott-Rodino antitrust clearance. We received that on August 18. And I'm very proud of the -- how hard our team worked to ensure that we filed approval applications very quickly and very efficiently in the states that we have applied for approval.

In fact, we announced on July 12. By August 10, we had filed applications in all four states. In each of those applications we requested a March 1 approval date. We have procedural orders in two of the states, Nebraska and Arkansas, that have hearings for January 12 and January 7 respectfully. And we are now currently seeking and working on procedural schedules in both Colorado and Wyoming.

We feel that, if we're fortunate enough to get settlements in all four states, it would be very easy for us to have a March 1 approval date for the transaction.

Discovery is ongoing. As you can imagine, in four states it's a lot of activity. We've had over 330-plus data requests. We have thoroughly -- we have responded to more than two-thirds of those, serving those on time. Usually you have a -- maybe a ten-day response time; sometimes as short as five. We worked very hard to respond on time, because we want the schedule to keep moving at a pace that we would appreciate, and give no reason for the regulators to slow us down, if you will.

We're working very hard on integration activities. We're integrating in four states and 425,000-plus customers into our system. The good news is, from our perspective, we've done this 19 times in the last ten years. We feel we're pretty good at it.

We don't want to get too big for our britches. Things can go wrong very quickly; but we have confidence in our processes, and the procedures, and frankly the leadership team, and the people we have working on these acquisitions. They worked on all the others prior to this one. We have about 15 different teams of people led by people who has led, frankly, these last 19 acquisitions. So, this is number 20 through 23 that we're working on now.

Confident in their abilities, and what they're doing. Working very hard. And things are going well, and essentially on track to where we want to be at this point in time. And importantly, we will be migrating all of SourceGas's datas and processes, as Dave indicated, onto our systems. So, this will be a fully-integrated utility.

The map says a lot in terms of the transaction for us. You can see the three states that we already serve -- how it's a great fill-in opportunity for us with respect to being a more efficient utility, and a utility with greater scale, as we move to 1.2 million customers. So -- and I think we -- customers are going to greatly benefit from this transaction.

We see SourceGas as having great growth opportunities. SourceGas itself has grown at 2% annual customer growth. We expect that to continue. They have processes and procedures that are very focused on growing a natural gas utility. We're excited by those. We think they will enhance our own processes and procedures with how we see growing a utility.

And interestingly, they use RMEs as their own measurement as well. So, they anticipate adding 11,300 Residential Margin Equivalents annually. They have extremely good or very good fuel conversion programs, converting other fuels like propane, et cetera, to natural gas.

They also have good programs and processes that allow them to aggressively go after agriculture, particularly poultry customers. And then some very good tariffs with respect to main extensions allow us to continue to grow the system. And it's going to bring to us pipeline and storage investment opportunities that we haven't had before.

And then finally, as Brian will talk about later, we do see a good opportunity for a future cost of gas service -- cost of service gas program, and the potential there with the acquisition.

And in fact, I mentioned, we're already in three of the four states, but we're adding Arkansas. We've learned a lot about Arkansas over the last several months and we're excited about that state. Fayetteville will be a town that we will serve. It's located in Washington County, Arkansas. We are informed that that's the seventh-fastest growing county in the US. So, great growth potential there, and we're very excited about that.

SourceGas. Much like ourselves (ph) -- like Black Hills, does have a constructive regulatory environment. You can see some of the cost recovery mechanisms that are in place, very similar to those that we have in our territory, so that's going to match very well with Black Hills.

And then transitioning back to growth. Growing through efficiency. As our population in our organization -- our employee population ages, we see great opportunity for us to invest in technology, and we've been doing that quite aggressively as an organization.

We see it as an investment that allows us to lower our pass-through costs and our O&M costs by investing capital, which means it's a win for the shareholders and a win for the customers as well. We put these programs through rigorous financial models and then we check on ourselves constantly to make sure we're getting the returns that we anticipated. If we're not, we make adjustments, and when we are, we're very happy about that, obviously. It also helps us lower our costs.

We were focused kind of in three categories: customer service, our grid, and our field operations. We focus on our customer operations -- lowering our customer service cost, while making it easy to do to business with us. So, our customers see the opportunity to improve how we do business with them and how we interact with them, while we lower our cost.

Improving reliability's important to us. Our AMR and our AMI, particularly, help us with that.

And then, most recently, we have been putting technology into the hands of the field employee. We have launched hundreds and hundreds of iPads. Every employee has iPad in the field, with all the data they need to do their job well. And we've also used that data and that information to improve how we dispatch employees -- much more automated. So, our field knowledge is better. Our efficiencies in the field with how we use labor and how we use equipment, has much improved. As you can see, some of the dramatic improvements in our performance of late.

We're always interested in building new things, particularly generation, transmission, pipelines, et cetera. These are some of the few examples on slide 32.

I will drill into the Cheyenne Light, Fuel & Power and some of the Colorado Electric stuff; but let me touch on the Black Hills Power transmission line before I move forward. We are working to construct a 144-mile, $54 million electric transmission line that's essentially a transmission line that will help us with reliability after having closed a couple of our older coal plants. That line should be in operation by mid-2016.

Looking at Colorado Electric on slide 33, we have two great growth opportunities. The first is one we're already working on. That's the 40-megawatt, $65 million natural gas-fired combustion turbine that we are currently building at the Pueblo Airport Generation Station. It's essentially a plant that will replace the W.N. Clark plant, which was a coal plant that we retired a couple of years ago, located in Cañon City, Colorado.

That construction and that project is on time and on budget. It represents our 19th project in about that many years. And it will be commercially operational the fourth quarter of next year, so I'm very proud of our team and what they're doing there.

We just recently announced a settlement agreement that we filed on September 24th with respect to our Wind Peak wind project. Colorado has a renewable energy standard of 30% by the year 2020. This gets us along that path of complying with that renewable energy standard.

As I said, we filed the settlement agreement with all intervening parties. The Commission, we anticipate deliberating this month. We hope to have an order next month. And the project will be purchased from a developer. It represents a $109 million investment if you include our interconnection cost and our AFUDC.

Cheyenne Light. Cheyenne continues to be a bright star in our portfolio of jurisdictions and utilities. It's growing quite rapidly for us. In fact, this year, this summer, Cheyenne Light set three peak records consecutively, with pretty doggone mild weather for Cheyenne. So, weather was not a big impact in demonstrating the load growth that we are seeing there.

And Microsoft happens to be one of the leaders with respect to growing that load for us and with us. To date, Microsoft has committed about $500 million of investment in data centers. They have announced another $250 million in investment -- will take their total investment to $750 million.

We're going to serve that load in a couple of different ways, being creative with Microsoft to encourage them to continue to grow and develop, while making sure that we have good returns for our shareholders. So, the first 35 megawatts of load, we're serving under a normal, or currently existing industrial contract services tariff. After 35 megawatts, they -- anything in excess of that will be served under a new proposed, what we call large power contract service agreement tariff. We filed that tariff on October 1 and we anticipate and hope that it will be effective by January 1, 2016.

Along with this growth and the investment that they make in terms of infrastructure, we're making our own infrastructure investment as well. As you can imagine, substations and transmissions, et cetera. So, it's a very good, and great opportunity for us at Cheyenne Light.

This slide attempts to combine all three of our electric utilities -- give you an idea of our capacity and our current energy demand, and where we forecast that it's going. You can see in the base load -- we've closed a number of base load plants, particularly coal plants, the last couple of years. So, we do see, hopefully, some opportunity in the near future to begin to fill in that base load capacity that we are now short. And these are not weather-adjusted, these are actual peaks, by the way.

And then, now, moving into the regulatory arena, before Brian comes up. We've shown you this slide before, but we have worked hard within our regulatory relationships to provide pass-through mechanisms that allow us to eliminate, as best we can, regulatory lag within our utilities.

Now, Brian's going to come up and talk about -- well, I think that I'm supposed to stop -- slow down and ask if there were questions first. So, any questions at this point, before I run away? Mike.

Unidentified Participant: Thanks, Linn. With regard to the $600 million of long-term pipeline safety and integrity investment that's gas source, how much of that is -- has been approved, or what is the process of getting that approved if it's not?

Linn Evans: I'm not aware that any of it has been approved, Michael. It's all capital investment that primarily SourceGas management has identified. We're reviewing it now. We think it looks -- you know, very legitimate capital opportunity. And it would be capital investment that we believe would largely be through riders and tariffs that they have in place over the long term. So, we're early in that process, and clearly identifying that what we see looks very legitimate and will be a good investment for us going forward.

Unidentified Participant: I don't (inaudible) Brian or not, but when are the right points for settlement discussions to take place in SourceGas? And, if you do not have four settlements done, what are the odds that March 1st slips (inaudible)?

Linn Evans: The question was, what are the -- what kind of -- what's the process procedure with respect to settlements in SourceGas, and what's the prospect of maybe a March 1 date slipping?

We think the prospects are quite good, particularly in the states that we've talked -- we've met on a number of opportunities and times with the Commissions, and with staff, with interveners including Office of Consumer Counsel. They know us, in three of the four states. They know us well. And we anticipate that we will use those relationships that we have now to continue to talk to them about settlement.

In some states the word has already come up, and so we're beginning to have those discussions, if you will, already. It's very early in the process. We're -- still owe them responses to some data requests. They tend to like to get those in place.

But we feel pretty good, subject to anything that might come along and surprise us with respect to getting settlements in all four states. And we are very focused as an organization on the March 1 closing.

Unidentified Participant: Do you need to go through hearings, or what's the protocol in the different states, as far as where you've seen settlements (inaudible)?

Linn Evans: The question is, do you go through hearings when you have settlements? The question is, oftentimes yes. They tend to be abbreviated hearings. So, usually the --

Unidentified Participant: Do you have to have the hearings before you can move to the settlements --

Linn Evans: Oh, I'm sorry.

Unidentified Participant: (Inaudible) states (inaudible) settle before the hearings?

Linn Evans: The question -- let me clarify. The question was, do we have settlements before the hearings or after? The answer would be, before the hearings, in all those states. We hope that the hearing would be essentially turned into a settlement hearing.

Unidentified Participant: If the Peak Wind project is approved by the Commission, would that be in a rate case early next year for implementation, I guess, late in '16, for Colorado?

Brian Iverson: Rate case timing.

Unidentified Participant: Yes.

Brian Iverson: This is Brian. That -- the settlement agreement in that -- so, this is public record -- works to pass the cost associated with that wind farm through, in Colorado, the ECA, and through our renewable energy rider. And so, all the costs get passed through on the rider. So, no rate case involved with putting that $100 million investment into service.

Unidentified Participant: And then when you're talking about future load and capacity -- I guess, capacity shortfall -- would the expansion of the Cheyenne Prairie Generating Station be one of the major potential expansion opportunities?

Linn Evans~~Brian Iverson~~: It could be very possible, yes. We have plenty of territory -- land, if you will -- to expand upon. And we have air permits in place that we could use if we chose to.

Jerome Nichols: We had a question from one our webcast participants. And the question is, can you explain the $150 million of tax benefits that will lower the effective price of SourceGas acquisition?

Rich Kinzley: Yes. This is Rich Kinzley. I'm live here? You can hear it?

Unidentified Participant: Yes.

Rich Kinzley: Okay. What that is -- it's a combination of two things. But it's the net present value of net operating loss carried forwards as part of the acquisition; and then additionally, we get to do a step-up on part of the acquisition. So, the tax benefits derive from both of those, creating that present value of approximately $150 million.

Jerome Nichols: Any other questions? All right.

Brian Iverson: Okay. Thanks, Linn. Good afternoon. Going to talk a little bit this afternoon about cost of service gas. It's something we've been talking about, and really made some good progress here, then, in the last month, of taking the next steps towards doing that.

We've spent the last couple of years really looking at the process, looking at what other people are doing. We've had about 18 meetings with the different consumer advocates, Commissions, Commission staff, and people -- other stakeholders in this.

And that all culminated, then, in September 30, of us filing in five of the six jurisdictions. ~~at~~ Colorado~~.~~, ~~W~~we had some ongoing docket activity going on, and so have -- delaying that till later in the month. But, once again, those are all ready to roll and the filings will be made and completed by the end of October here.

So, what the contract -- what the filings really cover, just to kind of give you a little bit of color and background on how this works, is a -- really, a prepackaged set of determination of, how does the relationship work between a non-regulated affiliate that's going to own the resources, and the utilities that are going to basically get the benefit of the resource?

And so, what we've done is provided new tariffs for the Commission to review. We've provided mechanisms on how we would transfer property into that and set up a more timely process to go through, with a 60-day window to, once we identify a property and have it turned in to the Commission, for there to be an approval process, so that we can move assets into that. Those assets could include some of our Piceance Mancos assets could include some third-party assets too. So, it's really made generic filing, to basically be able to provide the ownership of rate-based reserves for the benefit of customers.

Just to go a little bit further, in our case it's a non-affiliated provider. It's going to be owned by Black Hills Utility Holding Company, which is the actual holding company of our utilities. And the reason you do that is, there's tax benefits that you get from having it not being fully integrated in with the utilities.

The other practical benefit is, as you look at the utilities themselves, they're each going to have a fractional interest in what might be there. And so, it's just a lot easier to own it under one entity and then divvy it up under contract between the different utilities.

The other piece of our filings that we think is unique is, unlike a lot of utility companies, we've got 30 years of experience in the oil and gas business. And I think, when we've been having these conversations with our regulators, that's been something that you kind of wonder how they'll take that, because we're in the business -- you're in a utility business affiliate; questions always come up.

But they've really seen that as a positive view, in that we know what the business is about; we know how it operates; we understand the financials behind it; we understand the operations behind them. So, that's been a positive.

The other piece about the filings -- when you look at the long-term cost of gas, we all are -- have been exposed to what happens in the market. Long-term, we believe that this is going to provide more stable prices, and what a better time than right now to actually start getting into that program for the benefit of customers?

So, it's really a win-win in that you provide a stability of cost for customers, but also provide a great investment opportunity for utilities. You know, in particular, gas utilities, you've got integrity investment; you've got other things. But growth has been on the slower side. This is a great opportunity to really pick up that growth and provide more earnings potential out of a gas LDC. And we're also going to use it for part of our electric generation too. So, any of our gas fuel generation,~~.~~ ~~A~~and of course, with 111(d) and other items pushing out there, it's going to create some great opportunities in that respect.

Go to the next page here -- kind of give you an idea of how this works. We're not going to sell the physical gas to our affiliated utilities. So, it's going to be a financial structure. The resources will be owned and backed by physical assets, but the cost of service gas company that we're going to have will actually sell that gas into the market and provide a credit; or, if it's the other way round, provide an adder (ph) to the bill for the customers. And that'll flow through the -- our gas cost adjustments or electric cost adjustments.

So, just looking at some of these things here -- the filings propose that we put the resources in, and it's for the life of the well. So, these are 20-plus-year-type arrangements that we'll get into these programs. We're going to submit a billing -- a drilling program to the Commissions as part of this process, which will be approved.

And once we get that, every five years we'll go and file a new drilling program to tell them what we're going to be up to. So, it really kind of gives them an idea or a runway of what kind of capital costs and what kind of expenses they should expect.

When we look at the financial aspects of this to the company itself, we're going to target 50% of the demand, and we've got a slide a little later on that covers what that is, and we'll talk about it a little more. We're going to use the cost of debt -- typically it's going to be our -- we finance at the corporate level, so it'll be the corporate cost of debt. If we have any specifically-identified financing for this particular entity, that will be blended in there.

The capital structure -- what we propose is a 60% equity capital structure. We think that that is kind of a hybrid between what a utility capital structure would be, and an E&P-type structure. And so, it appropriately matches the kind of credit quality that you want to get out of this process.

Then, as I mentioned, the recovery mechanisms are through ECAs and the GCA. So, it's contemporaneous filing. We file those anywhere from every month to twice a year in the different states, depending on what the jurisdiction, and if it's gas or electric.

Jumping over to the right a little bit on that slide, we want to talk about the allowed return. What we've done is, instead of, as you might be familiar with in a typical rate case, you have expert testimony and you talk about equity returns a lot. And what we've done is try to make this a streamlined process, since it's going to be flowing through ECAs and PGAs, to really go back and look at the last 20 approved rate cases across the US, both gas and electric, and use the average of those to determine the cost of equity for this program. So, that will be the number.

If you did that today, it would be approximately 9.86% ROE on it, if you just did it today with the ROEs that have been out there, in the -- you know, the lower interest rate environment that we're in today.

The other piece of the return that we have built into this is kind of an incentive mechanism. So, to the extent that customers are getting a bill -- a credit on their bills as part of this PGA/ECA, we have the right under the contract to earn basically an extra 100 basis points.

So, instead of using that 9.86% that we talked about, it would be a 10.86% return. And that would adjust, you know, depending on what the -- what that allowed return is every year. By the same token, if the customers are seeing an adder (ph) onto their bill because of the program, we would then reduce the ROE for that piece of it by 100 basis points.

So, it really kind of provides that incentive -- makes it -- gives the regulators comfort with how the program's operating, that we're going to be motivated to do this in the best possible way. Gives us an opportunity, certainly in higher market environments, to actually enhance the return for this entity.

The other thing that we propose to help give comfort to the regulators is just third-party oversight. So, we're going to have hydrocarbon monitor, which is really the engineers, that would weigh in -- and this is particularly important in the process of when we're going to transfer reserves in.

That's -- hydrocarbon monitor would review it; validate our information, which then gives us that shorter timeframe for Commissions to approve the addition of reserves into the program. And then, of course, an accounting monitor, which goes through and helps audit and verify any of the filings that we would make, both the financials on the -- related to the engineering reports, but also in regards to the regular pass-on products.

You go on to this, and you've seen this slide before from us. There's a lot of other places that this is being done. It's -- certainly, with all the discussions we've had with the regulators, there hasn't been any questions that say, you know, this is really, really unique -- are you sure it's going to be work?

There's all kinds of -- whether it be down in Florida; Northwest Natural out in Oregon has done this; the -- LA Power and Water's been doing this for probably a decade. And so, there's a lot of precedents for owning resources for the benefit of your customers, to give them that long-term hedge.

Then, just gives you kind of an idea of the quantity that we have. This is based upon 2014 actual. You know, you'll notice this can go up and down as it goes along. About 75 Bs is our actual gas supply. And what we've proposed in the filings is that we would use -- we're suggesting that we work to get up to half of the supply through this program. And so, that's that 37.85 number you see on there.

So, to give you an idea of an order of magnitude, you know, one of the assets we've talked about transferring over into this, or using it -- this is the Mancos. You know -- and the other piece you look is that 37 Bs a year -- if you look at the potential resource that we have in the Mancos, still leaves plenty of other resource out there. That's just a fraction of what -- the resource we have in the Mancos itself. So, to look at, can you do this program; how do you get it done, there's plenty of gas out there to make it work.

And this last slide -- just to kind of an idea of -- you know, you've seen the history, and certainly back in that 2006, 2007, 2008, when everybody was looking at $20 gas prices, the technologies are -- $20 natural gas prices, that technology has certainly come down, and the shale gas formations have really been exploited to the point where they've made it much more efficient. But we still look to see that. Absent a program like this, you're going to see, you know, history kind of repeat itself.

And the goal through our cost of service gas program is to provide something more like the right-hand side of that slide there, to provide more stable prices for our customers; but also to give a great investment opportunity for the utilities.

I think what we've said in the past is, we've estimated, you know, between $1 to $2 per Mcf of investment opportunity for what we would supply here. So, with that, I'll take any questions that you may have, and -- Nancy?

~~Unidentified Participant~~Nancy Doyle – MetLife: How do you decide what assets to buy to put into this program? Do you have to justify that your -- say, your Mancos assets, are the cheapest source? Because there must be lots of assets for sale, to go into this program.

Brian Iverson: Yes. So, there are criteria that we have in the contract between the utilities and the cost of service gas company, that talk about the kinds of properties that we've looked for. And they've got to pass some financial tests. Okay? So, the PVs of the reserves and the cost of drilling and things like that, has to be -- meet certain criteria.

But as we look at that, we also look at -- one of the advantages is that we're going to own it and have operational expertise over the property. So, we typically would favor properties that we're going to own and operate in this context. And certainly the cost of service gas company isn't (ph) going to own anything. It's not a program which we take a working interest in, and apply that. There are other programs that work like that. That's not what we propose. So, there are financial metrics that we'd have to meet (ph), is the short answer. Chris?

Chris Turnure: Chris Turnure, JPMorgan. I just wanted to get a sense, if you in fact do it with your own properties, how do you determine the -- essentially, the cost of the asset itself? Is it just book value that's depreciated over time, and that's the return on capital?

Brian Iverson: It would be a formula that we use to -- basically, an evaluation with, you know, engineers and a financial present value. You know, it's a future (inaudible) kind of cash flow kind of analysis that we do. So, it wouldn't necessarily be the book value on our -- of our assets.

Chris Turnure: Okay. And can you talk a little bit more about the timing of hopefully getting approval in all six states here?

Brian Iverson: Yes. Thanks for that. So, we filed on September 30th. We'll be filing later this month. If you look, you know, reasonably, it's an eight- to ten-month process.

You know, I would hope that, as we look in the mid of next year, we're getting to the point where we're -- I would expect in the second and third quarter of next year, we're talking seriously about settlement, and really, they should understand the program and get it to that next point, so we have approvals in the third quarter.

We do have about $50 million of capital in our forward capital plan for next year, to deploy in this program, if you look back at the slides that Linn had; and also $100 million in 2017. So, we expect to get going on this in the third quarter (inaudible) next year.

Unidentified Participant: With respect to including your Mancos assets in the program, do you think regulators see advantages to that coming out of the gate, or are they going to be looking at that on a level playing field with whatever other assets may be available?

Brian Iverson: That -- I think -- you know, certainly, we -- and John will get into this a little more. We've got a lot of experience and understand those assets fairly well. And so, it's going to get into demonstrating the financial model around those assets, and if they make sense to put in, I don't think there'll be issues there.

But we haven't -- we also haven't closed our eyes or our vision to, you know, looking at other things that make sense in that. For us, you know, it's an opportunity to invest capital from the utilities perspective. Where that capital is invested, as long as it goes through the process and we get recovery on it, we really should be indifferent.

Jerome Nichols: We have a couple of questions from our webcast participants. The first question is, what percentage of annual gas supply is currently under long-term contract?

Brian Iverson: Under long-term contract, we don't have any.

Jerome Nichols: Very good. Second question is, you mentioned that one of the benefits of cost of service gas model is, that can help stabilize prices. Do you see -- foresee much price instability in natural gas in the coming years?

Brian Iverson: That's the, what, $62,000 question. You know, you guess -- you don't know about it until they come across it. If you look at some of the market forces out there, certainly the drilling technology's getting (ph) great. These shale plays have become -- it's not a matter of, if there's gas; it's more a matter of, how do you most economically get it out?

But you look at things like 111(d) -- the transformation from a coal generation fleet to a gas fleet. I think that's going to have significant impact. You do see -- so, I think most forecasts show a pretty steady, slight uptick in the forward cost of gas. But I think if you look at every forecast, it's right until the next day, and then it's wrong. So --

Jerome Nichols: All right. One last question. Your -- it says, your slides show cost of service gas CapEx of $100 million in 2017. If and when the program is fully implemented, is it fair to think about it as $200 million annual capital expenditures, 60% equity, and low double-digit return on equity?

Unidentified Participant: $1 to $2.

~~Brian Iverson~~Rich Kinzley: Yes. What we've been talking about's $1 to $2 per Mcf. And you can see the -- 50% of our demand's in that 35 Bcf range. That would be kind of the ongoing CapEx, probably. We would have to spend a little more on the front end, more than likely, to get built up to that level of production.

Brian Iverson~~Unidentified Participant~~: But that rate base model of how you would analyze what kind of income you'd get off of it, would be accurate?

Unidentified Participant: Just understand the ownership structure. So, the utilities don't own the reserves. The separate entity does. You guys (ph) are facing these delays (ph) on a financial contract that is delivered upon by the central entity that owns the reserves?

Brian Iverson: That's correct. So, the ultimate owner of all the entities is the Black Hills Utility Holdings. It's the intermediate holding company that we have, that owns the utilities. It also own the entity that's doing the drilling, and owning the reserves.

Unidentified Participant: And what are the performance requirements for production, right? So, you guys go into agreement on (inaudible) approve the project. What is the performance on -- drilling performance on (inaudible) performance on (inaudible)?

Brian Iverson: There are no restrictions on the agreement that we -- already met. So, basically, what you get into is, are you -- you know, it gets more of a prudency-type (ph) issue. You know, you identify the property, and you go out and you conduct a drilling program that you've identified -- your five-year drilling program. If you comply with that program and go along, that's what gets put into the program. So, you could have -- if you have a bad well, that's part of the process. You may have really good wells. They get the full benefit of the well.

Unidentified Participant: So, that would all get loaded into the cost of the program.

Brian Iverson: Right (ph).

Unidentified Participant: So, the -- like, a bad well gets sucked in and spread out over everything else.

Brian Iverson: Right.

Unidentified Participant: So, you guys don't carry exposure to that.

Brian Iverson: That's correct. So, what it gets to is, if you look at the returns of these kind of businesses, if you're taking that kind of risk, you're going to demand a higher than a utility return. So, what we've tried to do is look at this program and say, if you structure it this way, we're willing to accept that utility type of return on the program.

If it were a different kind of structure -- say, like the Questar model that they've got, which has got a higher return but there's some dry hole risk and things like that in that program. So, what we try to do is match up the business risk profile with the returns we'd ask for out of the program.

Unidentified Participant: At the $1 to $2 per Mcf cost of -- capital cost, going into this.

Brian Iverson: Uh-huh. Correct.

Unidentified Participant: What do you guys estimate is the delivered cost of the gas under this construct, if you look at, you know, drilling programs and further expansion on what you guys have? (Inaudible).

Brian Iverson: Yes. I don't know if we've talked about that. But maybe, Dave, you want to --

David Emery: Yes. You know, we've talked a little bit about it, Dan (ph), and said, you know, if we look back at our historical cost of gas delivered to utilities, and even in recent -- like this year, when that price is relatively low, it's not a spot price. Right?

So, you know, our real bogey is, we've got to be in that probably $4 to $4.50 range; maybe as high as $5. But, you know, you have to be at that number or really less, in order for this to really be a good, long-term, viable deal for customers. And those are the kind of numbers we've had conversations with our regulators about.

You know, look back at, what's the actual all-in delivered cost of gas for our utilities today? We buy gas in three ways for our utilities today. So, roughly a third of the gas comes from open market purchases, which sometimes can be awful expensive. A third of it comes from seasonal storage. And a third of it comes from financial hedges that are typically one year ahead. And the weighted average of those runs in that kind of a range, as far as what we're actually charging -- what the actual cost of gas is to our utilities. So, if we're in that range, we don't think we'll have a lot of challenges with this program.

Brian Iverson: And we've had that discussion -- you know, the bogey here is not the NYMEX cost, because customers pay more than that today, and we've had those specific discussions with regulators. So, what you get at is our -- regardless of the market conditions, they're going to pay the cost for this portion of their gas supply.

So, if it's $4.50 and gas is at $6, they're going to get $1.50 credit for each Mcf that they might have to buy. And if they're buying that for $6, it takes it back to $4.50.

David Emery: And that's the other thing that we've said about this going forward, is this piece will largely replace a lot of the hedging and the storage pieces of this, and some of the open market purchases. So, we'll probably have a little storage left, a little open market purchases, and maybe some hedging, but not a lot, depending on the state. And this is going to be the big, stable piece that would replace some of those other mechanisms that we use today.

Brian Iverson: Remember, they only get that protection for that one season. So, see -- if you did have a spike or issues in the supply chain, they only have that one season of protection for customers. And that's been the problem before.

Unidentified Participant: When you guys comp to the above or below on the ROE band, right -- so, the delivered cost of gas you're going to compare against -- is that what the other half of gas cost for the customer is over that time period? Or, how do you set the reference gas price to see (inaudible)?

Brian Iverson: It's really on, sort of (ph), getting that credit. If the customers are getting a credit, we get an enhanced return. If they're getting an add-on to their bill, it -- you know, in total, it's the reduced return. You're going to sell it, and if you're --

Unidentified Participant: (Inaudible) reference price gas is, I guess, my (inaudible).

Brian Iverson: Well, it's going to depend on what our cost to produce is. So, it's going to be directly tied to the cost to produce. If that's lower than market, you're going to generate that enhanced return. If it's higher than the market today, you're going to take the hit on the 100 basis points.

Unidentified Participant: And the market today would be $5 for you guys? Is that the right market reference price, given your delivered cost of gas, roughly?

Brian Iverson: Delivered cost of gas is probably a little lower than that.

David Emery: Lower than that.

Brian Iverson: Yes.

David Emery: $4s.

Brian Iverson: In the -- yes, in $4s. Any other questions? Okay. With that, I'll turn it over to Mark Lux, our Vice President of Power Delivery, to talk about some load generation projects.

Mark Lux: Well thank you, Brian, and good afternoon and thank you all for joining us today. It's a privilege for me to present Black Hills Corporation's business focus and strategy for two of the three non-regulated business segments, power generation and coal mining.

So, for the next ten minutes or so, you'll be hearing a little bit about the power generation business and our plan for continued profitability. We're going to spend a little bit of time on the new EPA rule, 111(d), and the impacts and opportunities that that creates for Black Hills Corporation. And then we'll conclude with just a brief update on our coal mining business segment.

Starting on slide 44, we describe the power generation business segment. The corporation's power generation business is vertically integrated and an extension of our utility business. We provide profitability as an energy partner of choice, contracting long-term capacity and energy supply to our affiliate electric utilities as an extension to that utility business, as Linn described earlier today.

In Wyoming we own 76½% of the Wygen I power plant, which is a 90-megawatt coal-fired power plant that's contracted to our affiliate utility, Cheyenne Light, Fuel & Power through 2022.

In Colorado we own 100% of the Pueblo Airport Generating Station, a 200-megawatt natural gas combined cycle facility. And that's contracted to our affiliate utility, Black Hills Colorado Electric, through 2031.

We also provide energy service solutions to municipalities. In Wyoming we operate, dispatch and share in market economic energy savings from the City of Gillette's 40-megawatt natural gas-fired simple cycle unit, located at our Gillette, Wyoming energy complex. These operation services are contracted to the City with a long-term economy energy purchase power agreement through 2034.

Very simply, our power generation is an energy solution provider of choice in the utility regions we serve. We provide efficiency by duplicating smaller plant facilities and managing the corporation's generation assets with one core and centralized management team.

We focus and prefer to duplicate our generating fleet designs at our existing brownfield facilities like our Cheyenne Prairie Generating Station, and with our proven record of developing, permitting, and constructing and operating power generation projects, we have demonstrated significant customer savings with successfully executing profitable generation investments.

On slide 45, our strategy is defined and is very clear. We focus on profitable growth within our geographic utility regions of our electric and natural gas utilities. We provide valued customer service while getting better every day, expanding energy partnerships, and we ensure we have a great place to work as the safest energy company in the nation.

Our growth strategy in power generation remains consistent. We sell power plant capacity and energy under long-term tolling arrangements to our affiliate utilities and other utilities in our regions; we provide energy operation services to municipalities under long-term service agreements; and we can provide energy solutions utilizing distributive energy resources within our utility geographic footprint.

On slide 46 and 47, we'll provide you brief~~ly~~ updates on two of the major power projects that have already previously been discussed. Slide 46 is the $65 million investment in a 40-megawatt natural gas-fired peaking unit for Black Hills Colorado Electric, located at our Pueblo Airport Generating Station in Pueblo, Colorado. As previously mentioned, this project was required to replace W.N. Clark as a result of the Clean Air, Clean Jobs statute in the state of Colorado, and our plan to comply with that state law.

This project is 21% complete, on budget and on schedule, for commercial operation in January 2007 (ph). And more importantly, our regulatory team has done a great job in getting cost recovery of this project in the construction cost throughout the construction period, so that we don't have any regulatory lag on the return on investment that we're making in this project.

Slide 47 is a depiction of our $109 million investment in the 60-megawatt Peak View project. This project is being developed again for Black Hills Colorado Electric to comply with the Colorado renewable energy standard, which mandates 30% renewable energy supply by 2020. Currently, Black Hills Colorado Electric is required to meet 20% of that 30%, and this will increase to 30% requirement in 2020, providing future renewable energy project investment opportunities.

The Peak View project, as mentioned, is currently awaiting approval from the Colorado Public Utility Commission, which we anticipate in November this year. And in the meantime, we continue to develop that project, and remain on schedule and on budget, ensuring that we have the safe harbor investment required to preserve the production tax credits which provide value as part of this economic investment. Again, as previously mentioned, this $109 million project is not included in the current forecasts of capital that have been presented previously.

In August of this year, the Clean Power Plan was issued by the EPA. Slide 48 briefly describes this rule. The plan simply requires greenhouse gas emission reductions beginning in 2022 through 2030, and impacts selected power plants across the nation.

For Black Hills Corporation, the units that are impacted are our coal plants at our Gillette, Wyoming energy complex, and two of our combined cycle units, one in Cheyenne, Wyoming, and one in Pueblo, Colorado. Our remaining generation fleet of simple cycle generating units are not impacted by this rule.

The rule simply requires more renewable generation and less coal-fired generation, with increased utilization of combined cycle natural gas-fired generation beginning in '22 and increasing through the year 2030. The plan requires states to file implementation plans for reductions, either through a rate base, which means pounds of CO_2 per megawatt generated, or mass-based, meaning tons of CO_2 emitted, both on an annual basis.

Within the context of the rule, it appears to Black Hills that regional mass-based programs are encouraged. Under either a rate- or mass-based approach, Black Hills can operate and re-dispatch its existing diversified modern generation fleet to comply with the state's emissions reduction required by this new rule.

Slide 49 describes the actions and expected compliance requirements that we'll have to meet in order to comply with the new EPA rule. As mentioned, EPA is clearly leaning towards a mass-based regional approach, and Black Hills is actively engaged in the discussion and formulation of the state's implementation plans for compliance with this rule.

With their new modern fleet of coal plants, compliance impacts will start first by the EPA's defined Building Block 1, which is energy efficiency improvement. Energy efficiency improvements of coal plants will be very minimal for Black Hills Corporation because of our modern, newer fleet of coal-fired power generation.

EPA's second Building Block 2 will require us to increase utilization of natural gas, as Brian previously discussed. So, we will see increased utilization of our combined cycles that we have in Cheyenne, Wyoming, and Pueblo, Colorado, with capacity factors in excess of 75% capacity factors on those units. And we expect infrastructure and equipment investments in our coal-fired power plants to be able to co~~al~~-fire part natural gas with part coal in order to comply with the new EPA rule and the requirements in 2030.

As part of EPA's Building Block 3, we will see increased utilization and expansion of renewable generation projects and new projects -- new renewable projects being developed, to be able to comply with this new rule.

Slide 50 further demonstrates this impact and opportunity in the Midwest, where all four of the electric utility states we serve and have customers in, are in the top ten list requiring the most significant emissions reductions as part of this rule.

Very simply, more reductions will require more energy to be delivered by natural gas and renewable generation, and these impacts will provide investment opportunity for new generation projects across the nation with these types of power projects with renewables and natural gas-fired generation.

We also want to provide you with the update of Wygen I and the impacts that this rule has on the Wygen I purchase option. The Wygen I plant provides profitable earnings with a power purchase agreement containing escalation and government imposition clauses. The purchase option in this contract allows our affiliate utility, Cheyenne Light, Fuel & Power, to purchase 76½% of this unit through the year 2019. The option period for that purchase ends at the end of 2019.

Uncertainty with the Clean Power Plan will, however, delay this decision for Cheyenne Light to exercise its option until the state implementation plans are approved by the EPA, which is anticipated in 2018 or 2019. Wygen I will continue to operate very efficiently and will continue to provide ongoing profitability and long term performance for the power generation segment with its existing power purchase agreement with Cheyenne Light, Fuel & Power.

This concludes the power generation business segment. We'll next move to the coal mining business segment on slide 52.

Our coal mine simply provides low-cost mine mouth coal supply to the five coal-fired power generation plants located at our Gillette, Wyoming energy complex, where we produce 4 million tons of year -- of coal annually. This supply is approximately 700 megawatts of electric power generation to the region and our affiliate utilities.

Slide 53 describes the strategy where we maximize margins from existing coal supply contracts by controlling operating expenses, providing a valued service with quality coal delivered at a low cost, providing great customer value to our partnerships with our coal supply contracts.

Additionally, our strategy is focused on safety and compliance, where this year, for the second year in a row, our coal mine employees received from the state of Wyoming Governor's Office a safety award for being the safest coal mine in Wyoming for a small mine operation. We also received a safety award from the National Safety Council in 2015 for the coal mine safety performance. As seen by the demonstration of the performance of our safety of our employees, our coal mine is a safe and a great place to work.

Slide 54 depicts our strategy for stable cash flows and continued earnings from our mining. The mining business segment continues to provide stable profitability, as demonstrated by our increasing revenues and controlling of our expenses as part of this slide 54.

The next slide shows a mine engineering plan and expected stripping ratios of overburden. Stripping ratio is the amount of dirt in yards to be removed to produce a ton of coal. The average strip ratio expected from 2015 to 2020, of approximately 1.8, is nearly equivalent to our current stripping ratios in 2015. With our mine engineering plan providing consistent, long-term average stripping ratios, we expect the mining business segment to provide consistent profitability and long-term performance.

Our next slide, 56, further depicts graphically our proven results, executing this low-cost supply strategy. The bar graph on the far left is demonstrated coal price of our coal mining operation at less than $1 per million Btus. The next, lighter gray bars -- the five lighter gray bars -- show regional coal-fired power plants and their delivered coal cost and adjacent coal-fired generation in Wyoming, Colorado and Montana.

The darker black graph, three from the right, is the national average of coal delivered in the United States -- in the nation.

And the two blue graphs on the far right are updates of the natural gas price forecast -- the NYMEX prices. And all of that just demonstrates our ability to execute our strategy as a low-cost fuel provider, providing great customer value as an integrated extension of our utility business. So, this concludes our coal mining business segment, and I thank you for your attention, and now turn it back to Jerome Nichols.

Jerome Nichols: Do we have any questions for anyone, for Mark, on power generation or coal mine?

Unidentified Participant: (Inaudible). So, with the Clean Power Plan, does -- how do you see the power generation business going forward? Do you expect that to be a greater proportion of your business? Is there, you know, build-out of potential CCCTs or renewables? And at the same token, how do you see your coal mining business being impacted from that?

Mark Lux: Yes. Good questions. The impacts of the Clean Power Plan on our generation fleet is a question. We certainly see a shift and a re-dispatch of our resources. We will continue to utilize our existing resources with the infrastructure that we'll have to invest, particularly in our coal plants, to be able to co~~al~~-fire with natural gas. And that certainly will reduce the amount of coal production in the later years of that plan, which is out there in that 2030 timeframe.

From now until 2022, we see no impacts, basically, with this plan. Because the reductions do not require anything to happen until 2022. We will see some opportunities for renewable generation projects and more renewable generation. And I think our modern fleet, that's diversified with coal and with combined cycle and with renewables, will certainly provide for best customer value, in terms of the cost impacts to comply with this rule.

So, with that, I think the thing you can take away is, we have, number one, no stranded assets; and, number two, we're going to provide the best economics for our customers with our blended modern fleet.

Unidentified Participant: If you look at the magnitude of reductions you have to have, you know, from a CO2 perspective, the reductions in CO2 basically means you have to go from a coal fleet to a gas fleet, is equivalent to what it is. Does that mean that the coal generation from here goes to fully gas-fueled at some point in time by 2030? Or, how else do you guys, you know, bend that gap to get, you know, a 45% reduction in CO2 emissions?

Mark Lux: Yes. The question is, does it require no coal generation, or less coal generation, than we have today? Certainly the rule does not require you to totally eliminate coal-fired generation. This is a 30% reduction nationally across the nation. And what we are exploring currently is blending a certain amount of coal-fired generation with natural gas. So, we do still foresee some amount of coal generation within our fleet. And the EPA rule actually provides opportunities for that. So, it doesn't eliminate coal totally; but it certainly requires more natural gas, combined cycle, and more renewables to be able to meet that requirement.

Unidentified Participant: Dave, I guess, bigger-picture, you guys spend a lot of time, you know, managing customer bills and being very conscious of that. When you guys look at the CPP and think about, you know, the change in, really, low-cost coal into something presumably more expensive in renewables and some other things, what sort of bill inflation effects do you think you're going to have for your customers as you comply with these EPA standards?

David Emery: Yes. From an outright percentage increase, Dan (ph), we don't know. You know, until we see the state implementation plans, it's a little tough to predict. We know approximately what it would be if Mark had to comply unit by unit. But this rule's not written unit by unit. It's written state by state. So, some of the actions that some of the other utilities might take in those states, may allow us to do less or more to comply with our units. So, the cost question's a real tough one.

You know, we think, though, given the low cost of our coal, even if we have to add gas, we have to add wind, we still have a relative advantage over some of our neighbors and peers. So, while everyone's bill might go up a whole bunch, our fleet's newer; it's more modern. They'll probably go up a little less than some of our nearby utilities.

So, you know, hopefully that'll be a positive from a political standpoint. You know. The rate pressure is going to be real. There's no doubt about it. But until we see these implementation plans it's going to be really difficult to calculate, you know, what we really think the impact's going to be on our customers.

One thing -- when we did the last round of generation at the Wyodak site -- the Wygen III unit; the Wygen II unit -- when we did that resource planning, we ran scenarios that included significant CO2 costs -- you know, like $10 and $20-a-ton-type CO2 scenarios. They were run assuming a CO2 tax, because we really had no idea what the actual plan might look like.

But it basically showed that those units could stand a substantial burden for CO2 costs, and they were still the best choice of resource at the time. So, we don't think we're going to find ourself in a position where the Commissions are second-guessing the decisions we made five and ten years ago to build coal. I mean, we still feel like we did a pretty good job of assessing that risk on the front end.

Unidentified Participant: Mark, you mentioned wind and solar. Maybe you could talk a little bit more about the potential for including solar. Was that kind of a placeholder, or is there anything in the hopper? You know, will the -- do you need the costs to come down a lot more? If you could just talk a little bit more about the solar side.

Mark Lux: Yes. Good question. The question regarding solar, and the cost of solar, and opportunities with solar. We competitively bid through our power generation business ~~and~~in various RFPs.

And most recently, we have started bidding both wind and solar, because the price of solar with the production tax credits that are provided today are becoming much more economical. We see higher capacity factors with wind, upwards of 40%-plus in the states that we have, compared to solar projects which have capacity factors of around 20% to 25% capacity factor. So, until solar panels come down in price a little bit more, we still see wind having a slight competitive advantage over solar at this point. But it's right on the heels, to your point.

So, we're keeping an eye on that, and certainly continue to explore those opportunities with solar as well as wind, in terms of meeting the renewable requirements.

Jerome Nichols: Any other questions for Mark? Very good.

So, at this point, we're going to take a quick ten-minute break. For those on the webcast, we're going to mute that line, and then we'll come back in about eight minutes. So, right now we have 22 minutes after the hour. So, at about 30 minutes after the hour we'll reconvene and get started again. Our next segment will be oil and gas, and we'll start with John Benton in about 10 minutes.

[break]

Jerome Nichols: Welcome back. Next up is John Benton, who is our Vice President and General Manager of Oil & Gas, and he'll give an update on our oil and gas business and strategy transition. John?

John Benton: Thank you. Thank you, Jerome, and thank you for all coming your afternoon, and devoting your afternoon and time to hear all of our stories.

Since last year, there's a lot that's changed in the upstream oil and gas business, since we were -- spoke to you about a year ago. Both oil and gas prices started their fall last fall, and started to decline. We adjusted to that last fall by reducing some of our oil exploration efforts. We went back -- of course, the usual thing: worked with our suppliers and our contractors to reduce our costs overall, so we can continue some of our programs.

By the second quarter of 2015, it was clear that excess oil and gas production supply had transformed the energy market. Our exploration appraisal programs had showed some promise, but the economics did not support our 2016 and '17 capital program, so we made some changes. We reduced our planned capital spending, as Dave mentioned earlier, to amounts that were just necessary -- needed to maintain our leases and our existing production.

We had some great Piceance well results to date -- allowed us to defer the last four completions we had in the plan for the program for this year. Also, we ended up with some impairments as a result of the low prices -- had to make a difficult decision, and reduced our staffing levels by about 25%, and started looking at potential monetization of some of our non-core unprofitable assets.

When you look at this price chart, it's been 30 years since we've experienced this much of a sustained drop in the price of oil and natural gas. I mean, there's probably a lot of folks in this room that weren't in this business 30 years ago. So, last time this happened, 60% of the individuals employed in the industry left the industry.

And the sustained low-price environment did bring about some efficiencies that helped returned the industry to profitability as it moved forward. That's going to happen again with our current environment. It's going to cause us to become more operationally efficient. But in addition to that, it creates an opportunity, including looking at long-term gas price stability and through the implementation of a cost of service gas program.

Quick summary of our program -- our 2014 and '15 program clearly demonstrated our oil and gas division's ability to efficiently execute our drilling and completion program. Once we removed the regulatory roadblocks, we were able to drill and case 13 wells in the Piceance.

By next week, we will finish completing a total of nine of those wells, and have already tested six of those nine. We could easily have completed the remaining four wells by the end of this year. We do not have to complete those wells. The performance of the first nine is expected to more than meet our plant capacity through 2016, and that will give us time to assess this asset for cost of service gas program and to support the utility business with obtaining approval for cost of service gas in the five states in which we will apply -- or the -- yes. Six states, sorry.

There's a table with a lot of data on here, that pretty much summarizes our program to date. I would want to make sure and call a note that the reserve estimates for the 9-41 wells at the top of the table are estimates. We still have a year-end third-party review to go through that, and it may result in some changes to those estimates.

I want to try to do this on the map very quickly. If you look up here, the six wells you see up here are the 9-11 wells. The 9-11 wells are the wells we just brought on in August and September.

We are in the process of completing three more wells on this pad, our Whittaker Flats, which is of course the area where we think there's some additional liquids, and has been demonstrated by the existing producers. And these wells, the 7-23 pad wells, are the last four that have been drilled and cased, and which we'll defer our completions.

Engineers always like pictures and diagrams, so we just threw this in there so could see a bit of a 3D image of what this looks like for us, and what our 9-11 pad looks like for wells. A lot of data out here. I don't know if you have any questions about it. I'll pause for a second, if you've got any questions, and then we'll move on.

One thing to note on this is -- before we move on, is the top of the Mancos pay area (ph) is about 900 feet, here. So, there's a lot of room between where our current well pads lay and where we could potentially lay in another row of wells. So, there's additional development from -- available from this pad as we move forward.

This graphic is a -- what's showing about (ph) our well costs, and what's happened since 2011 through 2015 -- as you can see consistently, we've seen reduction in well costs over that period of time. Some of those improvements have been through the reduced costs that we were able to secure through our service and supply companies -- the contractors that we use; and some of that's also been through program optimization. And we do believe that, when we move forward with this as a part of our cost of service gas program, that we will also see some additional improvements.

This chart just shows our cost per foot for cased and cemented wells. So, we the cased and cemented because sometimes you don't run casing all the way out to the end of the lateral. So, we look at that as our guidepost as it -- what we can do on a drilled and cased cost per foot? So, if you look at the 2013, '14 wells, those ran between $400 and $600 per cased foot. For the last half of 2015, as you move out and look at the wells on the far right of that chart, all those were equal to or less than $400 per foot.

This chart is a little bit slippery (ph). There's less wells on here. Essentially it's our finding and development cost chart. The others that are -- that were on the previous chart, aren't there yet, because we haven't booked reserves for the wells off the 9-11 pad, or the 7-23 pad, or the Whittaker Flats. And again, we'll have year-end bookings for the three 9-11 wells; the three Whittaker Flats wells. 7-23 wells, we won't show, because we won't complete those wells. We can defer those completions.

Now, if you look at this, you could say, well, don't see much improvement in the finding and development costs between what you did in 2013 and the end of 2014. Those are more or less about the same -- somewhere in that $1.50 per Mcf range.

Something to think about that. Those three wells in green -- those were 1,500 foot higher in elevation compared to the Whittaker Flats wells. So, we had to drill 1,500 extra feet in each of those wells, before we could go horizontal. In addition to that, those wells were dry gas wells, so we don't have the benefit of liquids content there also.

And finally, that was in an area where we drilled a well in 2011. It's prone to severe lost circulation drilling hazard, which -- that can add a significant amount to the cost. All three of those wells, we drilled without having a lost circulation problem. So, that's a big improvement in our execution capability in that area.

This is a production plot of our most recent wells, the 9-11 and the 9-41 wells. The early data on the 9-11 wells certainly look a little bit better than the 9-41 wells. All three of those wells, since we brought those on late August/early September -- their average rates have been somewhere between 6½ and 8½ million cubic feet a day; surface flowing pressures of more than 2,000 psi.

So, we've been pretty happy with those results. It fits our type curve. It's pretty difficult to see, but those plots are up there -- that -- up in the upper left-hand corner of the 9-11 and 9-41 wells -- the early data again indicate that they are doing quite well. The actual completed lateral lengths of these wells are somewhat under 9,000 feet. And, you know, we've plotted those in between a 5,000 and a 10,000-foot lateral. So, we're still confident that we're going to meet our expectations for this program.

In summary, our results to date in the Piceance continue to support the resource potential of between 2 and 4 Tcf. Our current project -- projected demand for our cost of service gas program -- I think Brian alluded to this in his presentation -- somewhere between 37 and 38 Bcf a year.

What that means is, a 20-year program for cost of service gas only requires about ¾ of a Tcf. That leaves us with a lot of additional resource potential to support expansion of the program; some non-regulated development potential to bring in other utility companies into the program; or, some partial monetization of the asset.

So, a lot of available opportunity there. We believe that it has great potential for the cost of service gas program and we think the results to date support that belief. While the drop in product prices has not favored the profitability of our current projects, we have made significant changes to the program to adapt to that changing market.

I'd like to thank you for your time, and if there are any questions -- yes, sir.

Unidentified Participant: What kind of gas price would you need to see to reinitiate the CapEx in the (ph) drilling program outside of that -- the cost of service gas program?

John Benton: For non-regulated? I'm sorry, (inaudible), I didn't thank you. So, the question was -- is, what gas price do we need to reinitiate our non-regulated gas program?

A bit of a moving target. As you continue to see improvement in the cost structure, you could say arguably somewhere between that $3.50 and $4.50 price would get you somewhere in there, to where you could reinitiate the program.

Unidentified Participant: Is that a wellhead price?

John Benton: Yes, sir. The question was, is that a wellhead price? And the answer is yes.

Unidentified Participant: Sorry. I meant to ask this when the -- in the utilities section, but if you added SourceGas to the cost of gas program, how much additional demand would that be?

John Benton: I'm going to defer that to -- I think to Brian or Dave. I can guess at that number, but Brian knows it much better than I do.

Brian Iverson: Yes. I mean, it's going to vary, but it's about two-thirds of what ours is, when you look at it. So, the actual throughput. And not the throughput; the actual gas sold. There's transport on top of that, so --

Unidentified Participant: Is there a potential to expand the cost of service gas program beyond what you currently have outdoors, to try to take more advantage of the available gas in the Piceance?

John Benton: So, the -- I'm -- make sure that I understand, the question is, could we expand the cost of gas program using the Piceance asset or other assets besides that?

Unidentified Participant: I guess if -- I was just thinking about, in terms of -- you're saying it's only --

John Benton: Three-quarters of a Tcf.

Unidentified Participant: Three-quarters of a (ph) Tcf. Potentially, other gas utilities that may, you know, be open to doing a cost of service gas with your assets, if it -- if the Piceance were to be included.

John Benton: I think that -- yes, I do believe that there's -- that's one of the opportunities that we've mentioned for expansion, is working with other utilities to bring them in with us as partners in the program.

Unidentified Participant: How much money do you guys have invested in the E&P business in its entirety, between this and legacy, you know, net of what you sold historically?

David Emery: We've got a current book -- we're roughly --

~~Mark Lux~~Rich Kinzley: Yes. If you go back to page 59, that shows you what the current book is. That doesn't exactly tell you how much we have invested, but --

Unidentified Participant: Is that net of impairments or (inaudible) --

~~Mark Lux~~Rich Kinzley: That is net of impairments, net of depletion.

John Benton: It's a good question. I do not have the answer for you.

Unidentified Participant: And then, I guess, you know, with the ongoing business that's -- you're not having a good profit year this year, shall we say, you -- what are the options as far as strategic alternatives to it, so you're not losing money on the (inaudible)?

Rich Kinzley: When I give the financial update in a few minutes, I'll give a little color on that. Yes.

Unidentified Participant: Okay. Thank you very much.

John Benton: How about I introduce Rich Kinzley now, to give the financial update.

Rich Kinzley: Thanks, John. So, I'm on slide 72. Pardon me -- 71. The team's done a good job kind of walking through our different strategies, and these bullet points reiterate, you know, from a financial perspective, a lot of the things that the team was talking about. But, as we acquire customers; invest money prudently in our utilities; you know, put capital in as -- to replace O&M expenses; continuous improvement efforts -- all those things strengthen us financially, help improve our earnings, and serve our customers efficiently.

On the capital structure side, we're committed to maintaining our solid credit ratings, and through the SourceGas acquisition we intend to maintain those as we finance that.

Now, of course, our track record of dividends -- we've got a slide coming up here. 45 years in a row of increases. Second-longest streak in the utility industry, and we intend to continue that as well.

Earnings guidance. We released yesterday an update to our 2015 earnings guidance. We upped each end $0.10. So, we're $2.90 to $3.10 per share now. Assumption-wise, we kept our capital forecast for this year the same as what we'd disclosed previously. And of course, this assumes normal weather and no outages at our facilities and so forth -- normal operations.

In the middle of this slide, you'll see the full year oil and gas assumptions. We've updated those. Our production range, we narrowed. We were 12½ to 14 Bcf; now we're at 12.9 to 13.3 Bcf production for the year. And then our pricing in the second sub-bullet -- all those numbers are down, of course.

Our last issued guidance on pricing was back in February, and of course prices have continued to remain weak, so we've updated for the full year what we -- what our average pricing looks like. And then the depletion expense -- our previous guidance on that was $2.35 to $2.55.

And if you look back on slide 59, you'll see the impairments that we took in the first and second quarter. And while we can't anticipate exactly what they might be in the third or fourth quarter, it's likely we're going to have more, because the average price -- you use a rolling 12-month average price to calculate those impairments and apply those to your reserves going forward. Those averages keep coming down. We know what the third quarter average is now, and the fourth quarter prices were higher last year, so they'll roll down further in the fourth quarter.

All that said, as we take those impairments it reduces our future depletion rate. So, our average depletion for the year, we've guided down to the range you see there of $1.90 to $2.10. Now, if we were -- if we have to take impairments in the third and fourth quarter -- which, again, based on prices, looks likely -- you'll see lower depletion going forward as well.

The guidance assumptions assume no equity financing this year and no acquisitions or divestitures for the remainder of the year; and then also, the -- it excludes the impairments we've taken, and any acquisition costs incurred during the year. We single those out as special items.

Dave mentioned earlier, we're looking at our Colorado IPP asset. And Mark described that asset when he was talking about our power gen assets. This is our 200-megawatt power plant in Colorado that is owned by our independent power division -- our power generation division. And it's contracted through the end of 2032 with Colorado Electric, our utility. We've had inquiries over the last couple of years on this asset, and given where we see the market on these kinds of assets, a premium valuation may be available to us.

And so, we are kicking a process off to see what kind of value we can generate out of that. If -- one other key point there, too, is, of course, we use bonus depreciation with that asset. And so, there is not much tax basis here. But because of our NOL position, there wouldn't be any immediate tax leakage if we in fact sell a portion of it. And then, if we do sell a portion of it, we would only probably sell up to 49.9% -- a minority interest. Because we want to maintain control of that asset, since it's contracted to our utility, and continue to operate it.

Financing update on the SourceGas. We completed our bridge facility. Of course, we had that in place when we announced the deal, as a backstop for the financing. We got that syndicated shortly after announcing the deal. We will assume $700 million to $720 million of SourceGas debt at close. And then the difference is -- the $1.17 billion on the $1.89 assumed price, is broken up between debt and equity.

Now, with the potential sale of Colorado IPP and on the oil and gas side, you know, certainly it's not going to generate the kind of dollars Colorado IPP would; but we're looking at selling non-core assets here as well. Between those asset sales, we will be able to reduce the financing needs for SourceGas.

So, we issued a revised range of equity that we'll need to the deal closed. Revised it to $450 million to $600 million from the previously-disclosed $575 million to $675 million. And then also, a little color around our plan to use the unit mandatory convertibles in the range of $200 to $300 million.

Other financing. We're also evaluating probably putting an at-the-market, or an ATM, program in, to dribble equity out in the future. That, we wouldn't be able to put in place probably until 2016, but we're looking at that.

We did hedge $250 million of ten-year treasury interest rate risk through April in '17. So, we can use that swap against debt that we place for the SourceGas financing or other financing needs that we see forthcoming. And we did that last Friday, when -- after the jobs report came out, and rates dropped a bit. So, we're pretty happy with what we executed there. And we'll continue to look for opportunities to do that as we move forward.

And then, of course, Peak View's coming. If approved by the Colorado PUC, we'll have to evaluate our options to finance that. But, as an example, if we do put an ATM in place, that could help with that.

I've got three slides on capital investment. Here's the first. You can see our strong historical capital program, which has helped us grow the business. A lot of that's been generation over the last five, six years. But you see, we still have a strong capital program in '16 and '17 in our utilities, and our capital in '16 and '17 is very focused on our utilities. Linn put that chart up earlier.

This is just more breakout. The top half of the -- you saw already in Linn's slides. But it's the utility capital. You can see the power gen. And then the rider eligible at the bottom. Linn talked a little bit about that. We do exclude from the rider eligible capital at the bottom the cost of service gas at this point, until we get regulatory approval. But effectively, that will be rider eligible, and we will include it at the bottom upon approval. These also -- the projected capital here also excludes Peak View and excludes any SourceGas additions.

When we look at CapEx -- and really, the point on this slide -- it's slide 77. At the bottom, you see, particularly in the bottom left, how our capital outstrips our depreciation for a nice rate base growth.

Financial metrics on slide 78. You see the improvement over the last five, six years. We're proud of that track record. Our earnings metrics and return metrics and cash flow metrics have all improved as we've moved through the last few years, and the addition of SourceGas will do nothing but strengthen our cash flows and profile moving forward.

Slide 79 is our dividend history. Did increase this year, a little higher than we've been doing the past few years. But, 45 years in a row. We're proud of that.

Capital structure. We have a strong balance sheet. We did take a little hit on the equity side because of the impairments we took in the first and second quarter this year, which -- non-cash, but they do reduce our equity. So, moves the debt to total cap up a bit, but still sitting in a good position there. Strong capitalization.

Credit ratings. When we announced the SourceGas deal, all three agencies affirmed their ratings on us. Moody's and Fitch gave us a negative outlook until they can see more clarity around the financing. But it was a good sign that they affirmed our ratings upon the announcement of the deal.

And lastly, on slide 82, here's a look at our historical earnings per share and operating income. Good, strong growth. You're all familiar with that. We like the fact that we were able to move this year's up to $3 as the midpoint of the guidance range. So, we continue to show that growth. And then on the far right you see the trailing 12 months.

As of June, our utilities really had nice growth, the trailing 12 months this year, compared to the trailing 12 months last year. The black-shaded area, the non-reg, went down a bit, and that's really commodity price-driven, and the fact that E&P hasn't fared as well in this commodity price environment.

With that, I'll open it to questions. Mike.

Unidentified Participant: Thanks, Rich. Just not clear -- what is the drivers that's driving up the $0.10 increase on the low end and the high end of the range?

Rich Kinzley: Yes. We didn't really disclose anything particularly there, and you'll get some more color when we release our third-quarter earnings at the beginning of November. But if you look at our year-to-date results through June, you know, the business units are all performing very well, Mike. Yes.

Unidentified Participant: Just sort of a -- I apologize for a mathematical question here, but if -- the SEC PV10 test benefit that you guys see for depletion -- what would -- what does that add specifically to your earnings? What is the EPS benefit from that? That's the first question.

Rich Kinzley: Sure. Well, if you go back to slide 59, I mean, I can't really give you a number. But what I can do is kind of guide you in the right direction, I think. If you -- you know, we previously disclosed a depletion range for this year of $2.35 to $2.55. Now we're in the $1.90 to $2.10 range. And that's really -- the decrease is driven off the impairments we took in the first and second quarter, primarily. So, the second half of the year's depletion is going to be lower than the first half was. Okay?

Unidentified Participant: Okay. So, it's very substantial.

Rich Kinzley: And then, you know, if you look at the trailing 12-month prices that we have on that chart for the third and fourth quarters -- which, the fourth quarter's, of course, using kind of strips -- you can kind of linearly maybe guess at where impairments are going to h~~it~~ead and what might happen to depletion moving forward.

Unidentified Participant: Okay. And then the second question I have is, with respect to the equity financing, with sort of a volatile market and what have you -- any thoughts about how to perhaps hedge that, or forward sales? We've seen, for instance, you know, in some transactions, people being very aggressive, and what have you. And I'm just wondering if you guys are thinking about there -- how we should think about the timing of equity issuance and what have you?

Rich Kinzley: Right. Well, we're looking at all our options there. Forward -- I mentioned the ATM. Certainly a straight equity issuance in the convert. From a timing perspective, you know, we're probably not going to be able to do anything before we get our third quarter earnings out. But we're going to continue to monitor the markets. We're going to look at all those options. Our intent is not to draw on the bridge, and get this financed ahead of close. So, that gives you an idea of when we'll be looking to move, but --

Unidentified Participant: So, I mean -- but won't this -- on top of that, though -- so, in other words, are you planning on waiting till basically close to close, or what have you, in terms of issuing is there any thought about perhaps hedging that -- the equity price risk, I guess, is what I'm sort of asking. Prior to that.

Rich Kinzley: As I said, we're looking at all those options. We're talking to our banks. And, you know, nothing imminent; but certainly, we're not going to wait too long either.

Unidentified Participant: You guys mentioned that you're looking at selling the 50% stake in one of your IPP assets. We've seen a couple of asset sales announced in the past couple of days. Is that more a function of just needing the cash right now for the transaction; or is it just, you're seeing more interested international buyers or yield-oriented investors there?

Rich Kinzley: Sure. Well, a little bit of all of the above. But really, we're certainly not selling it just because we need the cash for SourceGas. We're looking at, strategically, if we can get the kind of value that we think is in the market right now for that asset, it probably makes sense to sell it. We would probably be looking at this in any event. We've been approached by parties, and the timing may be real good.

Unidentified Participant: Good. And then I have another question for John. The guidance slide has, I think, an $0.89 wellhead gas price on there, that's assumed in your guidance right now. Could you talk a little bit about just the regional gas pricing in the Rockies, and how that compares to kind of a cash cost for the marginal price (ph) over the long term, or an all-in price over the long term?

John Benton: So, in -- I'm sorry, if you could help me out with some -- I'm not a finance guy.

Rich Kinzley: I may be able to answer this. John can probably give you better color on the particular basin pricing out there. But one of the things that is netted out of there is our gathering and processing cost. So, that drives it down quite a bit.

~~Unidentified Participant~~John Benton: Yes. And it also -- the $0.89 is a dry gas, so it doesn't reflect the value we get from the liquids as well. So, I'm not sure if that answers your question or not.

Unidentified Participant: I mean, is that abnormally low versus a long-term price, even if you adjust for the processing costs, versus peers in the region?

~~Unidentified Participant~~John Benton: No. I mean, that's -- our processing costs are a bit higher because we're running through a new plant, compared to, say, Williams or someone else. But notionally that's about what Piceance Basin is experiencing today for wellhead price. And that's after -- as Rich said, it's after taking our costs out.

Rich Kinzley: Nick?

Unidentified Participant: Sorry if I missed this, but the reduced equity need for SourceGas -- did that assume the Colorado IPP plant sale?

Rich Kinzley: Certainly the bottom end of that range would. The top end -- if we were able to bring the top end of the range down, too, you know, as we continue to hone in our forecast and look at CapEx in ’16 and beyond, you know, we knock the E&P CapEx down. So, that knocked the top end down a bit, even if we don’t sell Colorado IPP.

Unidentified Participant: Thanks. And then can you talk about how you plan to finance your CapEx, kind of, aside from SourceGas and any external capital needs there?

Rich Kinzley: After the deal? Yes. I think the cash -- you know, the cash flows that our business has generated are obviously very good, and adding SourceGas is going to do nothing but improve that. So, we’ll manage. We don’t anticipate needing additional equity, I guess, other than if we put an ATM in, in the short-term.

Maybe one other little bit of color on that: we probably will lever up a little more than you would normally see us at closing. So, we’re going to have to work over the next couple of years to get that de~~al-~~ levered through an ATM program, through strong CapEx management, and then the cash flows that the businesses are going to provide us.

Unidentified Participant: Thanks. And just a followup to that -- how should we think about the ATM program? Is that, you know, one of the tool that you use to finance the SourceGas acquisition, or is it kind of unrelated?

Rich Kinzley: That would really be to help finance any near-term CapEx post-acquisition, more than likely.

Unidentified Participant: Peak View.

Unidentified Participant: Like, basically (inaudible) -- like, Peak View or cost of service gas.

Rich Kinzley: Right.

Unidentified Participant: That’s what we’d use it for.

Rich Kinzley: Yes.

Unidentified Participant: Would it be possible for the utility to buy the IPP? Does that make sense?

Unidentified Participant: Brian, can you --

Brian Iverson: Yes. I think it’s certainly a possibility. You know, you’d have to do that analysis based upon what the bids come in, and how that would look, you know, on a rate-based model for customers, as far as customer cost.

Unidentified Participant: Hey. John from SNL Financial. Question for you on the balance between CapEx and the dividend increases. You guys said that you kind of plan -- or, you’re the second-highest consecutive increases in dividends consecutively. Is that plan to continue, and how do you balance that versus continue to reinvest back into the firm?

David Emery: Yes. We don't specifically state that -- what we're going to do for long-term dividends. I mean, we don't specifically state whether we're going to increase it or not, although we do state pretty heavily that we're awful proud of that track record. So, you know, you can infer into that what you will.

We do definitely balance capital investment opportunities versus that dividend increase. And if you look at the numbers in there, you know, we went back to $0.02 for a few years, and then we went up to $0.04, and then we went to $0.06. It's really a function of what we see the forward-looking capital investment opportunities to be, versus cash flows.

So, we had a period there when obviously we were in the recession. We knew we had a ton of generation to build. Backed it down to $0.02. Things started loosening up and we've got a lot stronger on the cash flow side. Credit metrics got better and better, so we raised it a little bit. We do have a tradeoff there. But, you know, both are important to us.

And obviously we want to maintain our capital investment. You know, our growth rate that Rich showed you, meant more that essentially double the industry average, is something we're also very proud of, and that's a key focus. But we're really proud of that 45-year track record.

Rich Kinzley: Any last questions? Dave, do you want to say anything in closing? Jerome?

David Emery: Jerome might have another question to do.

Jerome Nichols: Last chance. Any final questions? Right. That concludes our presentation for today. I'm going to turn it over to Dave for final remarks.

David Emery: Well, thanks again, everybody, for being here today. As you can see, we're excited about what the future holds for the company.

The SourceGas acquisition is going to be a large addition for us -- you know, 55% increase in the size of our utility customer base and, you know, one that provides a lot of forward investment opportunity, much of which is rider eligible capital. And that's one of the things that we found really attractive about the SourceGas opportunity. Plus, the obvious operational advantages of being in three of those states already. So, the combination there is exciting.

The part that makes us most excited about it is, we know we can execute on it. We've done it over and over, as Linn talked about. It's something we're very comfortable is in our skill set. All the acquisitions Linn talked about from 2004 on -- the core team of people that are doing all that work are the same people. So, they're very well-practiced at what they do, and they're really good at it. So, we're excited about that.

The base growth in our other businesses, from some of the other opportunities -- we talked about cost of service gas, is an excellent example. Some of load growth in areas like Cheyenne; just the base growth in areas like northern Arkansas -- all of those give us a good, stable, solid utility growth, absent some of these other things.

So -- and again, it's back to things we know well. You know. It's generation construction; transmission construction. You know, Mark and his crew have built 19 plants. That's a lot. And they're all done on time and on budget, which is phenomenal. So, it's a key skill set.

So, we're really excited that all of these opportunities are still available, that we've had and developed over the last ten years. Add on top of that SourceGas and cost of service gas and some other things. Future's exciting. We're really looking forward to executing on that opportunity.

So, thanks for your time today. We appreciate the attendance of everyone on the webcast and here in person. Hopefully you can join us here after we break up.

Before we do, I want to say a quick thanks to Jerome and Leslie Hartwell, who's been running the microphone around, out of Kimberly's group. These things take a lot of time and effort and work to put together, so let's give them a little round of applause, you think (ph)? All right. Thank you, everyone.