Black Hills Corporation

February 25, 2015
1:35 pm ET

Dan Eggers: All right, guys, we're going to keep moving. So it's my great pleasure with Black Hills joining us in Vail again this year. If you've seen our research, we like the Black Hills story, and there's a lot to offer. A lot of under-appreciated value in the E&P story as well as at the core that a very good utility story. So we're happy to have you guys here.

I want to turn it over to Dave Emery, Chairman, President, and CEO to get us started off on the update.

Dave Emery: Thank you, Dan. Welcome, everyone, thanks for being here today. I appreciate your interest in Black Hills.

A quick forward-looking statement slide here -- obviously, consult our public documents before making any investments in Black Hills.

Highlights -- we're a diversified energy company but very utility-centered, and our non-regulated subsidiaries complement our utility primarily, and we'll talk about that more in a little bit.

We strive to be the best at everything we do, so we run a great operation. We've got great upside in the oil and gas, Dan mentioned that. Continuing to get stronger on the balance sheet and credit rating and in 45 consecutive years of annual dividend increases. So a pretty good investment thesis in Black Hills.

From a Company overview perspective here, we started in 1883 in the Black Hills. We've expanded since then. Organized in two major groups, utilities and non-regulated energy. The utilities are pretty self-explanatory. The non-regulated energy side, our power generation and coal mining, both of those sell almost exclusively to our own utilities under long-term contracts.

So for all practical purposes, we consider those an integral part of our utility business. They earn like a utility, they have a risk profile like a utility, so we consider those part of our utilities for all practical purposes. And then oil and gas, we'll talk a little bit more about that, but a lot of upside potential in a large-shale gas play.

On the electric side, 206,000 customers or so in three small electric utilities. We also have one combination utility, that's Cheyenne Light in Wyoming. On the gas side, about 543,000, 544,000 customers in Colorado, Kansas, Iowa and Nebraska. Both electric and gas utilities for us. I think it's worth noting we're almost 100% AMI now, so we've got a lot of things going on from an improvement and operational excellence that we think will continue to drive success there really reducing truck rolls, doing that sort of thing.

Power generation, I talked about, but the two facilities we have sell to our own utilities for one circumstance or another, long-term contracts, no fuel risk, very good investments for us.

On the coal mining side, all coal, with the exception of just a little bit to a couple of industrial customers in the region, all of it's sold onsite power plants, all of which -- most of which we operate, one of which we just have a minority interest in but an excellent source of fuel. We deliver fuel to the pulverizers for less than $0.80 per million BTUs. So even in a low gas cost environment, we're extremely competitive.

Oil and gas, we've got operations in the Piceance Basin, the Powder River Basin, and the San Juan primarily operated properties and then some scattered non-operated interests.

Highlights -- recently, towards the end of last year and currently, we closed on a small natural gas LDC in northeast Wyoming. We also announced another small gas LDC acquisition in northwest Wyoming. The regulatory filings have been made there, and we're really hoping to get that one closed in the second quarter.

We talked about last year that we completed our jointly owned Cheyenne Prairie Generating Station. That's with two of our utilities -- Black Hills Power and Cheyenne Light. The plant was completed on budget on time. We completed the permanent financing for that plant last fall. We put in new rates for both Black Hills Power and Cheyenne Light in Wyoming, and we implemented interim rates in South Dakota.

South Dakota -- we delayed the hearing there until after year-end. We had a commissioner up for election in South Dakota last fall, so it was good to delay the hearing. Now we have the hearing in January, we filed our post-hearing briefs and expect a decision at any time out of the commission.

We had reached a settlement with some of the interveners and the staff. So we think we have a pretty good idea where the commission is going to come down, but there was a couple of interveners that still wanted to take the case to hearing, so that's pending.

Colorado Electric -- we've talked about this RFP we did for renewable resources there. Our power generation subsidiary did submit bids into that. Our bids were not one of the highly valued bids. An independent evaluator filed their recommendation with the Commission. The Commission actually deliberated and suggested that we not take any bids, and we just go buy RECs which -- that's really completely contradictory to what the Commission has been asking us to do, which is provide renewables at the lowest long-term cost for rate payers. So we're evaluating our options there, and some of the bidding parties may ask for a re-hearing as well. We'll see what we do there in the next couple of weeks.

We got approval at the end of the year for two rate cases, one at Colorado Electric and one at Kansas Gas. Both of those were pretty satisfactory results from our perspective and happy to get those behind us.

Our coal mine, we completed the price re-opener with the one power plant that we're not the operator of on the Wyodak site; got a very healthy increase in coal price there retroactive back to July 1st. So that was a good result.

Then on the oil and gas, I'll talk more about that in a little bit, but we're continuing to advance our Mancos Shale gas play in the Piceance Basin.

Corporately, a couple of weeks ago our Board declared an equivalent of a $0.06 per year annual dividend increase to shareholders, up from the last few years where we've been doing the equivalent of a $0.04 annual dividend increase. That's our 45th consecutive annual dividend increase record we're very, very proud of, and, of course, we've been talking for the last couple of months about some succession we've been doing in the leadership ranks, both at the senior leadership level and then more recently filling our Treasurer and Controller vacancies.

From a strategy perspective, we're focused on our utility business, but we run our overall strategy with four key corporate goals in mind. All of those really related to being the best at everything we do. So from an operational perspective, earnings growth perspective, workplace perspective and otherwise, we really focus on being at or above almost all of our utility peers, and that's our key focus on just operational excellence.

From a growth perspective, capital spending has been driving that growth for quite a few years, and we project that to continue in 2015, 2016, 2017. Actually, the three forward years, our spending levels will be at or above the three trailing years even in our utility spending. Those spending levels well above depreciation, continuing to drive real strong earnings growth in our utilities and our overall businesses as well.

The next slide here in the capital investment by segment just gives you a breakout on how that spending breaks out between our various business segments with, of course, a little more detail on the electric side to split out the generation and transmission, in particular.

Finally, the next slide, on 17, just gives you some specific detail on the major utility projects. It breaks out the spending by a year, so you can really see how we forecast spending in some of our transmission and distribution projects.

Utility growth opportunity that we've been talking a lot about lately, and we're very focused on, is implementing a cost-of-service gas program for our utilities. We're contemplating, obviously, both our LDC gas supply and fuel for our gas-fired generation; looking at proposing maybe up to half of our gas supply from cost-of-service gas. Obviously, it will take us quite a few years to get there. Maybe that's a five-year ramp-up, something like that, but pretty substantial volumes.

Currently at 50%, that would be just under 40 bcf a year, which is a large volume; a capital investment opportunity, about $1.00 to $2.00 per mcfe in that 40 bcf a year to keep up with that ongoing program. It certainly would be higher in the early years, as we are ramping up production.

We've had really good meetings in all of our states. Most states, we've had at least two meetings; several of them we've had three, including some real detailed, what we call "technical workshops" with staff of both consumer advocates and the Public Utilities Commissions, giving them a chance to kind of dig in and roll up their sleeves on the details.

So far, real good receptivity. We have not yet filed for approval to do that. We hope to be able to file something prior to the end of the year.

Oil and gas strategy -- we've talked about this consistently for quite a few years. We do have some emphasis in some oil exploration limited with oil prices where they are today, that obviously isn't going to occur. So we've kind of scrapped that part of the strategy, at least temporarily.

So we're focused on the Mancos Shale gas. We've got 94,000 net acres there, depending on the well spacing, 160s versus 80s well spacing there; 2 trillion to 4 trillion cubic feet of resources potential; huge opportunity for us.

2014 and 2015, we want to drill complete and test a total of 12 wells at various locations throughout our play to really help us prove up the value of that play. And then after we finish that, we'll consider our options for it. Obviously, one at the top of the list is cost-of-service gas, but then also some potential divestitures, joint venture opportunities, and other things.

If you think about it from a cost-of-service gas perspective, even if we do the full 40 bcf a year that we say would be our target, 20 years, that's still only 800 bcf. If we've got a 2 trillion to 4 trillion cubic foot resource, we still have a lot of other gas we can do something with besides cost-of-service gas.

Where we're at on that program -- we've drilled, completed three wells. Those wells were placed on production this month. We're continuing to flow back frac water and test those wells. We would expect to have good, solid production rates and information to release on our first quarter earnings call there.

We also have three more wells in progress that we're drilling, almost finished with the first one, and the other two are, like, two-thirds done. So we're making great progress there. We would expect to frac and test those wells in the second quarter.

And then we're continuing location building and infrastructure and things for the remaining six wells that we'll get drilled in the last half of the year.

Talking about growth again -- on the dividend side, I mentioned this one already, but you can see the equivalent in the $0.06 increase here this year. That 45-year track record is, I think, the second or third longest in the utility industry, so something we're very, very proud of.

Then the credit rating -- we had two rating agencies upgrade us from BBB to BBB+ this year; still have one yet to go, but our metrics are solid BBB+. We're pretty comfortable with that. Certainly, the banks treat us like we're solid BBB+.

This is the regulatory update. I'm not going to go over this because I think I've covered it almost all already.

Operating performance is something that we focus a lot of attention on. I'm going to skim through some of these slides pretty quickly, but things like power plant availability, starting reliability, the age of our fleet -- those sorts of things. We have one of the most modern fleets in the industry and one of the best operating track records in the industry for both construction and operations.

As I mentioned earlier, we're continuing to automate our field services. We've had dramatic reductions in truck rolls with full deployment of AMI and now starting to deploy basically the pad technology for all of our field techs to dispatch and manage all their work. It's going to continue to improve operations pretty dramatically.

Electric reliability -- we're consistently in the top quartile there; do a great job managing storms and outages and that sort of thing, so it's something we're pretty proud of.

Then, finally, on the worker side we've received quite a few recognitions this year. I'll mention just a couple of them here -- the Colorado Department of Environmental Quality, of Public Health and Environment gave us an award, a Gold Leader award on our environmental stewardship in the state.

And then recently Achievers recognized us as one of the 50 Most Engaged Workplaces in North America. This is the third year in a row we've that made that list, and we're the only utility on that list.

With that, I'll turn it over to Rich Kinzley, our CFO for the financial update. Rich?

Rich Kinzley: Thanks, Dave. Good morning. The first slide -- I'm on slide 29, for those on the webcast. We produce this each quarter to isolate special items and better indicate our ongoing performance. In 2014 we had none of those items, so you've got an 18% increase in the as-adjusted EPS from continuing ops, $2.45 to $2.89.

On slide 30 is our income statement for the fourth quarter and the full year. I'll talk about operating income on the next slide, but the real takeaway here is the big drop in interest expense in 2014. Late 2013, in the fourth quarter, we refinanced a lot of our debt at much lower cost, paid off some hedges and other activity that really helped there. So that was a big piece of our earnings driver for 2014. EBITDA up 3.2% would be the other thing I'd point out here.

On operating income, I'll talk briefly about each business unit. The electric utilities had a nice increase. We had, of course, the Cheyenne Prairie going into service in a number of rate cases. Results at the electric utilities were tempered by mild weather in the summer. We were about down 12% from normal on heating -- or pardon me -- cooling degree days at the electric utility. So that tempered their results a bit.

Gas utilities had another good year. Heating degree days were 7% above normal in 2014, but they were 9% above normal in 2013, but we still managed to sell, even though our heating degree days were down slightly from the prior year, we still managed to sell 2% more dekatherms of gas. We had 1% increase in customer count there, so good results at the gas utilities.

Power gen up slightly. That's predominantly due to increased PPA prices related to those power plants. Coal mine had an outstanding year. You can see the result there, but that is a two-piece story. One is, just, continued efficiency in mining, and then we had the re-pricing on the Pacific Corp contract midyear, which had a benefit there as well.

We do expect, moving into next year, to have a higher stripping ratio. Last year it was slightly under 1.1. Next year it's going to be in that 1.5, 1.6 range in 2015. So that will be one of our challenges, but the increased coal price on the Pacific Corp contract helps us there.

Oil and gas down compared to the prior year. That predominantly was just the delays in getting our production on, and Dave talked about our strategy there, and we expect to get those wells drilled and improve that this year. Commodity prices are a challenge.

Here's our last five, six years. We're very proud of the growth in op income and earnings per share there. We do expect to continue to grow earnings and op income. As we look forward, 2015 is going to be a bit of a challenge, predominantly due to the commodity prices.

Capital structure -- Dave mentioned our credit ratings. We're in real good shape there, keeping our debt to cap in good shape. Our other ratios look good, and we don't expect to have to issue equity for the foreseeable future.

Then guidance -- I won't go through this in detail, but the one thing I will point out here is the guidance that we've issued for 2015, we did use a $3.00 NYMEX gas price and a $50.00 NYMEX oil price for our unhedged production. That's about what prices are right now, so we'll see how the year plays out on that front.

And, finally, this is a -- we do this scorecard every year to help us and you keep track of the things that we're working on, and we'll look for those checkboxes to fill in as the year goes along.

With that, we'll take any questions.

Dan Eggers: I guess, Dave, we could kick it off just with -- we're on the E&P side, and the drilling activity. The timing for getting these first wells done has, clearly, been later than expected and getting the direction data longer than when we started in 2014. What is your level of confidence of getting all these wells online by the end of the year? Is there an opportunity to engage another rig, given the slowdown from everybody else we're hearing here as a way to just get faster in proving out these projects?

Dave Emery: Yes. I think our degree of confidence is pretty high, Dan, that we'll at least get those 12 wells done and drilled. And we may not get them all completed, but we certainly are going to be awful close.

I think our schedule is well underway now, operations are going very well. The first three wells, we're real encouraged by preliminary results there. The drilling and completion activity actually went pretty well once we got started.

The delay last year, we had a couple of issues. One, it took a little longer to get the rig to us than we had originally hoped, and then we had some delays getting some critical rights of way and some other things across some land that we needed for water infrastructure and other things to produce and test the wells.

So that was a little bit of a delay but once we got started, I mean, we're pretty much right on track with where we thought we would be; timing for each well drilling and completing and then results. We're continuing to see more efficiencies on the drilling side, and that was even before the downturn, where we're starting to see some opportunity to renegotiate service costs with some vendors. They're a lot more willing to negotiate when their equipment is sitting in the yard.

So that, I think, will be even more beneficial, going forward, but we're just starting to see the results of that. And, certainly, to your question, there is, with the downturn, there certainly would be an opportunity, if we think we need it, to pick up another rig to make sure we stay on schedule. And if that makes sense for us to do we may, indeed, do that.

Dan Eggers: You said that the preliminary looks are encouraging on the first three wells. How do they compare with what you guys did a year ago for the partner acreage? A little different but yet performance-wise, are you -- that kind of encouragement or partners -- ?

Dave Emery: In general, I think we're getting better at the drilling and completion operation. It's getting smoother and smoother, and that's what you would expect with an ongoing drilling program. You do two wells and quit; then you do three wells and quit; you just aren't going to get those synergies on the experience level to really help you out on your learning curve.

So I would say we've continued to make good progress operationally there. The drilling process itself and the costs associated with that, the completion process and costs associated with that, and then, certainly, the preliminary indications on production, they're very early. The wells are flowing back a lot of frac water, but there's certainly nothing disappointing at all on what we're seeing there.

We do expect the gas to be drier, and what we've seen, so far, it certainly is in the Homer Deep area and Whitaker Flats, where we drilled a year ago. That was pretty liquids rich, but we pretty much knew that before we started.

Dan Eggers: Do you have any updated thoughts on kind of the economic prices you need at a hub basis or maybe a wellhead basis for these wells you're drilling right now? Or is it still too early to kind of figure out where the economics make sense?

Dave Emery: It's a little early because we keep seeing the drilling costs come down, and I think that will get even more true now as we see those service costs are starting to come down already. Some of them even voluntarily coming in and offering discounts before you have to ask for them. They want to keep their crews and equipment busy and that sort of thing.

I think the economics will continue to look a little better, over time, but we've said all along, the charge we've given our folks is they need to be able to make money in this play at the $3.50 to $4.00 range. We've got to keep our finding and development costs in that $1.30 max of $1.50 and to really make this play work.

Frankly, the last few wells we drilled, we're getting awful close to the top end of that number already. So we're pretty encouraged about the results for getting it.

Dan Eggers: When you think about the gas reserves and rate-based conversation hoping to file something by the end of the year, as you're talking to all the different constituents in the different states, what is resonating in the conversation? Where are you hearing points of concern? And from a design perspective, the things they are looking at they would like to see, in particular, to make that make sense for everybody?

Dave Emery: The discussions have gone really well. The devil is in the details, and so you kind of get into this issue about, well, they can't really completely evaluate it until they actually file something, right?

But the communications we're getting, I think they really understand the concept, and that is the long-term price stability and, frankly, lower cost opportunity that you have through managing your gas supply using drilling instead of open market purchases, you get a life of well hedge, essentially, which is not available in the marketplace, at least not without paying through the nose for it. So that's very viable.

When we talk to the commissions and the way we buy gas today, we currently do about a third of it open-market purchases, a third of it hedging for one to two years max, typically through fixed price swaps, and then a third of it through seasonal storage. The blended cost of that gas to customers over the last couple of years, gas prices aren't quite where they are now, but they were $4.00, say. That blended cost has still been running $5.00 to $6.00 in mcf. And that's not unique to us. That's true for our peers as well.

So when you look at cost-of-service gas and go, wow, can I make it work at $3.00, well, I don't think we really need to be at $3.00 to make it work. It's kind of back to your earlier question -- it's probably more in the $4.00 range, maybe even a little above that. I think we'd still be pretty comfortable with the commissions at that kind of a level because you're talking about a life-of-well price.

Dan Eggers: What do you think about the process if you file toward year-end, how long do you think it's going to take for some sort of sign-off and you start moving assets over, start making some of those investments?

Dave Emery: It depends. I think in many states, at least in a couple of them, it's very likely to take nine to 10 months like a rate case would take. I think there's a couple of states maybe like Wyoming, who is very familiar with this program because Questar has been selling gas in their state like this for 40 years -- 30, whatever it is.

They may move -- I would find it hard to believe someone is going to get this done in less than five or six months. It's possible, but just the practical implications of going through the hearing process and intervention and all that. So it's a good six- to nine-month process, probably.

Dan Eggers: On the rate case, you've had a lot of folks involved in the settlement but, obviously, not everybody. What do you think has to get resolved in a rate case, or is there a way to settle with these guys to -- ?

Dave Emery: In South Dakota?

Dan Eggers: Yes.

Dave Emery: The hearing is over. Staff was pretty clear with the few interveners that didn't intervene; that staff wasn't even going to provide testimony against those interveners. They basically thought their case was pretty weak, and they weren't even going to waste their time.

So I guess our feeling -- you never know -- but our feeling is we worked out a really good settlement with staff and one of the larger industrial customers. The other group, frankly, has been getting, probably, too good of a deal. It's probably time that that comes to an end.

So I don't think the Commission viewed it as a negative -- that we had to litigate that case. I think we feel that we'll get treated pretty fairly there.

Dan Eggers: And then, I guess, just with all the companies here at the conference talking about slowdown and slowing activity and cost deflation. What effect is it having on your -- prospectively on your industrial load or your commercial load is kind of on your system from an electric and gas consumption perspective if these guys are starting to show some financial pain?

Dave Emery: Really, Dan, we're not much -- we have very, very little dependency on the oilfield for load. We've got a couple of tank manufacturers and things in the northern Black Hills and a couple of little things like that, but very little dependence on oil and gas.

Our loads, in fact, has been strong growth comparatively speaking. And we really don't see that slowing down. It might if this is real sustained, but we have such little impact from that business, that industry, on our business that I think we're pretty optimistic that the other drivers, things like data center business, gold mining expansion in Colorado, some of those things are real drivers to some of our utility growth, and we don't see that slowing down. In fact, it might even be accelerating a little bit.

Dan Eggers: Obviously, it's still in process, but with 111-D out there, how do you guys see that affecting, maybe, capital plans and the fleet and, maybe not directly, your coal plans, the coal mining business? How should we be thinking about the implications for you guys?

Dave Emery: We're in a very interesting and, frankly, I think it's an enviable position as an electric utility that in the states that we operate electric utilities in -- Wyoming, South Dakota, and Colorado -- there's very little we will have to do from a 111-D compliance perspective.

We have the most modern fleet there is in the area. We've shut all our smaller inefficient plants down because of the MATS rule or in Colorado because of the Clean Air Clean Jobs Act. And, frankly, if you look at the total megawatts in the state compared to what we have in the state, there's nothing we're going to do that's really going to influence that statewide average number.

It's Pacific Corp based in electric in Wyoming. They've got 1,000-plus megawatt facilities. They make a decision on one of those and that will solve the state's problem. South Dakota, we no longer have anything but a peaker in South Dakota; shut our coal plant down. It's Big Stone. So whatever the utilities, MDU Otter Tail and those guys do at Big Stone, that's going to solve South Dakota's problem. And in Colorado, obviously, you've got Xcel.

Our fleet is completely new. It's all natural gas-fired. It's either combined cycle or peakers, coal plant shut down, there's nothing we're going to do there that's going to impact the state averages, either.

So other than in Colorado, potentially integrated a little more renewable into our supply, there's really not much we're going to do that's going to affect results one way or the other, which is a great spot to be. We're not looking at how do we deploy a lot of capital? We're not looking to have some serious issues, consequences, shutdowns, a lot of rate pressure for customers, those sort of things.

So knock on wood, we think we're going to come out pretty well through all this, but the verdict is still out a little bit on what's that final rule really going to look like?

Dan Eggers: Perfect. Thank you, guys, we've used all of our time. Thanks for coming.

Dave Emery: Thanks, everyone.