Q. Please state your name, business address and present position with PacifiCorp dba Rocky Mountain Power ("the Company").

A. My name is Cindy A. Crane. My business address is 1407 West North Temple, Suite 310, Salt Lake City, Utah 84116. My position is Vice President, Interwest Mining Company and Fuel Resources for PacifiCorp Energy.

Qualifications

Q. Briefly describe your professional experience.

A. I joined PacifiCorp in 1990 and have held positions of increasing responsibility, including Director of Business Systems Integration, Managing Director of Business Planning and Strategic Analysis, and Vice President of Strategy and Division Services. My responsibilities have included the management and development of PacifiCorp's 10-year business plan, assessing individual business strategies for PacifiCorp Energy, managing the construction of the Company's Wyoming wind plants, and assessing the feasibility of a nuclear power plant. In March 2009, I was appointed to my present position as Vice President of Interwest Mining Company and Fuel Resources. In my position I am responsible for the operations of Energy West Mining Company and Bridger Coal Company, as well as overall coal supply acquisition and fuel management for PacifiCorp's coal-fired generating plants.

Purpose and Summary

Q. What is the purpose of your testimony?

A. I explain the Company's overall approach to providing the coal supply for the Company's coal-fired generating plants and support for the level of coal costs included in fuel expense in this case.

Q. Please summarize your testimony.

A. My testimony:

- Explains the primary causes of the $96.5 million price related coal cost increase reflected in the 2014 Utah general rate case for the June 2015 ending test period ("Test Period");
- Provides background on the third-party coal contracts and current contract price re-openers;
- Reviews the Company's affiliate mine coal costs; and
- Discusses the increasing sulfur content of the Company's coal supplies.

Overview of the Company's Coal Supplies

Q. How does the Company plan to meet fuel supplies for its coal plants for the test period?

A. As reflected below in Confidential Table 1: *Coal Sourcing*, the Company employs a diversified coal supply strategy. The Company will supply approximately 65.8 percent of its coal requirements with third party coal supplies and 34.2 percent with coal from the Company's affiliate mines. Approximately 29.5 percent of the Company's total coal requirements are supplied under fixed-price contracts, 32.0 percent under contracts that escalate or de-escalate based on changes to producer and consumer price indices, 4.0 percent will be supplied to the Dave Johnston plant from currently unidentified Powder River Basin mines and the remaining 0.3 percent represents the consumption of Carbon plant inventory associated with the plant closure in April 2014.

Confidential Table 1: Coal Sourcing

[redacted]

Q. Please explain how the Company's Utah plants are supplied with coal.

A. The Utah plants are sourced collectively through a diversified portfolio of coal supplies. While the Deer Creek mine supplies primarily the Huntington plant and a portion of the Hunter plant, the contract coal supplies are typically interchangeable between the plants.

Q. Why is it important that they be interchangeable?

A. Interchangeable coal supplies allow the Company to minimize transportation costs between the coal mines and generating plants while ensuring the coal quality blend meets plant quality specifications.

Q. Please explain the reference to spot/unidentified coal for the Dave Johnston plant in Confidential Table 1 above, in the context of the current fuel strategy for the Dave Johnston plant.

A. The Dave Johnston plant is projected to consume approximately 3.5 million tons during the Test Period; the Company currently has 2.5 million tons of coal for the plant under contract. The Company intends to solicit multi-year coal supplies from Powder River Basin mines during the second quarter of 2014.

Coal Cost Increases

Q. Do coal costs in the Test Period reflect an increase from levels reflected in the Company's 2012 general rate case ("2012 GRC"), a test period ending May 2013?

A. Yes. As mentioned in the testimony of Mr. Gregory N. Duvall, Test Period coal costs have increased, on a total-company basis, from $735.3 million in the 2012 GRC to $823.6 million, an increase of $88.3 million. The increase related to higher coal prices is approximately $96.5 million; the decrease relating to changes in volume is approximately $8.2 million.

Q. What are the primary drivers of the $96.5 million increase in coal prices?

A. Approximately [redacted] of the increase is associated with third-party coal purchases and transportation costs, [redacted] is associated with Bridger Coal Company, [redacted] is associated with increased Deer Creek and Cottonwood prep plant operating costs and [redacted] is associated with increased Trapper mine operating costs.

Third-Party Coal Costs

Q. Please identify the major aspects of the [redacted] increase in third-party coal supplies.

A. The Company expects third-party coal supply cost increases at the plants as set forth in Confidential Table 2 below:

Confidential Table 2: Coal and Transportation Contract Price Increases

[redacted]

Coal Supply Agreements for the Wyoming Plants

Naughton

Q. Please describe the coal supply arrangement for the Naughton plant.

A. The Naughton plant is supplied via an overland conveyor by Westmoreland's adjacent Kemmerer mine under a long-term coal supply agreement through 2021. The Kemmerer mine has supplied the Naughton plant with coal for more than 50 years. Westmoreland acquired the Kemmerer mine from Chevron Mining in January 2012.

The current coal supply agreement was renegotiated in September 2010. [redacted]. The contract allows for contract escalation/de-escalation of the new contract price based on quarterly changes in contract specific producer and consumer price indices as well as production taxes and royalties through 2015.

Q. How do Naughton plant costs compare to the Company's prior proceeding?

A. As reflected in Confidential Table 3 below, coal costs at the Naughton generating plant will increase from [redacted], is associated with the discontinuation of Naughton Unit 3 as a coal fired generating facility at the end of 2014. [redacted]

Q. Please explain the [redacted]

A. The cost increase is primarily attributable to a higher average cost of coal to the Naughton plant because of reduced volumes and [redacted]

Confidential Table 3: Naughton Contract Tonnage

[redacted]

As reflected in Confidential Table 3 above, the coal supply agreement includes two pricing tiers. The first tier is applied to the first [redacted], the contract minimum, delivered in each contract year. The second tier is applied to volumes between [redacted]. With the discontinuation of Naughton Unit 3 as a coal fired generating unit at the end of 2014, [redacted]

[redacted]. Comparatively, in the prior proceeding, the plant burned [redacted] of Tier 1 coal and almost [redacted] of Tier 2 coal 2012 GRC. The loss of Tier 2 tons is the primary driver of the increase in the average contract price from [redacted]

Q. How much of the [redacted]

A. As reflected above, [redacted]

Q. [redacted]

A. [redacted]

[redacted]

Wyodak

Q. Please describe the increase relating to the Wyodak contract.

A. Black Hills Corporation subsidiary, Wyodak Resources Development Company, has been the exclusive coal supplier to the Wyodak plant since it was placed in service in 1978. A contract dispute between Wyodak Resources and the Company over the billing of severance and ad valorem taxes and federal royalties resulted in the New Restated and Amended Coal Supply Agreement dated January 2001.

The previous coal supply agreement, Further Restated and Amended Coal Supply Agreement dated May 5, 1987, contemplated a June 8, 2013 termination with an option for the Company to extend the coal supply agreement for an additional 10 years, to June 8, 2023, at a coal price based upon "fair market value."

The Company was able to secure an approximate [redacted] reduction in the Wyodak coal price starting in 2001 under the New Restated and Amended Coal Supply Agreement. As part of the settlement, the Company exercised its extension option provided under the 1987 agreement. The contract was extended through 2022, which reflected the depreciable life of the Wyodak plant at that time. The settlement also incorporated the fair market valuation contemplated in the 1987 agreement with two price reopeners: July 1, 2014, and July 1, 2019.

Q. Please explain how the Wyodak coal price is reset under the July 1, 2014 price reopener.

A. The agreement provides for the purchase coal price to be set equal to the sum of the spot price of Powder River Basin 8400 Btu coal, average rail transportation costs from the two closest Powder River Basin mines to the Wyodak plant in railroad supplied railcars, and a levelized fixed charge associated with construction of a hypothetical rail unloading facility amortized on a straight-line basis over 20 years.

Q. Did the Company retain an engineering firm to analyze the costs required to construct a rail unloading facility?

A. Yes. The Company retained Burns & McDonnell Engineering Company to perform a feasibility study of a new railcar unloading facility, stackout, and transferring facilities at the Wyodak plant. Burns & McDonnell developed two cost estimates in 2012 dollars: [redacted]

Q. Has Wyodak Resources Development Company accepted the Company's feasibility study?

A. [redacted]

Q. Have you identified the overall increase in Wyodak plant costs as a result of the price reopener?

A. Yes. Based on the current forward price for Powder River Basin 8400 Btu coal and a projection of rail rates, as well as the [redacted] rail unloading facility adjusted for two years of escalation, the Company projects the contract price to increase by approximately [redacted] on July 1, 2014, to [redacted]. This July 1, 2014 price reset accounts for approximately [redacted] of the overall [redacted] Wyodak coal price increase. The remainder of the increase is associated with escalation of contract-specific producer and consumer price increases, and production taxes and royalties.

Dave Johnston

Q. Does the 2014 GRC reflect an increase in Dave Johnston generating plant coal supply costs?

A. Dave Johnston plant coal costs have increased minimally, [redacted] over the prior proceeding. While rail rates increased approximately [redacted], pursuant to a new a rail transportation agreement with the Burlington Northern Santa Fe Railway, coal costs decreased by approximately [redacted] based principally on a new coal supply agreement with Western Fuels Dry Fork mine and current forward pricing for PRB 8400 Btu coal.

Q. Please describe the new rail transportation agreement for the Dave Johnston plant.

A. The current rail agreement with the BNSF for the Dave Johnston plant, executed in January 1998, expires December 31, 2013. In November 2013, the Company negotiated a new multi-year transportation agreement for the Dave Johnston plant effective January 2014. The new contract extends through 2017 with a reduction in the annual contract minimum from the current 3.5 million tons to 3.0 million tons. [redacted]

Q. What are the coal supply arrangements for Dave Johnston in the current proceeding?

A. The average Free-On-Board ("F.O.B.") mine price decreased to [redacted] in the current proceeding from [redacted] in the prior proceeding. Following a March 2013 request for proposal for Powder River Basin coal supplies, the Company executed a three year coal supply agreement for the purchase of Dry Fork mine coal from Western Fuels through 2016. Approximately 35 percent of the test period requirements will be supplied by the new Dry Fork agreement. Approximately, 42 percent of the test period requirements are supplied collectively by the Cordero mine as a result of a April 2012 RFP solicitation and the Coal Creek mine under a April 2011 RFP solicitation. Both the Cordero and Coal Creek coal supply arrangements expire in December 2014. The Company intends to solicit additional coal supplies during the second quarter of 2014 for the remaining 23 percent, or 1 million ton open position. The coal price for Dave Johnston's open position reflects the forward price for Powder River Basin 8400 Btu coal as of November 8, 2013.

Bridger - Black Butte

Q. Please explain the [redacted] increase in third party coal costs.

A. The cost of Black Butte coal delivered to the Jim Bridger power plant has increased to [redacted] in this proceeding, an increase of [redacted]. The increase in cost is principally due an increase in the Black Butte F.O.B. mine costs associated with the delivery of contract deferred tonnage.

Coal Supply Agreements for the Utah Plants

Q. Which non-affiliated mines will supply coal to the Company's Utah plants in 2014?

A. The Company has a diversified portfolio of multi-year coal supply agreements with Bowie's Sufco mine, Utah American Energy's West Ridge mine and Rhino Energy's Castle Valley mine.

Q. Have prices for coal supply to the Utah plants increased above levels reflected in the 2012 GRC?

A. Yes. Collectively, purchased coal costs for the Utah plants have increased by approximately [redacted]. The preponderance of the increase, approximately [redacted], is associated with escalation of the Sufco contract price, which escalation is based on changes to the GDP-IPD (gross domestic product - implicit price deflator). The weighted average Sufco price increased from [redacted]

Q. Did the 2012 GRC include America West Resources' Horizon mine as coal supply for the Carbon plant?

A. Yes. However, subsequent to the filing of the net power cost update in the prior proceeding, the assets of America West's Horizon mine were sold through bankruptcy proceedings. The impact of the loss of the Horizon supply on current Test Period costs is approximately $0.5 million.

Coal Supply Agreements for the Joint-Owned Plants

Cholla

Q. Please describe the coal supply arrangements for the Cholla plant.

A. The Cholla plant is supplied under a long-term coal supply agreement with Peabody's Lee Ranch/El Segundo mine complex through 2024. The long-term contract was the result of a request for proposals issued in May 2005 and includes two price reopeners: January 1, 2013, and January 1, 2018.

Q. How are prices adjusted under the Peabody contract price reopener?

A. The contract allows for either party to request renegotiation of the contract price by providing written notice to the other Party no later than 90 days and no earlier than six months before the price reopener effective date. Peabody provided this notice in July 2012. The renegotiated price must adjust for changes in alignment between contract escalators and El Segundo mining costs, subject to independent verification, and may not adjust for production-related cost changes that were known at the time of signing the original contract.

Q. What is the status of current negotiations with Peabody?

A. The Cholla plant owners reached a tentative agreement with Peabody in November 2013.

Q. What price has the Company assumed for Cholla in the test period?

A. Based on the tentative agreement, the Company forecasts that test period coal costs will increase from [redacted] in the prior proceeding to [redacted] in the current proceeding, an increase of [redacted], with the contract reopener accounting for [redacted] of this amount. The remainder is primarily attributable to increased royalties resulting from more coal production from federal coal leases and escalation of contract indices. The Company will update its Cholla coal pricing prior to the filing of the net power cost update.

Q. Do most of the Company's long-term contracts include some price reopener or price reset?

A. Yes. Most of the Company's long-term coal supply agreements have a price reopener or price reset, which protects both parties. Considering the 19-year contract term of the Cholla coal supply agreement, multiple reopeners would be standard.

Q. Did the Company include any increase for the Cholla contract reopener starting in January 2013 in the prior proceeding?

A. No, the Company had not received any supporting documentation from Peabody at the time of the net power cost update in the prior proceeding.

Hayden

Q. Has the Hayden plant's coal cost changed from the 2012 general rate case?

A. Yes, delivered coal prices have increased from [redacted], an increase of $1.24 per ton or [redacted]. The increase is primarily due to a contract specified [redacted] increase effective January 1, 2014.

Colstrip

Q. Please explain the [redacted] increase in Colstrip test period costs.

A. Colstrip costs have increased from [redacted]. Colstrip costs are developed based on Western Energy's Annual Operating Plan (AOP) for the Rosebud mine. The AOP is reviewed and approved annually by the Colstrip Unit 3 & 4 owners.

Captive Mine Costs

Q. Please explain the increase associated with the captive mines.

A. Deer Creek mine production costs have increased from [redacted], an increase of [redacted]. Bridger mine costs have increased from [redacted], an increase of [redacted], and Trapper mine costs have increased from [redacted], or [redacted].

These changes result in the following increases shown in Confidential Table 4:

Confidential Table 4: Captive Mine Cost Increases

[redacted]

Deer Creek Mine

Q. Please describe the [redacted] increase related to Deer Creek mine production costs.

A. Deer Creek mine production costs are projected to increase from [redacted] per ton in the 2012 GRC to [redacted] in the current test period, an increase of [redacted] [redacted]. There are two primary drivers for the Deer Creek cost increase: (1) increased depreciation expense and (2) reduced coal production. Deer Creek's coal production is projected to decrease from 3.380 million tons to 2.849 million, a 0.53 million ton reduction; the lower production accounts for approximately [redacted] of the [redacted] increase.

Q. How much is depreciation, depletion, and amortization expense increasing?

A. Depreciation is increasing by approximately [redacted]. The increase in depreciation expense is the result of the new depreciation rates and the impact of a reduced economic life of the Deer Creek mine. Deer Creek is expected to deplete its economically recoverable reserves by September 2019.

Q. How is the Deer Creek mine life different than what was reflected the prior proceeding?

A. The 2012 GRC reflected a September 2021 economic life. As a result of an ongoing drilling program, Energy West personnel have identified reserve areas in the mine that are not economically recoverable in part due to adverse quality.

Q. Is the December 2019 depreciable life for the Deer Creek mine consistent with the Commission's recent Order Confirming the Bench Ruling on Depreciation Study as Modified by the Stipulation November 7, 2013 in Docket No. 13-035-02?

A. Yes.

Q. Why has current test year production declined by approximately 530 k tons?

A. Deer Creek coal is consumed by the Hunter and Huntington plants; both plants share a maximum ash target of 15 percent. The longwall system is projected to encounter elevated ash levels during August 2014 through September 2014, November 2014 through December 2014 and again in March 2015 through June 2015 and elevated sulfur content during August 2014 - September 2014. During periods of high ash coal production, the longwall system will be operating a single ten-hour shift instead of two ten hour shifts.

Q. Why would the Deer Creek longwall system be limited to a single shift during the high ash production periods?

A. All of Deer Creek's production is initially delivered to the Huntington plant via an overland conveyor. Once delivered to the Huntington plant stockpile, Deer Creek coal can either be diverted to the Carbon, Hunter or the Prep Plant via two truck loadouts or remain at the Huntington plant. The Huntington plant can typically transfer upwards of 8,000 tons of Deer Creek coal a day between the two loadouts. With Deer Creek's ash content approaching 20 percent during several months, the majority of the coal will need to be transferred to either the Hunter plant or the prep plant and subsequently blended with lower ash coals to meet plant quality specifications.

Q. How much coal is produced by the Deer Creek longwall in a single shift?

A. The longwall system will typically produce 8,500 tons per shift per day and the continuous miners will produce approximately 2,500 tons per day. Operating the longwall system more than one shift day during periods of elevated ash will exceed the physical transfer capability of the truck loadouts.

Q. Can Deer Creek avoid mining these high sulfur and ash areas?

A. Yes; however, not without significantly increasing Deer Creek's production costs and supplementing with higher cost third party coal purchases.

Bridger Coal Company

Q. Please describe the change in Bridger Coal Company coal costs.

A. Bridger Coal Company costs have increased by approximately [redacted] over 2012 GRC. Bridger Coal Company Test Period delivered costs have increased by approximately [redacted] and a decrease in Bridger Coal's heat content from 9,255 BTU's per pound to 9,196 BTU's per pound in the current proceeding accounts for the remaining [redacted].

Q. Have Bridger Coal Company's production levels changed?

A. Yes. As reflected in Confidential Table 5 below, Bridger Coal Company's production has decreased from [redacted] in the 2012 GRC to [redacted] in the current test period while Bridger Coal Company deliveries have increased from [redacted]

Confidential Table 5: Bridger Coal Production

[redacted]

Q. Please explain how Bridger Coal Company deliveries can increase by [redacted] while Bridger Coal production declines by [redacted]

A. [redacted]

An 80 day outage of the underground mine's longwall system during the summer of 2014 is the primary driver of the reduced underground mine production. Deliveries are being made from Bridger Coal Company surface and underground mine inventories to compensate for Bridger Coal's reduced production.

Q. What is the typical length of time required to move and setup the Bridger Underground longwall system once it has completed mining a longwall panel?

A. Longwall move times at Bridger Coal's underground mine are significantly dependent on geologic conditions and have ranged from 72 days to 25 days.

Absent significant geologic issues during a longwall move, the time required between finishing mining of a longwall panel and commencing mining of the next longwall panel should be approximately 20-30 days.

Q. Why is this longwall move longer?

A. In this instance, the Company is bypassing a longwall panel due to elevated levels of ash and low coal seam height. Based on an extensive drilling program of the 12th right longwall panel this past summer, Bridger Coal personnel identified in-seam ash content ranging up to 26 percent, levels considerably above the Bridger plant specification of 13.5 percent. Therefore, upon completion of mining of the 11th right longwall panel in June 2014, the longwall system will be idled until late August 2014 when the longwall system will commence mining of the 13th right longwall panel.

Q. Could the longwall system move directly from the 11th right longwall panel to the 13th right longwall panel in the typical 20-30 day move?

A. No. The longwall itself is not capable of development of a longwall panel. Instead longwall mining relies on continuous miners to drive gate roads to the back of each panel before longwall mining can commence. In this instance, the development of the 13th right longwall panel will not be advanced in time to commence longwall mining before late August.

Q. Please describe the major drivers of the increase in expense of Bridger Coal deliveries to the Bridger plant?

A. Besides the significant cost impact of reduced coal production, there are three other primary drivers for the Bridger Coal Company cost increase: (1) increased materials and supplies and outside services; (2) increased final reclamation expense, and (3) increased royalty and production tax expense.

Q. How much of the [redacted] increase is attributable to reduced coal production at the Bridger Coal surface and underground mines and additional deliveries from surface and underground inventories?

A. Approximately [redacted]. The decrease in inventory levels in the 2014 GRC results in approximately [redacted] (total Bridger Coal Company) being credited to coal inventory and debited to test period coal expense. In the prior proceeding, approximately [redacted] was credited to test period coal expense and debited to mine inventory.

Q. How much of the overall increase is associated with increased final reclamation trust contributions?

A. Approximately [redacted]. The Bridger Coal Company owners established a final reclamation trust in 1989 to fund actual final reclamation work. As part of its current long-range mine planning efforts, Bridger Coal Company has updated its final reclamation plan. The increase in trust contributions is necessary to ensure sufficient funds exist in the trust to support final reclamation activities during and after the mine ceases production.

Q. Why are controllable costs principally, materials & supplies and outside services, increasing, on a per ton basis, from [redacted] in the current test period?

A. The increase in materials and supplies and outside services is attributable to a greater percentage of underground mine production supplied by continuous miners and higher percentage of coal deliveries supplied by the Bridger surface mine. With the idling of the longwall system, a higher proportion of underground production is provided by the continuous miners, approximately 21 percent, compared to almost 16 percent in the prior case. Continuous miner production is both more labor intensive and consumes more supplies than longwall production.

Q. Do the above cost increases impact Bridger Coal's royalty expenses?

A. Yes. Average royalties and production taxes have increased from [redacted]. The Company's royalty obligations for coal production from federal and states leases are determined by adding a return on net mine investment to actual mine operating costs and production taxes are assessed based on 30 party coal supplies to Jim Bridger plant.

Trapper Mine

Q. Please describe the change in Trapper mine costs.

A. Trapper mine costs have increased from [redacted] in the 2012 GRC to [redacted] in the current Test Period, an increase of [redacted]. Trapper's increasing strip ratio, the amount of overburden and inner burned which must be removed to obtain a ton of coal, is the primary driver of the cost increase.

Q. Please summarize the benefits of the Company's coal supply strategy.

A. Customers have significantly benefited from the Company's diversified fueling strategy. The Company has pursued a diversified coal supply strategy, relying on fixed contracts, indexed contracts and affiliate-owned coal mines to meet the fuel needs of its coal-fired generating plants. While coal costs have increased in this case as a result of various factors, the Company's strategy has resulted in a long-term, stable and low-cost supply of coal for its customers.

Increasing Sulfur Content

Q. Is the Company projecting the sulfur content to increase during the test period?

A. Yes. As mentioned in the testimony of Mr. Dana M. Ralston, the sulfur content is increasing at the Jim Bridger, Wyodak, Hunter, and Huntington plants.

Q. Please discuss the increase at the Jim Bridger plant.

A. The increase in Bridger Coal Company deliveries corresponds with reduced coal deliveries from Black Butte during the first half of 2015. The sulfur content of Bridger Coal Company is consistently higher than Black Butte. The slight increase in sulfur content, from 0.58 percent sulfur in the Base Period to 0.59 percent sulfur in the Test Period, coincides with increased coal deliveries from Bridger Coal Company and reduced coal deliveries from Black Butte during the first six months of 2015.

Q. What is causing an increase in sulfur content increasing at the Wyodak plant?

A. In February 2013, Wyodak Resources Development Company presented the

Company with a multi-year coal quality projection. Wyodak Resources Development Company actively mines two seams with significantly different sulfur content. The Wyodak plant will be entirely supplied by the "top seam," the higher sulfur seam, during the test period; during the base period the plant was supplied with coal from both seams.

Q. What is the primary driver of the increase in sulfur content at Hunter to 0.68 percent and Huntington to 0.64 percent during the test year?

A. An increase in sulfur content in Deer Creek's coal production is the primary cause. While Sufco's sulfur content is expected to trend slightly higher through the test period, the weighted average sulfur content of Deer Creek's production in the test period is expected to exceed 0.7 percent during the test period. As I discussed earlier in my testimony, the Deer Creek mine will encounter elevated levels of sulfur exceeding 1.0 percent in August and September 2014.

Q. How does the Company manage high ash, high sulfur Deer Creek coal production?

A. To ensure emissions compliance, the Company segregates coal at the Huntington plant and then depending upon quality the coal will be shipped to the Hunter and/or Cottonwood Prep plant and/or remain at the Huntington plant. This coal is commingled with other coals to ensure the blended product does not cause a sulfur exceedance nor violates meeting minimum heat content requirements. For instance, approximately 2.2 million tons of coal will be transferred from the prep plant to the Hunter plant during the test year; 300,000 tons of this amount will be supplied from the segregated Deer Creek high ash, high sulfur pile located at the prep plant.

Q. Can Deer Creek avoid mining these high sulfur areas?

A. Yes, however, not without significantly increasing Deer Creek's production costs and supplementing with higher cost third party coal purchases.

Q. Does this conclude your direct testimony?

A. Yes.