Black Hills Corporation

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November 12, 2009

Advice No. 626

Public Utilities Commission
of the State of Colorado
1560 Broadway
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Denver, CO 80202

The accompanying tariff sheets issued by Black Hills/Colorado Electric Utility Company, LP, d/b/a Black Hills Energy ("Black Hills") are sent to you for filing in compliance with the requirements of the Public Utilities Law and the applicable rules of the Public Utilities Commission of the State of Colorado, including Rule 1210, 4 *Colorado Code of Regulations* 723-1 (2009). The following sheets are attached:

COLORADO P.U.C. NO. 8

Colorado P.U.C. Sheet Number	Title of Sheet	Cancels Colorado P.U.C. Sheet Number
First Revised Sheet No. 64	Purchased Capacity Cost Adjustment (PCCA) Electric	Original Sheet No. 64
Original Sheet No. 64A	Purchased Capacity Cost Adjustment (PCCA) (Continued) Electric	
Original Sheet No. 64B	Purchased Capacity Cost Adjustment (PCCA) (Continued) Electric	
Original Sheet No. 64C	Purchased Capacity Cost Adjustment (PCCA) (Continued) Electric	
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First Revised Sheet No. 33	Street, Alley, Park and Highway Lighting (Continued) Electric	Original Sheet No. 33
First Revised Sheet No. 36	Traffic Signal Lighting Electric	Original Sheet No. 36
First Revised Sheet No. 38	Street/Security Lighting Electric	Original Sheet No. 38
First Revised Sheet No. 54	Voluntary Load Curtailment (VLC) Rider Electric	Original Sheet No. 54

The purpose of this filing is to implement a Purchased Capacity Cost Adjustment ("PCCA") mechanism and rider in Black Hills' Colorado PUC No. 8 -- Electric tariffs, on more than thirty (30) days statutory notice. The filing of these tariffs has been compelled by a significant increase in wholesale purchased capacity rates requested by Public Service Company of Colorado ("Public Service") in a recent wholesale rate case filing, described in this Advice Letter. Black Hills requests that the PCCA tariffs attached as Appendix A be allowed to become effective on January 1, 2010 by operation of law without hearing and suspension, pursuant to Colo. Rev. Stat. § 40-6-111.

The proposed PCCA tariff will implement an annual adjustment clause designed to recover the incremental increased cost of capacity purchased from Public Service, on a dollar-for-dollar basis. The PCCA rate rider will recover purchase capacity costs that are not included in Black Hills' base electric rates, through annual or interim filings for any future incremental capacity cost changes authorized by the Federal Energy Regulatory Commission ("FERC"). As set forth in detail in the proposed PCCA tariffs, the Purchased Capacity Cost Adjustment will be the Projected Purchased Capacity Cost, less the Base Purchased Capacity Cost, plus the Deferred Purchased Capacity Cost, and the monthly rider rate will be charged on a dollar per kilowatt basis for tariff schedules with demand rates and on a per kilowatt-hour basis for tariff schedules without demand rates.

Black Hills purchases electric capacity and energy from Public Service pursuant to an amended long-term purchased power agreement that will expire on December 31, 2011. Black Hills currently purchases from Public Service approximately 75% of the electric capacity and energy with which Black Hills serves its approximately 93,300 retail electric customers in Colorado.

On October 30, 2009, Public Service filed with the FERC a wholesale rate case that will significantly increase the base wholesale rates Black Hills pays for the electric capacity and energy used to supply its customers in Colorado. (FERC Docket No. ER10-192-000.) In Public Service's wholesale rate filing, the existing demand rate for wholesale capacity of $11.02 per kW-Month will increase to a proposed total demand rate of $15.23 per kW-Month. Based upon the current purchased power agreement with Public Service, using Black Hills' coincident peak demand at a load of 300,000 kW per month, Black Hills estimates Public Service's wholesale rate filing will increase wholesale capacity costs by approximately $1.26 Million per month. Public Service has requested that the FERC allow the new wholesale tariffs and rate increase to become effective sixty (60) days after the filing date, on or about January 1, 2010. Relevant parts of the Public Service wholesale rate filing are attached as Appendix B to this Advice Letter.

When Public Service's increased wholesale capacity rates become effective, the incremental increase in purchased capacity costs will constitute a financial burden for Black Hills. Delaying recovery of these costs will have a significant impact on earnings and render an unhealthy operating level for the utility. Black Hills' Second Quarter 2009 Income Statement filed with the FERC (attached as Appendix C), shows a negative $2,427,411 for net income for the second quarter of 2009, while Black Hills' total net income for the current year was a negative $4,934,613. If relief is not granted the monthly increase in unrecovered purchased capacity costs, caused by Public Service's increased wholesale capacity rates, will further reduce net income by approximately $1.26 Million each month.

The amount of wholesale capacity costs currently recovered in Black Hills' base rates was based upon Public Service's previous wholesale demand rate of $10.80 per kW-Month. The difference between the amount of capacity costs Black Hills now recovers through base rates (calculated upon $10.80 per kW-Month) and the amount of capacity costs based upon the current Public Service demand rate ($11.02 per kW-Month) will not be recovered through the proposed PCCA. Those unrecovered costs will be addressed in the next revenue requirements (Phase I) rate case filing by Black Hills.

Black Hills' existing cost adjustment mechanisms, including the Electric Cost Adjustment ("ECA") mechanism, do not recover any wholesale capacity costs incurred through purchased power agreements with wholesale suppliers such as Public Service. The existing ECA mechanism allows recovery of the costs of fuel consumed in electric generating plants and of purchased energy, but not purchased capacity costs. As a result, Black Hills cannot recover its wholesale capacity payments unless it files a general rate case and receives a final Commission decision, permitting the recovery of wholesale capacity costs through new base rate tariffs. A general rate case could take a minimum of eight months from the filing of tariffs until new base rates become effective, which is too long of a delay for Black Hills to recover this significant increase in capacity costs from Public Service.

The PCCA mechanism and rider proposed by Black Hills in this tariff filing is designed to recover only the incremental increase in purchased capacity payments resulting from the recently filed Public Service wholesale rate case filing. In other words, the only increase costs to be included in the PCCA rider, and passed through to Black Hills' Colorado retail customers, will be the difference between the actual costs of Public Service's current wholesale demand rate and the actual incremental costs of the increased Public Service wholesale demand rate approved by the FERC. The PCCA tariff and rider will enable Black Hills to recover these increased incremental capacity costs on a timely basis. In addition, delaying recovery of these increased costs would cause capacity-related costs to accumulate quickly, resulting in a higher rate increase in the future to be borne by the customers after a general rate case. Granting expedited relief through the PCCA tariff is in the public interest because it will match cost recovery to the time when costs are incurred and permit a smoother recovery of increased capacity costs over time. These are all benefits both to the customers and to Black Hills.

The PCCA and rider tariff are intended to become effective concurrently with the effective date of the Public Service FERC tariffs and the increased wholesale capacity costs. The PCCA will be applied in accordance with the last class cost of service study that was approved in the utility's last rate case. The PCCA rider amounts in Sheet No. 64C will be applied to bills generated on or after January 1 of each year, or upon Commission approval of an interim rate request. The PCCA for all applicable rate schedules will be shown on the customer's bill as a separate line item and treated as a component of base rates for billing purposes, as is done with the ECA.

Applying the PCCA rider rates to customers' bills for sales after January 1, 2010 will result in increased revenues of approximately $1,263,000 per month, or $15,156,000 annually. If the PCCA rider tariff becomes effective as requested, Black Hills estimates the following impacts on average customers: A typical residential customer using an average of 600 kilowatt-hours ("kWh") per month during 2010 could expect an estimated total increase of $4.74 per month, or approximately 6.9 percent. A typical small non-demand commercial customer using 2,300 kWh per month could expect an estimated increase of $31.74 per month, or approximately 13.6 percent, while a typical small demand metered commercial customer with a monthly demand of 16 kilowatts (kW) could expect an estimated increase of $66.88 per month, or approximately 18 percent. Black Hills does not expect these estimates to change in 2011 and 2012, unless Public Service receives additional wholesale capacity rate increases (or decreases) from the FERC.

In the event that the FERC approves wholesale capacity rates for Public Service lower than the rates that will become effective on January 1, 2010, and order a refund, the PCCA mechanism and rider tariffs will enable Black Hills to pass through to retail customers any refund ordered by the FERC.

This filing will be noticed pursuant to the requirements of the Colorado Public Utilities Law. Black Hills requests that the tariff sheets accompanying this Advice Letter become effective on January 1, 2010.

Please send copies of all notices, pleadings, correspondence, and other documents regarding this filing to:

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Lakewood Ranch, FL 34202
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Sincerely,

Bryan Owens

Bryan S. Owens
Manager – Colorado Electric Regulatory Affairs

BLACK HILLS/COLORADO ELECTRIC UTILITY COMPANY, LP
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Colo. PUC No. 8
First Revised Sheet No. 64
Cancels Original Sheet No. 64

PURCHASE CAPACITY COST ADJUSTMENT
ELECTRIC

APPLICABILITY

All rate schedules for electric service are subject to a Purchased Capacity Cost Adjustment to reflect the incremental cost of capacity purchased to supply electric service over the level of purchase capacity costs included in base rates. The Purchased Capacity Cost Adjustment amount will be subject to annual changes to be effective on bills generated on or after January 1 of each year. The Purchased Capacity Cost Adjustment for all applicable rate schedules is as set forth on Sheet No. 64C, and will be added to the Company's Base Rate for billing purposes. The Purchased Capacity Cost Adjustment shall be different for each of the rate classes.

DEFINITIONS

Purchased Capacity Cost

For the purpose of this tariff, the Purchased Capacity Cost is defined as the fixed cost components of purchase power contracts and recorded in Account 555 Purchased Power Demand.

Purchased Capacity Cost Adjustment

The Purchased Capacity Cost Adjustment will be the Projected Purchased Capacity Cost, less the Base Purchased Capacity Cost, plus the Deferred Purchased Capacity Cost on a dollar per kilowatt for tariff schedules with demand rates and on a per kilowatt-hour basis for tariff schedules without demand rates.

Base Rate

Base Rate is the rate that incorporates the currently effective Base Purchased Capacity Cost.

Base Revenue

Base Revenue is equal to the overall revenue charged to the customers less Energy Cost Adjustment (ECA), Renewable Energy Standard Adjustment (RESA), Transmission Cost Adjustment (TCA) and Demand Side Management Cost Adjustment (DSMCA) revenue.

Base Purchased Capacity Cost

Base Purchased Capacity Cost is the amount of Purchased Capacity Cost included in the Base Rates.

Projected Purchased Capacity Cost

Projected Purchased Capacity Cost is the Purchased Capacity Cost forecasted for the effective period of the Purchased Capacity Cost Adjustment.

Deferred Purchased Capacity Cost

Deferred Purchased Capacity Cost is Actual Purchased Capacity Cost less Recovered Purchased Capacity Cost, and may be positive or negative.

Actual Purchased Capacity Cost

Actual Purchased Capacity Cost is the Purchased Capacity Cost amount recorded in Account 555.

Recovered Purchased Capacity Cost

Recovered Purchased Capacity Cost is the Purchased Capacity cost recovered by the Company's currently effective Base Revenue.

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PURCHASE CAPACITY COST ADJUSTMENT (CONTINUED)
ELECTRIC

Base Purchased Capacity Cost

1. A revised Base Purchased Capacity Cost will only be made in connection with the filing of a general rate case.

Projected Purchased Capacity Cost Amount

1. The Projected Purchased Capacity Cost will be equal to the Projected Purchased Capacity Cost projected for the effective period of the Purchased Capacity Cost Adjustment.

2. A revised Projected Purchased Capacity Cost Amount will be calculated and filed on November 1 of each year and will take effect on the next January 1.

Deferred Purchased Capacity Cost

1. The Deferred Purchased Capacity Cost amount will be equal to the Deferred Purchased Capacity Cost as of September 30.

2. The Deferred Purchased Capacity Cost will be calculated monthly by subtracting Recovered Purchased Capacity Cost from Actual Purchased Capacity Cost. The resulting amount, whether negative or positive, will be accumulated in Account 191. Interest shall accrue on the deferred balance (negative or positive) at the Commission's customer deposit interest rate.

3. Revised Deferred Purchased Capacity Cost rates will be calculated and filed on November 1 of each year to take effect on the next January 1.

Actual Purchased Capacity Cost

The Actual Purchased Capacity Cost will be the Purchased Capacity Cost amount recorded in Account 555 for the month.

Recovered Purchased Capacity Cost

The Recovered Purchased Capacity Cost will be calculated monthly by applying the sum of the Base Purchased Capacity Cost plus the Purchased Capacity Cost Adjustment to the actual rate components for the month.

Purchased Capacity Cost Adjustment

The following formula is used to determine the Purchased Capacity Cost Adjustment for class i:

$$\text{Purchased Capacity Cost Adjustment} = (A_i \pm C_i) / X_i$$

A_i = Class's share of Projected Purchased Capacity Cost
C_i = Class's share of Deferred Purchased Capacity Cost
X_i = Class i Billing Determinant

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d/b/a BLACK HILLS ENERGY
105 South Victoria
Pueblo, Colorado 81003

Colo. PUC No. 8
Original Sheet No. 64B
Cancels ______ Sheet No. ______

PURCHASE CAPACITY COST ADJUSTMENT (CONTINUED)
ELECTRIC

INFORMATION TO BE FILED WITH THE PUBLIC UTILITIES COMMISSION

Each proposed revision in the Purchased Capacity Cost Adjustment will be accomplished by filing an Advice Letter and revised Rate Table tariff sheet on November 1 of each year to take effect on bills generated on or after the next January 1 and will be accompanied by such supporting data and information as the Commission may require from time to time. In the event the Federal Energy Regulatory Commission, or other federal agency with subject matter jurisdiction, authorizes additional changes in wholesale purchased capacity rates during the period of January 1 and November 1 of any year, the Company will file an interim Purchased Capacity Cost Adjustment by filing an Advice Letter and revised Rate Table tariff sheet pursuant to applicable rules of the Public Utilities Commission of the State of Colorado.

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BLACK HILLS/COLORADO ELECTRIC UTILITY COMPANY, LP
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Colo. PUC No. 8
Original Sheet No. 64C
Cancels Sheet No.

PURCHASE CAPACITY COST ADJUSTMENT (CONTINUED)
ELECTRIC

RATE TABLE

Rate Schedule	Applicable Charge	Monthly Rider Rate
Residential Service		
RS-1	Energy Charge	$ 0.0079/kWh
Small General Service-Non-Demand		
SGS-N	Energy Charge	$ 0.0138/kWh
Small General Service-Demand		
SGS-D	Demand Charge	$ 4.18/kW-mo
Large General Service		
LGS-S	Demand Charge	$ 2.27/kW-mo
LGS-P	Demand Charge	$ 2.40/kW-mo
Large Power Service		
LGS-S	Demand Charge	$ 4.43/kW-mo
LGS-P	Demand Charge	$ 3.30/kW-mo
LGS-T	Demand Charge	$ 4.74/kW-mo
Irrigation Pumping		
IP-1	Energy Charge	$ 0.0114/kWh
Area, Street, Highway and Signal Lighting		
PAL-1	Energy Charge	$ 0.0067/kWh
SL-1	Energy Charge	$ 0.0067/kWh
SL-2	Energy Charge	$ 0.0067/kWh
SSL-1	Energy Charge	$ 0.0067/kWh

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Second Revised Sheet No. 3
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KEY TO SYMBOLS ON REVISED TARIFF SHEETS

C - To signify changed rate or regulation
D - To signify discontinued rate or regulation
I - To signify increase
N - To signify new rate or regulation
R - To signify reduction
S - To signify reissued matter
T - To signify a change in text but no change in rate or regulation

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d/b/a BLACK HILLS ENERGY
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First Revised Sheet No. 7
Cancels Original Sheet No. 7

RESIDENTIAL SERVICE (CONTINUED)
ELECTRIC

RATE DESIGNATION – RS-1   RATE CODE – CO860

General Rate Schedule Adjustment II:	This schedule is subject to the general rate schedule adjustment II.
Purchase Capacity Cost Adjustment:	This schedule is subject to the purchase capacity cost adjustment. N
Special Terms and Conditions:	Service supplied under this schedule is subject to the terms and conditions set forth in the Company's rules and regulations, and extension policy on file with the Public Utilities Commission of the State of Colorado.

1. Multiple Dwelling Units: Where two (2) or more dwelling units are served through one (1) meter, this rate shall be applicable by multiplying the above minimum charge and energy blocks by the number of dwelling units.

2. Motors: Service for single-phase motors in excess of 7-1/2 H.P. will be supplied only at the option of the Company.

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SMALL GENERAL SERVICE – NON-DEMAND (CONTINUED)
ELECTRIC

RATE DESIGNATION – SGS-N RATE CODE – CO710

Demand Side Management Cost Adjustment:	This schedule is subject to the demand side management cost adjustment.	
General Rate Schedule Adjustment II:	This schedule is subject to the general rate schedule adjustment II.	
Purchase Capacity Cost Adjustment:	This schedule is subject to the purchase capacity cost adjustment.	N
Contract Period:	Not less than one (1) year.	
Special Terms and Conditions:	Service supplied under this schedule is subject to the terms and conditions set forth in the Company's rules and regulations, and extension policy on file with the Public Utilities Commission of the State of Colorado.	

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SMALL GENERAL SERVICE - DEMAND (CONTINUED)
ELECTRIC

RATE DESIGNATION – SGS-D RATE CODE – CO711

Auxiliary Service Rider:	This schedule is subject to the auxiliary service rider.
Demand Side Management Cost Adjustment:	This schedule is subject to the demand side management cost adjustment.
General Rate Schedule Adjustment II:	This schedule is subject to the general rate schedule adjustment II.
Purchase Capacity Cost Adjustment:	This schedule is subject to the purchase capacity cost adjustment. N
Determination of Billing Demand:	The billing demand shall be the highest average kilowatt (kW) load measured during the fifteen (15) consecutive minutes of maximum use during the billing month.
Contract Period:	Not less than one (1) year.
Special Terms and Conditions:	Service supplied under this schedule is subject to the terms and conditions set forth in the Company's rules and regulations, and extension policy on file with the Public Utilities Commission of the State of Colorado.

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LARGE GENERAL SERVICE – SECONDARY (CONTINUED)
ELECTRIC

RATE DESIGNATION – LGS-S RATE CODE – CO720

Auxiliary Service Rider:	This schedule is subject to the auxiliary service rider when applicable.
Demand Side Management Cost Adjustment:	This schedule is subject to the demand side management cost adjustment.
General Rate Schedule Adjustment II:	This schedule is subject to the general rate schedule adjustment II.
Interruptible Rider:	This schedule is subject to the interruptible rider.
Purchase Capacity Cost Adjustment:	This schedule is subject to the purchase capacity cost adjustment. **N**
Determination of Billing Demand:	The billing demand shall be the highest average kilowatt (kW) load measured during the fifteen (15) consecutive minutes of maximum use; or 75% of the highest maximum kW demand in the previous eleven (11) months; or fifty (50) kW, whichever is greatest.
Power Factor Adjustment:	For the purposes of this computation, the reactive power demand shall be the highest average kilovar (kvar) load measured during the fifteen (15) consecutive minutes of maximum use during the billing month; the real power demand (kW) will be the billing demand. When the ratio of the kvar to kW demands thus determined exceeds .33, a power factor correction charge shall be applied. This charge shall be $.36 per kvar for each kvar in excess of 33% of the kW billing demand.
Contract Period:	Not less than one year.
Special Terms and Conditions:	Service supplied under this schedule is subject to the terms and conditions set forth in the Company's rules and regulations, and extension policy on file with the Public Utilities Commission of the State of Colorado. For the purposes of this rate, service voltages of less than 4.16 kV line-to-line will be considered secondary voltage levels. If metering is at other than delivery voltage, the measured demand and energy consumption will be increased or decreased by 1% to compensate for transformer losses.

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LARGE GENERAL SERVICE - PRIMARY (CONTINUED)
ELECTRIC

RATE DESIGNATION – LGS-P RATE CODE – CO725

Demand Side Management Cost Adjustment:	This schedule is subject to the demand side management cost adjustment.	
General Rate Schedule Adjustment II:	This schedule is subject to the general rate schedule adjustment II.	
Purchase Capacity Cost Adjustment:	This schedule is subject to the purchase capacity cost adjustment.	N
Determination of Billing Demand:	The billing demand shall be the highest average kilowatt (kW) load measured during the fifteen (15) consecutive minutes of maximum use; or 75% of the highest maximum kW demand in the previous eleven (11) months; or fifty (50) kW, whichever is greatest.	
Power Factor Adjustment:	For the purposes of this computation, the reactive power demand shall be the highest average kilovar (kvar) load measured during the fifteen (15) consecutive minutes of maximum use during the billing month; the real power demand (kW) will be the billing demand. When the ratio of the kvar to kW demands thus determined exceeds .33, a power factor correction charge shall be applied. This charge shall be $.36 per kvar for each kvar in excess of 33% of the kW billing demand.	
Contract Period:	Not less than one (1) year.	
Special Terms and Conditions:	Service supplied under this schedule is subject to the terms and conditions set forth in the Company's rules and regulations, and extension policy on file with the Public Utilities Commission of the State of Colorado. For the purposes of this rate, service voltages of 4.16 kV or greater, but less than 69 kV line-to-line, will be considered primary voltage levels. The point of delivery will be Company's primary metering point. Customer must own, operate and maintain all distribution facilities such as supporting structures, disconnect devices, transformers, fuses and wiring beyond point of delivery. If metering is at other than delivery voltage, the measured demand and energy consumption will be increased or decreased by 1% to compensate for transformer losses.	

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Cancels Original Sheet No. 17

LARGE POWER SERVICE – SECONDARY (CONTINUED)
ELECTRIC

RATE DESIGNATION – LPS-S | RATE CODE – CO730

Energy Cost Adjustment:	This schedule is subject to the energy cost adjustment.
Tax/Fee Adjustment:	This schedule is subject to the tax/fee adjustment.
Auxiliary Service Rider:	This schedule is subject to the auxiliary service rider when applicable.
Demand Side Management Cost Adjustment:	This schedule is subject to the demand side management cost adjustment.
General Rate Schedule Adjustment II:	This schedule is subject to the general rate schedule adjustment II.
Purchase Capacity Cost Adjustment:	This schedule is subject to the purchase capacity cost adjustment. N
Determination of Billing Demand:	The billing demand shall be the highest average kilowatt (kW) load measured during the fifteen (15) consecutive minutes of maximum use; or 75% of the highest maximum kW demand in the previous eleven (11) months; or fourteen hundred (1400) kW; or contract demand, whichever is greatest.
Power Factor Adjustment:	For the purposes of this computation, the reactive power demand shall be the highest average kilovar (kvar) load measured during the fifteen (15) consecutive minutes of maximum use during the billing month; the real power demand (kW) will be the billing demand. When the ratio of the kvar to kW demands thus determined exceeds .33, a power factor correction charge shall be applied. This charge shall be \$.36 per kvar for each kvar in excess of 33% of the kW billing demand.
Contract Period:	Not less than one (1) year.

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LARGE POWER SERVICE - PRIMARY (CONTINUED)
ELECTRIC

RATE DESIGNATION – LPS-P RATE CODE – CO735

Energy Cost Adjustment:	This schedule is subject to the energy cost adjustment.
Tax/Fee Adjustment:	This schedule is subject to the tax/fee adjustment.
Auxiliary Service Rider:	This schedule is subject to the auxiliary service rider when applicable.
Demand Side Management Cost Adjustment:	This schedule is subject to the demand side management cost adjustment.
General Rate Schedule Adjustment II:	This schedule is subject to the general rate schedule adjustment II.
Purchase Capacity Cost Adjustment:	This schedule is subject to the purchase capacity cost adjustment. N
Determination of Billing Demand:	The billing demand shall be the highest average kilowatt (kW) load measured during the fifteen (15) consecutive minutes of maximum use; or 75% of the highest maximum kW demand in the previous eleven (11) months; or fourteen hundred (1400) kW; or contract demand whichever is greatest.
Power Factor Adjustment:	For the purposes of this computation, the reactive power demand shall be the highest average kilovar (kvar) load measured during the fifteen (15) consecutive minutes of maximum use during the billing month; the real power demand (kW) will be the billing demand. When the ratio of the kvar to kW demands thus determined exceeds .33, a power factor correction charge shall be applied. This charge shall be $.36 per kvar for each kvar in excess of 33% of the kW billing demand.
Contract Period:	Not less than one (1) year.

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LARGE POWER SERVICE - TRANSMISSION (CONTINUED)
ELECTRIC

RATE DESIGNATION – LPS-T RATE CODE – CO736

Energy Cost Adjustment:	This schedule is subject to the energy cost adjustment.
Tax/Fee Adjustment:	This schedule is subject to the tax/fee adjustment.
Auxiliary Service Rider:	This schedule is subject to the auxiliary service rider when applicable.
Demand Side Management Cost Adjustment:	This schedule is subject to the demand side management cost adjustment.
General Rate Schedule Adjustment II:	This schedule is subject to the general rate schedule adjustment II.
Purchase Capacity Cost Adjustment:	This schedule is subject to the purchase capacity cost adjustment. N
Determination of Billing Demand:	The billing demand shall be the highest average kilowatt (kW) load measured during the fifteen (15) consecutive minutes of maximum use; or 75% of the highest maximum kW demand in the previous eleven (11) months; or fourteen hundred (1400) kW; or contract demand whichever is greatest.
Power Factor Adjustment:	For the purposes of this computation, the reactive power demand shall be the highest average kilovar (kvar) load measured during the fifteen (15) consecutive minutes of maximum use during the billing month; the real power demand (kW) will be the billing demand. When the ratio of the kvar to kW demands thus determined exceeds .33, a power factor correction charge shall be applied. This charge shall be $.36 per kvar for each kvar in excess of 33% of the kW billing demand.
Contract Period:	Not less than one (1) year.

Advice Letter No. 626	Decision or Authority No.	
Signature of Issuing Officer	Issue Date November 12, 2009	
Title Manager – Colorado Electric Regulatory Affairs	Effective Date January 1, 2010	

IRRIGATION PUMPING (CONTINUED)
ELECTRIC

RATE DESIGNATION – IP-1 RATE CODE – CO770

Tax/Fee Adjustment: This schedule is subject to the tax/fee adjustment.

General Rate Schedule Adjustment II: This schedule is subject to the general rate schedule adjustment II.

Purchase Capacity Cost Adjustment: This schedule is subject to the purchase capacity cost adjustment. N

Contract Period: The contract period extends one (1) year from the date of connection to the Company's system. A new one (1) year contract period starts on the same date each year thereafter.

Determination of Billing Demand: The billing demand shall be based upon the sum of the name-plate hp ratings of all motors connected.

Special Terms and Conditions: Service supplied under this schedule is subject to the terms and conditions set forth in the Company's rules and regulations, and extension policy on file with the Public Utilities Commission of the State of Colorado.

Customer and Demand Charges: Both customer and demand charges in this rate are based upon annual revenue requirements. They are incurred on a monthly basis (one-twelfth of the annual requirement) from the date the customer is actually connected to the Company's system. Partial month demand charges are prorated according to the same procedure used to prorate demand charges for the Company's other demand rates. Although charges are incurred during each and every month of connection, bills will only be rendered over an eight (8) month period according to the following schedule:

a. March – One-eighth (1/8) of annual customer and demand charges plus a charge for energy used between the read date for the previous year's October billing and the read date for the current March bill.

b. April through October – One-eighth (1/8) of annual customer and demand charges plus a charge for energy used during each billing month respectively.

c. November through February - No bills issued.

BLACK HILLS/COLORADO ELECTRIC UTILITY COMPANY, LP
d/b/a BLACK HILLS ENERGY
105 South Victoria
Pueblo, Colorado 81003

Colo. PUC No. 8
First Revised Sheet No. 29
Cancels Original Sheet No. 29

CO-GENERATION AND SMALL POWER PRODUCTION (CONTINUED)
ELECTRIC

RATE DESIGNATION – CG-SPP1 RATE CODE – CO700

Demand Side Management Cost Adjustment:	This schedule is subject to the demand side management cost adjustment.	
General Rate Schedule Adjustment II:	This schedule is subject to the general rate schedule adjustment II.	
Purchase Capacity Cost Adjustment:	This schedule is subject to the purchase capacity cost adjustment.	N
Special Terms and Conditions:	Service supplied under this schedule is subject to the terms and conditions set forth in Attachment 1 to Colorado Public Utilities Commission Decision No. C82-1438, dated September 14, 1982 and the Company's rules and regulations and extension policy on file with the Public Utilities Commission of the State of Colorado. Metering will be in accordance with the Company's interconnection standards for cogeneration and small power production facilities on file with the Public Utilities Commission.	

Advice Letter No. 626	Decision or Authority No.	
Signature of Issuing Officer	Issue Date November 12, 2009	
Title Manager – Colorado Electric Regulatory Affairs	Effective Date January 1, 2010	

PRIVATE AREA LIGHTING
ELECTRIC

RATE DESIGNATION – PAL-1

Effective In:	All territory served.
Classification:	Area and grounds lighting.
Availability:	Available for area lighting using street light equipment installed in accordance with Company street lighting standards, at the voltage and current of Company's established distribution system for such service, for use in lighting private areas and grounds, for protective and safety purposes only. This rate will not be applicable or available to new customers after March 20, 1994.
Character of Service:	Alternating current, 60 Hertz, single-phase, 120/240 V.
Monthly Rate:	Dusk to Dawn burning: Mercury Vapor Lamps - nominal lumen rating 7,000 lumens, 70 kWh, per lamp, per month .... $13.61 20,000 lumens, 154 kWh, per lamp, per month.... $23.22
Payment and Late Payment Charge:	Bills for electric service are due and payable within ten (10) days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge set forth in the Company's rules and regulations.
Energy Cost Adjustment:	This schedule is subject to the energy cost adjustment.
Tax/Fee Adjustment:	This schedule is subject to the tax/fee adjustment.
Demand Side Management Cost Adjustment:	This schedule is subject to the demand side management cost adjustment.
General Rate Schedule Adjustment II:	This schedule is subject to the general rate schedule adjustment II.
Purchase Capacity Cost Adjustment:	This schedule is subject to the purchase capacity cost adjustment. **N**

BLACK HILLS/COLORADO ELECTRIC UTILITY COMPANY, LP
d/b/a BLACK HILLS ENERGY
105 South Victoria
Pueblo, Colorado 81003

Colo. PUC No. 8
First Revised Sheet No. 33
Cancels Original Sheet No. 33

STREET, ALLEY, PARK AND HIGHWAY LIGHTING (CONTINUED)
ELECTRIC

RATE DESIGNATION – SL-1

Monthly Rate:	Type 2: High Pressure Sodium Lamps - Burning Dusk to Dawn: 16,000 lumens, 68 kWh, per lamp, per month........ $8.26 50,000 lumens, 160 kWh, per lamp, per month.... $14.73
Payment and Late Payment Charge:	Bills for electric service are due and payable within ten (10) days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge set forth in the Company's rules and regulations.
Energy Cost Adjustment:	This schedule is subject to the energy cost adjustment.
Tax/Fee Adjustment:	This schedule is subject to the tax/fee adjustment.
Demand Side Management Cost Adjustment:	This schedule is subject to the demand side management cost adjustment.
General Rate Schedule Adjustment II:	This schedule is subject to the general rate schedule adjustment II.
Purchase Capacity Cost Adjustment:	This schedule is subject to the purchase capacity cost adjustment. N
Contract Period:	Not less than five (5) years.
Special Terms and Conditions:	Service supplied under this schedule is subject to the terms and conditions set forth in the Company's rules and regulations, and extension policy on file with the Public Utilities Commission of the State of Colorado. The following provisions are intended to apply generally and in the absence of any precedential, Commission-approved, contractual agreements between the customer and the Company.

Advice Letter No. 626	Decision or Authority No.	
Signature of Issuing Officer	Issue Date November 12, 2009	
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BLACK HILLS/COLORADO ELECTRIC UTILITY COMPANY, LP
d/b/a BLACK HILLS ENERGY
105 South Victoria
Pueblo, Colorado 81003

TRAFFIC SIGNAL LIGHTING
ELECTRIC

RATE DESIGNATION – SL-2

Effective In:	All territory served.
Classification:	Municipalities, governmental agencies and subdivisions, and other customers who operate traffic signals on public thoroughfares or highways.
Availability:	Customers operating police and fire alarm lights, traffic lights, or other signal or warning lights owned, operated and maintained by the customer.
Character of Service:	Alternating current, 60 Hertz, single-phase, 120/240 volts.
Monthly Rate:	Traffic Signals - Stop and Go All kWh used, per month, per kWh........................ $0.04710 Flashers - Including School Flashers, per installation, per month $2.32
Payment and Late Payment Charge:	Bills for electric service are due and payable within ten (10) days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge set forth in the Company's rules and regulations.
Energy Cost Adjustment:	This schedule is subject to the energy cost adjustment.
Tax/Fee Adjustment:	This schedule is subject to the tax/fee adjustment.
Demand Side Management Cost Adjustment:	This schedule is subject to the demand side management cost adjustment.
General Rate Schedule Adjustment II:	This schedule is subject to the general rate schedule adjustment II.
Purchase Capacity Cost Adjustment:	This schedule is subject to the purchase capacity cost adjustment. **N**

Advice Letter No. 626	Decision or Authority No.	
Signature of Issuing Officer	Issue Date November 12, 2009	
Title Manager – Colorado Electric Regulatory Affairs	Effective Date January 1, 2010	

BLACK HILLS/COLORADO ELECTRIC UTILITY COMPANY, LP
d/b/a BLACK HILLS ENERGY
105 South Victoria
Pueblo, Colorado 81003

Colo. PUC No. 8
First Revised Sheet No. 38
Cancels Original Sheet No. 38

STREET / SECURITY LIGHTING
ELECTRIC

RATE DESIGNATION – SSL-1

Effective In:	All territory served.
Classification:	Street, alley, park, highway, area and ground lighting.
Availability:	Available to municipalities or other governmental subdivisions, school districts, and unincorporated communities and for lighting county streets, major highways and public grounds. Available for area lighting using street light equipment installed in accordance with Company street lighting standards, at the voltage and current of the Company's established distribution system for such service, for use in lighting private areas and grounds, for protective and safety purposes.
Character of Service:	Alternating current, 60 Hertz, single-phase, 120/240 V.
Monthly Rate:	Customer owned.. See Applicable Section Company owned..See Unmetered Facilities Table
Payment and Late Payment Charge:	Bills for electric service are due and payable within ten (10) days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge set forth in the Company's rules and regulations.
Energy Cost Adjustment:	This schedule is subject to the energy cost adjustment.
Tax/Fee Adjustment:	This schedule is subject to the tax/fee adjustment.
Demand Side Management Cost Adjustment:	This schedule is subject to the demand side management cost adjustment.
General Rate Schedule Adjustment II:	This schedule is subject to the general rate schedule adjustment II.
Purchase Capacity Cost Adjustment:	This schedule is subject to the purchase capacity cost adjustment. N

Advice Letter No. 626	Decision or Authority No.	
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BLACK HILLS/COLORADO ELECTRIC UTILITY COMPANY, LP
d/b/a BLACK HILLS ENERGY
105 South Victoria
Pueblo, Colorado 81003

Colo. PUC No. 8
First Revised Sheet No. 54
Cancels Original Sheet No. 54

VOLUNTARY LOAD CURTAILMENT (VLC) RIDER
ELECTRIC

Effective In:	All territory served.
Availability:	This Rider is available to any nonresidential Customer that has a peak demand in the past twelve (12) months exceeding two hundred fifty (250) kW and that has a contract with the Company for service under this Rider. Availability is further subject to the economic and technical feasibility of required metering equipment. The decision to execute a contract with any Customer under this Rider is subject to the sole discretion of the Company. The decision to reduce load upon request of the Company is subject to the sole discretion of each eligible Customer.
Payment and Late Payment Charge:	Bills for electric service are due and payable within ten (10) days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge set forth in the Company's rules and regulations.
Minimum Charge:	Charges for service shall be computed in accordance with the applicable rate schedule.
Energy Cost Adjustment:	This schedule is NOT subject to the energy cost adjustment.
Tax/Fee Adjustment:	This schedule is subject to the tax/fee adjustment.
Auxiliary Service Rider:	This schedule is subject to the auxiliary service rider when applicable.
Demand Side Management Cost Adjustment:	This schedule is subject to the demand side management cost adjustment.
General Rate Schedule Adjustment II:	This schedule is subject to the general rate schedule adjustment II.
Purchase Capacity Cost Adjustment:	This schedule is NOT subject to the purchase capacity cost adjustment. **N**

Advice Letter No. 626	Decision or Authority No.	
Signature of Issuing Officer	Issue Date November 12, 2009	
Title Manager – Colorado Electric Regulatory Affairs	Effective Date January 1, 2010	

Xcel Energy

Direct Dial: 303-294-2377
karen.t.hyde@xcelenergy.com

October 30, 2009

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Public Service Company of Colorado, Docket No. ER10-___-000

Dear Ms. Bose:

Pursuant to Section 35.13 of the Commission's regulations, 18 C.F.R. § 35.13 (2009), Public Service Company of Colorado, a wholly-owned subsidiary of Xcel Energy Inc. ("PSCo" or "Company"), submits for filing changes in base rates applicable to service to the following seven wholesale electric customers (collectively, the "Wholesale Customers"): Black Hills/Colorado Electric Utility Company, LP ("Black Hills"); the City of Burlington, Colorado ("Burlington"); the Town of Center, Colorado ("Center"); Grand Valley Rural Power Lines, Inc. ("Grand Valley"); Holy Cross Electric Association, Inc. ("Holy Cross"); Intermountain Rural Electric Association ("IREA") and Yampa Valley Electric Association, Inc. ("Yampa Valley").

PSCo also is proposing to make three changes to its Wholesale Fuel Cost and Economic Purchased Power Adjustment Clause ("FCA").

PSCo's filing is submitted in seven volumes as follows:

1. Volume I, containing this transmittal letter; a list of customers and state commissions served with this filing; the testimony and exhibits of Ms. Deborah Blair, Director Revenue Analysis for Xcel Energy Services Inc. (XES), Mr. William Avera, President of FINCAP, Inc., Mr. James Jordan, Pricing Consultant for XES, Mr. James Vader, Director, Plant Projects for XES, and the required attestation of Ms. Teresa S. Madden, Vice President and Controller of Xcel Energy Services Inc., as to the cost of service statements and supporting data submitted as part of the filing;

2. Volume II, containing the testimony and exhibits of Ms. Lisa H. Perkett, Director, Capital Asset Accounting for XES;

3. Volume III, containing the revised rate sheets for the individual Wholesale Customers, both a clean version and a red-lined version;

4. Volume IV, containing Statements AA through BL relating to Period I (calendar year 2008) and Statements AA through BL relating to Period II (calendar year 2010);

5. Volume V, containing supporting attachments for Statement AV;

6. Volume VI, containing the workpapers related to the Statements; and

7. Volume VII, containing Budget Documentation.

As required by the Commission's regulations, PSCo submits an original and five (5) copies of each of the seven volumes.

Reasons for the Filing

The Company is making this filing in order to have an opportunity to recover its costs and to earn an appropriate rate of return in light of significant increased costs. In particular, the Company is placing two significant generation additions in service: Comanche Unit 3 and Fort St. Vrain Units 5 and 6.

A. Base Rates

PSCo's current wholesale rates for all of the Wholesale Customers other than IREA are based on a 2008 calendar year Period II and have been in effect since May 1, 2008 pursuant to settlements approved by the Commission in the Company's last rate case for service to those customers at Docket No. ER08-527, *Public Service Company of Colorado*, 123 FERC ¶ 61,268 (2008). PSCo's current wholesale rates for IREA also are based on a 2008 calendar year Period II and have been in effect since January 1, 2009 pursuant to a settlement between the Company and IREA at Docket No. ER09-133, *Public Service Company of Colorado*, 125 FERC ¶ 61,370 (2008).

In all of the settlements, the Company and the affected customer agreed that in a subsequent rate filing -- this filing -- the Company could place rates that include certain Additional Plant Costs into effect, subject to refund, on the Comanche 3 commercial operation date if that date coincided with the first day of a month. If the two dates did not coincide, rates inclusive of the Additional Plant Costs are to go into effect on the first day of the month following the commercial operation date. Thus, the customers agreed not to seek more than a nominal suspension of a rate increase premised on the Additional Plant Costs. To the extent that PSCo also filed to increase rates based on other increased costs, the customers retained the right, as to those increases, to seek a longer suspension pursuant to Section 205 of the Federal Power Act.[1]

The Additional Plant Costs are limited to the costs of Comanche 3, the pollution control facilities for Comanche 1 and 2, and the two additional combustion turbine peaking generators at Fort St. Vrain. The Fort St. Vrain units were put in service in April 2009. All of the pollution control equipment for Comanche 1 and 2 is scheduled to be in service on or before January 1, 2010 and Comanche 3 is expected to achieve commercial operation on or before that date.

In addition to the Additional Plant Costs, the 2010 test year includes, *inter alia*, 12 months of the O&M costs related to Comanche 3 and the additional Fort St. Vrain units and revised depreciation rates. The revised depreciation rates will increase the revenue requirement for Period II by about $5.9 million. The revised rates result from a new depreciation study and the retirement of three power plants. Certain plants are being retired early per the approval of the Colorado Public Utilities Commission in order to reduce carbon dioxide emissions and start on a path toward reaching the kind of carbon dioxide emissions the Company anticipates will be required at the federal level pursuant to future legislation.

B. The FCA

The first change to the FCA involves changes to the Company's Windsource program, a retail premium pricing renewable energy program, and how these changes modify the resource pool available for Wholesale Customers. The second change involves the Company's proposal for time-of-use differentiated energy rates. The third change involves the potential for Congressional approval of climate change legislation.

<u>The Filing</u>

The total increase in revenue requirements for the Wholesale Customers is $36,930,145, of which $26,391,944 is attributable to the Additional Plant Costs. The Period II revenue increases that reflect the full $36,930,145 are as follows:

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[1] PSCo also agreed in the settlements with all of the Wholesale Customers to a moratorium on a wholesale rate increase until the earlier of the commercial operation date of the Comanche 3 generating facility or January 1, 2010.

Customer	Increase Over Present	Percentage
IREA	$9,887,036	14.44%
Holy Cross	$4,373,186	10.55%
Grand Valley	$2,825,147	18.80%
Yampa Valley	$4,131,548	12.63%
Burlington	$217,907	12.04%
Center	$51,234	7.18%
Black Hills	$15,444,064	14.17%
Total	$36,930,145	13.94%

The rates proposed for the Wholesale Customers are designed to generate a Period II return on common equity ("ROE") of 12.5 percent, which is 50 basis points less than the mid-point of the Discounted Cash Flow ("DCF") range calculated by the Company's cost of capital expert, Dr. William E. Avera, based on a 20-company proxy group. The Company is sensitive to the rate impact of including the Comanche 3 and additional Fort St. Vrain facilities in rate base and has therefore chosen to file a ROE that is considerably less than it could reasonably have requested.

Miscellaneous Tariff Housekeeping Revisions

Black Hills is served under Rate Schedule No. 6, which currently identifies the customer as Aquila, Inc. On July 17, 2008, Black Hills Corporation notified the Commission that, pursuant to authorizations granted in Docket No. EC07-99, et al., Black Hills had consummated its acquisition of five Aquila, Inc. utility subsidiaries, including Aquila's Colorado electric utility in Colorado. A new legal entity, Black Hills/Colorado Electric Utility Company, LP, has been established to own Aquila's former Colorado utility assets. PSCo is therefore filing a revised Rate Schedule No. 6 that reflects this name change.

Since the Company's filing in Docket No. ER08-527, PSCo has revised its transmission rates to reflect a formula rate approach. Accordingly, the relevant provisions of the wholesale tariffs that address calculation and billing for transmission services related to the wholesale supply services have been revised to reflect PSCo's new transmission rate setting mechanism.

Finally, in the course of preparing its application in this case, PSCo discovered certain ministerial errors in the text and pagination of the tariff sheets currently on file for the seven service agreements impacted by the current application. Accordingly, PSCo is including in this application revised tariff sheets to correct these typographical and pagination errors.

A list of all of the proposed revised tariff sheets is included in this filing.

Effective Date

Consistent with the Commission-approved settlements in Docket Nos. ER08-357 and ER09-133, and an expected commercial operation date for Comanche 3 on or before January 1, 2010, the Company has filed tariff sheets with increased rates based only on the Additional Plant Costs, to be effective January 1, 2010 (the "Additional Plant Costs Tariff Sheets"). The Company has also filed tariff sheets that reflect both the Additional Plant Costs and the other Period II cost increases, also with a proposed effective date of January 1, 2010 (the "Full Costs Tariff Sheets").

Per the terms of the settlements, the Additional Plant Cost Tariff Sheets are subject to only a nominal suspension.[2] The Company requests that the Additional Plant Cost Tariff Sheets be made effective only in the event that the Commission suspends the Full Cost Tariff Sheets for a period ending after January 1, 2010. In that event, once the suspension period for the Full Cost Tariff Sheets ends and those sheets are allowed to go into effect, the Full Cost Tariff Sheets would supersede the Additional Plant Cost Tariff Sheets.

PSCo respectfully submits that the revenues generated by the proposed rates set forth on the Full Cost Tariff Sheets are not substantially excessive. First, the proposed ROE is 50 basis points less than the ROE supported by the Company's rate of return witness using the Commission's preferred DCF method. Second, the proposed rates do not include approximately $4.9 million of non-PC CWIP although inclusion of that CWIP in the Wholesale Customers' rates clearly would be allowed under the Commission's regulations. Third, although Commission policy would permit PSCo to include in the wholesale customer class rate base a cash working capital allowance in excess of $3 million developed in accordance with the 45-day convention, PSCo is proposing a zero cash working capital allowance. Therefore, the proposed rates can be accepted for filing without suspension, or, at the least, qualify for a minimum suspension under the Commission's suspension policy.

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[2] *See* 123 FERC ¶ 61,268 at P 11; 125 FERC ¶ 61,370 at P 3. As noted above, the settlements provide that, if the Additional Plant Cost Tariff Sheets are made effective, they will be in effect subject to refund. The settlements do not require that the Full Cost Tariff Sheets be subject to refund, i.e. those sheets may be made effective without suspension.

Other Filing Requirements

PSCo has reviewed the power and energy supply contracts with each of the Wholesale Customers and has determined that there is no bar to a unilateral filing to make the rates, terms and conditions submitted herewith effective on January 1, 2010, pursuant to Section 205 of the Federal Power Act.

No expense or cost included in the cost of service statements for Period I or Period II has been alleged or judged in any administrative or judicial proceeding to be illegal or duplicative or an unnecessary cost or expense that is demonstrably the product of discriminatory employment practices. No specifically assignable facilities have been or will be installed or modified in order to supply the service rendered under the rate schedules that PSCo seeks to change by this filing.

Service

PSCo has served a copy of the complete filing on each of the Wholesale Customers as indicated on the attached service list. PSCo also has mailed a complete copy of the filing to the PUC and the Colorado Office of Consumer Counsel. Copies of the filing are available for public inspection in PSCo's offices in Denver, Colorado.

Correspondence and Communications

Correspondence and communications with respect to this filing should be addressed to the following:

Karen T. Hyde
Vice President, Rates and Regulatory
Affairs - Colorado
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1225 17th Street
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rwhite@ssd.com
nawhite@ssd.com

PSCo requests that the above-listed persons be included on the service list to be established in this proceeding.

Request for Waiver

PSCo has made every effort to comply fully with the Commission's filing requirements set forth in Section 35.13 of the Commission's regulations. In the event that the Commission, upon review of the filing, should find that PSCo has misinterpreted or failed to respond in some detail to the filing requirements, PSCo requests that the Commission waive any failure to comply strictly with such filing requirements in recognition of PSCo's good faith attempt at compliance.

Respectfully submitted,

Karen T. Hyde /KSW

Karen T. Hyde
Vice President, Rates and Regulatory Affairs
Colorado
Xcel Energy Services Inc., on behalf of
Public Service Company of Colorado

cc: All affected customers (See Attachment A to this letter)
Colorado Public Utilities Commission
Colorado Office of Consumer Counsel

Public Service Company of Colorado
Proposed Rate Design
Service and Facility Charges
12 Months Ended December 31, 2010

Line No.	Customer	Customer Months	Customer Costs (1) Billing and Customer Service $	Meters $	Specific Distribution Substations $	Total Customer Costs $	Proposed Service & Facility Charge $ / Month
1	Burlington	12	16,161	3,259	0	19,420	1,600
2	Center						
3	Transmission	12	16,161	3,259	0	19,420	1,600
4	Primary	12	10,748	2,305	0	13,053	1,100
5	Total		26,909	5,564	0	32,473	2,700
6	Intermountain						
7	Transmission	12	199,545	420,104	91,909	711,558	59,300
8	Primary	12	10,748	2,305	0	13,053	1,100
9	Total		210,293	422,409	91,909	724,611	60,400
10	Holy Cross	12	146,022	119,738	142,814	408,574	34,000
11	Grand Valley	12	54,035	72,277	768,571	894,883	74,600
12	Yampa Valley	12	37,803	42,291	0	80,094	6,700
13	Black Hills - CO	12	40,754	0	0	40,754	3,400
14	Total at Issue		531,977	665,538	1,003,294	2,200,809	183,400

(1) Customer Costs from Statement BE, Period II, Pages 1, 2, and 3.

Public Service Company of Colorado
Proposed Rate Design
Production Demand Charges
12 Months Ended December 31, 2010

Line No.	Customer	Billing Demand kW-Mo	Production Demand Costs: Production Demand Cost (1) $	Prod Demand Additional Facilities Cost (1) $	Prod CWIP Poll. Control Cost (1) $	Subtotal $	Sched 2,3,5,6 Ancillary Services (2) $	Total Demand Costs $	Proposed Demand Charge $ / kW-Mo	Proposed Demand Charge Additional Facilities $ / kW-Mo
1	Burlington	57,459	730,538	171,899	2,075	904,512	(32,340)	872,172	15.18	2.99
2	Center									
3	Transmission	19,766	195,864	46,087	760	242,711	(8,666)	234,045	11.82 (3)	2.33 (3)
4	Primary	5,628	56,750	13,354	183	70,287	(2,514)	67,773	12.10 (3)	2.38 (3)
5	Total	25,394	252,614	59,441	943	312,998	(11,180)	301,818		
6	Intermountain									
7	Transmission	2,431,828	29,496,551	6,940,665	112,196	36,549,412	(1,243,393)	35,306,019	14.52 (3)	2.85 (3)
8	Primary	47,718	584,677	137,577	1,221	723,475	(22,506)	700,969	14.86 (3)	2.92 (3)
9	Total	2,479,546	30,081,228	7,078,242	113,417	37,272,887	(1,265,899)	36,006,988		
10	Holy Cross	1,383,174	15,645,460	3,681,444	53,197	19,380,101	0	19,380,101	14.01	2.66
11	Grand Valley	532,693	6,493,710	1,527,998	25,623	8,047,331	(287,414)	7,759,917	14.57	2.87
12	Yampa Valley	1,016,737	12,944,016	3,045,782	39,608	16,029,406	(572,914)	15,456,492	15.20	3.00
13	Black Hills - CO	3,600,000	46,013,350	10,827,138	8,278	56,848,766	(2,036,620)	54,812,146	15.23	3.01
14	Total at Issue	9,095,003	112,160,916	26,391,944	243,141	138,796,001	(4,206,367)	134,589,634		

(1) Production Demand Costs from Statement BK, Period II, Page 43
(2) Schedule 2, 3, 4 and 5 Ancillary Service Charges form this Statement BL, Page 6
(3) See Page 3 of this Statement BL for Center and Intermountain demand charge determination.

Public Service Company of Colorado
Proposed Rate Design
Production Demand Charges - Town of Center & IREA
12 Months Ended December 31, 2010

Line No.	Customer	A Billing Demand kW-Mo	B Distrib. Loss Factor	C (A x B) Adjusted Billing Demand kW-Mo	D Total Demand Costs $	E (D x C) Unit Cost @ Transmission Level $ / kW-Mo	F Distrib. Loss Factor	G (E x F) Proposed Demand Charge $ / kW-Mo
	Total Demand Charge							
1	Center							
2	Transmission	19,766	1.0000	19,766			1.0000	11.82
3	Primary	5,628	1.0235	5,760			1.0235	12.10
4	Total	25,394		25,526	301,818	11.8239		
5								
6	Intermountain							
7	Transmission	2,431,828	1.0000	2,431,828			1.0000	14.52
8	Primary	47,718	1.0235	48,839			1.0235	14.86
9	Total	2,479,546		2,480,667	36,006,988	14.5150		
10								
11								
12	**Additional Facilities Only**							
13								
14	Center							
15	Transmission	19,766	1.0000	19,766			1.0000	2.33
16	Primary	5,628	1.0235	5,760			1.0235	2.38
17	Total	25,394		25,526	59,441	2.3286		
18								
19	Intermountain							
20	Transmission	2,431,828	1.0000	2,431,828			1.0000	2.85
21	Primary	47,718	1.0235	48,839			1.0235	2.92
22	Total	2,479,546		2,480,667	7,078,242	2.8534		

Public Service Company of Colorado
Proposed Rate Design
Production Demand Charges
12 Months Ended December 31, 2010

Line No.	Customer	Existing Demand Rate $/kW-Mo	Proposed Additional Facilities Demand Rate $/kW-Mo	Proposed Demand Rate 60 Days After Filing $/kW-Mo (1)	Total Proposed Demand Rate $/kW-Mo
1	Burlington	11.20	2.99	14.19	15.18
2	Center - Transmission	8.83	2.33	11.16	11.82
3	Center - Primary	9.04	2.38	11.42	12.10
4	Intermountain - Transmission	10.60	2.85	13.45	14.52
5	Intermountain - Primary	10.85	2.92	13.77	14.86
6	Holy Cross	10.77	2.66	13.43	14.01
7	Grand Valley	10.47	2.87	13.34	14.57
8	Yampa Valley	11.02	3.00	14.02	15.20
9	Black Hills - Colorado	11.02	3.01	14.03	15.23

Public Service Company of Colorado
Proposed Rate Design
Base Energy Charges
12 Months Ended December 31, 2010

On-Peak/Off Peak Differential	1.36
Burlington Wheeling Losses	1.06
Primary Distribution Losses	1.0235

Line No.	Customer	Billing kWh	On-Peak Billing kWh	Off-Peak Billing kWh	On Peak Equivalent Off-Peak Billing kWh	Total Equivalent Off-Peak Billing kWh	Base Fuel & PP Cost (1) $	Non-Fuel Energy Cost (1,2) $	Specific Third Party Wheeling Charge $ / kWh	Proposed Off-Peak Fuel Base Energy Charge $ / kWh	Proposed On-Peak Fuel Base Energy Charge $ / kWh	Proposed Non-Fuel Base Energy Charge $ / kWh
1	Burlington	30,692,573	17,554,269	13,138,304					0.00130000	0.02627	0.03572	0.00532
2	Center											
3	Transmission	10,893,323	3,872,738	7,020,585					-	0.02478	0.03370	0.00379
4	Primary	2,568,704	1,565,920	1,002,784					-	0.02536	0.03449	0.00388
5	Total	13,462,027	5,438,658	8,023,369								
6	Intermountain											
7	Transmission	1,081,849,041	638,290,934	443,558,107					-	0.02478	0.03370	0.00379
8	Primary	22,986,935	13,750,081	9,236,854					-	0.02536	0.03449	0.00388
9	Total	1,104,835,976	652,041,015	452,794,961								
10	Holy Cross	769,520,153	446,321,689	323,198,464					-	0.02478	0.03370	0.00379
11	Grand Valley	270,603,175	163,563,732	107,039,443					-	0.02478	0.03370	0.00379
12	Yampa Valley	632,605,062	360,820,349	271,784,713					-	0.02478	0.03370	0.00379
13	Black Hills - CO	2,049,840,001	1,233,316,831	816,523,170					-	0.02478	0.03370	0.00379
14	Total	4,871,558,967	2,879,056,543	1,992,502,424	3,915,516,898	5,908,019,322	146,391,415	18,459,188		0.02478	0.03370	0.00379

(1) Base Energy Costs from Statement BK, Period II, Page 46
(2) Includes Rate Case Expenses of $310,310

Public Service Company of Colorado
Proposed Rate Design
Production Time-of-Use Energy Charges
12 Months Ended December 31, 2010

Line No.	Customer	Proposed Off-Peak Fuel & Purch Power $/kWh	Proposed On-Peak Fuel & Purch Power $/kWh	Proposed Non-Fuel Energy $/kWh	Total Proposed Off-Peak Energy Charge $/kWh	Total Proposed On-Peak Energy Charge $/kWh
1	Burlington	0.02627	0.03572	0.00532	0.03159	0.04104
2	Center - Transmission	0.02478	0.03370	0.00379	0.02857	0.03749
3	Center - Primary	0.02536	0.03449	0.00388	0.02924	0.03837
4	Intermountain - Transmission	0.02478	0.03370	0.00379	0.02857	0.03749
5	Intermountain - Primary	0.02536	0.03449	0.00388	0.02924	0.03837
6	Holy Cross	0.02478	0.03370	0.00379	0.02857	0.03749
7	Grand Valley	0.02478	0.03370	0.00379	0.02857	0.03749
8	Yampa Valley	0.02478	0.03370	0.00379	0.02857	0.03749
9	Black Hills - Colorado	0.02478	0.03370	0.00379	0.02857	0.03749

Public Service Company of Colorado
Proposed Rate Design
Ancillary Services Costs
12 Months Ended December 31, 2010

Line No.	Customer	Annual Coin Peak @ Tran Output kW-Mo	Loss Factor	Annual Coin Peak @ Tran Input kW-Mo	Ancillary Services Full Tariff Rate Req'd Purchase	Billing kW-Mo	Rate $/kW-Mo	Revenue $
Schedule 2: Reactive Supply and Voltage Control from Generation Sources								
1	Burlington	57,158	3.00%	58,873	100.0%	58,873	0.0775	4,563
2	Center							
3	Transmission	15,318	3.00%	15,778	100.0%	15,778	0.0775	1,223
4	Primary	4,442	3.00%	4,575	100.0%	4,575	0.0775	355
5	Intermountain							
6	Transmission	2,197,865	3.00%	2,263,801	100.0%	2,263,801	0.0775	175,445
7	Primary	39,778	3.00%	40,971	100.0%	40,971	0.0775	3,175
8	Holy Cross	1,196,073	3.00%	1,231,955	-	-	-	-
9	Grand Valley	508,056	3.00%	523,298	100.0%	523,298	0.0775	40,556
10	Yampa Valley	1,012,715	3.00%	1,043,096	100.0%	1,043,096	0.0775	80,840
11	Black Hills - CO	3,600,000	3.00%	3,708,000	100.0%	3,708,000	0.0775	287,370
Schedule 3: Regulation and Frequency Response								
12	Burlington	57,158	3.00%	58,873	1.5%	883	6.740	5,951
13	Center							
14	Transmission	15,318	3.00%	15,778	1.5%	237	6.740	1,597
15	Primary	4,442	3.00%	4,575	1.5%	69	6.740	465
16	Intermountain							
17	Transmission	2,197,865	3.00%	2,263,801	1.5%	33,957	6.740	228,870
18	Primary	39,778	3.00%	40,971	1.5%	615	6.740	4,145
19	Holy Cross	1,196,073	3.00%	1,231,955	-	-	-	-
20	Grand Valley	508,056	3.00%	523,298	1.5%	7,849	6.740	52,902
21	Yampa Valley	1,012,715	3.00%	1,043,096	1.5%	15,646	6.740	105,454
22	Black Hills - CO	3,600,000	3.00%	3,708,000	1.5%	55,620	6.740	374,879
Schedule 5: Spinning Reserves								
23	Burlington	57,158	3.00%	58,873	3.5%	2,061	6.875	14,169
24	Center							
25	Transmission	15,318	3.00%	15,778	3.5%	552	6.875	3,795
26	Primary	4,442	3.00%	4,575	3.5%	160	6.875	1,100
27	Intermountain							
28	Transmission	2,197,865	3.00%	2,263,801	3.5%	79,233	6.875	544,727
29	Primary	39,778	3.00%	40,971	3.5%	1,434	6.875	9,859
30	Holy Cross	1,196,073	3.00%	1,231,955	-	-	-	-
31	Grand Valley	508,056	3.00%	523,298	3.5%	18,315	6.875	125,916
32	Yampa Valley	1,012,715	3.00%	1,043,096	3.5%	36,508	6.875	250,993
33	Black Hills - CO	3,600,000	3.00%	3,708,000	3.5%	129,780	6.875	892,238
Schedule 6: Supplemental Reserves								
34	Burlington	57,158	3.00%	58,873	3.5%	2,061	3.715	7,657
35	Center							
36	Transmission	15,318	3.00%	15,778	3.5%	552	3.715	2,051
37	Primary	4,442	3.00%	4,575	3.5%	160	3.715	594
38	Intermountain							
39	Transmission	2,197,865	3.00%	2,263,801	3.5%	79,233	3.715	294,351
40	Primary	39,778	3.00%	40,971	3.5%	1,434	3.715	5,327
41	Holy Cross	1,196,073	3.00%	1,231,955	-	-	-	-
42	Grand Valley	508,056	3.00%	523,298	3.5%	18,315	3.715	68,040
43	Yampa Valley	1,012,715	3.00%	1,043,096	3.5%	36,508	3.715	135,627
44	Black Hills - CO	3,600,000	3.00%	3,708,000	3.5%	129,780	3.715	482,133
Total Schedules 2,3,5 and 6:								
45	Burlington	57,158	3.00%	58,873				32,340
46	Center							
47	Transmission	15,318	3.00%	15,778				8,666
48	Primary	4,442	3.00%	4,575				2,514
49	Intermountain							
50	Transmission	2,197,865	3.00%	2,263,801				1,243,393
51	Primary	39,778	3.00%	40,971				22,506
52	Holy Cross	1,196,073	3.00%	1,231,955				-
53	Grand Valley	508,056	3.00%	523,298				287,414
54	Yampa Valley	1,012,715	3.00%	1,043,096				572,914
55	Black Hills - CO	3,600,000	3.00%	3,708,000				2,036,620

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills/Colorado Electric Utility Company, LP	(1) [X] An Original (2) [ ] A Resubmission	08/28/2009	End of 2009/Q2

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Report in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	83,654,694		40,421,115	
3	Operating Expenses					
4	Operation Expenses (401)	320-323	73,277,556		34,454,810	
5	Maintenance Expenses (402)	320-323	2,417,646		1,488,060	
6	Depreciation Expense (403)	336-337	6,558,645		3,257,077	
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	150,948		88,507	
	Amort. of Utility Plant Acq. Adj. (406)	336-337				
	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)					
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	1,250,421		555,144	
15	Income Taxes - Federal (409.1)	262-263	-8,997,230		-5,126,366	
16	- Other (409.1)	262-263	-517,227		-294,461	
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	10,698,624		5,372,517	
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	4,033,573		1,486,177	
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		80,805,810		38,309,111	
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		2,848,884		2,112,004	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills/Colorado Electric Utility Company, LP	(1) [X] An Original (2) [ ] A Resubmission	08/28/2009	End of 2009/Q2

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
1‹ ‹ive concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be ‹ the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected \ ‹ss revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
83,654,694						2
						3
73,277,556						4
2,417,646						5
6,558,645						6
						7
150,948						8
						9
						10
						11
						12
						13
1,250,421						14
-8,997,230						15
-517,227						16
10,698,624						17
4,033,573						18
						19
						20
						21
						22
						23
						24
80,805,810						25
2,848,884						26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills/Colorado Electric Utility Company, LP	(1) [X] An Original (2) [ ] A Resubmission	08/28/2009	End of 2009/Q2

STATEMENT OF INCOME FOR THE YEAR (continued)

Line	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		2,848,884		2,112,004	
28	Other Income and Deductions					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		930,261		891,140	
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		912,310		531,511	
33	Revenues From Nonutility Operations (417)		240,874		118,484	
34	(Less) Expenses of Nonutility Operations (417.1)		142,187		76,582	
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		60,566		32,571	
38	Allowance for Other Funds Used During Construction (419.1)		-16		-16	
39	Miscellaneous Nonoperating Income (421)		6,939		6,567	
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		184,127		440,653	
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		30,963		22,250	
46	Life Insurance (426.2)					
47	Penalties (426.3)		-22		-22	
	Exp. for Certain Civic, Political & Related Activities (426.4)		35,120		29,513	
	Other Deductions (426.5)					
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		66,061		51,741	
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	17,000		15,224	
53	Income Taxes-Federal (409.2)	262-263	35,355		143,032	
54	Income Taxes-Other (409.2)	262-263	2,020		8,174	
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277				
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277				
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		54,375		166,430	
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		63,691		222,482	
61	Interest Charges					
62	Interest on Long-Term Debt (427)		1,246,350		1,246,350	
63	Amort. of Debt Disc. and Expense (428)		2,894,696		2,176,856	
64	Amortization of Loss on Reaquired Debt (428.1)					
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		237,982		208,322	
68	Other Interest Expense (431)		3,955,892		1,505,830	
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		487,732		375,461	
70	Net Interest Charges (Total of lines 62 thru 69)		7,847,188		4,761,897	
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		-4,934,613		-2,427,411	
72	Extraordinary Items					
	Extraordinary Income (434)					
	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		-4,934,613		-2,427,411	

Appendix D

Date of Notice: November ____, 2009

NOTICE OF REQUEST TO IMPLEMENT A PURCHASED CAPACITY COST ADJUSTMENT TARIFF By Black Hills/Colorado Electric Utility Company, LP d/b/a Black Hills Energy

You are hereby notified that Black Hills/Colorado Electric Utility Company, LP, d/b/a Black Hills Energy, 105 South Victoria Avenue, Pueblo, Colorado, 81003, has filed with the Public Utilities Commission of the State of Colorado ("Commission"), in compliance with the Public Utilities Law and pursuant to Colo. Rev. Stat. §§ 40-3-111 and 40-6-111, new tariffs to implement a Purchased Capacity Cost Adjustment (''PCCA'') mechanism and rate rider to recover the increased costs that it incurs for purchased capacity through a purchased power agreement with Public Service Company of Colorado ("Public Service"). The proposed new PCCA tariff and rate rider are requested to become effective on January 1, 2010, and would affect all retail customers if the Commission allows the tariffs to become effective.

The filing of the new PCCA tariffs is in direct response to a wholesale rate case filed by Public Service on October 30, 2009 with the Federal Energy Regulatory Commission ("FERC"). Public Service has requested that the FERC allow the new wholesale tariffs and rate increase to become effective sixty (60) days after the filing date, or on January 1, 2010. The Public Service wholesale rate case will significantly increase the wholesale rate Black Hills pays for electric capacity used to supply its retail customers in Colorado. (FERC Docket No. ER10-192-000.) Based upon Black Hills' purchase of 300,000 kW per month, Public Service's wholesale rate filing will increase Black Hills' wholesale capacity costs by approximately $1.26 Million per month.

Applying the PCCA rider rates from Tariff Sheet No. 64C to bills issued on or after January 1, 2010 will result in increased revenues of approximately $1,263,000 per month, or $15,156,000 annually. This is an approximate 8.49 percent increase in annual revenues for Black Hills' electric utility operations in Colorado. The increase in revenues will be a dollar-for-dollar recovery of actual increased wholesale purchased capacity costs resulting from the Public Service wholesale rate increase. In other words, the new PCCA rider charges will generate no additional profits for Black Hills.

Under the proposed new PCCA rider tariff, Black Hills estimates the following impacts on customers: A typical residential customer using an average of 600 kilowatt-hours ("kWh") per month during 2010 could expect an estimated total increase of $4.74 per month, or approximately 6.9 percent. A typical small non-demand commercial customer using 2,300 kWh per month could expect an estimated increase of $31.74 per month, or approximately 13.6 percent, while a typical small demand-metered commercial customer with a monthly demand of 16 kilowatts (kW) could expect an estimated increase of $66.88 per month, or approximately 18 percent. Large volume customers may call Black Hills Energy at 719-546-6474 to obtain information concerning how the requested increase in rates would affect them.

Copies of the Advice Letter and filed tariffs and rate rider filed with the Commission are available for examination and explanation at the public offices of Black Hills Energy in Pueblo or at the office of the Public Utilities Commission, 1560 Broadway, Suite 250, Denver, Colorado 80202. In addition, the Company's present tariffs and rules and regulations may be viewed at www.blackhillsenergy.com and the applicable Colorado statutes and Commission rules may be viewed at www.dora.state.co.us/PUC.

Anyone who desires to file a written objection to the tariffs, or an intervention to participate as a party pursuant to applicable Commission rules, may contact the Colorado Public Utilities Commission, 1560 Broadway, Suite 250, Denver, Colorado, 80202. Filing of written objections or intervention pleadings must be made at least ten (10) days prior to the proposed effective date. Filing a written objection by itself will not allow you to participate as a party in any proceeding established in these matters. If you wish to participate as a party in this matter, you must file written intervention documents under Commission Rule 723-1-1401, 4 Colorado Code of Regulations 723-1.

The Commission may suspend the effective date of the proposed tariffs, rates, rules or regulations. The Commission may hold a hearing to determine which tariffs, rates, rules and regulations will be authorized. Any member of the public may attend the hearing and may make a statement under oath about the proposed PCCA tariff, whether or not he or she has filed a written objection or intervention.

By: Gary Stone

Vice President Operations