

Exhibit A to Stipulation

FUEL AND PURCHASED POWER ADJUSTMENT

APPLICABLE

This Fuel and Purchased Power Adjustment as authorized by SDCL 49-34A-25 applies to all rate schedules for all classes of service authorized by the South Dakota Public Utilities Commission.

FUEL AND PURCHASED POWER ADJUSTMENT

For each month in which the cost of fuel and purchased power and energy per kWh of sales during the second calendar month preceding the billing month exceeds or is less than 2.555¢ per kWh, the energy charge shall be increased or decreased, respectively, by the following adjustment factor:

$$\text{Adjustment Factor} = \left[\frac{F_m}{S_m} - \frac{F_b}{S_b} \right] \times \left[\frac{T_m}{T_n} \right] = \text{_____} \text{¢ per kWh}$$

Where: (F) is the expense of fuel and purchased power and energy in the base (b) and current (m) periods; (S) is the firm kWh sales in the base and current periods; and (T) is the South Dakota kWh sales for the current or expected (n) billing periods. The adjustment factor shall be rounded to the nearest 0.001¢ for billing purposes and applied to each kWh delivered.

Provided, for the fuel cost and purchased power and energy incurred in the months of July and August of 1988 which shall be billed in September and October of 1988, the base Adjustment Factor shall be 1.109¢ per kWh.

The cost of fuel and purchased power and energy as used herein shall be the cost of (a) fuel costs of the Company's net generation for items listed in Federal Energy Regulatory Commission's Account 151 as may be adjusted by the Affiliate Coal Adjustment below, (b) the costs of all power and energy purchases, and (c) less the incremental cost of intersystem sales.

Affiliate Coal Adjustment. The amount paid for coal purchased by the Company from its affiliate, Wyodak Resources Development Corp. (WRDC) (i) to fuel the Company's Neil Simpson, Osage, Kirk and Ben French electric generating plants (referred to as BH's Plants) to be included in (F) in the above formula shall be the amount as

determined by the Coal Supply Agreement, dated September 1, 1977 between WRDC and the Company as amended by the First Amendment, dated May 1, 1980 and the Second Amendment, dated November 2, 1987; and (ii) to fuel the Company's 20 percent interest in the Wyodak electric generating plant (referred to as the "Wyodak Plant") to be included in (F) in the above formula shall be the amount as determined by the Further Restated and Amended Coal Supply Agreement, dated May 5, 1987 among Pacific Power & Light Company (PPL), the Company and WRDC, both (i) and (ii) subject, however, to the following adjustment. Each April 1 commencing with April 1, 1989, the Company shall cause WRDC to determine the return on equity earned by WRDC during the previous calendar year on sales of coal to the Company to fuel BH's Plants and to fuel the Company's 20 percent interest in the Wyodak Plant. In determining the rate of return on equity, the following methods shall be included in the calculation:

- (a) The investment base is WRDC's actual cost for its land, coal reserves and mining and Processing Plant and plant held for coal mining and processing purposes as of the calendar year for which the calculations is being made.
- (b) The investment base and costs related thereto include the WRDC obligations under the Coal Handling System Agreement, dated June 8, 1978, as amended by the First Amendment to Coal Supply System Agreement, dated as of April 8, 1983.
- (c) Processing Plant and related costs shall not be allocated to the coal to fuel the Wyodak Plant. The Processing Plant is divided into three categories, (1) truck loadout facilities; (2) facilities for delivering coal to railcars and the Neil Simpson Plant; and (3) facilities needed to serve (1) and (2). Allocations of the Processing Plant and related costs are to be allocated among the sales for which the categories of plant are used.
- (d) New investment base acquired by WRDC after July 1, 1988 to mine and process coal to fulfill new WRDC coal sale contracts of 100,000 tons or more per year entered into after July 1, 1988 and the costs connected therewith of such new investment base shall be allocated to the sales under the said new coal sale contracts.

- (e) The capitalization of WRDC shall consist of (1) long term debt devoted to mining operations and (2) common equity defined as being the total proprietary capital of WRDC less such investment as WRDC may have in subsidiary companies.
- (f) For each of the five years of 1988 through 1992, the investment base and costs related thereto shall be adjusted for canceled contracts by deleting portions of the investment base and costs by the methodology as illustrated by column (3) of pages 1 and 2 of attached Addendum A. For such purposes, the percentage allocated to canceled contracts at lines 3, 4, 6 and 7 of page 7 shall remain constant for the calculation for all five years, except that, if actual sales are made to Hastings or Grand Island, the actual sales shall be reflected in the normal allocation of WRDC's costs, and the actual tonnages shall be subtracted from the tonnages used on page 7 to derive the otherwise constant allocation factors.
- (g) Addendum A attached hereto is an illustration of the forecast calculation of the rate of return for 1988. For years after 1992 allocations of plant and costs are the same under columns (2) and (3) of pages 1 and 2.

If for any calendar year the return on equity earned by WRDC from sales to the Company for BH's Plants and the Company's 20 percent interest in the Wyodak Plant, as calculated by the above methodology, is higher than the Cap Rate as of the April 1 for which the calculation is being determined, (F) shall be reduced for each of the 12 months following the said April 1 in an amount equal to one-twelfth of the reduction in revenue WRDC would have received from sales of coal to the Company for BH's Plants and the Company's 20 percent interest in the Wyodak Plant during the previous calendar year if WRDC had earned a return on equity equal to the Cap Rate.

For the purposes of the Affiliate Coal Adjustment the Cap Rate shall be the total of (i) the average interest rate for fixed rate new long term bonds (20 years average life or longer) issued by utilities during the calendar year previous to the April 1 for which the calculation is being made rated "A" by Moody's, and (ii) 400 basis points (4%).

For the purposes of the Affiliate Coal Adjustment "Processing Plant" is that plant which is owned by WRDC at

the time of the calculation for the purpose of crushing coal to 0 inches to approximately 2 inches, delivery through the crushing process and to storage, storage and delivery to rail car, highway licensed motor carrier or mine mouth generating plants.

Balancing Account. A balancing adjustment to offset any accumulated difference between fuel and purchased power cost adjustments actually billed and the actual cost variable from Fb/Sb during prior months of operation shall be used in determining the fuel and purchased power adjustment factor.

ADDENDUM A
to
Fuel and Purchased
Power Adjustment

ILLUSTRATION OF AFFILIATE COAL
ADJUSTMENT BASED ON 1988 FORECAST

Total Company Adjustment is \$7,838,322 less \$7,107,516, or \$730,806.

Allocation to South Dakota:

1988 Estimated MWH Sales - South Dakota	-	1,080,000	equals 73.072%
1988 Estimated MWH Sales - Total Company	-	1,478,000	

73.072% of \$730,806 equals \$534,012 the affiliated coal adjustment
based on the 1988 forecast

- (1) Column (1) on pages 2 and 3 are plant and costs of entire WRDC.
- (2) Column (2) on pages 2 and 3 are allocations of plant and costs to BHP/L sales to determine actual return on equity.
- (3) Column (3) on pages 2 and 3 are allocations of plant and costs on method to be applied for 5 years, 1988 - 1992 to reflect excess base resulting from canceled coal contracts and to determine income allowed by Rate Caps to determine any over-charge adjustment. After five years, the allocations of plant and costs in columns (2) and (3) will be identical and column (3) will determine income allowed by Rate Cap to determine any overcharge.

This Addendum A, based on estimates for 1988, was prepared to illustrate the calculation of the Affiliate Coal Adjustment as set forth in the Fuel and Purchased Power Adjustment attached hereto.

ALLOCATION METHOD FOR PROCESSING PLANT

The total Processing Plant at year end 1987 had an investment cost of \$11,646,556 with reserve for depreciation of \$3,589,663.

The Processing Plant falls into three categories - (1) truck loadout facility; (2) facilities for delivering coal to Hastings and Grand Island and the Neil Simpson Plant; and (3) facilities, namely the crushers and conveyors, etc. needed to serve (1) and (2). Facilities in (3) were allocated to (1) and (2) on the basis of coal thru the respective facility to the sum of coal thru (1) and (2). Coal delivered thru the truck loadout facility in 1987 was 625,708 tons of which 397,864 tons was for Black Hills Power and Light Company. Coal delivered to Hastings and Grand Island (388,265 tons) and to Black Hills Power and Light Company (Neil Simpson Plant) (128,659 tons) totaled 516,924 tons. Thus facilities in (3) were allocated to (1) by 54.760% ($625,708 \div (625,708 + 516,924)$) facilities in (3) were allocated to (2) by 45.240% ($100\% - 54.760\%$).

Gross Processing Plant plus its reserve in 1987 breaks down as follows:

Processing Plant-Truck Loadout related	\$6,096,354
Reserve for Depreciation	\$1,519,863
Processing Plant-Other	5,550,202
Reserve for Depreciation	2,069,800

RESTATED AND AMENDED COAL SUPPLY AGREEMENT FOR
NEIL SIMPSON UNIT #2

between

WYODAK RESOURCES DEVELOPMENT CORP.

and

BLACK HILLS CORPORATION

Date: February 12, 1993

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RESTATED AND AMENDED COAL SUPPLY AGREEMENT FOR
NEIL SIMPSON UNIT #2

This Restated and Amended Coal Supply Agreement for Neil Simpson Unit #2, dated as of February 12, 1993, is entered into by and between WYODAK RESOURCES DEVELOPMENT CORP. and BLACK HILLS CORPORATION.

1. DEFINITIONS AND RECITALS.

1.1 Definitions. The following capitalized terms and phrases when used in this Agreement shall have the respective meanings as follows:

"1977 Coal Agreement" refers to the following contracts:

Coal Supply Agreement, dated September 1, 1977
between Wyodak Resources and Black Hills;

First Amendment to Coal Supply Agreement between
Wyodak Resources Development Corp. and Black Hills
Power and Light Company, dated May 1, 1980; and

Second Amendment to Coal Supply Agreement for
Black Hills Power and Light Company, dated
November 2, 1987.

The above contract and its two amendments are attached hereto as Exhibit A. The 1977 Coal Agreement obligates Wyodak Resources to furnish all of the coal requirements to fuel Black Hills' Existing Plants during their remaining used and useful life.

"Affiliate Price Limitation" is an amount Black Hills would pay Wyodak Resources during a calendar year for which the calculation is being determined for all coal sold for consumption at the Existing Plants, Black Hills' 20 percent interest in the Wyodak Plant and for Unit #2, which would allow Wyodak Resources to earn on those sales an after-tax rate of return to be applied to the Investment Base of 4 percent above the average rate of long-term A-rated utility bonds issued during the calendar year for which the calculation is being made as recorded in Moody's Bond Survey. The Affiliate Price Limitation shall be determined as of each April 1 for the previous calendar year. Except

where otherwise specifically provided by this Agreement, generally accepted accounting principles shall be applied in determining the Affiliate Price Limitation. Attached hereto as Exhibit D is a sample calculation of the Affiliate Price Limitation based upon assumed facts. The calculation of Affiliate Price Limitation shall be consistent with the methodology used in Exhibit D.

"Agreement" is this Restated and Amended Coal Supply Agreement for Neil Simpson Unit #2.

"Black Hills" is Black Hills Corporation, a South Dakota corporation which operates its electric utility business under the assumed name of Black Hills Power and Light Company.

"Coal Handling Facilities" are those facilities from time to time that are constructed and used to process and deliver coal at the Mine to the Existing Plants, the Wyodak Plant, Unit #2 and to fulfill any further sales of coal from the Mine.

"Colstrip Agreement" is the Power Sales Agreement between PacifiCorp and Black Hills dated as of December 31, 1983, a copy of which is attached as Exhibit C, except for Appendices C, D and E.

"Dispatch Discount" is an amount that Wyodak Resources will reduce the coal price for coal delivered to any of the Existing Plants if necessary to make the Existing Plant Economically Dispatchable over the Estimated Variable Costs of the Colstrip Agreement; provided, Wyodak Resources is not required to grant a Dispatch Discount if such discount will not result in a net reduction of the total of the cost of Black Hills' fuel and purchased power.

"Economically Dispatchable" means for these purposes that under Prudent Utility Practice, Black Hills would not have generated power from one or more of the Existing Plants unless the coal price to be paid under the 1977 Coal Agreement was reduced.

"Estimated Variable Costs" are those variable costs as estimated and first billed by PacifiCorp for an applicable period under the Colstrip Agreement.

"Existing Plants" are Black Hills' wholly owned plants consisting of Neil Simpson Unit #1, located at the Mine; Osage Units #1, #2 and #3, located at Osage, Wyoming; Kirk

Unit #4, located at Kirk, near Lead, South Dakota; and Ben French Plant, located at Rapid City, South Dakota.

"Investment Base" is the investment base of Wyodak Resources and shall include all of its actual investment from time to time in the Mine, including coal reserves, coal leases, land and mining and processing equipment at original cost depreciated. Generally accepted accounting principles shall be applied in determining the Investment Base, except as otherwise provided by this Agreement.

"Mine" is the surface coal mine owned and operated by Wyodak Resources in Campbell County, Wyoming, approximately six miles east of Gillette, Wyoming. Coal reserves now owned or leased by Wyodak Resources or acquired in the future and located in Campbell County, Wyoming are included as a part of the Mine.

"PacifiCorp" is an Oregon corporation that is the successor to Pacific Power & Light Company, a party to the PacifiCorp Coal Agreement.

"PacifiCorp Coal Agreement" is the Further Restated and Amended Coal Supply Agreement, dated as of May 5, 1987, entered into among Wyodak Resources, PacifiCorp and Black Hills. Attached as Exhibit B is a copy of the PacifiCorp Coal Agreement without the attached exhibits.

"Prudent Utility Practice" is the same as that definition at Section 1.9 of the Colstrip Agreement.

"Term" is that period of time described at Section 1.

"Unit #2" is Neil Simpson Unit #2, an 80 MW coal-fired electric generating plant which Black Hills plans to construct at the site of the Mine and bring into commercial operation by January 1, 1996.

"Wyodak Plant" is the 330 MW coal-fired electric generating plant in operation at the Mine and owned 80 percent by PacifiCorp and 20 percent by Black Hills.

"Wyodak Resources" is Wyodak Resources Development Corp., a Delaware corporation, and is a wholly-owned subsidiary of Black Hills.

1.2 Recitals. Black Hills is planning to construct Unit #2 at the site of the Mine. Wyodak Resources has sufficient

uncommitted coal reserves to commit sufficient coal for the used and useful life of Unit #2. Black Hills desires to purchase and Wyodak Resources desires to reserve sufficient coal reserves and sell all of the coal requirements to fuel Unit #2 for its used and useful life, estimated to be 50 years. The purpose of this Agreement is to set forth the terms and provisions of such sale and purchase.

1.3 Term of Agreement. The Term of this Agreement shall commence at such a time Unit #2 requires coal and shall terminate at such time Unit #2 is no longer used and useful for electric utility purposes.

2. SOURCE OF COAL.

The source of the coal to be sold and purchased shall come from Wyodak Resources' coal reserves presently held by Wyodak Resources at the Mine together with any subsequent coal reserves which Wyodak Resources may acquire hereafter in Campbell County, Wyoming. Wyodak Resources represents that the coal reserves contain sufficient coal for the fulfillment of this Agreement. It is understood that Wyodak Resources reserves the right to mine and sell coal from the Mine for other purposes, provided that Wyodak Resources retains sufficient coal reserves to fulfill this Agreement and providing further that sales to others do not in any way prevent Wyodak Resources from carrying out the terms of this Agreement.

3. QUANTITIES OF COAL TO BE SOLD AND PURCHASED.

Wyodak Resources agrees to sell and Black Hills agrees to buy all of the coal which is required to fuel Unit #2 during the Term. It is specifically understood and agreed that Black Hills does not promise Wyodak Resources any minimum amount of coal to be purchased. Without limiting the obligations herein, it is estimated that the maximum yearly coal consumption of Unit #2 is 490,000 tons.

4. PLACE OF DELIVERY AND SALE.

Coal for Unit #2 shall be delivered to Black Hills at the point where the Coal Handling Facilities will interconnect to the coal delivery system of Unit #2. By mutual agreement the parties may change this delivery point from time to time.

5. QUALITY OF COAL.

The coal to be furnished hereunder shall be raw, run-of-mine coal, crushed to a size of 0" to no more than 5 percent exceeding 1.5", produced without selective mining, with a base analysis of approximately 8000 Btu per pound. Wyodak Resources warrants that the quality of coal as delivered shall be within the ranges as set forth at Exhibit E. The quality of the coal delivered shall be determined from the coal samples taken by Wyodak Resources and pursuant to Section 7.

6. WEIGHING.

The weights of the coal delivered to Black Hills shall be determined from weights taken from Wyodak Resources' scales at the Mine. The aggregate weights of such delivered coal shall be accepted as the quantity of coal delivered for which invoices are to be rendered and payments to be made. The scales should be tested from time to time to determine their accuracy and adjusted accordingly.

7. SAMPLING AND ANALYSIS.

Sampling and analysis shall be made by Wyodak Resources and shall be taken by sampling equipment provided by Wyodak Resources. Sampling and analysis shall be performed in accordance with the latest methods approved by the American Society for Testing and Materials or such alternates as the parties may agree upon.

8. PURCHASE PRICE PAYMENT AND ADJUSTMENTS TO COAL SOLD FOR EXISTING PLANTS.

8.1 Purchase Price. For all coal sold by Wyodak Resources to Black Hills under this Agreement during any calendar year of the Term, Black Hills shall pay Wyodak Resources a total purchase price determined under the following formula:

$$P = A - T - DD$$

where

"P" is the total purchase price to be paid by Black Hills to Wyodak Resources for all coal sold during the calendar year

for consumption at Unit #2 and for which the calculation is being made;

"A" is the amount of the Affiliate Price Limitation determined for the calendar year for which the purchase price is being determined;

"T" is the total amount paid by Black Hills to Wyodak Resources for coal for consumption at the Existing Plants under the 1977 Coal Agreement and for Black Hills' 20 percent interest in the Wyodak Plant under the PacificCorp Coal Agreement for the calendar year for which the purchase price is being determined; and

"DD" is the total amount of the actual Dispatch Discount Wyodak Resources is obligated to discount coal sold for consumption at the Existing Plants during the calendar year for which the calculation of the purchase price is being made.

If for any calendar year "P" is a negative number, Black Hills shall not pay Wyodak Resources any purchase price for coal sold for consumption at Unit #2 during that calendar year.

8.2 Negative Amount Adjustments for Coal Sold to Existing Plants. For any calendar year the calculation made under the formula at Section 8.1 of this Agreement determines a negative amount, Wyodak Resources shall reduce the adjusted base mine price under the 1977 Coal Agreement by reducing that price in the amount of the negative amount so calculated. The credit shall be applied over a 12-month period in equal installments commencing as of the April 1 when the negative amount was determined.

8.3 Invoice and Payments. Wyodak Resources shall invoice Black Hills by the 5th working day of each month for coal ordered to be delivered for that calendar month and an adjustment

for actual coal sold the previous calendar month at a purchase price to be estimated based on the formula at Section 8.1. Black Hills shall pay each invoice to Wyodak Resources by the 15th day of the month the invoice is rendered. On each April 1, Wyodak Resources shall calculate the purchase price for coal sold to Black Hills under this Agreement for the preceding calendar year. Appropriate charges and credits shall thereupon be applied for coal sold during the previous calendar year in order that the actual purchase price paid for coal during that calendar year is consistent with the formula at Section 8.1.

8.4 Retroactive Adjustments. Adjustments to cost items affecting "A" or "T" under the formula at Section 8.1 and discovered after the April 1 calculation of the purchase price for any calendar year shall be applied to an adjustment in the purchase price for that calendar year at such time the actual costs are discovered, and appropriate credits and charges shall be made. If Wyodak Resources fails to make an adjustment in billings within two years from the date information is reasonably available to Wyodak Resources to fully determine the actual amount of the adjustment, Wyodak Resources shall be barred from making that adjustment. If Black Hills fails to protest to Wyodak Resources in writing within two years of a date when information is reasonably available to Black Hills to determine that an adjustment included in a billing received prior to that

date is incorrect, Black Hills shall be barred from contesting that adjustment even if the adjustment was incorrect.

9. INSPECTION.

Each party shall, at all reasonable times, have the right to enter upon the premises of the other to inspect coal receiving equipment and the weighing, measuring and testing facilities. Black Hills shall at all reasonable times have the right to inspect the Mine, maps and operating records of Wyodak Resources relating to the operation of the Mine. Black Hills shall further have the right to inspect the books and accounts of Wyodak Resources to the degree that such inspection is necessary in order to determine cost data affecting the purchase price being paid under this Agreement; provided, during any time that Wyodak Resources may not be affiliated with Black Hills, such inspection of books and accounts shall be conducted by Black Hills' outside auditing firm who at the time of the inspection has been appointed to do the independent auditing of Black Hills' books of account.

10. UNCONTROLLABLE FORCES.

If, because of uncontrollable forces, either party hereto is unable to carry out any part or all of its obligations under this Agreement, and if such party promptly gives to the other party hereof notice of such uncontrollable forces, then the obligations of the party giving such notice shall be suspended to the extent

made necessary by such uncontrollable forces and during its continuance, provided the effect of such uncontrollable forces is eliminated insofar as possible with all reasonable dispatch. The term "uncontrollable forces" as used herein shall mean any causes beyond the control of the party in which, by the exercise of reasonable diligence, the party is unable to overcome include but not be limited to acts of God, acts of the public enemy, insurrections, riots, strikes, labor disputes, labor and material shortages, fires, explosions, floods, breakdowns of or damage to plants, equipment or facilities, interruptions to transportation, embargoes, orders or injunctions of federal, state or local governmental bodies and jurisdictions, or acts of civil or military authority, failure of equipment, or inability to obtain materials, supplies, or equipment from others because of similar causes. It shall be considered an uncontrollable force and shall relieve Wyodak Resources from performing its obligation under this Agreement if valid state or federal legislation is enacted which prohibits the strip mining of the federal coal which has been leased by Wyodak Resources.

11. APPLICABLE LAW.

This Agreement shall be considered to have been entered into and shall be interpreted under the laws of the State of Wyoming.

12. AMENDMENT.

No provision of this Agreement may be amended, modified, supplemented or waived except by an instrument in writing signed by both parties.

13. SUCCESSORS AND ASSIGNS.

This Agreement and all the terms and provisions hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the parties hereto.

14. CONDITION PRECEDENT.

If for any reason, including a decision made in the absolute discretion of Black Hills, Black Hills does not give notices to proceed to vendors and contractors to commence the construction of Unit #2 on or before July 1, 1993, this Agreement shall become null and void.

15. COMPLETE AGREEMENT.

This Agreement constitutes the complete and full agreement between the parties relating to the matters set forth herein and supersedes any oral conversations or writings prior thereto. This Agreement supersedes and replaces the Coal Supply Agreement for Neil Simpson Unit #2 dated January 15, 1993.

IN WITNESS WHEREOF, the parties hereunder have executed this Agreement as of the date set forth in the first paragraph hereof.

WYODAK RESOURCES DEVELOPMENT
CORP.

By *Alab E. Clement*
Its Senior Vice President -
Finance

BLACK HILLS CORPORATION

By *Samuel O. Lundquist*
Its Chairman, President and
Chief Executive Officer

COAL SUPPLY AGREEMENT

September 1, 1977

between

WYODAK RESOURCES DEVELOPMENT CORP.

and

BLACK HILLS POWER AND LIGHT COMPANY

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Annex

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COAL SUPPLY AGREEMENT

This agreement ("Agreement"), is dated as of September 1, 1977, by and between Wyodak Resources Development Corp., a Delaware corporation ("Seller") and Black Hills Power and Light Company, a South Dakota corporation ("Buyer").

WHEREAS, Seller mines leased and owned coal at a coal mine, herein referred to as "Mine" in Campbell County, Wyoming, containing certain coal reserves (herein referred to as "Coal Reserves"); and

WHEREAS, Buyer owns and operates coal-fired steam electric generating plants at Rapid City and Lead, South Dakota, and at Osage and Wyodak, Wyoming (hereinafter called "Plants"); and

WHEREAS, the parties intend that Seller will mine and deliver to Buyer all of the coal requirements of the Plants during the Term of this Agreement;

NOW THEREFORE, Seller agrees to sell and deliver and Buyer agrees to accept and buy coal, as hereinafter provided, upon the following terms and conditions:

Section 1. Term of Agreement. The term of this Agreement (herein referred to as "Term") shall commence September 1, 1977 and shall run for a period of one year and thereafter until terminated by either party giving the other two months written notice.

Section 2. Source of Coal. The source of the coal to be sold and purchased shall come from the Coal Reserves presently held by Seller at the Mine. Seller represents that the Coal Reserves contain sufficient coal for the fulfillment of this Agreement. It is understood that Seller reserves the right to mine and sell coal from the Mine for other purposes, provided that the Seller retains sufficient Coal Reserves to fulfill this agreement and providing further that sales to others do not increase the cost of the coal to the Buyer under this Agreement nor in any way prevent the Seller from carrying out the terms of this Agreement.

Section 3. Quantities of Coal to be Sold and Purchased and Scheduling. Seller agrees to sell and Buyer agrees to buy all of the coal which is necessary to fuel the Plants during the Term.

Section 4. Place of Delivery and Sale. Coal for all of the Plants which are not located at the Mine shall be delivered by Seller to Buyer at the Mine by depositing the same in railroad cars or trucks provided by Buyer. Coal for Plants at the Mine shall be delivered to the stockpile or the silo exit at the Mine to be designated by Buyer. Delivery to railroad cars shall be on a 8-hour, 7-day week basis. Delivery to trucks shall be on a 24-hour, 7-day week basis. Upon delivering coal to cars, trucks or stockpile, title to the coal shall pass to Buyer. Buyer shall be responsible for transporting the coal to the Plants.

Section 5. Quality of Coal. The coal furnished hereunder shall be raw, run-of-mine coal crushed to a size of 0 inches to no more than 5% exceeding 1.5 inches, produced without selective mining, with a base analysis of 8000 B.T.U. per pound. Seller warrants that coal as delivered shall meet minimum specifications as follows:

Calorific value - not less than 7500 B.T.U. per pound

Ash - not more than 10% of weight

Sulfur - not more than 0.7% nor less than 0.26% of weight

Ash softening temperature - not less than 2000°F

Average moisture - not more than 30% by weight over a period of 30 days

The quality of the coal delivered shall be determined from the coal sample analysis taken by Buyer made pursuant to Section 7 hereof.

Section 6. Weighing. The weights of the coal delivered to Buyer shall be determined from weights (a) taken on Seller's scales for coal loaded into trucks; (b) in accordance with the railroad average weight agreement for coal loaded into railroad cars; (c) taken from the Buyer's scales at the Mine for coal delivered to a stockpile; or (d) as otherwise agreed to by the Parties. The aggregate weights of such delivered coal shall be accepted as the quantity of coal delivered for which invoices are to be rendered and payments to be made. The scales shall be tested from time to time to determine their accuracy and adjusted accordingly.

Section 7. Sampling and Analysis. Sampling and analysis shall be made at the direction of Buyer and shall be taken by

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sampling equipment provided by the Buyer. Sampling and analysis shall be performed in accordance with the latest methods approved by the American Society for Testing and Materials (ASTM) or such alternates as the parties may agree upon. Each party shall be entitled to examine the testing results from coal sold to others; and if the parties agree, the analysis made pursuant to other coal sale contracts may be used for the purposes herein if the samples taken for such analysis was coal from which the coal sold to Buyer was taken.

Section 8. Determining of Weighted Average Heat Content. As soon as practicable after the end of each month, the weighted average heat content, in B.T.U.'s per pound, of coal delivered hereunder during such month shall be computed pursuant to the analysis made pursuant to Section 7.

Section 9. Base Mine Price. Buyer shall pay Seller for each ton (2,000 pounds) for coal delivered herein the sum of 223.9 cents per ton, f.o.b. receiving hopper in the south pit of the Mine, subject, however, to the adjustments provided for in Sections 10 and 11 hereof. The Base Mine Price has been computed as of September 30, 1974, and adjustments shall be based upon conditions and costs compared to said day to the day the adjustment is being made. Terms used herein relating to the price of the coal shall have the following meanings:

"Base Mine Price" shall mean 223.9 cents per ton.

"Adjusted Base Mine Price" shall mean the Base Mine Price as adjusted for certain changes in Seller's costs and quality of coal pursuant to the provisions of Sections 10 and 11.

Section 10. Adjustments to Base Mine Price. The Base Mine Price per ton of coal shall be adjusted (to the nearest one-tenth of a cent) from time to time as provided in subsection 10(k) hereof, to give effect to changes in the cost to Seller of mining the coal and to adjust for changes in the purchasing power of the dollar. Seller agrees that it will use its best efforts to keep all costs at the lowest practicable levels. The following sets forth adjustments to be made to the Base Mine Price. Each adjustment shall be calculated independently; however, the sum of all such adjustments shall be added to the Base Mine Price.

(a) Direct Mine Labor. The Base Mine Price includes a factor of 51.1 cents per ton for direct mine labor cost per ton. This factor is based on an estimated average labor force (of various classifications) required over the term of this Agreement as set forth in Annex A attached hereto, taking into account direct

labor costs prevailing at the Mine on September 30, 1974, under the then current standard hours of work and working practices. The calculation of this labor factor takes into consideration all current factors affecting direct labor costs. Direct labor costs for the purposes of this subsection (a) are the aggregate cost to Seller of all factors affecting direct labor expense at the Mine, now and in the future, consisting of:

- Basic wage rates, i.e., straight time pay;
- Overtime and overtime pay rates;
- Vacations and vacation pay;
- Holidays and holiday pay;
- Hours of work;
- Working practices;
- Bonus pay;
- Shift differential pay;
- Fringe benefits;
- Limitations on production imposed by unions;
- Pension, retirement benefits, old age benefits, unemployment benefits, social security, premiums for Workmen's Compensation and all other payments to or for the benefit of employees;
- Governmental, judicial, or legislative requirements;

provided, however, that the above costs shall not include the cost of supervisory labor at the Mine or miners' welfare benefits, which items are covered by subsections (b) and (c) below.

If, after September 30, 1974, the total of Seller's labor costs which are necessary to fulfill its contract herein should increase or decrease due to any one or more of the factors in this section, the Base Mine Price shall be adjusted by the amount the direct mine labor factor increases or decreases when changed in the same proportion as the direct labor costs of the estimated average labor force have increased or decreased from September 30, 1974.

Adjustments on account of changes in direct labor costs shall be made by applying such changes to the estimated average labor force irrespective of the actual labor employed at the Mine at any time. It is understood, however, that the labor adjustment will be affected when the number of persons in the average labor force would necessarily change due to any of the factors listed in this Section 10(a) of this contract.

(b) Supervisory Labor at the Mine. The cost factor for supervisory labor at the Mine included in the Base Mine Price is 5.8 cents per ton. If pursuant to subsection (a) of this Section 10, direct labor costs at the Mine shall be changed, the cost factor for supervisory labor at the Mine shall be changed by the same

percentage change in the direct labor cost factor and the amount of the resulting change in the cost per ton for supervisory labor shall be reflected in an Adjusted Base Mine Price.

(c) Miners' Welfare Benefits. The Base Mine Price does not include anything to be paid by Seller to or for its Mine labor force as miners' welfare benefits. Any payment by Sellers in miners' welfare benefits, or sums paid in lieu thereof, shall be reflected by a corresponding change in the price of coal hereunder.

The adjustment provisions of this subsection shall apply to miners' welfare benefits, any similar benefits, or any benefits substituted for the welfare benefits referred to hereinabove, provided only that said benefits are not included as a part of direct labor costs within the provisions of subsection (a) hereof.

(d) Explosives and Explosive Accessories. The Base Mine Price includes an estimated cost factor of 5.8 cents per ton of coal for costs of explosives and explosive accessories based on an assumed average volume of use of explosives and explosive accessories. The Base Mine Price shall be adjusted from time to time to compensate for changes in these costs. Such adjustments shall be based upon changes in the wholesale price index for other chemicals and allied products, Code No. 06-7, published by the Bureau of Labor Statistics, United States Department of Labor. Such change shall be reflected in a new Adjusted Base Mine Price determined by adding to or subtracting from the Base Mine Price the change in the cost of explosives and explosive accessories as reflected by the difference between 5.8 cents and the product of 5.8 cents times the most recent index for explosives as of the time of adjustment divided by such index as of the month of September, 1974.

(e) Materials and Supplies. Seller's cost factor as of September 30, 1974, for construction machinery and equipment is 37.4 cents per ton; and the cost factor for petroleum products is 3 cents per ton. Whenever change shall occur in the cost of materials and supplies, as evidenced by an increase or decrease in either the Price Index for Construction Machinery and Equipment (Code No. 11-2) in the Machinery and Equipment Group as published by the Bureau of Labor Statistics, United States Department of Labor or the Price Index for Petroleum Products, Refined (Code No. 05-7) in the Fuels and Related Products and Power Group as published in the Wholesale Price Index, by the Bureau of Labor Statistics, United States Department of Labor such change shall be reflected in a new Adjusted Base Mine Price determined as follows:

(i) when a change occurs in the Index for Construction Machinery and Equipment, the change shall be reflected in a new Adjusted Base Mine Price

determined by adding to or subtracting from the Base Mine Price the change in the cost of construction machinery and equipment as reflected by the difference between 37.4 cents and the product of 37.4 cents times the most recent price index for Construction Machinery and Equipment as of the time of adjustment divided by the Construction Machinery and Equipment Index as of the month of September, 1974.

(ii) when a change occurs in the Index for Petroleum Products, Refined, the change shall be reflected in a new Adjusted Base Mine Price determined by adding to or subtracting from the Base Mine Price the change in the cost of petroleum products as reflected by the difference in 3 cents and the product of 3 cents times the most recent price index for adjustment divided by the Petroleum Products, Refined Index as of the month of September, 1974.

(f) Taxes. When any increase or decrease in taxes, whether due to increases or decreases in taxes or enactment of additional ones as of September, 1974 levied or assessed by local, state or federal authorities, on the coal sold hereunder or on Seller's mining facilities or operations, including increases or decreases in amounts of taxes payable resulting from the price for coal sold hereunder exceeding the Base Mine Price due to price adjustments as set forth in Sections 10 and 11 of this Agreement, results directly or indirectly in an increase or decrease per ton to Seller of the cost of mining, preparing and delivering coal hereunder, such increase or decrease shall be reflected in a new Adjusted Base Mine Price. Included, without limitation, in matters within the price adjustment provisions of this subsection are severance taxes, import, ad valorem taxes, sales tax, tax or assessment imposed for reclamation purposes, fees, and any and all other taxes, special assessments, and governmental impositions of any kind and character whatsoever. Any taxes based upon Seller's net income shall be excluded from this adjustment. For those taxes and impositions incurred by Seller in the same amount or on the same basis no matter from what source the coal was mined, adjustments shall be based upon actual taxes paid in the year of adjustment divided by the actual tons mined by Seller for all of its purposes in the same year. At any time Seller should incur a tax or other governmental imposition which is incurred in a different amount or on a different basis for coal mined from one source than from coal mined from another source, adjustments shall be based upon actual taxes incurred in the year of adjustment for the actual coal sold by Seller to Buyer. The cost per ton as of September 30, 1974, for Wyoming severance tax is 3.1 cents, for Wyoming production tax 5.6 cents, for Wyoming (including local) property tax 1.6 cents.

(g) Pneumoconiosis Disease. The Base Mine Price shall be adjusted to reflect the cost to Seller to comply with all laws and regulations now or hereinafter enacted relating to pneumoconiosis disease attributable to mining at the Mine, including, but not necessarily limited to, the cost of claims made thereunder including the cost of insurance to pay such claims by adding to the Base Mine Price the cost per ton determined by dividing the total costs incurred by the Seller for this purpose during the period of adjustment in mining coal for all purposes by the total tons of coal sold by the Seller for all of its purposes during the period of adjustment.

(h) Legislation and Government Imposition, Regulatory Requirements, Rules and Regulations. Whenever any federal, state or local laws, rules, regulations, or requirements, whether due to change in, additions to or difference in interpretation or enforcement by any governmental authority of existing laws, rules, regulations, or requirements after September 30, 1974, should cause an increase or decrease in cost to the Seller of mining coal in complying with all of such laws, rules, regulations, or requirements, the actual additional cost per ton of Seller on account thereof shall be reflected in a new Adjusted Base Mine Price. Costs covered by this paragraph include but are not limited to those of reclamation, prevention or reduction of water and air pollution and compliance with mine safety laws and environmental quality acts, rehabilitation, and the handling and processing of mine refuse including bond premiums for bonds required to be posted thereunder. The Base Mine Price includes all reclamation costs and other costs in the fulfillment of the Reclamation Plan described in Annex B attached hereto. If Seller is required to incur further expense in its Reclamation Plan due to governmental impositions and requirements as set forth herein other than as described in said Annex B the Base Mine Price shall be adjusted in order to reflect the additional costs as set forth herein. It is understood that payment for these costs shall be made on an accrual basis so that payment is made at the time the Seller incurs the obligations even though Seller may not fulfill said obligations until some time later. The estimated cost of Seller to comply with reclamation laws as of September 30, 1974 is .5 cents (\$.005) per ton.

(i) Royalties. As of September 30, 1974, the average royalty for coal mined in September, 1974 from the lease with Homestake Mining Company was 25 cents per ton and coal mined from the lease with the United States was 15 cents per ton. Any change in these royalties will be reflected in an addition to or subtraction from the Base Mine Price. The average royalty component of the Base Mine Price based upon the expected ratio of Homestake to United States coal to be mined for the purposes of fulfilling this agreement is 16.3 cents per ton. The Base Mine Price shall be adjusted by an amount, plus or minus, equal to the average per ton cost of royalties incurred by Seller during the month of adjustment for the tonnage mined by Seller for Buyer during the period less 16.3 cents.

(j) All Other Costs and Value of Product. The Base Mine Price hereunder shall also be adjusted to compensate for changes in administrative costs and all other costs not included herein and changes in the purchasing power of the dollar. Such adjustments shall be based upon changes in the Consumers Price Index, all items, issued by the Bureau of Labor Statistics, U. S. Department of Labor. Such change shall be reflected in a new Adjusted Base Mine Price determined by adding to or subtracting from the Base Mine Price the change in all other costs and value of product as reflected by the difference between 93.7 cents and the product of 93.7 cents times the Consumers Price Index, all items, as of the time of adjustment, divided by the Consumers Price Index, all items, as of the month of September, 1974.

(k) Time of Making Price Adjustment. Price adjustments required to be made hereunder pursuant to subsections (a), (b), (c), (f), (g), (h) and (i) shall be made monthly, but in such manner so as to accurately reflect the actual dates when the changes in costs occurred. Price adjustments required to be made pursuant to subsections (d), (e) and (j) shall be made in respect to all coal delivered hereunder in the month following the month in which an event occurs requiring a price adjustment pursuant to such subsections. When an adjustment is based on changes in indices published by the U. S. Department of Labor, such adjustments shall be made on the basis of the latest index or indices then available whether said index or indices have been published or not. At the end of each calendar year of this Agreement, all cost adjustments made pursuant to Section 11 will be further adjusted by appropriate accounting methods and supplemental billing or credit statements when any such cost may not be fully determinable in the month when the original adjustment is made.

(l) Auditing of Records. If at any time Buyer desires to receive assurances of the accuracy of Seller's records affecting the price adjustment herein, Buyer may request Seller to authorize the nationally recognized independent certified public accounting firm doing Seller's auditing work at the time of the request to audit Seller's records and certify the accuracy to Buyer of certain information so requested. If Seller does not have a nationally recognized accounting firm retained at the time of the request, a nationally recognized accounting firm shall be selected upon mutual agreement of the parties hereto. The information request must be relevant to the amount of any price adjustment herein. The accounting firm's charges for any work requested of it under this provision shall be paid by Buyer.

(m) Procedure in Event Indices are Discontinued or Changed. In the event any index which is used in this Section 10 is discontinued or otherwise becomes unavailable, the parties hereto

shall undertake in good faith to agree upon a substitute index which will most nearly reflect the same type of adjustments which would have been made if the present index had been continued.

(n) Computations. Annex C attached hereto is a sample computation of the Adjusted Base Mine Price based upon assumed facts to illustrate the application of Sections 10 and 11.

Section 11. Price Adjustments--Calorific Quality. For coal delivered in each month hereunder the Base Mine Price as adjusted pursuant to the application of Section 10 shall be further adjusted monthly for calorific quality by multiplying the Base Mine Price as adjusted by Section 10 times the actual weighted average B.T.U. per pound of coal delivered (as determined in Section 8) for the period for which the calculation is being made and dividing the result by 8000. The result so determined and computed to the nearest one-tenth of a cent shall constitute the Adjusted Base Mine Price for the coal sold during the period for which the calculation is made.

Section 12. Invoices and Payments. Seller shall invoice Buyer by the fifth day of each month for the actual coal delivered for the preceding calendar month at the Adjusted Base Mine Price. Buyer shall pay each invoice to Seller by the tenth day of the month the invoice is rendered.

Section 13. Inspection. Each party shall, at all reasonable times have the right to enter upon the premises of the other to inspect the coal receiving equipment and the weighing, measuring and testing facilities. Buyer shall at all reasonable times have the right to inspect the Mine, maps and operating records of the Seller relating to the operation of the Mine.

Section 14. Uncontrollable Forces. If, because of uncontrollable forces, either party hereto is unable to carry out any part or all of its obligations under this Agreement, and if such party promptly gives to the other party hereof notice of such uncontrollable forces, then the obligations of the party giving such notice shall be suspended to the extent made necessary by such uncontrollable forces and during its continuance, provided the effect of such uncontrollable forces is eliminated insofar as possible with all reasonable dispatch. Failure of deliveries of coal hereunder caused by uncontrollable forces shall be made up as soon as practicable under the cessation of any uncontrollable forces. The term "uncontrollable forces" as used herein shall mean any causes beyond the control of the party and which, by the exercise of reasonable diligence, the party is unable to overcome and shall include but not be limited to acts of God, acts of the public enemy, insurrections, riots, strikes, labor disputes, labor or

material shortages, fires, explosions, floods, breakdowns of or damage to plants, equipment or facilities, interruptions to transportation, embargoes, orders or injunctions of federal, state, or local governmental bodies having jurisdiction, or acts of civil or military authority, failure of equipment, or inability to obtain materials, supplies, or equipment from others because of similar causes. It shall be considered an uncontrollable force and shall relieve Seller from performing its obligation under this Agreement if valid state or federal legislation is enacted which prohibits the strip mining of the federal coal which has been leased by Seller. The parties are aware that Seller does not have at this time federal mining permits which will be necessary for the mining of all of the coal to fulfill this Agreement.

Section 15. Applicable Law. This Agreement shall be considered to have been entered into and shall be interpreted under the laws of the State of Wyoming.

Section 16. Amendment. No provision of this Agreement may be amended, modified, supplemented or waived except by an instrument in writing signed by Seller and Buyer.

Section 17. Complete Agreement. This Agreement supersedes and cancels all prior coal contracts between the parties and constitutes the complete agreement of the parties.

IN WITNESS WHEREOF, Wyodak Resources Development Corp. and Black Hills Power and Light Company have caused this Agreement to be signed and acknowledged by a duly authorized officer thereof, and their corporate seals to be affixed hereunto, and the same to be duly attested, all as of the day and year first above written.

WYODAK RESOURCES DEVELOPMENT CORP.

ATTEST:

By

Robert E. Anderson
PRESIDENT

Lester S. L. L.
ASSISTANT SECRETARY

(CORPORATE SEAL)

BLACK HILLS POWER AND LIGHT COMPANY

ATTEST:

By

Neal B. L.
CHAIRMAN OF THE BOARD

[Signature]
SECRETARY

(CORPORATE SEAL)

ANNEX A
to
COAL SUPPLY AGREEMENT
ESTIMATED AVERAGE LABOR FORCE

<u>Position</u>	<u>Number</u>
Engineer Technician	2
Accountant	1
Clerks and Secretaries	4
OVER BURDEN REMOVAL CREW	
Scraper Operators	5
Dozer Operators	3
MINING CREW	
Shovel Operators	3
Shovel Oilers	3
Driller/Shooter	2
Driller/Shooter Helper	2
Coal Haul Operator	8
Dozer or Loader Operator	3
Grader Operator	1
Power Spray Operator	1
RAIL LOADING OPERATORS AND CAR DROPPERS	
Rail Loading Operator	2
Car Droppers	2
RECLAMATION CREW	
Dozer Operators	2
MINE MAINTENANCE CREW	
Mechanic for Heavy Equipment Working Foreman	1
Mechanic/Welder	6
Electricians	2
Equipment Oiler	1
Trainees	2
MISCELLANEOUS--MANUAL	
Helper-relief	3
Materialman	1
Janitor	1

ANNEX B
to
COAL SUPPLY AGREEMENT

DESCRIPTION OF RECLAMATION PLAN OF SELLER

The present use of the land is for the grazing of livestock. The proposed use of the land after reclamation shall also be for the grazing of livestock.

The exposed coal faces on both sides of the south pit will be covered with overburden and have a slow, gentle slope towards the center of the mined out coal pit. The areas with a higher overburden ratio will be placed back within approximately three hundred feet of the original location and with an elevation of approximately forty to sixty feet lower. The overburden will be removed from the top of the coal and deposited on the exposed coal faces on the side of the pit during the mining operation. This overburden will be graded to a long, gentle slope toward the center of the pit and covered with topsoil and reseeded.

When the surface has had its final grade and topsoil placed, it will be sown with native grasses and legumes and a cover crop of a small grain variety to allow for proper soil cover.

The topsoil varies from two inches on the hills to about four feet in the valleys. The first step in the mining operation will be to remove the material defined as topsoil and spread it over land which has been back filled and final graded. This subsoil and spoils are the same and will be placed below the area and along the coal faces to provide for adequate cover to prevent firing. When the spoil piles have been completed, they will be graded and the topsoil will be placed. In the mining operation if the topsoil to be removed is not needed, it will be temporarily stockpiled. The stockpile will have low slopes on each side or angles less than the angle of repose and seeded with crested wheat grass or a fast cover to prevent wind and water erosion.

The estimated cost of reclaiming land under this plan as of the date of the contract is \$650 per acre.

ANNEX C
to
COAL SUPPLY AGREEMENT

SAMPLE COMPUTATION OF ADJUSTED BASE MINE PRICE
TO ILLUSTRATE APPLICATION OF SECTIONS 10 and 11

	<u>Adjusted Base Mine Price</u>
1. Base Mine Price	\$2.239
2. Section 11(a) - Direct Mine Labor Assume that none of the factors in subsection (a) changed the number of persons needed in average labor force, but assume that increase in hourly wages of various classifications changed as set forth in attached Schedule 1.	
$\frac{373.62}{348.80} \times .511 - .511 =$	.036
3. Section 11(b) - Supervisory Labor	
$.058 \times \frac{373.62}{348.80} - .058 =$	.004
4. Section 11(c) - Minors' Welfare Benefits Assume Seller started paying minor welfare benefits.	
Benefits paid constitute 2 cents per ton mined for all of Seller's purposes. Add on .	.02
5. Section 11(d) - Explosives	
$.058 \times \frac{165}{162.6} \times \frac{\text{index 06-7}}{\text{index 06-7 Sept., 1974}} - .058 =$	.001
6. Section 11(e) - Materials & Supplies Construction Machinery	
$.374 \times \frac{166}{163.4} \times \frac{\text{Code 11-2 index}}{\text{Code 11-2 Sept., 1974}} - .374 =$	.006
Petroleum Products	
$.03 \times \frac{235}{243} \times \frac{\text{Code 05-7}}{\text{Code 05-7 Sept., 1974}} - .03 =$	(.001)

ANNEX C (continued)

7. Section 11(f) - Taxes

Assume Wyoming severance taxes actually paid by Seller for period of adjustment divided by actual tons mined for all of its purposes during adjustment came to .061 per ton.

$$.061 - .031 = .03$$

Assume United States levies tax on all coal mined of 35 cents per ton for reclamation purposes	.35
--	-----

Assume a special tax of 20 cents a ton is levied on coal mined for the United States coal leases and not against coal mined from the Homestake lease and during the month of adjustment, Seller mined and delivered to Buyer 60,000 tons of coal of which 36,000 came from the Homestake lease and 24,000 from United States coal leases.

$$\frac{24,000 \times .20}{60,000} = .08$$

8. Section 11(g) - Pneumoconiosis Disease

Assume that during the period of adjustment Seller incurred total costs to comply with the pneumoconiosis disease laws the sum of \$49,500 and mined 1,500,000 tons of coal for all its purposes. The calculation for this add on adjustment is as follows:

$$\frac{49,500}{1,500,000} = .033$$

9. Section 11(h) - Governmental

Assume reclamation plan approved by State of Wyoming will cost Seller for reclamation purposes for the land affected by the mining of the coal sold to Buyer is .01 per ton.

$$.01 - .005 = .005$$

ANNEX C (continued)

10. Section 11(i) - Royalties

Assume that for the month of the adjustment, the Seller mined and delivered to Buyer 50,000 tons of coal of which 20,000 tons was mined from the Homestake Coal Lease and 30,000 from United States Coal Leases. Assume the actual royalty paid per ton of Homestake coal for said month was 35 cents and the actual royalty paid during said month for United States coal was 40 cents. The calculation for this adjustment would be as follows:

$$\frac{(20,000 \times .35) + (30,000 \times .40)}{50,000} - .163 = .217$$

11. Section 11(j) - Other Cost and Value of Product

	Cons. Price Ind.		
.937 x 154	month of adj.	~ .937 =	.013
151.9	Cons. Price Ind.		
	Sept., 1974		

Adjusted Base Mine Price per ton for Sample
Computation Based upon above assumptions
without calorific adjustment 3.033

12. Section 12 - Calorific Quality

Assume actual weighted average BTU per pound of coal delivered for period of the calculation is 8300

$$\frac{3.033 \times 8300}{8000} = 3.147$$

Adjusted Base Mine Price for sample
computation 3.147

SCHEDULE 1 OF ANNEX C
to
COAL SUPPLY AGREEMENT

	<u>September, 1974</u> <u>Hourly rate</u>	<u>Total</u>	<u>Hourly rate</u> <u>at Adjust.</u>	<u>Total</u>
2 Engineer Technician	@ \$5.44	\$10.88	@ \$6.00	\$12.00
1 Accountant	@ 5.50	5.50	@ 5.80	5.80
4 Clerks and Secretaries	@ 3.08	12.32	@ 3.25	13.00
<u>Over Burden Removal Crew</u>				
5 Scraper Operators	@ 5.21	26.05	@ 5.75	28.75
3 Dozer Operators	@ 5.21	15.63	@ 5.85	17.55
<u>Mine Crew</u>				
3 Shovel Operators	@ 5.34	16.02	@ 5.50	16.50
3 Shovel Oilers	@ 5.21	15.63	@ 5.40	16.20
2 Driller/Shooter	@ 4.96	9.92	@ 5.10	10.20
2 Driller/Shooter Helpers	@ 4.96	9.92	@ 5.10	10.20
8 Coal Hauler Operators	@ 4.96	39.68	@ 5.10	40.80
3 Dozer or Loader Operators	@ 5.34	16.02	@ 5.40	16.20
1 Grader Operator	@ 4.96	4.96	@ 5.10	5.10
1 Power Spray Operator	@ 4.96	4.96	@ 5.10	5.10
<u>Rail Loading Operators and</u> <u>Car Droppers</u>				
2 Rail Loading Operators	@ 4.25	8.50	@ 4.50	9.00
2 Car Droppers	@ 4.25	8.50	@ 4.50	9.00
<u>Reclamation Crew</u>				
2 Dozer Operators	@ 5.21	10.42	@ 5.75	11.50
<u>Mine Maintenance Crew</u>				
1 Mechanic for Heavy Equipment	@ 5.34	5.34	@ 5.50	5.50
6 Mechanic/Welder	@ 5.34	32.04	@ 5.50	33.00
2 Electricians	@ 5.34	10.68	@ 5.50	11.00
1 Equipmnt Oiler	@ 5.21	5.21	@ 5.75	5.75
2 Trainees	@ 3.08	6.16	@ 3.35	6.70
3 Helper-relief	@ 4.25	12.75	@ 4.50	13.50
1 Material Man	@ 4.25	4.25	@ 4.50	4.50
1 Janitor	@ 4.25	4.25	@ 4.50	4.50
		\$295.59		\$311.35
* 18% fringe benefits		295.59		311.35
		53.21		
		<u>348.80</u>		

SCHEDULE 1 OF ANNEX C (continued)

Due to same factor listed in
subsection (a) such as amount
of vacation, overtime, holidays,
etc., fringe benefits at time
of adjustment changed to 20%

62.27
\$ 573.62

-
- * Assume further fringe benefits in addition to hourly wage were paid equal
to 2% more of base hourly rate.

FIRST AMENDMENT TO COAL SUPPLY AGREEMENT
BETWEEN WYODAK RESOURCES DEVELOPMENT CORP.
AND BLACK HILLS POWER AND LIGHT COMPANY

This First Amendment ("First Amendment") dated as of May 1, 1980, is an amendment to that Coal Supply Agreement dated September 1, 1977 ("Agreement") by and between Wyodak Resources Development Corp., a Delaware corporation ("Seller") and Black Hills Power and Light Company, a South Dakota corporation ("Buyer").

W I T N E S S E T H

1. RECITALS. Under the provisions of Section 1 of the Agreement, the Seller gave Buyer a notice dated May 1, 1980 to Buyer of Seller's intent to either cancel the Agreement or enter into this First Amendment providing for an increase in the Base Mine Price for all coal delivered to Buyer commencing July 1, 1980 and thereafter and providing for a change in the time of payment. The Buyer determined to exercise the alternative of entering into this First Amendment. In consideration of the Agreement and the mutual promises herein contained, the Seller and Buyer agree to amend the Agreement as contained herein.

2. PROCESSING CHARGE. Commencing July 1, 1980, and on the first day of each and every month thereafter during the entire Term of the Agreement, the Base Mine Price shall be adjusted (in addition to all adjustments provided in Section 10 of the Agreement) by adding thereto a processing charge ("Processing Charge") for each ton of coal delivered equal to the product of 66 cents times a fraction, the numerator of which shall be the Producers Price Index--All Commodities as compiled by the Bureau of Labor Statistics of the United States Department of Labor

NOTICE OF INTENT TO CANCEL
COAL SUPPLY AGREEMENT OR IN THE ALTERNATIVE AMEND

Wyodak Resources Development Corp., the "Seller" of that Coal Supply Agreement dated as of September 1, 1977 does hereby notify Black Hills Power and Light Company as "Buyer" that under the provisions of Section 1 of said Agreement, the Seller does hereby exercise its right to terminate the said Coal Supply Agreement as of July 1, 1980.

However, Wyodak Resources Development Corp. is willing to enter into an amendment to said Coal Supply Agreement, a copy of such proposal of which is attached to this notice and made a part hereof which provides by its terms two changes to the Coal Supply Agreement for coal delivered on and after July 1, 1980.

If Black Hills Power and Light Company is interested in entering into the First Amendment to the Coal Supply Agreement, please execute the copies of the First Amendment to Coal Supply Agreement and return to Wyodak Resources Development Corp. and the original Coal Supply Agreement as amended by the First Amendment shall apply to all coal deliveries commencing on July 1, 1980 and thereafter.

Dated this 1st day of May, 1980.

WYODAK RESOURCES DEVELOPMENT CORP.

By [Signature]
Its [Signature] Secretary

Black Hills Power and Light Company does hereby acknowledge receipt of the within and foregoing notice with attachments on this 1st day of May, 1980.

BLACK HILLS POWER AND LIGHT COMPANY

By [Signature]
Its [Signature] President

which is the most recent available on the date of adjustment and the denominator of which is 249.4. This computation shall be made on the first day of each month and such Processing Charge so computed shall be added to the Base Mine Price along with all other adjustments provided by Section 10 of the Agreement and the total thereof shall be further adjusted for calorific quality as provided by Section 11 of the Agreement.

3. INVOICES AND PAYMENTS. Section 12 of the Agreement is hereby amended to read as follows:

Invoices and Payments. Commencing July 1, 1980, Seller shall invoice Buyer by the fifth day of each month for the coal ordered to be delivered for that calendar month at an estimated Adjusted Base Mine Price together with an adjustment, credit or debit, for actual coal sold the previous calendar month based upon the actual Adjusted Base Mine Price for that month. Buyer shall pay each invoice to Seller by the fifteen day of the month in which the invoice is rendered.

4. BALANCE OF AGREEMENT. All other provisions of the Agreement not specifically amended herein be and the same shall remain in full force and effect.

5. DEFINITION OF TERMS. All capitalized terms in this First Amendment which are not specifically defined herein shall be deemed to have the same meaning as defined in the Agreement.

This First Amendment is executed by the parties as of the date first above mentioned.

WYODAK RESOURCES' DEVELOPMENT CORP.

By [Signature]
Its Vice President and
Secretary

BLACK HILLS POWER AND LIGHT COMPANY

By [Signature]
Its President

SECOND AMENDMENT TO COAL SUPPLY AGREEMENT
FOR
BLACK HILLS POWER AND LIGHT COMPANY

This Second Amendment to Coal Supply Agreement for Black Hills Power and Light Company, dated as of November 2, 1987, is made and entered into by and between Wyodak Resources Development Corp., a Delaware corporation, and Black Hills Power and Light Company, an assumed name of Black Hills Corporation, a South Dakota corporation, as a second amendment to the Coal Supply Agreement, dated as of September 1, 1977, as amended by the First Amendment to Coal Supply Agreement, dated as of May 1, 1980.

1. DEFINITIONS AND RECITALS.

1.1 Definitions. The following capitalized words and phrases when used in this Second Amendment shall have the respective meanings as follows:

"Agreement" is the Original Agreement as amended by the First Amendment and this Second Amendment.

"Ben French Plant" is the coal fired generating plant at Rapid City, South Dakota and which is owned by the Buyer.

"Buyer" is Black Hills Power and Light Company an assumed name of Black Hills Corporation, a party to this Second Agreement.

"First Amendment" is the First Amendment to the Original Agreement, dated as of May 1, 1980 between the Seller and Buyer.

"Kirk Plant" is the 4 coal fired generating units situated at Kirk near Lead, South Dakota and which are owned or leased by the Buyer.

"Mine" is the Seller's coal mine situated in Campbell County, Wyoming.

"Neil Simpson Plant" is the coal fired generating plant belonging to the Buyer and situated at Wyodak, Wyoming.

"Original Agreement" is the Coal Supply Agreement, dated as of September 1, 1977 between Seller and Buyer.

"Osage Plant" is the 3 coal fired generating units located at Osage, Wyoming and which are owned or leased by the Buyer.

"Plants" are the Neil Simpson Plant, the Osage Plant, the Kirk Plant and the Ben French Plant.

"Price Concession" is a price concession granted under Section 4 herein.

"Second Amendment" is this Second Amendment to Coal Supply Agreement for Black Hills Power and Light Company.

"Seller" is Wyodak Resources Development Corp., a party to this Second Agreement.

"Term" is the period of time set forth in Section 2 of this Second Agreement.

Other capitalized terms herein shall have the meaning as set forth in the Original Agreement or First Amendment.

1.2 Recitals. This Second Amendment is entered into for the purpose (i) to grant Buyer the Price Concession on coal purchased in excess of a certain amount as an inducement to Buyer to economically generate more energy from the Plants and therefore purchase a larger quantity of coal, (ii) to assure Buyer a long term supply of coal for its Plants for as long as they are used and useful from a mine with adequate loading facilities for both rail or truck delivery and (iii) to obtain selective mining for coal to be delivered to Ben French. Other than the Price Concession granted herein, this Second Amendment preserves the life of the Plants commitment which was made by the Seller to the Buyer in 1977 and preserves the purchase price

based upon the arm's-length negotiated contract between the Seller and PacifiCorp for coal for the 330 MW power plant in Campbell County, Wyoming

2. TERM OF AGREEMENT.

Section 1 of the Original Agreement is hereby amended to read as follows:

The Term of this Agreement shall commence September 1, 1977 and shall continue until all of the Ben French Plant, Neil Simpson Plant, Osage Plant and Kirk Plant are no longer used and useful for electric utility purposes and are permanently retired.

3. QUALITY OF COAL.

Each minimum specification provided at Section 5 of the Original Agreement shall be based upon the average quality of coal which is delivered during any 30-day period of the Term. An additional quality requirement is added to Section 5 of the Original Agreement as follows:

All coal which is delivered as a fuel supply for the Ben French Plant and Neil Simpson Plant shall be selectively mined. For the purpose herein "selectively mined" shall mean that the Seller will use its best efforts to deliver coal for the Ben French Plant which will minimize the need for Buyer to use alternative fuels in firing said plant and to deliver coal for the Neil Simpson Plant which will minimize any opacity standard violations. The Seller shall from time to time communicate to Buyer the anticipated quality of coal to be mined, and Buyer shall from time to time determine and communicate to Seller the cause for fuel related problems and the qualities of coal needed to maximize the efficiency of the said plants.

4. QUANTITY PRICE ADJUSTMENT.

Commencing with the date of this Second Amendment, a Price Concession shall be deducted from the total of the Adjusted Base Mine Price, as determined by Section 10 of the Original Agreement, and the Processing Charge as determined by Section 2 of the First Amendment, for each ton of coal sold under this Agreement in excess of 500,000 tons in 1987 and in each of the years following thereafter. The Price Concession for each ton shall be equal to the product of \$1.50 times a fraction, the numerator of which shall be the most recently available Producers Price Index--All Commodities as compiled by the Bureau of Labor Statistics of the United States Department of Labor on the date of adjustment, and the denominator of which is the most recently available Producers Price Index--All Commodities which was available on the date of this Second Amendment. This adjustment shall be applied to each ton of coal purchased in any calendar year in excess of 500,000 tons as of the first day following the month in which the excess coal was purchased. The Price Concession shall not be adjusted for calorific quality as provided by Section 11 of the Original Agreement. Seller shall levelize the Price Concession credit based upon an estimate of the total quantity of coal to be purchased that year according to Buyer's estimates of the need for coal; and appropriate charges and credits shall be made as of the end of each calendar year when the exact quantity of coal sold that year may be ascertained.

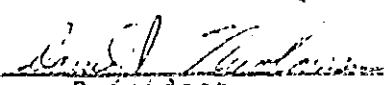
and the Price Concession may be accurately calculated and correctly applied thereto.

5. BALANCE OF AGREEMENT.

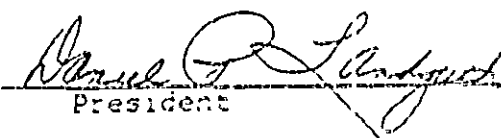
All other provisions of the Original Agreement as amended by the First Amendment and which are not specifically amended herein be and the same shall remain in full force and effect.

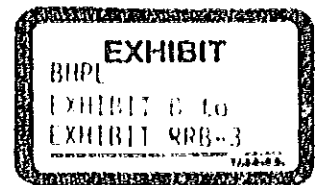
IN WITNESS WHEREOF the parties have executed this Second Amendment as of the date set forth in the first paragraph.

WYODAK RESOURCES DEVELOPMENT CORP.

By 
Its President

BLACK HILLS POWER AND LIGHT COMPANY

By 
Its President



FURTHER RESTATED AND AMENDED
COAL SUPPLY AGREEMENT

dated as of May 5, 1987

among

WYODAK RESOURCES DEVELOPMENT CORP.

and

PACIFIC POWER & LIGHT COMPANY

BLACK HILLS POWER AND LIGHT COMPANY

Coal-Fired Steam Electric Generating
Facility at Wyodak, Wyoming

Coal Supply Agreement

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FURTHER RESTATED AND AMENDED COAL SUPPLY AGREEMENT

FURTHER RESTATED AND AMENDED COAL SUPPLY AGREEMENT ("Agreement"), dated as of May 5, 1987 by and among WYODAK RESOURCES DEVELOPMENT CORP., a Delaware corporation ("Seller"), PACIFIC POWER & LIGHT COMPANY, an assumed business name of PacifiCorp, a Maine corporation, and BLACK HILLS POWER AND LIGHT COMPANY, an assumed business name of Black Hills Corporation, a South Dakota corporation (said Pacific Power & Light Company being referred to herein as "Pacific Power" and Black Hills Power and Light Company being referred to herein as "Black Hills" and both being herein collectively called "Buyers").

WHEREAS, Seller mines coal at a coal mine (the "Mine") in Campbell County, Wyoming, pursuant to leases described in Annex A attached hereto (the "Coal Leases," or the "United States Coal Leases," when referring to items 1, 2 and 3 of Annex A, or the "Homestake Coal Lease" when referring to item 4 of Annex A), and owns coal properties in land described in Annex B, all of which Coal Leases and coal properties contain certain coal reserves (the "Coal Reserves");

WHEREAS, a coal-fired steam electric generating facility having a name-plate rating of 330,000 kilowatts (the "Facility") has been constructed adjoining the Coal Reserves;

WHEREAS, Buyers lease the Facility from The Wyoming National Bank of Casper, as Lessor and Owner Trustee (the "Owner Trustee"), under an agreement (the "Lease Agreement") for a term commencing June 8, 1978; and

WHEREAS, the parties intend that Seller will mine and deliver all of the coal requirements of the Facility during the Term of this Agreement and during the Extended Term under certain conditions;

WHEREAS, this Agreement will be substituted, as of the date of its execution, for the Restated and Amended Coal Supply Agreement dated June 8, 1978 as amended by the Coal Supply Agreement for Wyodak Unit #2 and the Ancillary Agreement to Coal Supply Agreement for Wyodak Unit #2, both dated February 3, 1982, hereinafter referred to as the "Prior Agreement".

NOW, THEREFORE, Seller agrees to sell and deliver and Buyers agree to accept and buy coal, as hereinafter provided, upon the following terms and conditions:

SECTION 1. TERM AND EXTENDED TERM OF AGREEMENT.

The term of this Agreement (the "Term") shall commence upon the date hereof and shall terminate June 8, 2013. The Term shall be extended for a period of 10 years (the "Extended Term" immediately following the Term if the Option provided for in Section 15 is exercised in the manner set forth therein.

SECTION 2. REPRESENTATIONS, ETC. OF SELLER; DEDICATION OF COAL RESERVES; SECURITY INTEREST AND MORTGAGE; SUBSTITUTION AND RELEASE OF COAL RESERVES, ETC.

(a) Certain Representations, Warranties and Covenants of Seller. The source of the coal to be sold and purchased shall be the Coal Reserves. Seller represents and warrants to Buyers that:

A. The Coal Reserves contain approximately 178,000,000 tons of mineable coal;

B. Seller has valid and existing leasehold rights under the Coal Leases except that the United States Coal Lease described in item 1 of Annex A and the Homestake Coal Lease are subject to a mortgage dated May 13, 1976, granted by Seller to Homestake Mining Company securing the payment of a \$4,400,000 obligation of Seller;

C. Seller has title to the Coal Reserves under the real property described in Annex B, but its right to mine such coal may be subject to obtaining the consent of the owner of the surface rights to said property;

D. Seller has certain valid and existing rights as described in Annex C hereto) to use the surface of the land under which the Dedicated Reserves, as hereinafter defined in this Section 2, are located (such rights to the extent they relate to the Dedicated Reserves being herein referred to as "Surface Rights"); and

E. Seller holds the following permits, licenses and approvals (the "Governmental Approvals") to mine the Dedicated Reserves:

Permit No. 232C-A1 issued by The Department of Environmental Quality of the State of Wyoming permitting the surface mining (pursuant to the mine plan filed by Seller with said Department) of coal in the Dedicated Reserves and other portions of the Coal Reserves.

License No. 232C issued by the Department of Environmental Quality of the State of Wyoming authorizing

Seller to surface mine (pursuant to the mine plan referred to above) coal in the Dedicated Reserves and other portions of the Coal Reserves.

Approval by the Geological Survey of the United States Department of the Interior of the mining plan of Seller to mine the Dedicated Reserves and other portions of the Coal Reserves.

F. Seller has valid and existing easement rights to use the real property described in Annex E as a Permanent Stockpile (as defined in Section 4); and

G. The rights of Seller under the Coal Lease described in item 3 of Annex A (such rights to the extent they relate to the Dedicated Reserves being referred to herein as "Lease Rights"), the Surface Rights and the Governmental Approvals are sufficient to permit Seller to mine the Dedicated Reserves, subject to the claims and rights of others and applicable mining and reclamation requirements and governmental approvals as are set forth in Exhibit A to the Security Agreement and Real Estate Mortgage (the "Security Agreement and Mortgage") being executed and delivered simultaneously with the execution and delivery of this Agreement and further subject to obtaining approval of an amendment to Seller's mine plan to allow the mining of the Dedicated Reserves at an earlier time than now contemplated by Seller's present mine plan.

Seller shall use its best efforts to maintain the Coal Leases, the Surface Rights and the Governmental Approvals in full force and effect during the Term and the Extended Term, to obtain all necessary renewals thereof, and to obtain all mining permits and other governmental approvals or authorizations and any consents from others as may be necessary in order to permit Seller to perform its obligations hereunder and under the Restated Security Agreement and Mortgage.

(b) Dedication of Coal Reserves; Security Interest and Mortgage; Access to Dedicated Reserves. Seller does hereby dedicate to the Facility all coal (constituting at least 50,000,000 tons of mineable coal meeting the quality requirements set forth in Section 6) from the Coal Reserves under the following described real property:

Township 50 North, Range 71 West of the 6th Principal Meridian, Campbell County, Wyoming:

Section 15: Northwest Quarter, the West Half of the East Half, and the East Half of the Southwest Quarter; and

Section 22: The North Half of the Northeast Quarter
of the Northwest Quarter.

(The afore-described portion of the Coal Reserves is herein referred to as the "Dedicated Reserves".)

Seller shall not mine, sell or use coal from the Dedicated Reserves for any purpose other than fulfilling its obligations under this Agreement, unless otherwise permitted under this Agreement. Seller shall, simultaneously with the execution and delivery of this Agreement, execute and deliver the Security Agreement and Mortgage.

As contemplated by the Access Easement to Dedicated Reserves, substantially in the form of Annex D hereto, Buyers shall have the right to enter upon Seller's premises for the purpose of transporting coal from the Dedicated Reserves to the Facility.

(c) Substitution and Release of Coal Reserves, etc. Other Coal Reserves and the lease rights and surface rights associated therewith shall be substituted for the Dedicated Reserves, Coal Reserves shall be released from the Dedicated Reserves, and Coal Reserves, Lease Rights and Surface Rights may be released from the lien of the Security Agreement and Mortgage under certain conditions as follows:

(1) If for any reason any Coal Lease which includes the right to mine the Dedicated Reserves terminates or expires and is not renewed, Seller shall dedicate to the Facility other portions of the Coal Reserves containing coal of the same quality and as readily recoverable, both legally and physically, in substitution for those which have been lost to the extent, if any, that Seller at the time of the loss has such quality of Coal Reserves which have not been sold, committed or dedicated to others. Such substituted Coal Reserves and the lease rights and surface rights associated therewith shall be subjected to the lien of the Security Agreement and Mortgage subject only to the exceptions referred to therein and, to the extent Seller only has Coal Reserves, lease rights and surface rights subject to liens or security interests granted to others prior to the date of such substitution, to such prior liens or security interests, provided that such substituted Coal Reserves, lease rights and surface rights shall not be subjected to the lien of the Security Agreement and Mortgage to the extent such substitution would be a breach of the terms of any prior lien or security interest and the consent to such subjection cannot be obtained by Seller from the holder(s) of such lien or security interest.

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(2) Subject to the quality requirements set forth in Section 6, Seller may from time to time, at its option, supply coal to the Facility in fulfilling its obligations under this Agreement from sources other than the Dedicated Reserves, and in such event Buyers shall (from time to time upon Seller's written request) release equivalent quantities of the Dedicated Reserves from the dedication thereof pursuant to this Agreement and shall release such quantities of the Dedicated Reserves and the Lease Rights and Surface Rights associated therewith from the lien of the Security Agreement and Mortgage, but only if after giving effect to such release the Dedicated Reserves shall contain a quantity of mineable coal of a quality required by Section 6 in an amount which, when added to all of the coal sold by Seller to Buyers under this Agreement up to the date of such release, equals at least 50,000,000 tons.

(3) Seller shall have the option from time to time to cause Buyers to release quantities of the Dedicated Reserves from the dedication thereof pursuant to this Agreement and to release such quantities of the Dedicated Reserves and the Lease Rights and Surface Rights associated therewith from the lien of the Security Agreement and Mortgage, but only if after giving effect to such release the Dedicated Reserves shall contain a quantity of mineable coal of a quality required by Section 6 in an amount which, when added to all of the coal sold by Seller to Buyers under this Agreement up to the date of such release, equals at least 50,000,000 tons.

(4) Seller shall further have the option to dedicate other equivalent reserves from the Coal Reserves in substitution for all or any part of the Coal Reserves dedicated pursuant to this Agreement and to cause Buyers to release an equivalent quantity of the Dedicated Reserves (at the location to be designated by Buyers) from the dedication thereof pursuant to this Agreement and to release such quantity of Dedicated Reserves and the Lease Rights and Surface Rights associated therewith from the lien of the Security Agreement and Mortgage, but only if after giving effect to such release (i) the Dedicated Reserves shall contain a quantity of mineable coal of a quality required by Section 6 in an amount which, when added to all of the coal sold by Seller to Buyers under this Agreement up to the date of such release, equals at least 50,000,000 tons, (ii) such substituted reserves are of the same quality and are as readily recoverable, both legally and physically, as the portion of the Dedicated Reserves to be released, and (iii) the reserves so substituted and the lease rights and surface rights associated therewith shall be subjected to the lien of the Security Agreement and Mortgage, subject only to the exceptions set forth in Exhibit A thereto.

(5) Any part of the Coal Reserves substituted in accordance with this Section 2(c) shall be coal under surface either owned by Seller or in which Seller has all necessary surface rights to surface mine such coal.

(6) The quantities of the Dedicated Reserves to be released pursuant to clauses (2) and (3) of this Section 2(c), shall be released in the parcels designated in the Plat of the Dedicated Reserves (the "Plat") attached as Annex K hereto. Each parcel shall be released in the numerical order set forth in the Plat upon delivery by Seller from sources other than the Dedicated Reserves of the amount of coal described in the Plat as being contained in such parcel and upon fulfillment of the other terms and conditions applicable to release of quantities of the Dedicated Reserves set forth in this Section 2(c).

(7) In the event compliance with this Section 2 requires Seller to subject additional Coal Reserves to the lien of the Security Agreement and Mortgage, such subjection shall be evidenced by an agreement supplemental to the Security Agreement and Mortgage, or by such other agreement as may be necessary, in view of applicable law at the time of such subjection, to grant Buyers substantially the same rights in such additional Coal Reserves as Buyers had with respect to the Dedicated Reserves pursuant to the Security Agreement and Mortgage, subject, however, to the provisions of clause (1) of this Section 2(c).

(8) At the time Seller substitutes other Coal Reserves for Dedicated Reserves under clause (1) or (4) of this Section 2(c), and in order for Seller to obtain a release of Coal Reserves from the Dedicated Reserves under such clause (4), Seller shall (at its expense) deliver to Buyers a certificate executed by an engineer satisfactory to Buyers certifying that the Coal Reserves to be substituted contain coal of the quality and quantity, and are as physically recoverable, as required by such clause (1) or (4) and an opinion of Messrs. Wehrli and Williams or other counsel satisfactory to Buyers and the Owner Trustee to the effect that Seller has all permits, licenses, consents and approvals from governmental bodies and other parties legally necessary for Seller to mine the Coal Reserves being substituted (subject to amending the mine plan of Seller to allow the mining of the Coal Reserves being substituted at an earlier time than may be contemplated by Seller's mine plan at the time of the substitution), that such substituted reserves and the lease rights and surface rights associated therewith have been duly subjected to the lien of the Security Agreement and Mortgage to the full extent required hereby, and that all recordations or filings required to perfect the rights of Buyers under such Security Agreement and Mortgage, as then supplemented, have been duly made and are in full force and effect. Such substituted Coal Reserves, lease rights and surface rights

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shall thereupon be considered Dedicated Reserves. Lease Rights and Surface Rights for the purposes of this Agreement and the Security Agreement and Mortgage and, as such, shall be subject to release or substitution in accordance with the terms of this Section 2(c). In order to obtain a release of Coal Reserves from the Dedicated Reserves under clause (2) or (3) of this Section 2(c), Seller shall (at its expense) deliver to Buyers a certificate executed by an engineer satisfactory to Buyers certifying that the Dedicated Reserves which are to remain after such release contain the quantity of coal required by such clause (2) or (3), as the case may be.

(9) Upon satisfaction of all applicable conditions as set forth above for the release or substitution of Coal Reserves from the dedication hereunder and for the release of Coal Reserves, Lease Rights and Surface Rights from the lien of the Restated Security Agreement and Mortgage, Buyers shall execute and deliver to Seller appropriate instruments for effecting such release.

At the time of the completion of Seller's obligations under this Agreement, Buyers shall release any remaining unmined coal from the dedication of Coal Reserves pursuant to this Agreement and shall release such coal and the lease rights and surface rights associated therewith from the lien of the Security Agreement and Mortgage. The lien of the Security Agreement and Mortgage shall not in any way alter Seller's rights granted in any of the United States Coal Leases to mine and remove the coal therefrom, except to the extent Seller's rights may be affected by the exercise of Buyers' rights in the event of Seller's default pursuant to the terms of the Security Agreement and Mortgage.

SECTION 2B. ADDITIONAL PROVISIONS CONCERNING RELEASE OF COAL FROM SECURITY AGREEMENT.

Buyers acknowledge that under the Prior Agreement, Seller has sold and Buyers have purchased approximately 15,000,000 tons of coal and that without this Agreement, Seller would be now entitled to have Buyers release from the Security Agreement and Mortgage 14 parcels of the Dedicated Reserves as shown on Annex K and as authorized by Section 2(c)(3). In order to retain adequate Dedicated Reserves for the 10,000,000 tons of additional coal dedicated under Section 3B of this Agreement, Buyers shall, as of the date of this Agreement release only the first seven parcels of Annex K, leaving the Dedicated Reserves as of the date of this Agreement to be at least 45,000,000 tons. As additional coal is sold under this Agreement hereafter, Seller shall be entitled to further release of the parcels as provided in Section 2(c)(3).

SECTION 3. QUANTITIES OF COAL TO BE SOLD AND PURCHASED;
SCHEDULING.

Seller agrees to sell and Buyers agree to buy all of the coal which is necessary to fuel the Facility during the Term, but not to exceed 50,000,000 tons of coal, of which approximately 300,000 tons has been sold as a Permanent Stockpile as set forth in Section 4 and the balance shall be delivered as set forth in this Section. At least 6,400,000 tons of the coal to be sold herein shall be coal derived from the Homestake Lease during the first 25 years of the Term. Buyers shall notify Seller at least twenty days prior to the beginning of each month of the quantities of coal to be delivered to Buyers during such month and shall provide a schedule for delivery. In addition, Buyers will furnish Seller an estimate of the quantities to be ordered in each of the two months following such month. Buyers may at any time increase or decrease the amount of the coal to be delivered at a rate necessary to properly fuel the Facility, but, subject to the right of Buyers to increase the delivery rate as set forth below, the amount of coal to be delivered shall not exceed 41,000 tons for any one week or 1,900,000 tons for any one year. If Buyers do not purchase sufficient coal during 1978 so that Seller has received sufficient consideration therefor from Buyers to compensate Seller for its fixed costs and operating expenses (not including a return on equity) in being ready to deliver 1,420,000 tons of coal to Buyers in 1978, Buyers shall pay Seller a sufficient amount so that said amount plus the amount received by Seller from Buyers for coal sold in 1978 compensates Seller for its said fixed costs and operating expenses. Seller shall use reasonable efforts in minimizing its operating expenses during any delay without jeopardizing its ability to perform hereunder when delivery starts. Notwithstanding the maximum weekly and annual limitations set forth above, Buyers shall have the right to cause Seller to deliver up to 43,700 tons of coal per week or up to 2,050,000 tons of coal per year if the fuel requirements of the Facility require that rate of delivery, but in that event Buyers shall, in addition to paying the Adjusted Base Mine Price (as hereinafter defined) for the coal delivered, compensate Seller for the incremental cost per ton, if any, incurred by Seller in delivering at a rate in excess of 41,000 tons per week. Nothing herein shall increase the maximum amount of coal to be sold hereunder.

SECTION 3B. ADDITIONAL RESERVES.

If necessary to fuel the Facility during the Term, Seller agrees to sell 10,000,000 tons of coal in addition to the 50,000,000 tons of coal set forth in Section 3 pursuant to the same terms and conditions applicable to the 50,000,000 tons as set forth in this Agreement. To fuel its 80 percent share of

the Facility, Pacific Power shall purchase from seller a minimum of 1,280,000 tons of coal during each calendar year of the Term subsequent to 1986. This minimum amount of coal shall be purchased by Pacific Power regardless of the quantity of coal purchased by it during prior years. Seller's sole remedy for Pacific Power's failure to purchase this minimum amount of coal shall be the Short-Fall Payment provided for in Section 11(m).

SECTION 4. PERMANENT STOCKPILE.

Seller has stripped and segregated from other coal approximately 300,000 tons of coal (the "Permanent Stockpile"), which has been transferred to Buyers pursuant to, and is located on the 5.03 acres described in, the Easement Assignment and Bill of Sale to Permanent Stockpile substantially in the form of Annex E hereto. Buyers have paid Seller an amount equal to the Adjusted Base Mine Price, determined as of January 1, 1978, times the number of tons of coal contained in the Permanent Stockpile, except that, in computing the Adjusted Base Mine Price for such coal, the Base Mine Price was deemed to be 215.2 cents (computed by deducting 3.1 cents for severance tax and 5.6 cents for production tax from the Base Mine Price of 223.9 cents) and no adjustment was made for any tax assessed on the basis of coal mined. Seller has prepaid all royalties payable pursuant to the Homestake Coal Lease for the mining of the coal contained in the Permanent Stockpile. Buyers shall assume and pay any severance tax, production tax, industrial development impact tax, federal reclamation fees and any other taxes or assessments levied or assessed by any governmental body on the basis of coal mined from the Permanent Stockpile.

Buyers shall at all times have the right to enter upon Seller's premises to seal the Permanent Stockpile or to mine, remove and use the coal contained therein without the payment to Seller of any additional consideration.

SECTION 5. PLACE OF DELIVERY AND SALE.

(a) Delivery shall be made to Buyers by dumping the coal to be delivered into the receiving hopper in the south pit of the mine which is a part of the coal supply system to be furnished by Buyers. The point of delivery shall change as provided in Section 6.5 of the Amended Agreement dated as of May 5, 1987 among the parties. Title to that portion of the coal dumped into the receiving hoppers by Seller in fulfillment of its obligations under this Agreement shall thereupon pass to Buyers and Buyers shall be responsible for transporting said coal to the Facility. In the event of emergencies of Buyers preventing the delivery or acceptance of the coal at the hoppers, the coal shall be delivered at such different location as may be designated by Buyers, and in that event Seller shall be

compensated by Buyers for any additional cost to Seller resulting from the delivery of said coal at a different location.

SECTION 6. QUALITY OF COAL.

The coal furnished hereunder shall be raw, run-of-mine coal, produced without selective mining, with a base analysis of 8000 B.T.U. per pound. Seller warrants that coal as delivered shall meet minimum specifications as follows:

Calorific value--not less than 7500 B.T.U. per pound
Ash--not more than 10% of weight over a period of 30 days

Sulfur--not more than 0.7% nor less than 0.26% of weight over a period of 30 days

Ash softening temperature--not less than 2000 degrees F

Average moisture--not more than 32% by weight over a period of 30 days

The quality of the coal delivered shall be determined from the daily composite coal sample analysis taken by Buyers pursuant to Section 8 hereof. Seller may deliver and sell coal having a sulfur content in excess of the sulfur limitation herein during any time that Buyers are able to utilize such coal in the facility as then equipped and operating and meet all applicable federal and state emission standards, provided that, if such excess sulfur content increases the costs of Buyers in any way including but not limited to increased operating costs and taxes, Seller shall reimburse Buyers for all of said increased costs.

SECTION 7. WEIGHING.

The weights of the coal delivered to Buyers shall be determined from weights taken by Buyers on Buyers' scales located at such places as the parties hereto may agree. The aggregate weights of such delivered coal shall be accepted as the quantity of coal delivered for which invoices are to be rendered and payments to be made. Seller shall have the right to have a representative present at any and all times to observe the weighing of coal delivered hereunder, and if Seller shall, at any time, question the accuracy of the weights thus determined, Seller shall so advise Buyers and Buyers shall permit Seller's representative to test Buyers' scales. If any such tests show the scales being used are in error, such scales shall be adjusted to an accurate condition, provided that if Seller and Buyers are unable to agree upon such test and adjustments or the method thereof, the scales shall be tested and adjusted to a condition of accuracy within manufacturer's tolerances by a qualified third party, mutually chosen by Seller and Buyers, and the cost of the testing and adjusting by such third party shall

be shared one-half by Seller and one-half by Buyers. The sole remedy for inaccurate scales shall be to adjust the scales to an accurate condition so as to provide proper measurement of quantities of coal delivered thereafter.

SECTION 8. SAMPLING AND ANALYSIS.

Analysis of calorific value, ash, sulfur and ash softening temperature shall be made by Seller or at its direction. Analysis shall be performed in accordance with the latest methods approved by the American Society for Testing and Materials (ASTM) or such other methods as the parties may agree upon. Samples shall be taken by Buyers on a regular basis by a "grab sample" method to be agreed to by the parties from time to time. All samples shall be divided into three parts and put in suitable airtight containers. One part shall be taken and analyzed by Seller, one part shall be retained by Buyers and may be analyzed by Buyers at their discretion and the third part shall be retained by Seller for not less than one month in one of the aforesaid containers properly sealed and labeled to be analyzed if a dispute arises due to any differences between Seller's analysis and Buyers' analysis. The results of Seller's analysis shall be promptly communicated to Buyers so that they can perform the calculations described in Section 9. Seller shall pay for the cost of the analysis of the samples to be analyzed by it. Buyers shall bear the cost of any analysis they should decide to make of their samples. The analysis of the third part of each sample, should its analysis be found necessary, shall be made by an independent commercial testing laboratory mutually chosen, and the results of such commercial laboratory analysis shall be made available and accepted by all parties hereto as the quality of the coal represented by such sample. The costs thereof shall be shared one-half by Seller and one-half by Buyers.

SECTION 9. DETERMINING OF WEIGHTED AVERAGE HEAT CONTENT.

As soon as practicable after the end of each month, the weighted average heat content, in B.T.U.'s per pound, of coal delivered hereunder during such month shall be computed by Buyers from the daily coal delivered weight readings from the coal scales and from the analysis made by Seller from the daily composite coal samples taken by Seller pursuant to Section 8. Computations made by Buyers shall be communicated to Seller.

SECTION 10. BASE MINE PRICE.

Buyers shall pay Seller for each ton (2,000 pounds) of coal delivered pursuant to this Agreement the sum of 223.9 cents f.o.b. receiving hopper in the south pit of the Mine, subject, however, to the adjustments provided for in Sections 11 and 12

hereof. The Base Mine Price has been computed as of September 30, 1974, and the adjustments shall be based upon conditions and costs on such date compared to the date the adjustment is being made. Terms used herein relating to the price of the coal shall have the following meanings:

"Base Mine Price" shall mean 223.9 cents per ton.

"Adjusted Base Mine Price" shall mean the Base Mine Price as adjusted for certain changes in Seller's costs and quality of coal pursuant to the provisions of Sections 11 and 12.

SECTION 11. ADJUSTMENTS TO BASE MINE PRICE.

The Base Mine Price per ton of coal shall be adjusted (to the nearest one-tenth of a cent) from time to time as provided in Section 11(n) to give effect to changes in the cost to Seller of mining the coal and to adjust for changes in the purchasing power of the dollar. Seller agrees that it will use its best efforts to keep all costs at the lowest practicable levels. The following sets forth adjustments to be made to the Base Mine Price. Each adjustment shall be calculated independently; however, the sum of all such adjustments shall be added to the Base Mine Price.

(a) Direct Mine Labor. The Base Mine Price includes a factor of 51.1 cents per ton for direct mine labor cost per ton. This factor is based on an estimated average labor force (of various classifications) required over the term of this Agreement as set forth in Annex E attached hereto; taking into account direct labor costs prevailing at the Mine on September 30, 1974, under the then current standard hours of work and working practices. The calculation of this labor factor takes into consideration all current factors affecting direct labor costs. Direct labor costs for the purposes of this Section 11(a) are the aggregate cost to Seller of all factors affecting direct labor expense at the Mine, now and in the future, consisting of:

- Basic wage rates, i.e., straight time pay;
- Overtime and overtime pay rates;
- Vacations and vacation pay;
- Holidays and holiday pay;
- Hours of work;
- Working practices;
- Bonus pay;
- Shift differential pay;
- Fringe benefits;
- Limitations on production imposed by unions;
- Pension, retirement benefits, old age benefits,

unemployment benefits, social security, premiums for Workmen's Compensation and all other payments to or for the benefit of employees; and Governmental, judicial, or legislative requirements,

provided that the above costs shall not include the cost of supervisory labor at the Mine or miners' welfare benefits, which items are covered by Sections 11(b) and 11(c) below.

If, after September 30, 1974, the total of Seller's labor costs which are necessary to fulfill its obligations under this Agreement should increase or decrease due to any one or more of the factors in this section, the Base Mine Price shall be adjusted by the amount the direct mine labor factor increased or decreases when changed in the same proportion as the direct labor costs of the estimated average labor force have increased or decreased from September 30, 1974.

Adjustments on account of changes in direct labor costs shall be made by applying such changes to the estimated average labor force irrespective of the actual labor employed at the Mine at any time. It is understood, however, that the labor adjustment will be affected when the number of persons in the average labor force would necessarily change due to any of the factors listed in this Section 11(a).

(b) Supervisory Labor at the Mine. The cost factor for supervisory labor at the Mine included in the Base Mine Price is 5.8 cents per ton. If pursuant to Section 11(a) direct labor costs at the Mine shall be changed, the cost factor for supervisory labor at the Mine shall be changed by a factor equal to the percentage change in the direct labor cost factor and the amount of the resulting change in the cost per ton for supervisory labor shall be reflected in an Adjusted Base Mine Price.

(c) Miners' Welfare Benefits. The Base Mine Price does not include amounts to be paid by Seller to or for its Mine labor force as miners' welfare benefits. Any payment by Seller in miners' welfare benefits, or sums paid in lieu thereof, shall be reflected by a corresponding change in the price of coal hereunder.

The adjustment provisions of this Section 11(c) shall apply to miners' welfare benefits, any similar benefits, or any benefits substituted for the welfare benefits referred to hereinabove, provided only that said benefits are not included as a part of direct labor costs within the provisions of Section 11(a).

(d) Explosives and Explosive Accessories. The Base Mine Price includes an estimated cost factor of 5.8 cents per ton of

cost for costs of explosives and explosive accessories based on an assumed average volume of use of explosives and explosive accessories.

The Base Mine Price shall be adjusted from time to time to compensate for changes in these costs. Such adjustments shall be based upon changes in the wholesale price index for Other Chemicals and Allied Products, Code No. 06-7, published by the Bureau of Labor Statistics, United States Department of Labor. Such change shall be reflected in a new Adjusted Base Mine Price determined by adding to or subtracting from the Base Mine Price the change in the cost of explosives and explosive accessories as reflected by the difference between 5.8 cents and the product of 5.8 cents times the most recent index for Other Chemicals and Allied Products as of the time of adjustment divided by such index as of the month of September, 1974.

(e) Materials and Supplies. Seller's cost factor as of September 30, 1974 for construction machinery and equipment is 37.4 cents per ton; and the cost factor for petroleum products is 3 cents per ton. Whenever a change shall occur in the cost of materials and supplies, as evidenced by an increase or decrease in either the Price Index for Construction Machinery and Equipment (Code No. 11-2) in the Machinery and Equipment Group as published by the Bureau of Labor Statistics, United States Department of Labor or the Price Index for Petroleum Products, Refined (Code No. 05-7) in the Fuels and Related Products and Power Group as published in the Wholesale Price Index, by the Bureau of Labor Statistics, United States Department of Labor, such change shall be reflected in a new Adjusted Base Mine Price determined as follows:

(i) when a change occurs in the index for Construction Machinery and Equipment, the change shall be reflected in a new Adjusted Base Mine Price determined by adding to or subtracting from the Base Mine Price the change in the cost of construction machinery and equipment as reflected by the difference between 37.4 cents and the product of 37.4 cents times the most recent price index for Construction Machinery and Equipment as of the time of adjustment divided by the index for Construction Machinery and Equipment as of the month of September, 1974.

(ii) when a change occurs in the index for Petroleum Products, Refined, the change shall be reflected in a new Adjusted Base Mine Price determined by adding to or subtracting from the Base Mine Price the change in the cost of petroleum products as reflected by the difference between 3 cents and the product of 3 cents times the most recent price index for Petroleum Products, Refined as of the time of adjustment divided by

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the Index for Petroleum Products, Refined as of the month of September, 1974.

(f) Taxes. When any increase or decrease in taxes, whether due to increases or decreases in taxes or enactment of taxes in addition to those in effect as of September, 1974, levied or assessed by local, state or federal authorities on the coal sold hereunder or on Seller's mining facilities or operations, including increases or decreases in amounts of taxes payable resulting from the price for coal sold hereunder exceeding the Base Mine Price due to price adjustments as set forth in Sections 11 and 12 of this Agreement, results directly or indirectly in an increase or decrease per ton to Seller of the cost of mining, preparing and delivering coal hereunder, such increase or decrease shall be reflected in a new Adjusted Base Mine Price. Included, without limitation, in matters within the price adjustment provisions of this subsection are any severance taxes, import taxes, ad valorem taxes, sales taxes, taxes or assessments imposed for reclamation purposes, fees, and any and all other taxes, special assessments and governmental impositions of any kind and character whatsoever. Any taxes based upon Seller's net income shall be excluded from this adjustment. For those taxes and impositions incurred by Seller in the same amount or on the same basis whether coal from the Homestake Coal Lease or coal from the United States Coal Leases is sold to the Buyers, adjustments shall be based upon actual taxes paid in the year of adjustment divided by the actual tons mined and sold by Seller for all of its purposes in the same year. If at any time Seller should incur a tax or other governmental imposition which is incurred in a different amount or on a different basis for coal mined from the United States Coal Leases than from coal mined from the Homestake Coal Lease, adjustments shall be based upon actual taxes incurred the year of adjustment for the actual tons mined and sold by Seller divided by said actual tons in the same year until such time that Seller has sold Buyers 6,400,000 tons of coal mined from the Homestake Coal Lease, after which the adjustments shall be based upon the assumption that all coal is mined from the United States Coal Leases, notwithstanding its actual source. The cost per ton as of September 30, 1974, for Wyoming severance tax is 3.1 cents, for Wyoming production tax 5.6 cents, and for Wyoming (including local) property tax 1.6 cents.

(g) Pneumoconiosis Disease. The Base Mine Price shall be adjusted to reflect the cost to Seller to comply with all laws and regulations now or hereinafter enacted relating to pneumoconiosis disease attributable to mining at the Mine, including, but not necessarily limited to, the cost of claims made hereunder including the cost of insurance to pay such claims by adding to the Base Mine Price the cost per ton determined by dividing the total costs incurred by the Seller for this purpose during the

period of adjustment in mining coal for all purposes by the total tons of coal sold by the Seller for all of its purposes during the period of adjustment, and multiplying the quotient thereof times a ratio, the numerator of which shall equal the total tons of coal sold through the period of adjustment by Seller to Buyers under this Agreement and the denominator of which shall equal the tons of coal mined by Seller from the Mine from November 1, 1956 to the end of the period of adjustment.

(h) Legislation and Governmental Imposition, Regulatory Requirements, Rules and Regulations. Whenever any federal, state or local laws, rules, regulations or requirements, whether due to change in, additions to or difference in interpretation or enforcement by any governmental authority of existing laws, rules, regulations, or requirements after September 30, 1974, should cause an increase or decrease in cost to the Seller of mining coal in compliance with all of such laws, rules, regulations, or requirements, the actual additional cost per ton of coal to Seller on account thereof shall be reflected in a new Adjusted Base Mine Price. Costs covered by this paragraph include but are not limited to those of reclamation, prevention or reduction of water and air pollution and compliance with mine safety laws and environmental quality acts, rehabilitation, and the handling and processing of mine refuse including bond premiums for bonds required to be posted thereunder. The Base Mine Price includes all reclamation costs and other costs in the fulfillment of the Reclamation Plan described in Annex G attached hereto. If Seller is required to incur further expense in its Reclamation Plan due to governmental impositions and requirements as set forth herein other than as described in said Annex G the Base Mine Price shall be adjusted in order to reflect the additional costs as set forth herein. It is understood that payments for these costs shall be made on an accrual basis so that payment is made at the time Seller incurs the obligations even though Seller may not fulfill said obligations until some time later. The estimated cost of Seller to comply with reclamation laws as of September 30, 1974 is .5 cents (\$.005) per ton.

(i) Royalties. The Base Mine Price shall be adjusted by an amount, plus or minus, equal to the average per ton cost of royalties incurred by Seller during the month of adjustment for coal mined by Seller for all of its purposes from the United States Coal Leases, including any additional federal coal leases acquired by Seller subsequent to the execution of the Prior Agreement, less 16.3 cents, regardless of the actual source of coal sold Buyers during the period, until the total coal delivered under this Agreement and the Prior Agreement totals 50,000,000 tons, and less 15 cents for all coal sold thereafter for the balance of the Term.

(j) All Other Costs and Value of Product. The Base Mine Price hereunder shall also be adjusted to compensate for changes in administrative costs and all other costs not included herein and changes in the purchasing power of the dollar. Such adjustments shall be based upon changes in the Consumer Price Index - All Urban, issued by the Bureau of Labor Statistics, U.S. Department of Labor, ("Consumer Price Index"). Such change shall be reflected in a new Adjusted Base Mine Price determined by adding to or subtracting from the Base Mine Price the change in all other costs and value of product as reflected by the difference between 93.7 cents and the product of 93.7 cents times the Consumer Price Index, all items, as of the time of adjustment, divided by the Consumer Price Index, all items, as of the month of September, 1974.

(X) Supplemental Payment. In consideration of the incremental Coal Discount provided for in Section 11(1) and the 10,000,000 ton increase in dedicated reserves provided for in Section 3B, during the period commencing March 1, 1987 and ending June 8, 2013, Pacific Power shall pay Seller an additional 125 cents per ton of coal taken for its account. This Supplemental Payment shall be adjusted to reflect the purchasing power of the dollar. Such adjustment shall be based upon changes in the Consumer Price Index. Such change shall be reflected in a new Adjusted Supplemental Payment determined by adding to or subtracting from the Supplemental Payment an amount equal to the difference between 125 cents and the product of 125 cents times the Consumer Price Index as of the time of the adjustment, divided by the Consumer Price Index as of the month of March, 1987. Added to such Adjusted Supplemental Payment, to be paid by Pacific Power, shall be an amount that reflects all increases in taxes, governmental impositions and royalties (other than taxes based on net income) incurred by Seller as a result of its receipt of the Adjusted Supplemental Payment.

(1) Incremental Coal Discount.

(1) Commencing with the month of March, 1987, to the extent Pacific Power purchases in excess of 110,000 tons of coal for its own account during any month, the total of the Adjusted Supplemental Payment and the Adjusted Base Mine Price shall be reduced by 300 cents per ton. For purposes of this calculation, the 110,000 monthly limit shall be reduced by 3,500 tons for each day during the month that the Facility was not operated because of normally-scheduled maintenance activities and increased by any amount of deliveries during the month deemed to be delivered from the Permanent Stockpile pursuant to the parties' letter agreement of October 3, 1985. This discount shall be adjusted to reflect the purchasing power of the dollar. Such adjustment shall be based upon changes in the Consumer Price Index. This change shall be reflected in a new Adjusted Incre-

mental Coal Discount determined by adding to or subtracting from the Incremental Coal Discount an amount equal to the difference between 300 cents and the product of 300 cents times the Consumer Price Index, as of the time of the adjustment, divided by the Consumer Price Index, as of the month of March, 1967.

(2) No incremental Coal Discount shall be allowed for any coal purchased after a year during which Pacific Power did not purchase sufficient coal and became obligated to pay a full Short-Fall Payment for such deficiency under Section 11(m) until such time that Pacific Power has purchased after said year for its account a quantity of coal in excess of 1,280,000 tons a year equal to the total of the deficiency and all other such deficiencies in years subsequent to 1986 that have not previously been made up.

(3) If, during any year subsequent to 1986, Pacific Power receives an Adjusted Incremental Coal Discount pursuant to Section 11(1)(1), but for any reason (including an excuse under Sections 20 and 11(m)(2)) purchases less than 1,280,000 tons of coal (not counting coal deemed acquired from the Permanent Stockpile), during the following January, it shall refund any and all such discounts it receives to Seller together with interest on each discount payment from the date the discount is credited to the date Pacific Power refunds the discounts to the Seller. For this purpose, and for purposes of Sections 11(1)(4) and (5) the rate of interest shall be interest rate of the Morgan Guaranty Trust Company of New York as of the second Monday of the January following the year for which the refund is due plus one percent. Payment shall be made on or before the January 31 following the year for which the payment is being made.

(4) During the January following any year subsequent to 1986 in which Pacific Power purchased more than 1,280,000 tons of coal for its own account (not counting coal deemed to be from the Permanent Stockpile), there shall be a reconciliation of Pacific Power's Incremental Coal Discount. If the result of the following equation is a positive number, Pacific Power shall pay that number of dollars to Seller. If the result of the following equation is a negative number, Seller shall credit Pacific with that number of dollars.

$$\text{Reconciliation Amount} = I + R - X(P - 1,280,000 - S - D)$$

I = The total of interest on each Incremental Coal Discount which was credited during the year of adjustment for the time commencing from the date the credit was applied to the date the Reconciliation Amount is paid; provided, no interest shall be included in I on any Incremental Coal Discount

credited for coal purchased by Pacific Power after Pacific Power has purchased that year the total of 1,280,000 tons (not including S) plus that amount included as D for that year.

R = Total Incremental Coal Discount received by Pacific Power during year for which reconciliation is being made.

X = The Adjusted Incremental Coal Discount as of the time of the reconciliation calculation.

P = Tons of Coal purchased by Pacific Power during year for which reconciliation is being made.

S = Tons of coal purchased by Pacific Power during year for which reconciliation is being made which were deemed to have been delivered from the Permanent Stockpile pursuant to the Parties' letter agreement of October 3, 1985.

D = The remainder, if any, of the total of the deficiencies of coal for which Pacific Power became obligated to pay a full Short-Fall Payment under Section 11(1)(m) for all years subsequent to 1986 and prior to the year for which the reconciliation payment calculation is being determined after subtracting the total of tons included as D by the application of this formula in years prior to the date of the reconciliation calculation. D shall never exceed the remainder of P less 1,280,000 less S.

(5) In addition to the discount in the Adjusted Base Mine Price provided for herein, Seller shall credit to Pacific Power, with interest any savings in taxes, royalties and government impositions (other than taxes based upon net income) enjoyed by Seller as a result of the Adjusted Incremental Coal Discount, taking into account any refunds or increases of those discounts under Sections 11(1)(3) and 11(1)(4). Any such credit shall be made prior to January 31 following any year in which an Incremental Coal Discount is received by Pacific Power.

(m) Short-Fall Payment.

(1) For any year during the Term, subsequent to 1986, Pacific Power shall pay a Short-Fall Payment if it purchases fewer than 1,280,000 tons of coal for its own account. This

Short-Fall Payment shall be equal to the result of the following equation.

$$(1,280,000 - P) (B-C)$$

Where:

P = number of tons purchased by Pacific Power during the year.

B = sum of the per ton Adjusted Base Mine Price and Adjusted Supplemental Payment as of the payment of the Short-Fall Payment.

C = per ton costs as of the payment of the Short-Fall Payment associated with taxes and royalties (other than taxes based on net income) that Seller need not pay until coal is mined.

(2) Pacific Power shall be excused from paying the Short-Fall Payment for any calendar year if failure to purchase the minimum 1,280,000 tons of coal for its account was caused by a partial or total suspension of deliveries pursuant to Section 20, provided that the effect of such uncontrollable force is eliminated insofar as possible with all reasonable dispatch and any missed deliveries are made up as soon as practicable upon the cessation of such uncontrollable force. Notwithstanding the foregoing, in no event shall Pacific Power be excused from paying the Adjusted Supplemental Payment portion of the Short-Fall Payment. For purposes of Pacific Power's obligation to pay the full Short-Fall Payment, Pacific Power's lack of need for power generated by the Facility, or its inability to economically market the power generated by the Facility, shall not be considered an uncontrollable force under Section 20.

(3) If Pacific Power incurs a Short-Fall Payment, during any subsequent year in which Pacific Power's purchases exceed 1,280,000 tons, Seller shall afford Pacific Power a dollar-for-dollar credit for any previously-paid Short-Fall Payment, against amounts otherwise owing by Pacific Power for its annual purchases in excess of 1,280,000 tons. No credit shall be allowed for those payments by Pacific of only the Adjusted Supplemental Payment portion of the Short-Fall Payment during times of a partial or total suspension of deliveries under Sections 20 and 11(m)(2). Any accrued Short-Fall Payments existing at the end of the Term, for which a credit has not been given, shall be forfeited by Pacific Power.

(4) Any Short-Fall Payment owing shall be paid no later than January 31 of the year following the year giving rise to it.

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(5) On June 30, 2013, Pacific Power shall pay Seller a Short-Fall Payment for the remainder (if any) of 561,778 tons after subtracting the tons of coal purchased by Pacific Power for its account during the period of January 1, 2013 through June 8, 2013. Such payment, if any, shall be calculated in a manner consistent with Section 11(m)(1).

(n) Time of Making Price Adjustment. Price adjustments required to be made hereunder pursuant to Sections 11(a), 11(b), 11(c), 11(f), 11(g), 11(h) and 11(i) shall be made monthly, but in such manner so as to accurately reflect the actual dates when the changes in costs occurred. Price adjustments required to be made pursuant to Sections 11(d), 11(e) and 11(j), (k), (l) and (m) shall be made in respect to all coal delivered hereunder in the month following the month in which an event occurs requiring a price adjustment pursuant to such subsections. When an adjustment is based on changes in indices published by the U.S. Department of Labor, such adjustments shall be made on the basis of the latest index or indices then available whether said index or indices have been published or not. All cost adjustments made pursuant to this Section 11 will from time to time be further adjusted by appropriate accounting methods and supplemental billings or credit statements when any such costs may not be fully determinable in the month when the original adjustment is made. It is understood that some costs which are to be added to the Base Mine Price under this Section 11 may be not known or determinable on the date the billings are made for the coal for which such costs are incurred; and in that event retroactive adjustments and appropriate billings and credit statements shall be made at such time that such costs become known and determinable. If Seller fails to make an adjustment in billings within two years from the date information is reasonably available to Seller to fully determine the actual amount of the adjustment, the Seller shall be barred from making that adjustment. If Pacific Power fails to protest to Seller in writing within two years of a date when information is reasonably available to Pacific Power to determine that an adjustment included in a billing received prior to that date is incorrect, Pacific Power shall be barred from contesting that adjustment even if the adjustment was incorrect.

(o) Auditing of Records. If at any time Buyers, or either of them, desire to receive assurances of the accuracy of Seller's records affecting the price adjustments provided for herein, Buyers may request Seller to authorize the nationally recognized independent certified public accounting firm doing Seller's auditing work at the time of the request to audit Seller's records and certify the accuracy to Buyers of certain information so requested. If Seller does not have a nationally recognized accounting firm retained at the time of the request, a nationally recognized accounting firm shall be selected upon

mutual agreement of the parties hereto. The information requested must be relevant to the amount of any price adjustment herein. The accounting firm's charges for any work requested of it under this provision shall be paid by Buyers.

(5) Procedure in Event Indices are Discontinued or Changed. In the event any index which is used in this Section 11 is discontinued or otherwise becomes unavailable, the parties hereto shall undertake in good faith to agree upon a substitute index which will most nearly reflect the same type of adjustments which would have been made if the former index had been continued.

(6) Computations. Annex H attached hereto is a sample computation of the Adjusted Base Mine Price based upon assumed facts to illustrate the application of Sections 11 and 12. Annex I attached hereto is the actual calculation of the Base Mine Price as of September 30, 1974.

(7) Conditions of Sections 11(f) and 11(h). In the computation of the Adjusted Base Mine Price at any time to reflect changes in actual costs caused by any of those cost items in Sections 11(f) and 11(h), each such actual cost change shall affect only one of such items so that any such cost change will be included only once in such computation.

SECTION 12. PRICE ADJUSTMENTS--CALORIFIC QUALITY.

For coal delivered in each month hereunder the Base Mine Price as adjusted pursuant to the application of Section 11 shall be further adjusted monthly for calorific quality by multiplying the Base Mine Price as adjusted by Section 11 times the actual weighted average B.T.U. per pound of coal delivered (as determined in Section 9) for the period for which the calculation is being made and dividing the result by 8000. The result so determined and computed to the nearest one-tenth of a cent shall constitute the Adjusted Base Mine Price for the coal sold during the period for which the calculation is made. The Adjusted Supplemental Payment and Adjusted Incremental Coal Discount provided for in Section 11 shall not be adjusted for calorific quality.

SECTION 13. INVOICES AND PAYMENTS.

Seller shall invoice Buyers through its plant operator by the fifth day of each month for the coal ordered to be delivered for that calendar month at an amount estimated under the provision of Section 11 together with an adjustment, credit or debit, for actual coal sold the previous calendar month based upon the actual Adjusted Base Mine Price for that month. Buyers

shall pay each invoice to Seller by the fifteenth day of the month in which the invoice is rendered.

SECTION 14. NO RESTRICTION ON COAL RESERVES OTHER THAN DEDICATED RESERVES.

This Agreement shall not restrict Seller from mining, selling, using, committing, dedicating, mortgaging or encumbering in any manner the Coal Reserves other than the Dedicated Reserves for any purpose except for such portion of the Coal Reserves which may be dedicated upon the exercise of the Option under Section 15. Notwithstanding this provision, Seller shall not dedicate or commit to any new electric generating plant constructed by or for either of the Buyers an amount of coal in excess, on a per megawatt year basis, of the amount of coal dedicated to the Facility for the Term.

SECTION 15. COAL DURING EXTENDED TERM.

Pacific Power shall have the option (the "Option") to purchase from Seller during the Extended Term any portion of the 50,000,000 tons of coal referred to in Section 3 which was not purchased by Buyers during the term (the "Remaining Coal") and Additional Coal, as defined in subparagraph (d) below, under the following terms and conditions:

(a) The Option must be exercised during the period commencing on March 8, 2013 and ending on June 8, 2014.

(b) The Option shall be considered exercised by Pacific Power giving Seller written notice of its intent to purchase coal under this provision and specifying the amount of coal desired to be purchased. Failure to exercise the Option within the time provided in subparagraph (a) of this Section 15 shall render the Option null and void. The Option shall apply only to the amount of coal designated at the time of the exercise of the Option, and shall be null and void as to any additional coal.

(c) The coal purchased shall not be used for any purpose other than to fuel the Facility.

(d) "Additional coal" for the purposes of this Section 15 shall mean any coal from the Coal Reserves which Seller may not have otherwise sold, committed or dedicated for any other purpose prior to the exercise of the Option; provided that Additional Coal shall not exceed in any event an amount which when added to the Remaining Coal is sufficient to fuel the Facility during the Extended Term.

(e) The new base mine price to be paid for the Remaining Coal and Additional Coal shall be the fair market value (the

"Fair Market Value"), as of the last day of the Term, for coal of the quality and quantity required hereunder, which shall be the amount which would then be paid for such coal under an arm's-length contract having a term equivalent to the period for which such coal is required and negotiated as of such time by a willing Seller under no compulsion to sell and by a willing buyer under no compulsion to buy. Such new base mine price shall be determined by agreement of Seller and Pacific Power (or, if they are unable to reach an agreement, shall be determined by a board of arbitration to be composed of three persons, one to be selected by Seller, one to be selected by Pacific Power and the third to be appointed by the two so selected) and shall be subject to escalation provisions equivalent to those applicable during the term.

(f) All other provisions of this Agreement applying during the Term shall be applicable to the sale of coal if the Option is exercised except where inconsistent with the terms of the Option. Seller shall not be obligated to grant a security interest and mortgage in the coal to be purchased under the Option.

(g) Upon the exercise of the Option, Seller shall dedicate sufficient reserves for the fulfillment of the sale of the coal to be purchased.

SECTION 15B. ADDITIONAL PROVISIONS RELATED TO REMAINING COAL AND ADDITIONAL COAL.

(a) Remaining Coal shall include any portion of the additional 10,000,000 tons of coal dedicated by Seller pursuant to Section 3B.

(b) The price to be paid for Remaining Coal and Additional Coal shall not include any Supplemental Payment, Short-Fall Payment or Incremental Coal Discount.

SECTION 16. INSPECTION.

Each party shall at all reasonable times have the right to enter upon the premises of the other to inspect the coal receiving equipment and the weighing, measuring and testing facilities. Buyers shall at all reasonable times have the right to inspect the Mine, maps and operating records of Seller relating to the operation of the Mine.

SECTION 17. NORTH CONVEYOR SYSTEM.

Seller is the owner and operator of the North Conveyor System, which is defined as the truck hopper, the primary crusher conveyor linking the primary crusher to the secondary

crusher, the secondary crusher and all related facilities being located in the north pit of the Mine.

(a) During the Term, Seller shall make the North Conveyor System available to Buyers as a backup, standby system for the delivery of coal to the Facility in common with the Seller's use of the North Conveyor System for its own purpose.

(b) All operations and maintenance expenses of the North Conveyor System and capital additions and replacements shall be borne 72% by Buyers and 28% by Seller commencing January 1, 1978; provided, however, capital additions or replacements to such System made by Seller without the prior written consent of Buyers shall be borne by Seller; and further provided that all costs of operation and maintenance shall be borne by Seller during such period that the North Conveyor System is used exclusively by Seller.

(c) Seller reserves the right to dismantle and dispose of or abandon the North Conveyor System at any time, but in such event, Seller shall give written notice of such intent to Buyers. Within 60 days of receipt of such notice, Buyers shall have the option to purchase the North Conveyor System for a consideration to be determined by appraisers mutually selected by the parties. In the event Buyers exercise their option to purchase the North conveyor System by giving written notice thereof to Seller during said 60-day period, Seller shall convey the North Conveyor System to Buyers upon payment by Buyers to Seller of the appraised price. If such option is not exercised within the 60-day period, Buyers shall have no further right or interest in the North Conveyor System.

SECTION 18. ASH DISPOSAL.

Seller shall furnish a site on Seller's property at its Mine for the disposal of fly ash and bottom ash from the Facility during the Term and the Extended Term at no additional cost to Buyers. Seller reserves the right from time to time to designate and to change the designation of the particular location and method for such disposal so that the disposal of such ash will conform to Seller's mining and reclamation program. Seller shall furnish Buyers reasonable access to and from the disposal sites. Seller shall not be responsible for the cost of transporting such ash from the Facility to the site designated from time to time for disposal.

SECTION 19. EASEMENT FOR WORKING STOCKPILE.

It is anticipated that Seller will maintain a Working Stockpile in close proximity to the receiving hopper referred to in Section 5. Seller shall upon the signing of this Agreement

execute and deliver to Buyers an Easement for Working Stockpile substantially in the form of Annex J attached hereto. If for any reason and at any time and from time to time Seller does not deliver sufficient coal in the performance of its obligations under this Agreement, Buyers shall have access to the Working Stockpile and shall have the right to deliver any coal which may be in the Working Stockpile to the receiving hopper, in fulfillment of Seller's obligation. Unless Seller has a defense or excuse under Section 20, Seller shall pay Buyers their cost incurred in the delivery of said coal.

SECTION 20. UNCONTROLLABLE FORCE.

If because of uncontrollable force, either party hereto is unable to carry out any part or all of its obligations under this Agreement, and if such party promptly gives to the other party hereof notice of such uncontrollable force, then the obligations of the party giving such notice shall be suspended to the extent made necessary by such uncontrollable force and during its continuance, provided the effect of such uncontrollable force is eliminated insofar as possible with all reasonable dispatch. Failure of deliveries of coal hereunder caused by uncontrollable force shall be made up as soon as practicable upon the cessation of such uncontrollable force. The term "uncontrollable force" as used herein shall mean any cause beyond the control of the party and which, by the exercise of reasonable diligence, the party is unable to overcome and shall include but not be limited to acts of God, acts of the public enemy, insurrection, riot, strike, labor dispute, labor or material shortage, fire, explosion, flood, breakdown of or damage to a plant, equipment or facilities, interruption of transportation, embargo, orders or injunctions of a federal, state or local court, agency or governmental body having jurisdiction, acts of civil or military authority, failure of equipment, or inability to obtain materials, supplies, or equipment from others because of similar causes. It shall be considered an uncontrollable force and shall relieve Seller from performing its obligations under this Agreement if valid state or federal legislation is enacted which prohibits the strip mining of the federal coal which has been leased by Seller.

SECTION 21. BUYERS' RIGHTS TO MINE COAL FROM DEDICATED RESERVES DURING PERIOD OF UNCONTROLLABLE FORCE.

During any time and from time to time that Seller is not delivering coal as required by this Agreement due to uncontrollable force as provided in Section 20, Buyers shall have the right, after giving Seller at least two months' notice of their intent to do so, to mine coal for the Facility from the Dedicated Reserves. The exercise of such right shall be subject to obtaining all necessary governmental approvals therefor, and any

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such mining shall be conducted in conformance with all governmental laws and regulations applicable thereto. Buyers shall pay Seller the Adjusted Base Mine Price for the coal mined by Buyers under this Section less the actual costs incurred by Buyers in obtaining the right to and in mining and delivering such coal including all royalty payments and taxes due as a result of such mining. Subject to Buyers incurring all of the expense thereof, Seller shall use its best efforts to assist Buyers to obtain such governmental approvals as it may need for the exercise of its rights under this Section 21. Buyers shall assume all obligations to pay all costs relating to such mining of the Dedicated Reserves which may exceed the Adjusted Base Mine Price. The rights granted in this Section shall terminate at such time that Seller has restored the deliveries of coal in the fulfillment of this Agreement.

SECTION 21. NOTICES.

Unless otherwise expressly provided herein, all notices required to be given by the provisions of this Agreement shall be deemed to be duly served if given in the manner and to the addresses set forth in, or determined in accordance with, Section 22 of the Participation Agreement (as defined in the Lease Agreement).

SECTION 23. APPLICABLE LAW.

This Agreement shall be considered to have been entered into and shall be interpreted under the laws of the State of Wyoming.

SECTION 24. AMENDMENT.

(a) No provision of this Agreement may be amended, modified, supplemented or waived except by an instrument in writing signed by Seller, Buyers and the Owner Trustee; provided that Seller and Buyers by a signed instrument in writing, without the consent of the Owner Trustee, may amend, modify or waive any matter set forth in Section 5, Place of Delivery and Sale; Section 6, Quality of Coal; Section 7, Weighing; Section 8, Sampling and Analysis; Section 9, Determining of Weighted Average Heat Content; Section 10, Base Mine Price; Section 11, Adjustments to Base Mine Price; Section 12, Price Adjustments--Calorific Quality; Section 13, Invoices and Payments, and operate under such amendments, modifications or waivers during the Term so long as the Lease Agreement shall not have been declared to be in default pursuant to Section 20 thereof. From and after the time of any such declaration of default, this Agreement shall be binding upon the parties as originally written on the date hereof or as amended by consent of the Owner Trustee, Seller and Buyers.

SECTION 24B. PACIFIC POWER'S CONTINUING OBLIGATIONS.

It is the parties' intent that Pacific Power and Black Hills will remain liable under this Agreement for its full Term, if because Pacific Power has failed to exercise the renewal options set forth in Section 15 of the Lease Agreement, or because Pacific Power is in default under the Lease Agreement, Pacific Power does not remain a lessee of the Facility for the full Term of this Agreement, Pacific Power will reimburse Seller the difference between amounts paid Seller by any successor lessee or operators of Pacific Power's share of the Facility during the remaining Term of this Agreement and amounts the Seller would have received from Pacific Power under this Agreement had it remained a lessee for the full Term of this Agreement. If Pacific Power is in default under the Lease Agreement, but remains the lessee or operator of the Facility, it shall remain fully liable under this Agreement, notwithstanding the provisions of Section 24.

SECTION 25. SUCCESSORS AND ASSIGNS.

This Agreement and all the terms and provisions hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the parties hereto.

SECTION 26. COMPLETE AGREEMENT.

Except as to obligations accruing prior to the execution of this Agreement, this Agreement supersedes and cancels the Prior Agreement and constitutes the complete agreement of the parties. Notwithstanding the preceding sentence, the time for making adjustments as set forth in Section 11(n) shall apply to obligations accruing prior to the execution of this Agreement.

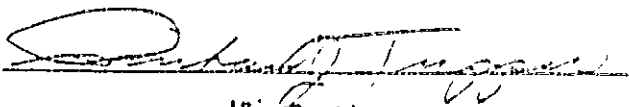
SECTION 27. EXECUTION IN COUNTERPARTS.

This Agreement may be executed by the parties hereto on separate counterparts, each of which when so executed and

delivered shall be an original, but all such counterparts shall together constitute but one and the same instrument.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be duly executed by their respective officers thereunto duly authorized as of the date first above written.

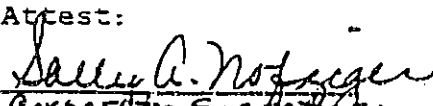
WYODAK RESOURCES DEVELOPMENT CORP.

By 
Vice President

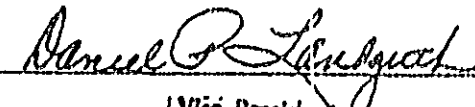
Attest: 
ASSISTANT SECRETARY
(Corporate Seal)

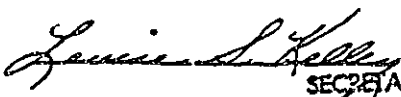
PACIFICORP
dba PACIFIC POWER & LIGHT COMPANY

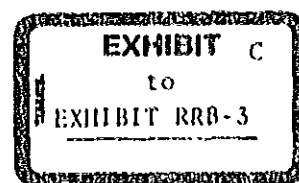
By 
Sr. Vice President

Attest: 
Corporate Secretary
(Corporate Seal)

BLACK HILLS CORPORATION
dba BLACK HILLS POWER AND LIGHT COMPANY

By 
Vice President

Attest: 
SECRETARY
(Corporate Seal)



POWER SALES AGREEMENT
BETWEEN
PACIFIC POWER & LIGHT COMPANY
AND
BLACK HILLS POWER AND LIGHT COMPANY

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POWER SALES AGREEMENT

BETWEEN

PACIFIC POWER & LIGHT COMPANY

AND

BLACK HILLS POWER AND LIGHT COMPANY

This Power Sales Agreement, dated as of the 31st day of December, 1983, is entered into by and between Pacific Power & Light Company ("Pacific"), a Maine corporation, and Black Hills Power and Light Company ("Black Hills"), a South Dakota corporation.

RECITALS

In order to meet the needs of its customers for electric capacity and energy, Black Hills has been planning to build at a place internal to its electric transmission system a coal-fired electric generating plant which would have a capability of generating 75 megawatts ("MW") of electric power net of station service. Pacific's power supply situation allows Pacific to sell and deliver to Black Hills 75 MW of capacity and associated energy which, in turn, will allow Black Hills to defer construction of its own coal-fired electric generating plant. The fixed formulae for determining prices herein are intended to fairly and equitably price the services to be rendered hereunder over a period approximating

the expected life of a generating plant Black Hills could have constructed for operation commencing on July 1, 1988. The purpose of this Agreement is to provide the terms and conditions for this transaction.

Section 1: Definitions

As used in this Agreement, the following terms shall have the following meanings:

1.1. "Agreement" is this power sales agreement, together with the Appendices A through E, attached hereto.

1.2. "Black Hills' System" is Black Hills' entire electric power generating and transmission system as it exists from time to time, and includes contract transmission paths.

1.3. "Colstrip Project" is Pacific's share in Unit Nos. 3 and 4 of the coal-fired electric generating plant being constructed near Colstrip, Montana.

1.4. "FERC" is the Federal Energy Regulatory Commission of the United States.

1.5. "Net Colstrip Generation" is Pacific's combined share of the output of the Colstrip Project Unit Nos. 3 and 4 generation. When expressed in MW, Net Colstrip Generation is the sum of the rated net MW output capability of each unit determined in accordance with the most recent test as specified in Appendix D; provided, Net Colstrip Generation, expressed in MW, shall not, for purposes of this Agreement,

be less than 135 MW, nor more than 142.5 MW and, until tested, shall be 140 MW. When expressed in megawatthours ("MWh"), Net Colstrip Generation is the actual energy production less station service requirements and less generator step-up transformer losses.

1.6. "Operator" is the entity defined in Section 1(k) of the Colstrip Unit Nos. 3 and No. 4 Ownership and Operation Agreement dated May 6, 1981, among the Montana Power Company, Puget Sound Power & Light Company, The Washington Water Power Company, Portland General Electric Company, First Trust Company of Montana, and Pacific.

1.7. "Pacific's Embedded Fixed Costs" is Pacific's actual levelized capital-related fixed costs per MW, excluding that portion of the Colstrip Project cost reflected by Black Hills' payment of Annual Fixed Costs, determined in a manner as illustrated in Appendix E, for all of Pacific's owned, leased, or Purchased coal-fired electric generating plants in commercial operation for use on Pacific's System from time to time. As used in this section, Section 5, and Appendix E, "Purchase" or "Purchased" means Pacific's purchase of capacity from designated coal-fired electric generating plants for a period of at least one (1) year.

1.8. "Pacific's System" is Pacific's entire electric power generating and transmission system as it exists from time to time, and includes contract transmission paths.

1.9. "Prudent Utility Practice" is at any particular time either any of the practices, methods, and acts engaged in or approved by a significant portion of the electrical utility industry prior thereto or any of the practices, methods, or acts which, in the exercise of reasonable judgment in the light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety, and expedition. Prudent Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others but, rather, to be a spectrum of possible practices, methods, or acts. Prudent Utility Practice shall also include those practices, methods, and acts that are required by applicable laws and final orders or regulations of regulatory agencies having jurisdiction; provided, that the definition of Prudent Utility Practice shall not be construed to allow regulatory bodies to amend the fixed formulae used to determine prices under this Agreement, nor any other provision of this Agreement. Prudent Utility Practice shall not be interpreted as justification for discriminating among customers, including Black Hills.

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Section 2: Term

2.1. Term. This Agreement shall commence on January 1, 1984, and, subject to the provisions of Sections 2.2, 2.3, 2.4, and 2.5, shall terminate on December 31, 2023.

2.2. Early Termination: FERC. If, in response to the initial filing of this Agreement pursuant to Section 6.1, the FERC does not accept for filing the terms and conditions hereof in toto, or disapproves any portion of this Agreement, either party hereto may terminate this Agreement within thirty (30) days of such event by providing the other party written notice thereof.

2.3. Early Termination: State Regulatory Authorities. Either party may terminate this Agreement by giving the other party thirty (30) days' written notice thereof prior to March 1, 1984, in the event that any of the utility regulatory commission(s) of the States of South Dakota, Wyoming, Oregon, Washington, or Montana indicate that any portion of the Agreement is not acceptable.

2.4. Early Termination: Black Hills' Review of Costs. Black Hills may terminate this Agreement by giving Pacific thirty (30) days' written notice prior to March 1, 1984, in the event that Black Hills determines that the costs associated with the Agreement substantially exceed its expectations as of the date of execution hereof.

2.5 Early Termination: Conditional Future Adjustment.

In the event of an adjustment in prices pursuant to Section 5.5.2, Black Hills may terminate this Agreement by giving Pacific not less than thirty-six (36) months' notice thereof in writing.

2.6. Effect of Early Termination. In the event of early termination under Sections 2.2, 2.3, 2.4, or 2.5, neither party shall owe the other any further performance hereunder as of the date of such termination, but all performances and rights to payments incurred to such date shall remain in effect.

Section 3: Sale and Delivery of Capacity and Energy

3.1. Sale of Capacity. For the term of this Agreement, Pacific shall sell, and Black Hills shall purchase, capacity in the following increments at times no later than those set forth below:

January 1, 1984	15 MW (total: 15 MW)
January 1, 1985, an additional 15 MW	(total: 30 MW)
January 1, 1986, an additional 15 MW	(total: 45 MW)
January 1, 1987, an additional 15 MW	(total: 60 MW)
January 1, 1988, an additional 15 MW	(total: 75 MW)

Black Hills may accelerate the amounts of capacity purchased in the years 1984 through 1987 in five (5) MW increments by providing Pacific written notice of its election to do so by not later than July 1 of the preceding year. In the

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event of such an acceleration in capacity purchases, a corresponding reduction, as selected by Black Hills, in any of the following years' additional capacity purchases shall occur, such that the total capacity purchased on January 1, 1988, shall not exceed 75 MW.

3.2. Minimum Energy Purchases. Each month Black Hills shall purchase a minimum of 300 MWh per MW of capacity purchased under Section 3.1.

3.3. Points of Delivery. Pacific shall deliver power and energy purchased under this Agreement to the Wyodak Substation point of interconnection between Pacific's System and Black Hills' System, as defined in the Wyodak Substation Construction, Ownership and Operation Agreement among Pacific, Black Hills, and Tri-County Electric Association, Inc., dated September 28, 1981, or to any other point of interconnection as mutually agreed upon by the parties which has adequate capacity to accommodate such deliveries. Neither party shall unreasonably withhold its consent to establishing such other points of interconnection.

3.4. Prudent Utility Practice. Consistent with Prudent Utility Practice, Pacific shall take steps to assure that it has available electric facilities sufficient to meet its obligations under this Agreement for the term hereof.

Section 4: Scheduling

4.1. Amounts of Capacity and Energy. Commencing on the date each increment of capacity is purchased under

Section 3.1 and continuing during the term hereof, Pacific shall make available from Pacific's System, and Black Hills shall schedule, those amounts of energy associated with the increments of capacity so purchased; provided, that Pacific shall not be obligated under this Agreement to schedule and deliver energy to Black Hills in excess of the following amounts:

Hourly -- One (1) MWh per MW of capacity purchased under Section 3.1.

Weekly -- 134 MWh per MW of capacity purchased under Section 3.1.

Monthly -- One hundred ten percent (110%) of the estimated monthly energy under Section 4.2.

4.2. Estimated Monthly Energy. At least five (5) days prior to the commencement of each month, Black Hills shall deliver to Pacific a written estimate of MWh purchases for the following month.

4.3. Schedules. Black Hills shall preschedule all deliveries of power and energy purchased under this Agreement no later than 1400 hours Pacific time on each workday prior to the day of such schedule and in accordance with normal scheduling practices. Such schedules of power and energy shall be deemed to be delivered during the hours and in the amounts scheduled; provided, that if scheduled deliveries

are interrupted due to forces beyond either party's control, including but not limited to loss of facilities, such scheduled deliveries shall be adjusted to reflect such interruptions.

4.4. Limitations on Variations. Black Hills shall use its best efforts, consistent with Prudent Utility Practice, to minimize rapid changes in deliveries hereunder; provided, that, unless otherwise agreed, the hour-to-hour variation in such scheduled deliveries shall be limited to thirty-three percent (33%) of the total capacity generation purchased under Section 3.1, per hour.

Section 5: Prices and Payments

5.1. Fixed Cost Payments. Except as provided in Sections 5.2 and 5.5, commencing on January 15, 1984, and on the fifteenth (15th) of each month thereafter, Black Hills shall pay Pacific one-twelfth ($1/12$) of the Annual Fixed Cost as determined pursuant to Appendix A, multiplied by the cumulative total capacity purchased under Section 3.1 in MW. Upon commercial operation of the Colstrip Unit No. 4, Pacific shall adjust all prior payments made under this Section in accordance with the provisions of Section A4 of Appendix A.

5.2. Reduced Interim Fixed Cost Payments. Black Hills shall pay reduced fixed cost payments commencing on January 15, 1984, and ending June 15, 1988. The reduced Fixed Cost payments shall equal one-half ($1/2$) of the total of the

monthly payments due Pacific under Section 5.1, plus an amount equal to the product of the total cumulative increments of capacity purchased under Section 3.1 in MW as of the month for which payment is made, multiplied by one thousand four hundred dollars (\$1,400).

5.3. Variable Cost Payments.

5.3.1. Payments for Estimated Energy.

Commencing on January 15, 1984, and on the fifteenth (15th) of each month thereafter, Black Hills shall pay Pacific an amount determined by multiplying the estimated annual variable costs in dollars per MWh (\$/MWh), as determined by Pacific consistent with Appendix B, by the estimated monthly MWh of energy as provided under Section 4.2.

5.3.2. Monthly Adjustments. Commencing with the February 1984 invoice, and for all monthly invoices thereafter, Pacific shall use the following formula to calculate an adjustment to each prior month's invoice:

$$z = (a - b)(c)(1.0 + i)$$

Where: z = the amount of charge to Black Hills (if positive) or credit to Black Hills (if negative);
 a = the actual energy scheduled for prior month in MWh;
 b = the energy which was estimated to be scheduled for prior month, in MWh, under Section 4.2;

c = the estimated annual variable cost in dollars per MWh (\$/MWh);

i = the prime interest rate, expressed in decimal form on an annual basis, as established by the Morgan Guaranty Trust Company of New York as of the first day of the prior month, divided by twelve (12).

5.3.3. Annual Adjustments. Pacific shall determine the actual variable cost for the preceding calendar year by May 1 of the succeeding year, deduct therefrom the estimated variable cost employed in such preceding calendar year, and multiply the result by the number of MWh scheduled in such year. To this amount, Pacific shall add simple interest at the time-weighted average prime rate as established by the Morgan Guaranty Trust Company of New York for periods between payments made by Black Hills during such preceding calendar year and May 15 of the current year. If the amount as determined above is a positive number, Pacific shall add such amount to the total May invoice; if such amount is a negative number, Pacific shall deduct such amount from the total May invoice.

5.4. Payment Schedules. Pacific shall mail to Black Hills, first-class postage prepaid, an invoice for all services hereunder, by the third (3rd) working day of each month. Black Hills shall pay such invoices by the

fifteenth (15th) of such month. Each monthly payment shall be made in immediately available funds by the due date. Simple interest shall accrue on any amount not paid when due at a rate of one hundred twenty-five percent (125%) of the prime rate as established by the Morgan Guaranty Trust Company of New York during the period of delinquency.

5.5. Conditional Future Adjustment.

5.5.1. Calculation of Cumulative Account.

As of December 31, 1984, and as of each December 31st thereafter, Pacific shall determine the following amount: (a) the total Annual Fixed Cost payments (excluding payments under Section A2.6 of Appendix A) as calculated under Section 5.1 for that year, minus (b) Pacific's Embedded Fixed Costs for that year multiplied by the number of MW purchased in such year under Section 3.1. Each such amount so determined, whether positive or negative, shall be recorded and accumulated in an unfunded account ("Cumulative Account"). As of December 31, 1984, and as of each December 31st thereafter, an additional amount shall be added as determined under the following formula:

$$a = (x + \frac{Y}{2})(i)$$

Where: a = the additional amount to be added;
x = the balance of the Cumulative Account as of January 1 of the year for which the calculation is being made;

y = the amount as determined as of the December 31st for which the calculation is being made by the application of the first sentence of this Section 5.5.1; and

i = the composite weighted cost of capital, expressed in decimal form, utilized in determining the Initial Levelized Annual Fixed Cost for the calendar year then ending.

5.5.2 Adjustment. If, by January 1, 1999, or at any time thereafter, the Cumulative Account is reduced to zero, Black Hills shall, in lieu of making payments under Section 5.1, pay Pacific's Embedded Fixed Costs per MW for each MW of capacity purchased under Section 3.1 for the balance of the term of this Agreement; provided, if during any calendar year Pacific, together with any affiliates, does not own, lease, or Purchase at least 2,500 MW of coal-fired electric generation (such 2,500 MW to be reduced on a MW-for-MW basis for coal-fired electric generating Plant Retirements after the effective date hereof), Black Hills shall make payments for that calendar year without the adjustment provided in this Section 5.5.2. As used in this section, "Plant Retirements" means plants which have been both retired from books and permanently removed from operation.

Section 6: Governmental Regulation

6.1. Filing. The parties shall submit this Agreement for filing to the FERC.

6.2. Fixed-Formulae Contract. The terms, conditions, and formulae for prices for service specified herein shall remain in effect for the term hereof, and shall not be subject to change through application to the FERC pursuant to the provisions of Section 205 of the Federal Power Act absent the agreement of the parties hereto. The parties covenant that neither shall request relief from any of the provisions of this Agreement pursuant to the provisions of Section 206 of the Federal Power Act absent the agreement of the parties hereto. The foregoing statutory references are intended to include any subsequent similar enactments.

Section 7: Reports and Consultation; Audit

7.1. Reports and Colstrip Project Agreement

Compliance. During the term hereof, Pacific shall send to Black Hills, first-class postage prepaid, copies of all written reports, certificates, statements, billings, and other material writings which are furnished to Pacific by the Operator. Pacific shall use its best efforts to cause all parties to the Colstrip agreements to comply with the terms thereof. Within a reasonable time of obtaining knowledge of any material failure to perform by any party to the Colstrip

agreements, Pacific shall notify Black Hills in writing of the nature of such failure to perform. Pacific shall keep Black Hills informed concerning all issues which are to come before the committee (as defined in the Colstrip Ownership and Operation Agreement referred to in Section 1.6) and which will substantially affect the payments to be paid by Black Hills under this Agreement. When reasonably possible, Pacific shall consult with Black Hills prior to the committee's making such decision in order to allow Black Hills to make known its views.

7.2. Representations. Pacific represents that it has provided Black Hills with a written notice listing: all governmental approvals required to be obtained for the construction and operation of Colstrip Unit Nos. 3 and 4, and the status of each as of the date of such notice, of which Pacific has knowledge; all pending litigation, together with the status of each case, which directly affects Pacific's cost of the Colstrip Project; and all material disputed claims and threatened governmental actions of which Pacific has knowledge as of the date of the notice regarding construction and operation of the Colstrip Project.

7.3. Audit. Black Hills may, at its cost, from time to time cause all of Pacific's books and records related to the Colstrip Project to be audited by an independent certified public accounting firm of national reputation.

Section 8: Arbitration

If any dispute arises under this Agreement as to any factual matter, the parties shall submit the factual dispute to a board of three arbiters, one to be selected by each party and the parties to agree on the selection of a third arbiter. If the parties are unable to agree on the third arbiter, the parties shall request the senior district judge of the United States District Court of the District of Wyoming to submit a list of five (5) persons. Each party shall alternately strike one name from the list, the first exercise to be determined by lot. The last person remaining on the list shall serve as the third (3rd) arbiter. Except as otherwise set forth herein, the arbitration shall be held under the rules of the American Arbitration Association. The arbiters shall render their decision in writing not later than thirty (30) days after the matter has been submitted to them, and the decision of a majority of the board of arbiters of the factual dispute shall be binding on the parties. The arbiters may, in their discretion, award arbitration costs and attorneys' fees to either party.

Section 9: Uncontrollable Forces

Neither party to this Agreement shall be considered to be in default in performance of any obligation hereunder if failure of performance shall be due to uncontrollable forces.

The term "uncontrollable forces" means any cause beyond the control of the party affected, including, but not limited to, failure of facilities, flood, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance, labor disturbance, sabotage, and restraint by court order or public authority, which by exercise of due foresight such party could not reasonably have been expected to avoid, and which by exercise of due diligence it shall be unable to overcome. A party shall not, however, be relieved of liability for failure of performance if such failure be due to causes arising out of its own negligence or to removable or remediable causes which it fails to remove or remedy with reasonable dispatch. Any party rendered unable to fulfill any obligation by reason of uncontrollable forces shall exercise due diligence to remove such inability with all reasonable dispatch. Nothing contained herein, however, shall be construed to require a party to prevent or settle a strike against its will. It is specifically understood and agreed that Pacific's delivery of capacity and energy to Black Hills under this Agreement comes from Pacific's System and shall not depend upon the existence, operation, or efficiency of the Colstrip Project alone. In determining any uncontrollable force justifying any nonperformance by Pacific herein, the entire Pacific System shall be taken into consideration.

Section 10: Notices

Any notice, demand, or request provided for in this Agreement shall be deemed properly served, given, or made if delivered in person or sent by registered or certified mail, postage paid and return receipt requested, to the person so designated as its authorized representative. The titles and addresses of the authorized representatives hereunder are as follows:

For Black Hills: Vice President, Finance
Black Hills Power and Light Company
625 Ninth Street
PO Box 1400
Rapid City, South Dakota 57709

For Pacific: Vice President, Power Resources
Pacific Power & Light Company
920 SW Sixth Avenue
Portland, Oregon 97204

Section 11: Waiver

Any waiver by a party of its rights with respect to default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not be deemed to be a waiver with respect to any subsequent default or matter. No delay in asserting or enforcing any right hereunder shall be deemed a waiver of such right.

Section 12: Several Obligations

Except where specifically stated in this Agreement to be otherwise, the duties, obligations, and liabilities of

the parties are intended to be several and not joint or collective. Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership, or joint venture or to impose a trust or partnership duty, obligation, or liability on or with regard to either party. Each party shall be individually and severally liable for its own obligations under this Agreement.

Section 13: Amendments

No amendment of this Agreement shall be effective without written approval of each party.

Section 14: Assignment

This Agreement shall not be assigned to any third party without the written consent of the other, and such consent shall not be withheld unreasonably. No assignment of this Agreement shall operate to discharge the assignor of any duty or obligation hereunder without the written consent of the other party.

Section 15: Choice of Law

This Agreement shall be subject to and be construed under the laws of the State of Wyoming.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed in their respective names by their respective officers thereunder duly authorized.

PACIFIC POWER & LIGHT COMPANY

By: Fredric D. Reed
Vice President

Date: January 10, 1984

Attest: Sally A. Nofziger
Secretary

BLACK HILLS POWER AND LIGHT COMPANY

By: [Signature]
Vice President

Date: January 11, 1984

Attest: [Signature]
Secretary

APPENDIX A: ANNUAL FIXED COSTS

Introduction

This Appendix sets forth the elements and techniques to calculate the annual fixed costs under Section 5.1 for the term of the Agreement.

The Annual Fixed Cost is the per-MW sum of: (a) initial levelized annual fixed cost, (b) subsequent levelized annual fixed costs (if any), and (c) other fixed annual charges, including but not limited to property taxes, insurance, and taxes other than income tax.

Section A1: Discussion of Methodology

Levelized fixed charges are the basis of annual fixed costs hereunder. While actual capital-related charges associated with an investment may vary considerably from year to year, the levelized fixed charge translates these charges into a level annual amount which remains constant over time. The present values of the two streams (varying versus constant) are equal.

The levelized fixed charge includes three basic components: (a) return on investment, given a specific capital structure and cost of capital; (b) recovery of investment, given the appropriate depreciation period related to the investment; and (c) income tax requirements, given tax law considerations. These components are commonly expressed as: (a) interest expense on debt and return required by shareholders; (b) book depreciation; and, (c) income taxes

incorporating the effects of investment tax credits and tax depreciation.

An initial levelized annual charge rate will be applied to the original investment of Colstrip Project Unit Nos. 3 and 4. The rate will be recalculated effective each January 1 only in the event of a change during the preceding calendar year in any of the following: (a) the percentage of pollution control revenue bonds outstanding; (b) the interest rate on pollution control revenue bonds; (c) the weighted average authorized return on common equity; or, (d) income tax law, but not to be applied retroactively.

Subsequent levelized annual fixed charge rates will be calculated each year to reflect the most current information and will be applied each year to the amount of capital additions, replacements (less credit for net salvage and insurance proceeds, if any) and betterments of the Colstrip Project completed through the end of the preceding calendar year.

Section A2: Determination of Annual Fixed Costs

Annual Fixed Costs will be determined by (a) adding the amounts calculated under Sections A2.1 through A2.5, (b) dividing the total by Net Colstrip Generation in MW, and (c) after June 30, 1988, adding the amount set forth in Section A2.6. In the event that figures are unavailable for calculating the Colstrip Project costs under Sections A2.2 through A2.5 of this Appendix, to determine surrogate costs

Pacific shall utilize its system coal-fired generating units' comparable costs, excluding any initial SO₂ scrubber capital costs on such units, on a MW basis. The costs referred to above are:

A2.1. Pacific's initial levelized annual fixed charge rate determined annually in accordance with Section A3 of this Appendix, multiplied by the original investment in the Colstrip Project. For the purposes of this section, Pacific's original investment in Colstrip Unit No. 3 is \$113,000,000. Until Colstrip Unit No. 4 is completed, Pacific estimates the original investment therein to be \$98,000,000. Immediately following commercial operation of Colstrip Unit No. 4, Pacific will calculate the original investment in Colstrip Unit No. 4, and (a) adjust all prior payments made under Section 5.1 in accordance with Section A4 hereof, and (b) use the original investment in the Colstrip Project to determine all succeeding initial levelized annual fixed costs; provided, if Pacific's original investment in Colstrip Unit No. 4 exceeds \$108,000,000, the original investment in such unit shall be \$108,000,000 for all purposes herein. Black Hills shall pay no initial levelized annual fixed costs after the completion of the thirty-fifth (35th) year of this Agreement.

A2.2. The sum for such year of each of the subsequent levelized annual fixed charges determined for each year from 1985 to date. Each subsequent annual levelized fixed charge shall be determined by multiplying (a) Pacific's subsequent

levelized annual fixed charge rate, as calculated in accordance with Section A3, below, by (b) the dollar investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments of the Colstrip Project, completed during the calendar year immediately preceding establishment of such subsequent levelized annual fixed charge.

A2.3. All ad valorem taxes imposed upon the Colstrip Project.

A2.4. Any tax, assessment, payment in lieu of taxes, or other charge imposed by any governmental body assessed or charged against Pacific relating to the Colstrip Project, excluding ad valorem taxes, state and federal income taxes, and taxes covered under Section B2.9 and B2.11 of Appendix B.

A2.5. All insurance premiums incurred by Pacific related to the Colstrip Project.

A2.6. An amount equal to zero dollars (\$0) through June 30, 1988; thereafter, the amount is twenty-eight thousand dollars (\$28,000).

Section A3: Elements of Levelized Annual Fixed Charge Rates

A3.1. Capital Structure:

A3.1.1. For purposes of calculating initial levelized annual fixed charge rates, Pacific's capital structure will remain constant for the duration of this Agreement. The capital structure is:

Long-Term Debt and Pollution Control Revenue Bonds	52%
Preferred Stock	12%
Common Stock Equity	<u>36%</u>
Total Capital	100%

The proportion of Pollution Control Revenue Bonds to Total Capital will be the quotient of (a) \$45,000,000 (the principal amount of Pollution Control Revenue Bonds relating to the Colstrip Project issued in December 1981) divided by (b) \$211,000,000, i.e., the sum of Pacific's original investment cost of Colstrip Unit No. 3 and Pacific's estimated original investment cost of Colstrip Unit No. 4.

The proportion of Long-Term Debt to Total Capital will be the difference between (a) fifty-two percent (52%) and (b) the proportion of Pollution Control Revenue Bonds as calculated above. If Pacific's \$45,000,000 City of Forsyth, Rosebud County, Montana, Floating Rate Monthly Demand Pollution Control Revenue Bonds, Series 1981 (Pacific Power & Light Company Colstrip Project), as referenced above, are prepaid, redeemed in their entirety, or exchanged for bonds, the interest of which is taxable under federal income tax laws, the capital structure will be adjusted to determine the initial levelized annual charge rates in the calendar years immediately succeeding the year of prepayment or redemption, such that the Pollution Control Revenue Bond proportion will be zero (0) and the Long-Term Debt proportion will be fifty-two

percent (52%). In the event that the above-referenced pollution control revenue bonds are exchanged for another issue of bonds, the interest of which is exempt under federal income tax laws, the capital structure consequent to the subsequent issue will be employed prospectively for calculations under this section.

A3.1.2. Pacific's capital structure will remain constant for the duration of the Agreement for purposes of calculating subsequent levelized annual fixed charge rates and is as follows:

Long-Term Debt	52%
Preferred Stock	12%
Common Stock Equity	<u>36%</u>
Total Capital	100%

Provided, if any part of Pacific's portion of the capital additions, replacements, or betterments which occasioned a subsequent levelized annual fixed charge cost is financed by long-term debt, the interest of which is exempt from federal income taxes, the long-term debt portion of the above capital structure shall be apportioned between the long-term debt and the tax exempt long-term debt accordingly. In no case shall the long-term debt portion exceed fifty-two percent (52%) of total capitalization.

A3.2. Cost of Capital:

A3.2.1. Long-Term Debt: Bond interest applicable in the calculation of each initial levelized annual fixed

charge rate will be twelve and eight-tenths percent (12.8%). Bond interest applicable in the calculation of each subsequent levelized annual fixed charge rate for future capital additions, replacements, or betterments shall be the effective cost rate to Pacific of the most recent issue of long-term bonds, excluding special-purpose issues not related to the Colstrip Project, in the twelve (12) month period prior to the date of the completion of construction of the capital additions, replacements or betterments for which the subsequent levelized annual fixed charge rate is calculated. In the event there are no bond issues within the said twelve (12) month period, then an estimated bond interest rate will be used in the billings based upon the bond rating applicable to Pacific until such time as there is a bond issue, at which time all future billings will reflect the actual cost to Pacific of such bond issue. In the event such bond issue is subsequently exchanged for other bonds, the new bond rate shall be used for subsequent billings.

A3.2.2. Pollution Control Revenue Bonds: Bond interest applicable in the calculation of the 1984 initial levelized annual fixed charge rate shall be five and ninety-nine hundredths percent (5.99%). Bond interest applicable in the calculation of the initial levelized annual fixed charge rate in each year from 1985 through 2023 shall be the average of that effective interest rate paid by Pacific during the previous calendar year relating to its \$45,000,000 City of

Forsyth, Rosebud County, Montana, Floating Rate Monthly Demand Pollution Control Revenue Bonds, Series 1981 (Pacific Power & Light Company Colstrip Project). If such series of bonds is prepaid, redeemed, or exchanged for bonds, the interest of which is subject to federal income taxes, there will be no interest relating to Pollution Control Revenue Bonds in the initial levelized annual fixed charge rates computed in the calendar year immediately following such prepayment or redemption. In the event that the above-referenced pollution control bonds are exchanged for another issue, the interest of which is exempt from federal income taxes, the interest rate consequent to the subsequent issue shall be employed prospectively for calculations under this section.

A3.2.3. Preferred Stock: Return on preferred stock applicable in the calculation of each initial levelized annual fixed charge rate shall be thirteen and three-tenths percent (13.3%). Return on preferred stock applicable in the calculation of subsequent levelized annual fixed charge rates for future capital additions, replacements, or betterments shall be the same as for bond interest used in calculation of subsequent annual fixed charge rate, plus fifty (50) basis points.

A3.2.4. Common Stock Equity: Return on common stock equity applicable in the calculation of each initial levelized annual fixed charge rate and each subsequent levelized annual fixed charge rate shall be that weighted average

percentage authorized by Pacific's jurisdictional commissions as of January 1 of that year. Weighting shall be based on Pacific's actual retail energy (MWh) sales in each jurisdiction in the prior year.

A3.3. Book Depreciation: Book depreciation charges shall be at a straight-line rate based on a thirty-five (35) year life in calculating the initial levelized annual fixed charge rates. Book depreciation charges for subsequent levelized annual fixed charge rates shall be based on the estimated service life.

A3.4. Income Tax Requirements: Income Tax Requirements applicable in calculating both initial and subsequent levelized annual fixed charge rates shall be based on the following items; provided, subsequent changes in tax laws shall be incorporated in computing levelized annual fixed charge rates for periods following such tax law change:

A3.4.1. The federal corporate income tax rate (currently forty-six percent (46%)).

A3.4.2. A state corporate income tax rate equal to the estimated composite weighted average of Pacific's three-factor formula for unitary allocation of state taxable income based upon payroll, property, and revenue in each state in which Pacific provides retail service. The rate is currently four and three-tenths percent (4.3%).

A3.4.3. Use of Accelerated Cost Recovery System (ACRS) method of tax depreciation in accordance with the Tax Equity and Fiscal Responsibility Act of 1982.

A3.4.4. Regular Investment Tax Credits allowed in accordance with the provisions of the Internal Revenue Code of 1954, as amended, regardless of whether Pacific is able to use such credits.

A3.4.5. Tax basis will be seventy-five percent (75%) of the book basis in calculating each initial levelized annual fixed charge rate and one hundred percent (100%) of the book basis in calculating each subsequent levelized annual fixed charge rate. Such amounts will be adjusted for allowed Regular Investment Tax Credits. Notwithstanding Section A1, by December 31, 1985, Pacific shall provide Black Hills with a calculation showing its actual percentage relationship between book basis and tax basis of the Colstrip Project. If such calculation shows a percentage relationship in excess of seventy-five percent (75%), such percentage relationship shall be amended for all subsequent billings.

Section A4: Adjustment of
Initial Levelized Annual Fixed Cost

Upon commercial operation of Colstrip Unit No. 4, Pacific shall calculate an adjustment to all prior payments made under Section 5.1 of the Agreement. The following formula shall be used to calculate the adjustment:

$$\text{Adjustment} = (0.46445 \times) \left(\frac{y}{\$98,000,000} - 1 \right) (1.0 + i)$$

Where: x = the sum of all Appendix A, Section A2.1-related charges made under Section 5.1, as reduced by Section 5.2 of the Agreement, prior to the date of commercial operation of Colstrip Unit No. 4;
y = the lesser of (1) \$108,000,000, or (2) Pacific's original investment in Colstrip Unit No. 4;
i = the weighted average prime rate as established by the Morgan Guaranty Trust Company of New York from January 1, 1984, expressed in decimal form, to the date of commercial operation of Colstrip Unit No. 4.

If calculation of the adjustment produces a positive number, Black Hills shall pay Pacific such amount; if a negative number is produced, Pacific shall pay Black Hills such amount.

APPENDIX B: VARIABLE COSTS

This Appendix sets forth the elements and techniques to calculate the variable costs under Section 5.3 for each year of the Agreement.

B1. Until January 1, 1985, the Variable Cost shall be sixteen dollars and fifty cents (\$16.50) per MWh.

B2. From January 1, 1985, and for the duration of this Agreement, Variable Cost will be, except as specified in Section B3 of this Appendix, the sum of the following Colstrip Project costs, divided by Net Colstrip Generation in MWh for each year. Costs under Sections B2.1 through B2.10 are accrued by Pacific under the agreement described in Section 1.6 hereof; costs under Sections B2.11 and B2.12 are incurred directly by Pacific.

B2.1. cost of coal fuel;

B2.2. payroll, including related fringe benefits and payroll taxes, of direct full-time project employees, none of which are employees of Pacific;

B2.3. payroll of Operator's employees, other than those charged to its administrative and general expenses, and other than direct full-time project employees, on an actual time basis including related fringe benefits and payroll taxes;

B2.4. materials and supplies including related purchasing and handling costs;

B2.5. reasonable traveling expense including use of Operator's transportation equipment;

B2.6. start-up and flame stabilization fuel costs;

B2.7. purchased power costs;

B2.8. all net costs relating to injury or damage;

B2.9. all sales, use, and/or generation taxes and payments in lieu of taxes which may be imposed upon the Operator in connection with the production of energy from the project;

B2.10. administrative and general costs of Operator applicable to project operation and maintenance;

B2.11. all sales, use, and/or generation taxes and payments in lieu of taxes which may be imposed upon Pacific in connection with the production of energy from the Colstrip Project; and

B2.12. an amount equal to two percent (2%) of the sum of B2.1 through B2.3 to reflect Pacific's administrative and general expenses.

B3. After 1984, in years in which the capacity factor of Colstrip Unit Nos. 3 and 4 together is less than forty percent (40%), or if Colstrip Project costs are not available, Variable Cost will be the average comparable variable costs from the costs of all coal-fired generation on Pacific's System in such year.

34. Any cost included in the charges pursuant to Appendix A to determine the annual fixed costs shall not be included in the calculation of variable costs under this Appendix.

APPENDIX C: ILLUSTRATIONS

The following three items are illustrations of computations under this Agreement.

SAMPLE INVOICE
FOR FIXED COSTS
PACIFIC POWER & LIGHT COMPANY

C.M.R. DEPARTMENT
920 S.W. Sixth Avenue
Portland, Oregon 97256

INVOICE

CERTIFIED MAIL

January 1, 1984

Black Hills Power and Light Company
P. O. Box 1400
Rapid City, South Dakota 57709

Attention: George T. Locke
Senior Vice President

January 1984

Delivery of firm thermal energy under the terms and conditions of Power Sales Agreement dated as of December 31, 1983, Sections 5.1, 5.2, and Appendix A.

5.1 Fixed Cost Payment

Annual Fixed Cost \$3,770,871.43*
x 1/12

Fixed Cost Payment \$ 314,239.29

5.2 Reduced Interim Fixed Cost Payments

Adjustments: (\$314,239.29) (50%) (157,119.64)
(\$ 1,400.00) (15 MW) 21,000.00

Amount Due \$ 178,119.65

Payment is due January 15, 1984.

Interest accrues at a rate of 125% of the daily prime rate.

*See Attached Memorandum

CREDIT MEMO: 9143-01-000-09840

PACIFIC POWER & LIGHT COMPANY

C.M.R. Department

January 1, 1984

Memorandum

In accordance with the provisions of Section 5.1 of the Power Sales Agreement dated as of December 31, 1983, between Pacific Power & Light Company and Black Hills Power and Light Company for the month of January, 1984.

The amounts are billed on an estimated basis in accordance with Section A2 of Appendix A to this Agreement and are subject to adjustment pursuant to Section A4 of Appendix A to this Agreement.

A2.1 Initial Levelized Annual Fixed Charge

Colstrip Unit #3	\$113,000,000
Colstrip Unit #4	<u>98,000,000</u>
Total Investment	\$211,000,000

Initial Levelized Annual Fixed Charge Rate	14.863
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Initial Levelized Annual Fixed Charge	\$ 31,354,600.00
--	------------------

<u>A2.2 Subsequent Levelized Annual Fixed Charge</u>	-0-
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<u>A2.3 Ad Valorem Tax</u>	3,376,000.00
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<u>A2.4 Other Tax</u>	-0-
-----------------------	-----

<u>A2.5 Insurance</u>	<u>464,200.00</u>
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Total	\$ 35,194,800.00
-------	------------------

Net Colstrip Generation - 140 MW

Annual Fixed Cost per MW (excl. A2.6)	\$ 251,391.43
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<u>A2.6 Other</u>	<u>-0-</u>
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Annual Fixed Cost per MW	\$ 251,391.43
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Capacity Purchased - 15 MW

Annual Fixed Cost	<u>\$ 3,770,871.43</u>
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SAMPLE INVOICE

FOR VARIABLE COSTS

(Assumes 80% Black Hills Load Factor)

PACIFIC POWER & LIGHT COMPANY

C.M.R. DEPARTMENT
920 S.W. SIXTH AVENUE
PORTLAND, OREGON 97256

CERTIFIED MAIL

INVOICE

Black Hills Power and Light Company
P. O. Box 1400
Rapid City, South Dakota 57709

January 1, 1985

Attention: George T. Locke
Senior Vice President

JANUARY 1985

Delivery of firm thermal energy under the terms and conditions of
Power Sales Agreement as of dated December 31, 1983, Sections 5.2,
5.4, and Appendix B.

Variable Cost

17,856,000 kWh @ \$17.2319*/kWh =

\$307,692.81

*See Attached Exhibit

Payment is due January 15, 1985.

Interest accrues at a rate of 125% of the daily prime rate.

Credit Memo: 9143-01-000-09342

PACIFIC POWER & LIGHT COMPANY

Appendix C - Item 2

Page 2 of 2

Year 1985
Estimate
Variable Cost Exhibit

Variable Cost Calculation as per Power Sales Agreement between Pacific Power & Light Company and Black Hills Power and Light Company, Appendix B, dated as of December 31, 1983.

Colstrip Unit #3 (PP&L Share)
Appendix B

Note: This estimate was developed by using a 6% escalation factor on the 1984 budget.

Power Statistics

WJM 12/7/83

Sec. B2.1 Cost of Fuel

Assumptions:

Burn Rate = 0.636 Tons/MWh	
Coal Cost: Commodity Charge	= \$10.919/Ton
Fixed Charge	= \$727,567/Yr.
Conveyor Cost: Commodity Charge	= \$1.167/Ton
Fixed Charge	= \$103,032/Yr.
Net Generation = 369,756 MWh	

Calculations:

Total Commodity Charge		
Fuel Burned 369,756 MWh x 0.636 Tons/MWh = 235,165 Tons		
Fuel Burned Cost 235,165 Tons x \$12.086/Ton	\$2,842,204	
Coal Fixed Charge	727,567	
Conveyor Fixed Charge	103,032	
Total Cost of Fuel		\$3,672,803

Sec. B2.2 Payroll, etc., direct full-time employees
Labor

\$ 823,191

Associated Payroll Taxes

65,804

Total Payroll, etc.

\$ 888,995

Sec. B2.3 Operator's Employees Payroll

\$ 113,751

Sec. B2.4 Materials and Supplies

\$ 653,498

Sec. B2.5 Travel Expenses

\$ 26,225

Sec. B2.6 Start-up and Flame Stabilization Fuel Cost

\$ 411,280

Sec. B2.7 Purchased Power Costs - None Assumed

\$ -0-

Sec. B2.8 Injury or Damage Costs - None Assumed

\$ -0-

Sec. B2.9 In Lieu Payments - None Assumed

\$ -0-

Sec. B2.10 Administrative and General Costs

A & G Expense

\$ 200,777

Contract Expense (Includes Special Maintenance)

263,595

Other Expense

25,339

Total Administrative and General Costs

\$ 489,711

Sub Total

\$6,256,263

c. B2.11 In Lieu Payments - None Assumed

\$ -0-

Sec. B2.12 Pacific's A & G Expense

(B2.1 through B2.9)x2%: .02 x \$5,766,552

\$ 115,331

Total Annual Cost (B2.1 through B2.12)

\$ 6,371,594

Variable Cost \$6,371,594/369,756 MWh = \$17.2319/MWh

12/09/83

CALCULATION OF INITIAL LEVELIZED
FIXED CHARGE RATE

Appendix C - Item 3
Page 1 of 2

CAPITAL STRUCTURE:

DEBT 52.00% OF TOT INVEST. RATE 10.01%
PREFERRED 12.00% OF TOT INVEST. RATE 13.30%
COMMON 36.00% OF TOT INVEST. RATE 15.49%
DEF TAXES .00% OF TOT INVEST. RATE .00%

CALCULATED DATA:

CAPITAL RECOVER FACTOR .12592

INPUT DATA:

INVESTMENT TAX CREDIT 10% ITC BASIS 75%
SALVAGE VALUE: ZERO

RESULTS:

1. INITIAL LEVELIZED FIXED CHARGES ON \$10,000: \$1,486
2. INITIAL LEVELIZED FIXED CHARGE RATE: 14.86%

IN SERVICE DATE 1984

BOOK LIFE 33 YEARS—STRAIGHT LINE

TAX LIFE 15 YEARS—ACRS

TAX RATE 48.3% (STATE AND FEDERAL COMBINED)

TAX BASIS 95.00% OF BOOK BASIS -
1984 PW AT 12.38%

YEAR	BOOK DEPREC	TOTAL RETURN	INTER- EST	DEFERRED TAX	INCOME TAX	ANNUAL COST	TAX DEPREC	ITC	ANNUAL COST	MILLS KWH
1984	296	678	492	74	560	2090	356	-750	1860	
1985	286	621	451	246	334	1937	713	-729	1534	
1986	286	586	425	211	336	1843	641	-707	1299	
1987	286	553	401	177	339	1756	570	-686	1101	
1988	286	522	379	143	345	1675	499	-654	934	
1989	286	493	358	143	313	1597	499	-643	793	
1990	286	465	338	108	326	1523	428	-521	673	
1991	286	438	318	108	301	1452	428	-500	571	
1992	286	412	299	108	276	1381	428	-579	483	
1993	286	385	279	108	252	1310	428	-557	408	
1994	286	358	260	108	227	1239	428	-536	343	
1995	286	332	241	108	202	1168	428	-514	288	
1996	286	305	221	108	177	1097	428	-493	240	
1997	286	278	202	108	152	1026	428	-471	200	
1998	286	251	182	108	127	954	428	-450	166	
1999	286	232	169	-98	315	903		-429	140	
2000	286	220	160	-98	304	871		-407	120	
2001	286	208	151	-98	293	840		-386	103	
2002	286	196	143	-98	282	908		-364	88	
2003	286	185	134	-98	271	776		-343	75	
2004	286	173	125	-98	260	745		-321	64	
2005	286	161	117	-98	248	713		-300	55	
2006	286	149	108	-98	237	681		-279	47	
2007	286	137	99	-98	226	650		-257	39	
2008	286	125	91	-98	215	618		-236	33	
2009	286	113	92	-98	204	587		-214	29	
2010	286	101	73	-98	193	555		-193	24	
2011	286	99	65	-98	182	523		-171	20	
2012	286	77	56	-98	171	492		-150	17	
2013	286	65	48	-98	159	460		-129	14	
2014	286	54	39	-98	148	428		-107	11	
2015	286	42	30	-98	137	397		-86	9	
2016	286	30	22	-98	126	365		-64	8	
2017	286	18	13	-98	115	333		-43	6	
2018	286	6	4	-98	104	302		-21	5	
TOTAL	10,000	9,058	6,574		9,462	34,094	7,125	-13,500	11,798	
PW TOTAL	2,269	3,582	2,600	928	2,513	11,798				

NET INVESTMENT

<u>YEAR</u>	<u>BEG.</u>	<u>END.</u>	<u>AVG.</u>
1984	10,000	8,912	9,456
1985	8,912	8,402	8,657
1986	8,402	7,926	8,164
1987	7,926	7,485	7,706
1988	7,485	7,078	7,291
1989	7,078	6,671	6,875
1990	6,671	6,299	6,485
1991	6,299	5,926	6,113
1992	5,926	5,554	5,740
1993	5,554	5,181	5,368
1994	5,181	4,809	4,995
1995	4,809	4,437	4,623
1996	4,437	4,064	4,250
1997	4,064	3,692	3,878
1998	3,692	3,319	3,505
1999	3,319	3,153	3,236
2000	3,153	2,987	3,070
2001	2,987	2,821	2,904
2002	2,821	2,655	2,738
2003	2,655	2,489	2,572
2004	2,489	2,323	2,406
2005	2,323	2,157	2,240
2006	2,157	1,992	2,075
2007	1,992	1,826	1,909
2008	1,826	1,660	1,743
2009	1,660	1,494	1,577
2010	1,494	1,328	1,411
2011	1,328	1,162	1,245
2012	1,162	996	1,079
2013	996	830	913
2014	830	664	747
2015	664	498	581
2016	498	332	415
2017	332	166	249
2018	166	0	93

APPENDIX D: RATED NET
MEGAWATT OUTPUT CAPABILITY

Rated Net Output MW Capability, as determined by the procedures outlined below, is intended to be that maximum level of production that could reasonably be expected to be attained and utilized in actual system operation.

The Rated Net Output Capability of Colstrip Nos. 3 and 4 shall be established by the Operator. The Operator, as it deems necessary, will conduct tests to determine the rated capability. Such testing shall be performed from time to time when the Operator determines a significant change in capability has occurred, or after significant modifications.

Test conditions shall be: (1) valve opening between 96 and 100 percent of wide open, (2) throttle pressure between 95 and 105 percent of rated, (3) all feed water heaters operating, (4) all flue gas cleaning systems operating in compliance with regulatory requirements, and (5) all systems operating normally. Valve settings, throttle pressure, and other operating systems are to be operated at a level consistent with Operator's practice for determining unit maximum dependable capability. The test period will be twenty-four (24) continuous hours, during which time Operator shall attempt to achieve the maximum sustainable output. Such test may be performed in the course of normal operation of the generating facility during periods when maximum output is desired. Test output

will be corrected to design backpressure conditions to take into account variations associated with ambient test conditions different than design as defined in the Bechtel heat balance.

The Operator will compute or measure the total energy output net of station service in MWh at the high side of the generator step-up transformer for the twenty-four (24)-hour period. The rated net MW output capability of each unit is such total energy in MWh divided by twenty-four (24), rounded to the nearest whole MW.

APPENDIX E: CALCULATION OF PACIFIC'S
EMBEDDED FIXED COSTS

Introduction

Pacific currently owns outright or has an undivided interest in four (4) coal-fired electric generating plants. Pacific also leases a share of one (1) coal-fired electric generating plant. Each year Pacific's Embedded Fixed Cost will include actual capital-related fixed costs related to the above-referenced plants (with the exception of those Colstrip Unit Nos. 3 and 4 costs related to capacity purchased by Black Hills in accordance with Section 3.1), and all future coal-fired electric generating plants or Purchases from coal-fired generating plants.

Section E1: Discussion of Methodology

At the end of each calendar year, Pacific will calculate the embedded cost of each plant and Purchases as of December 31 of that calendar year. Pacific's Embedded Fixed Costs will be that weighted average cost of all of Pacific's owned and leased coal-fired electric generating plants, together with all Purchases from coal-fired electric generating plants as of December 31, 1984 and as of December 31 each year thereafter. Weighting will be based on the total installed capacity of each plant as of December 31 as determined in FERC Form No. 1.

Pacific's Embedded Fixed Cost will be determined by (a) adding the amounts calculated under Sections E2.1 through E2.5, and (b) dividing the total by the total installed capacity of plants and Purchases which were included in the costs for that year.

E2.1. Determination of Levelized Annual Fixed Costs:

For each owned plant, a levelized annual fixed charge rate will be calculated annually in accordance with Section E3, below, and multiplied by the cost of plant as determined in Pacific's FERC Form No. 1; such product will be the levelized annual fixed costs.

E2.2. Lease Payments or Purchases: For each leased plant, rent as determined in FERC Form No. 1 will be included in lieu of a levelized annual fixed cost; provided, in the event the leased plant is purchased by Pacific, a levelized annual fixed charge rate will be calculated in accordance with Section E3, and the rate shall be applied to the purchase price in determining the levelized annual fixed charge relating to the plant; and provided in the event the ratemaking treatment of the lease changes such that Pacific is allowed to recover the asset as it would normally recover owned assets, a levelized annual fixed charge rate will be calculated in accordance with Section E3, including the implicit interest rate of the capitalized lease, and the rate shall be applied to the capitalized lease amount in determining the levelized annual fixed charge relating to the plant.

For Purchases, Pacific's embedded cost will be the annual fixed charges related to such purchase.

E2.3. All ad valorem taxes imposed upon the plants.

E2.4. Any tax, assessment, payment in lieu of taxes, or other charge imposed by any governmental body assessed or charged against Pacific relating to the plants or Purchases excluding ad valorem taxes, state and federal income taxes, and taxes covered under Section B2.9 and B2.11 of Appendix B.

E2.5. All insurance premiums incurred by Pacific related to the plants.

Section E3: Elements of Levelized Annual Fixed Charge Rates

E3.1. Capital Structure: Pacific's capital structure will remain constant throughout the duration of the Agreement for purposes of calculating the levelized annual fixed charge rate for existing owned plants as of the date of this Agreement. The capital structure is as follows:

Long-Term Debt	52%
Preferred Stock	12%
Common Stock Equity	36%

For purposes of calculating a levelized annual fixed charge rate for future owned plants, the capital structure will be Pacific's targeted capital structure at the time the future plant is placed in commercial operation.

E3.2. Cost of Capital:

E3.2.1. Long-Term Debt: 3rd interest applicable in the calculation of the levelized annual fixed charge rate

will be Pacific's embedded cost of debt (including pollution control revenue bonds) as of December 31 of that year.

E3.2.2. Preferred Stock: Return on preferred stock applicable in the calculation of the levelized annual fixed charge rate will be Pacific's embedded cost of preferred stock as of December 31 of that year.

E3.2.3. Common Stock Equity: Return on common stock equity will be calculated in the same manner as that used in Section A3.2.4 in Appendix A.

E3.3. Book Depreciation: A book life will be determined each year for each plant by dividing the cost of plant as of December 31 of that year by the actual depreciation booked in that year. Book depreciation charges will be on a straight-line basis over the predetermined book life.

E3.4. Income Tax Requirements: Income tax requirements will vary by plant due to plant location and vintage, and will be subject to any retroactive or future tax law changes. The income tax requirements will reflect the tax law in effect during construction of a plant.

APPENDIX E

PACIFIC POWER & LIGHT COMPANY

Sample Calculation of Estimated Cumulative Account

	Black Hills Contractual Payments ^{1/}		Pacific's Embedded Fixed Cost	Capacity Purchased	Deposit Into Cumulative Account	Account Balance Before Interest	Interest ^{3/}	Ending Account Balance
	(\$)	(\$/MW/Yr.)	(\$/MW/Yr.) ^{2/}	(MW)				
1984	\$ 2,137,436	\$142,496	\$ 59,960	15	\$ 1,238,040	\$ 1,238,040	\$ 76,635	\$ 1,314,675
1985	4,274,068	142,496	62,930	30	2,386,980	3,701,655	310,511	4,012,166
1986	6,412,308	142,496	62,046	45	3,620,250	7,632,416	720,800	8,353,216
1987	8,549,740	142,496	61,154	60	4,880,520	13,233,736	1,336,232	14,569,968
1988	14,245,754	189,943	60,252	75	9,726,825	24,296,793	2,405,853	26,702,646
1989	18,854,357	251,391	60,252	75	<u>14,335,425</u>	41,038,071	<u>4,193,150</u>	45,231,221
					<u>\$36,188,040</u>		<u>\$9,043,181</u>	

1/ Estimated Actual Fixed Cost Payments in accordance with Section 5.1 and 5.2. Excludes Section A2.6.

2/ Among other future plant investment, approximately \$300 million of pollution control equipment will be added to Pacific's plant investment during the next 7 to 8 years which is not included above. It is estimated that these additions will increase Pacific's Embedded Fixed Cost by approximately \$15,000/MW/Yr. as early as 1988. These figures are estimates and are subject to change.

3/ Interest calculated by applying 12.38% composite weighted cost of capital in accordance with Section 5.5.1.

PACIFIC POWER & LIGHT COMPANY
SAMPLE CALCULATION OF
PACIFIC'S 1984 EMBEDDED FIXED COSTS
(THOUSANDS OF DOLLARS)

Plant	Installed Capacity (MW)	Cost of Plant	Levelized Annual Fixed Charge Rate (¢)	Levelized Annual Fixed Charge
Save Johnston	750	198495	15.91 1	31581
Centralia	632	149702	15.59 1	23339
Jin Bridger	1356	564278	15.21 1	83827
Colstrip	55	88786	14.47 2	12047
Wydat	265	210350	N/A	16694
	3058	1211811		\$ 170287
Estimated Property Tax				10405
Estimated Insurance Premiums				2666
				\$ 183358
Total Installed Capacity(MW)	3058			
Pacific's 1984 Embedded Fixed Costs (¢/kW/YR)				59.96

- 1) Source: 1982 FERC Form No. 1
- 2) Net Colstrip Generation less Capacity Purchased by
Black Hills in accordance with Section 3.1
- 3) Capital-related costs relating to 55 MW installed capacity of
Unit No. 3
- 4) Leased Facility. Rents in 1982 FERC Form No.1.

CALCULATION OF UTILITY TYPE INVESTMENT BASE

LINE NO	(1) TOTAL COMPANY	(2) APPLICABLE TO SALES TO BLACK HILLS
1 GROSS MINING PLANT	\$32,293,500	
2 ACCUMULATED PROVISION FOR DEPRECIATION, DEPLETION AND AMORTIZATION - MINING PLANT	11,783,762	
3 NET MINING PLANT (LINE 1 LESS 2)	20,509,738	7,106,624 (1)
4 PROCESSING PLANT-TRUCK LOADOUT	7,411,316	
5 ACCUMULATED PROVISION FOR DEPRECIATION	3,788,613	
6 NET PROCESSING PLANT-TRUCK LOADOUT (LINE 4 LESS 5)	3,622,703	2,172,535 (2)
7 PROCESSING PLANT-OTHER	5,372,319	
8 ACCUMULATED PROVISION FOR DEPRECIATION	3,172,056	
9 NET PROCESSING PLANT-OTHER (LINE 7 LESS 8)	2,200,263	1,893,766 (3)
10 NET MINING AND PROCESSING PLANT (LINE 3 PLUS 6 PLUS 9)	25,332,704	11,172,925
11 UNAMORTIZED STRIPPING COSTS	1,094,000	379,071 (1)
12 MATERIALS, SUPPLIES & PREPAYMENT	569,091	197,190 (1)
13 TOTAL UTILITY TYPE INVESTMENT BASE (LINE 10 PLUS 11 PLUS 12)	\$27,995,795	\$11,749,186

34.65%

69.97%

86.07%

AFFILIATE PRICE LIMITATION
FOR COAL SALES TO BLACK HILLS CORPORATION
FOR THE TWELVE MONTHS ENDED DECEMBER 31

PAGE 2 OF 7

CALCULATION OF UTILITY TYPE RATE OF RETURN

LINE NO	(1) TOTAL COMPANY	(2) APPLICABLE TO SALES TO BLACK HILLS	(3) ADJUSTED
1 RECEIPTS FROM COAL SALES	\$20,295,665	\$9,810,751	8,404,535
2 OPERATING EXPENSES:			
3 MINING EXPENSES	9,895,416	3,425,297 (1)	3,425,297
4 PROCESSING EXPENSES-TRUCK LOADOUT	270,203	162,041 (2)	162,041
5 PROCESSING EXPENSES-OTHER	489,408	421,233 (3)	421,233
6 DEPRECIATION AND DEPLETION OF MINING PLANT	924,711	320,412 (1)	320,412
7 DEPRECIATION-PROCESSING PLANT TRUCK LOADOUT	351,388	210,727 (2)	210,727
8 DEPRECIATION-PROCESSING PLANT OTHER	202,947	174,676 (3)	174,676
9 FEDERAL INCOME TAX (PAGE 4, LINE 4)	3,350,241	1,008,856 (4)	601,766
10 TAXES EXCLUSIVE OF FIT & PROPERTY	4,469,990	1,548,352 (1)	1,548,352
11 PROPERTY TAXES			
MINING	73,661	25,524 (1)	25,524
TRUCK LOADOUT	30,348	18,200 (2)	18,200
OTHER PROCESSING	21,998	18,934 (3)	18,934
12 TOTAL OPERATING EXPENSES	20,070,311	7,334,752	6,927,662
13 NET MINING INCOME	8,225,354	2,475,989	1,476,873
14 OTHER NON-MINING INCOME (NET)	3,749,371		
15 LESS: INTEREST ON LONG-TERM DEBT	(286,683)		
16 NET INCOME	11,528,042		
17 UTILITY TYPE INVESTMENT BASE			
APPLICABLE TO SALES TO BLACK HILLS		11,749,186	11,749,186
18 UTILITY TYPE RATE OF RETURN RELATED TO SALES TO BLACK HILLS		21.07%	12.57%

(1) PERCENT APPLICABLE TO MINING (PAGE 3, LINE 11) =

34.65%

(2) PERCENT APPLICABLE TO PROCESSING TRUCK LOADOUT (PAGE 3, LINE 13) =

59.97%

(3) PERCENT APPLICABLE TO PROCESSING OTHER (PAGE 3, LINE 15) =

86.07%

(4) AMOUNT APPLICABLE TO BLACK HILLS (PAGE 4, LINE 11) =

1,008,856

AFFILIATE PRICE LIMITATION
FOR COAL SALES TO BLACK HILLS CORPORATION
FOR THE TWELVE MONTHS ENDED DECEMBER 31

PAGE 3 OF 7

CALCULATION OF INVESTMENT BASE ALLOCATORS

LINE
NO

1	TOTAL COAL SOLD	2,958,000
2	TOTAL COAL SOLD - WYODAK PLANT	2,079,268
3	TOTAL COAL SOLD - LUMP COAL	1,811
4	TOTAL TONS SOLD - BLACK HILLS WYODAK	415,437
5	TOTAL COAL SOLD - BLACK HILLS OTHER PLANTS	609,404
6	TOTAL COAL SOLD - BLACK HILLS BY OTHER PROCESSING PLANT	275,030
7	TOTAL COAL SOLD - BLACK HILLS BY TRUCK LOADOUT	334,374
8	OTHER COAL SOLD BY TRUCK LOADOUT	223,221
9	OTHER COAL SOLD BY OTHER PROCESSING PLANT	44,496
10	PERCENT APPLICABLE TO MINING	
11	(LINE 4 + LINE 5) / LINE 1	34.85%
12	PERCENT APPLICABLE TO PROCESSING TRUCK LOADOUT	
13	LINE 7 / (LINE 7 + LINE 8)	59.97%
14	PERCENT APPLICABLE TO PROCESSING OTHER	
15	LINE 6 / (LINE 6 + LINE 9)	86.07%

AFFILIATE PRICE LIMITATION
FOR COAL SALES TO BLACK HILLS CORPORATION
FOR THE TWELVE MONTHS ENDED DECEMBER 31

PAGE 4 OF 7

CALCULATION OF FEDERAL INCOME TAX APPLICABLE TO BLACK HILLS CORPORATION

LINE NO		
1	TOTAL FIT APPL TO MINING INCOME	3,350,241
2	INCOME BEFORE FIT:	
3	NET INCOME	8,222,268
4	PLUS FIT	3,350,241
5		<u>11,572,509</u>
6	FIT APPLICABLE TO MINING INCOME	3,350,241
7	<u>MINING INCOME BEFORE FIT</u>	<u>11,572,509</u>
8		<u>28.95%</u>
9	INCOME BEFORE FIT APPL TO BLACK HILLS	3,484,855
10	X LINE 6	<u>28.95%</u>
11		<u>1,008,266</u>

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AFFILIATE PRICE LIMITATION
FOR COAL SALES TO BLACK HILLS CORPORATION
FOR THE TWELVE MONTHS ENDED DECEMBER 31

PAGE 5 OF 7

CALCULATION OF WEIGHTED AVERAGE COST OF LONG-TERM DEBT

LINE NO	(1) AMOUNT OUTSTANDING	(2) RATE	(3) ANNUAL COST
LONG TERM DEBT:			
1 20-YEAR NOTE PAYABLE IN ANNUAL INSTALLMENTS OF \$7,950 THROUGH 1995	23,850	10.00%	2,385
2 MMS OBLIGATION - PEERLESS	2,880,608	10.50%	302,464
3 TOTAL	2,904,458		304,849
4 WEIGHTED AVERAGE COST OF LONG-TERM DEBT		10.50%	

AFFILIATE PRICE LIMITATION
FOR COAL SALES TO BLACK HILLS CORPORATION
FOR THE TWELVE MONTHS ENDED DECEMBER 31

PAGE 6 OF 7

CALCULATION OF WEIGHTED COST OF CAPITAL

	AMOUNT	PERCENT OF TOTAL	COST	WEIGHTED COST
LONG TERM DEBT	2,904,458	5.63%	10.50%	0.59%
COMMON EQUITY	48,690,819	94.37%	21.70%	20.48%
TOTAL CAPITALIZATION	51,595,277	100.00%		21.07%
RETURN ON EQUITY - UTILITY A RATED BONDS -				8.55%
PLUS 400 BASIS POINTS -				4.00%
ROE				12.55%
WEIGHTED COST OF EQUITY	12.55%	X	94.37%	11.98%
WEIGHTED COST OF DEBT	10.50%	X	5.63%	0.59%
WEIGHTED COST OF CAPITAL				12.57%

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AFFILIATE PRICE LIMITATION
FOR COAL SALES TO BLACK HILLS CORPORATION
FOR THE TWELVE MONTHS ENDED DECEMBER 31

PAGE 7 OF 7

CALCULATION OF AFFILIATE PRICE ADJUSTMENT

1	COAL RECEIPTS FROM BLACK HILLS	9,810,751
2	COAL RECEIPTS FROM BLACK HILLS AS ADJUSTED	8,404,535
3	AFFILIATE PRICE ADJUSTMENT (LINE 1 - LINE 2)	1,406,216

EXHIBIT E

to
EXHIBIT RRB-3WYODAK RESOURCES COAL TO BE DELIVERED
TO THE NEIL SIMPSON UNIT #2 POWER PLANT

<u>Proximate Analysis</u>	<u>As Received (Raw)</u> Range	
Moisture (%)	24.00	to 34.00
Ash (%)	4.00	to 10.00
Volatile Matter (%)	28.09	to 36.99
Fixed Carbon (%)	29.45	to 37.40
Total		
BTU per pound (as received)	7600	to 8400
BTU per pound (dry)	11100	to 12250
Sulfur (%)	0.30	to 1.20
<u>Ultimate Analysis</u>		
Carbon (%)	46.07	to 52.38
Hydrogen (%)	3.04	to 3.50
Nitrogen (%)	0.50	to 0.80
Chlorine (%)	0.00	to 0.03
Sulfur (%)	0.20	to 0.70
Ash (%)	4.00	to 10.00
Oxygen (Diff) (%)	11.02	to 12.54
Moisture (%)	24.00	to 34.00
<u>Sulfur Forms</u>		
Pyritic Sulfur (%)	0.01	to 0.63
Sulfate Sulfur (%)	0.00	to 0.02
Organic Sulfur (%)	0.14	to 1.34
<u>Fusion Temp. of Ash, °F</u>	<u>Reducing/Oxidizing</u>	
Initial Deformation	2101/2180	2310/2390
Softening (H=W)	2160/2180	2400/2430
Hemispherical (H=1/2W)	2170/2205	2415/2500
Fluid	2185/2215	2560/2630

Mineral Analysis of Ash
(Percent Weight Ignited Basis)

Silica, SiO_2	16.52 to 40.19
Alumina, Al_2O_3	11.98 to 27.01
Titania, TiO_2	0.43 to 2.01
Ferric oxide, Fe_2O_3	2.91 to 8.40
Lime, CaO	11.62 to 30.81
Magnesia, MgO	2.36 to 8.62
Potassium oxide, K_2O	0.01 to 1.28
Sodium oxide, Na_2O	0.18 to 2.22
Sulfur trioxide, SO_3	6.94 to 22.26
Phos. pentoxide, P_2O_5	0.23 to 2.01

Total

Miscellaneous

Equilibrium Moisture	28.60 to 31.80
Hardgrove Grindability Index	50 to 65
Free Swelling Index	0 to 0
Slag Viscosity T250, °F	2160 to 2450
Water Soluble Na_2O	0.40 to 0.22
Silica Value	42.80 to 66.09

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COAL PRICE UNDER AFFILIATE COAL ADJUSTMENT

DECEMBER 7, 1994

INCREMENTAL COST OF COAL FOR
NEIL SIMPSON UNIT #2

1996 1997 1998 1999

REVENUE ALLOWED FROM ALL
BHPL COAL SALES

\$10,178,243 \$11,551,196 \$11,390,436 \$11,939,117

REVENUE FROM BHPL/WYODAK PLANT:
TONS OF COAL SOLD
FORECASTED CONTRACT PRICE/TON

408,279	373,388	407,710	407,776
\$10.128	\$10.399	\$10.679	\$10.967
4,135,050	3,882,862	4,353,035	4,472,079

REVENUE FROM BHPL/OTHER EXISTING PLANTS:
TONS OF COAL SOLD
FORECASTED CONTRACT PRICE/TON

386,211	481,994	495,057	505,073
\$11.345	\$11.654	\$11.971	\$12.298
4,381,564	5,617,158	5,926,327	6,211,388

REVENUE FROM NEIL SIMPSON UNIT #2

1,661,629 2,051,176 1,110,174 1,255,650

TONS OF COAL SOLD TO NEIL SIMPSON UNIT #2

404,386 509,353 465,269 511,983

INCREMENTAL COST OF COAL/TON FOR
NEIL SIMPSON UNIT #2

\$4.109 \$4.027 \$2.386 \$2.453

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DECEMBER 7 1994

COAL PRICE UNDER AFFILIATE COAL ADJUSTMENT

REVENUE FROM BHPL COAL SALES	1996	1997	1998	1999
UTILITY TYPE INVESTMENT BASE				
ALLOCATED TO BHPL SALES	14,498,504	15,481,320	14,456,040	14,815,537
UTILITY TYPE RATE OF RETURN ALLOWED	12.75	12.75	12.75	12.75
EAFININGS ALLOWED ON BHPL COAL SALES	1,848,559	1,973,868	1,843,145	1,888,981
FEDERAL INCOME TAXES:	952,288	1,062,852	992,463	1,017,144
OPERATING EXPENSES:				
MINING EXPENSES	2,414,528	2,836,498	2,878,344	3,080,470
PROCESSING EXP - TRUCK LOADOUT	88,740	110,980	116,600	121,237
PROCESSING EXP - OTHER	430,608	478,470	478,551	505,030
DEPRECIATION & DEPLETION - MINING	888,757	1,009,292	1,004,893	1,054,698
DEPRECIATION - TRUCK LOADOUT	101,603	123,805	132,687	132,544
DEPRECIATION - OTHER PROCESSING	234,122	264,923	272,899	288,953
FEDERAL RECLAMATION, PRODUCTION, FICA & UNEMPLOYMENT	1,000,806	1,159,712	1,180,032	1,249,628
PROPERTY TAXES:				
MINING	43,381	52,540	48,412	46,887
TRUCK LOADOUT	12,344	14,930	14,561	12,897
OTHER PROCESSING	29,528	32,696	31,048	28,392
ROYALTIES	1,272,280	1,443,900	1,423,805	1,492,390
SEVERANCE TAX	431,730	499,898	492,941	516,686
BLACK LUNG TAX	428,968	486,832	480,057	503,181
REVENUE ALLOWED FROM				
BHPL COAL SALES	10,178,243	11,551,196	11,390,436	11,939,117
WYODAK PLANT - BHPL	408,279	373,388	407,710	407,776
OTHER PLANTS - BHPL	790,597	991,347	960,326	1,017,036
BHPL TONNAGES	1,198,876	1,364,735	1,368,036	1,424,812
AVG PRICE PER TON	\$8.490	\$8.464	\$8.326	\$8.379

COAL PRICE UNDER AFFILIATE COAL ADJUSTMENT

OPERATING EXPENSES	1996	1997	1998	1999
MINING EXPENSES	6,505,183	6,767,946	7,147,018	7,467,429
PROCESSING EXPENSES - TRUCK LOADOUT	222,523	238,882	246,408	253,214
PROCESSING EXPENSES - OTHER	451,687	497,386	498,501	524,684
DEPRECIATION & DEPLETION - MINING PLANT	1,867,314	1,941,328	2,009,335	2,082,395
DEPRECIATION - MINING INVESTMENT FOR SALES T	195,667	195,667	195,667	195,667
DEPRECIATION - TRUCK LOADOUT	254,778	266,488	280,405	276,828
DEPRECIATION - PROCESSING OTHER	245,583	275,397	284,276	300,199
FEDERAL RECLAMATION, PRODUCTION, FICA & UNEMPLOYMENT TAXES	2,696,354	2,767,097	2,930,055	3,020,248
PROPERTY TAXES:				
MINING	116,877	125,361	120,208	113,660
TRUCK LOADOUT	30,955	32,137	30,771	26,936
OTHER PROCESSING	30,974	33,988	32,342	29,497

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DECEMBER 7, 1994

COAL PRICE UNDER AFFILIATE COAL ADJUSTMENT

UTILITY TYPE INVESTMENT BASE ALLOCATED TO BHPL SALES	1996	1997	1998	1999
NET MINING PLANT	10,722,595	11,152,637	10,036,254	10,064,983
NET PROCESSING PLANT - TRUCK LOADOUT	1,076,127	1,140,034	1,079,278	976,735
NET PROCESSING PLANT - OTHER	1,866,877	1,848,343	1,767,833	1,701,726
NET MINING & PROCESSING PLANT	13,665,598	14,141,013	12,883,365	12,743,446
UNAMORTIZED STRIPPING COSTS	652,517	1,136,620	1,376,946	1,871,607
MATERIALS, SUPPLIES, & PREPAYMENTS	180,389	203,686	195,729	200,485
UTILITY TYPE INVESTMENT BASE ALLOCATED TO BHPL SALES	14,498,504	15,481,320	14,456,040	14,815,537
PERCENT APPLICABLE TO MINING	37.12%	41.91%	40.27%	41.25%
PERCENT APPLICABLE TO PROCESSING - TRUCK LOADOUT	39.88%	46.46%	47.32%	47.88%
PERCENT APPLICABLE TO PROCESSING - OTHER	95.33%	96.20%	96.00%	96.25%

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DECEMBER 7, 1994

COAL PRICE UNDER AFFILIATE COAL ADJUSTMENT

COMPUTATION OF UTILITY TYPE INVESTMENT	1996	1997	1998	1999
GROSS MINING PLANT	40,065,377	40,834,808	41,472,890	43,603,043
ACCUM DEPR & DEPL - MINING PLANT	17,502,679	19,359,888	21,411,020	23,473,187
NET MINING PLANT	22,562,698	21,474,919	20,061,870	20,129,856
MINING INVESTMENT FOR SALES TO BHPL	2,935,000	2,935,000	2,935,000	2,935,000
ACCUM DEPR - MINING INVESTMENT FOR SALES TO	587,001	782,667	978,334	1,174,001
NET MINING INVESTMENT FOR SALES TO BHPL	2,347,999	2,152,333	1,956,666	1,760,999
PROCESSING PLANT - TRUCK LOADOUT	6,822,809	6,801,365	6,954,626	6,943,516
ACCUM DEPR - TRUCK LOADOUT	4,124,323	4,347,466	4,673,808	4,903,530
NET PROCESSING PLANT - TRUCK LOADOUT	2,698,486	2,453,899	2,280,817	2,039,986
PROCESSING PLANT - OTHER	6,827,074	7,193,087	7,309,745	7,603,700
ACCUM DEPR - PROCESSING OTHER	4,868,808	5,271,668	5,468,211	5,835,744
NET PROCESSING PLANT - OTHER	1,958,266	1,921,418	1,841,534	1,767,957
NET MINING & PROCESSING PLANT	29,567,450	28,002,570	26,140,886	25,698,799
UNAMORTIZED STRIPPING COSTS	1,758,000	2,712,000	3,419,000	4,537,000
MATERIALS, SUPPLIES, & PREPAYMENTS	486,000	486,000	486,000	486,000
TOTAL UTILITY TYPE INVESTMENT	31,811,450	31,200,570	30,045,886	30,721,799

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DECEMBER 7, 1994

COAL PRICE UNDER AFFILIATE COAL ADJUSTMENT

ALLOCATION OF CONVEYOR EXPENSES	1996	1997	1998	1999
PLANT:				
TRUCK LOADOUT	1,778,935	1,686,514	1,756,359	1,698,665
OTHER	2,565,359	2,657,780	2,587,935	2,645,629
RESERVE FOR DEPRECIATION:				
TRUCK LOADOUT	1,187,877	1,172,224	1,268,738	1,273,453
OTHER	1,713,010	1,847,309	1,869,441	1,983,372
DEPRECIATION EXPENSE:				
TRUCK LOADOUT	48,584	46,060	47,968	46,392
OTHER	70,062	72,586	70,678	72,254
ALLOCATION OF MINING/PROCESSING	1996	1997	1998	1999
PLANT:				
TRUCK LOADOUT	401,558	472,536	555,950	602,535
OTHER	578,078	744,670	819,173	938,434
MINING	2,909,660	3,074,091	3,712,173	4,047,326
RESERVE FOR DEPRECIATION:				
TRUCK LOADOUT	275,008	345,016	406,056	470,053
OTHER	396,583	543,712	598,309	732,097
MINING	1,992,689	2,244,512	2,711,302	3,157,423
DEPRECIATION EXPENSE:				
TRUCK LOADOUT	37,405	51,639	63,649	69,427
OTHER	53,941	81,379	93,784	108,130
MINING	271,033	335,942	424,992	466,350
ALLOCATION OF ADMINISTRATIVE & GENERAL	1996	1997	1998	1999
ADMINISTRATIVE & GENERAL EXPENSES:				
TRUCK LOADOUT	122,523	135,882	140,318	143,941
OTHER	176,687	214,136	206,754	224,185
MINING	887,790	883,982	936,928	966,874

COAL PRICE UNDER AFFILIATE COAL ADJUSTMENT

STATE - R: INPUT	1996	1997	1998	1999
GROSS MINING PLANT	37,155,717	37,760,717	37,760,717	39,555,717
ACCUM DEPR & DEPL - MINING PLANT	15,509,989	17,115,376	18,699,719	20,315,764
MINING INVESTMENT FOR SALES TO BHPL	2,935,000	2,935,000	2,935,000	2,935,000
ACCUM DEPR - MINING INVESTMENT FOR SALES TO	587,001	782,667	978,334	1,174,001
MINING/PROCESSING PLANT	3,890,296	4,291,296	5,087,296	5,508,296
ACCUM DEPR - MINING/PROCESSING	2,664,281	3,133,241	3,715,666	4,359,573
PROCESSING PLANT - TRUCK LOADOUT	4,642,316	4,642,316	4,642,316	4,642,316
ACCUM DEPR - TRUCK LOADOUT	2,661,437	2,830,226	2,999,015	3,160,024
PROCESSING PLANT - CONVEYOR	4,344,294	4,344,294	4,344,294	4,344,294
ACCUM DEPR - CONVEYOR	2,900,887	3,019,533	3,138,179	3,256,825
PROCESSING PLANT - OTHER	3,682,637	3,790,637	3,902,637	4,019,637
ACCUM DEPR - PROCESSING OTHER	2,759,215	2,880,647	3,000,461	3,120,275
UNAMORTIZED STRIPPING COSTS	1,758,000	2,712,000	3,419,000	4,537,000
MATERIALS, SUPPLIES & PREPAYMENTS	486,000	486,000	486,000	486,000
MINING EXPENSES	5,617,393	5,883,964	6,210,090	6,500,555
ADMINISTRATIVE & GENERAL EXPENSES	1,187,000	1,234,000	1,284,000	1,335,000
PROCESSING EXP - TRUCK LOADOUT	100,000	103,000	106,090	109,273
PROCESSING EXP - OTHER	275,000	283,250	291,748	300,500
DEPRECIATION - MINING PLANT	1,376,641	1,383,959	1,353,355	1,381,179
DEPRECIATION - MINING INVESTMENT FOR SALES T	195,667	195,667	195,667	195,667
DEPLETION	219,639	221,428	230,988	234,866
DEPRECIATION - MINING/PROCESSING	362,379	468,960	582,425	643,907
DEPRECIATION - PROC TRUCK LOADOUT	168,789	168,789	168,789	161,009
DEPRECIATION - PROC CONVEYOR	118,646	118,646	118,646	118,646
DEPRECIATION - PROC OTHER	121,580	121,432	119,814	119,814
FEDERAL RECLAMATION, PRODUCTION,				
FICA & UNEMPLOYMENT	2,696,354	2,767,097	2,930,055	3,029,248
PROPERTY TAXES	178,805	191,487	183,321	170,094
TOTAL COAL SOLD	3,229,992	3,256,287	3,396,876	3,453,916
TOTAL COAL SOLD - WYODAK PLANT	2,141,395	1,966,940	2,138,550	2,138,880
TOTAL COAL SOLD - LUMP COAL	0	0	0	0
TOTAL COAL SOLD - BHPL WYODAK	408,279	373,388	407,710	407,776
TOTAL COAL SOLD - BHPL OTHER	790,597	991,347	960,326	1,017,036
TOTAL COAL SOLD - TRUCK LOADOUT	445,767	500,542	508,730	514,193
TOTAL COAL SOLD - BHPL OTHER PROC	612,830	758,805	719,596	770,843
OTHER COAL SOLD - TRUCK LOADOUT	268,000	268,000	268,000	268,000
COAL SOLD - OTHER PROCESSING PLANT	642,830	788,805	749,596	800,843
LAND EXEMPTIONS FROM PROPERTY TAX	14,304,194	14,304,194	14,304,194	14,304,194
UTILITY "A" RATED BONDS	8 75	8 75	8 75	8 75

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DECEMBER 7, 1994

COAL PRICE UNDER AFFILIATE COAL ADJUSTMENT

WRDC O & M	1996	1997	1998	1999
TONS MINED	3,229,992	3,256,287	3,396,876	3,453,916
WYODAK TONS	(2,141,395)	(1,966,940)	(2,138,550)	(2,138,880)
	1,088,597	1,289,347	1,258,326	1,315,036
MINING RATE PER TON	0.359	0.374	0.389	0.404
PROCESSING RATE PER TON	0.448	0.466	0.484	0.504
GOVT REQ RATE PER TON	0.053	0.055	0.057	0.060
MAINTENANCE	0.000	0.000	0.000	0.000
RECLAMATION - BOOK & TAX	0.215	0.215	0.215	0.215
STRIPPING	0.450	0.450	0.460	0.470
COST BASED ON TONNAGE:				
MINING	1,159,567	1,217,851	1,321,385	1,395,382
PROCESSING (EXCLUDES WYODAK)	487,691	600,836	609,030	662,778
GOVT REQ	171,190	179,096	193,622	207,235
MAINTENANCE	0	0	0	0
RECLAMATION - TAX & BOOK	694,448	700,102	730,328	742,592
STRIPPING	1,453,496	1,465,329	1,562,563	1,623,341
OTHER O & M	3,213,000	3,341,000	3,475,000	3,614,000
	7,179,393	7,504,214	7,891,928	8,245,328
ADMINISTRATIVE & GENERAL EXPENSES	(1,187,000)	(1,234,000)	(1,284,000)	(1,335,000)
PROCESSING EXPENSES - TRUCK LOADOUT	(100,000)	(103,000)	(106,090)	(109,273)
PROCESSING EXPENSES - OTHER	(275,000)	(283,250)	(291,748)	(300,500)
MINING EXPENSES	5,617,393	5,883,964	6,210,090	6,500,555
OTHER TAXES:				
FEDERAL RECLAMATION	1,130,497	1,139,700	1,188,907	1,208,871
PRODUCTION	1,363,057	1,416,485	1,521,800	1,592,255
FICA & UNEMPLOYMENT	202,800	210,912	219,348	228,122
	2,696,354	2,767,097	2,930,055	3,029,248
DEPLETION	219,639	221,428	230,988	234,866

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DECEMBER 7, 1994

COAL PRICE UNDER AFFILIATE COAL ADJUSTMENT

BHPL ANNUAL TONNAGES W/ NSS #2	1996	1997	1998	1999
WYODAK PLANT - BHPL	408,279	373,388	407,710	407,776
NEIL SIMPSON UNIT #1	112,561	117,565	117,270	117,796
OSAGE	133,736	187,103	194,840	200,840
BEN FRENCH	81,884	100,655	103,673	105,109
KIRK	58,030	76,671	79,274	81,328
NEIL SIMPSON UNIT #2 - BHPL	404,386	509,353	465,269	511,963
BHPL TONNAGES	1,198,876	1,364,735	1,368,036	1,424,812
PPL TONNAGES	1,733,116	1,593,552	1,730,840	1,731,104
OTHER TONNAGES	298,000	298,000	298,000	298,000
TOTAL TONS SOLD	3,229,992	3,256,287	3,396,876	3,453,916
LUMP	0	0	0	0
TOTAL WYODAK	2,141,395	1,966,940	2,138,550	2,138,880
TOTAL BHPL	1,198,876	1,364,735	1,368,036	1,424,812
BHPL - WYODAK	408,279	373,388	407,710	407,776
BHPL - OTHER	790,597	991,347	960,326	1,017,036
TOTAL TRUCK LOADOUT	445,767	500,542	508,730	514,193
BHPL OTHER PROCESSING	612,830	758,805	719,596	770,843
OTHER TRUCK LOADOUT	268,000	268,000	268,000	268,000
TOTAL OTHER PROCESSING	642,830	788,805	749,596	800,843

CA123VRBDATEX-RRB08 WG2

NET DELIVERED COST PER TON OF COAL DELIVERED TO BLACK HILLS' PLANTS

(based upon actual 1993 costs)

(in cents per million Btu)

PLANT	FERC FORM 1 \$ PER TON DELIVERED	STATEMENT-R REFUND ON PER TON BASIS	NET DELIVERED \$ PER TON OF COAL	DELIVERED COST IN CENTS PER MILLION BTU
EIEN FRENCH	\$16.41	\$1.05	\$15.36	95.99
OSAGE	\$14.16	\$1.05	\$13.11	81.93
WYODAK	\$9.46	\$1.05	\$8.41	52.56
KIRK	\$17.97	\$1.05	\$16.92	105.77
NEIL SIMPSON UNIT #1	\$10.65	\$1.05	\$9.60	59.98
TOTAL COMPANY	\$12.39	\$1.05	\$11.34	70.87

TABLE 27
FOSSIL FUELS USED FOR ELECTRIC GENERATION
TOTAL ELECTRIC UTILITY INDUSTRY

FUEL BURNED UNDER BOILERS AND BY INTERNAL COMBUSTION ENGINES
 1990-1993 BY GEOGRAPHIC DIVISION

Division	Year	Compos. & Averages			Coal (a)			Oil (b)			Gas (c)		
		Cost per Million Btu Con- sumed	Cost of Fuel per Net KWh	Btu per Net KWh	Cost per Million Btu Con- sumed	Cost per Ton	Btu per Pound	Cost per Million Btu Con- sumed	Cost per Bbl	Btu per Gallon	Cost per Million Btu Con- sumed	Cost per MCF	Btu per Ccf
United States	1990	174.1	1.80	10,366	151.2	\$31.73	10,492	332.1	\$20.85	149,453	234.2	240.53	1,027
	1991	169.6	1.75	10,322	151.5	31.45	10,379	293.8	18.50	149,936	221.1	225.05	1,022
	1992	166.6	1.72	10,340	148.2	30.86	10,414	278.3	17.53	149,962	235.8	241.06	1,022
	1993	166.6	1.72	10,351	144.8	30.03	10,370	272.5	17.17	150,015	260.4	266.10	1,022
New England	1990	250.6	2.54	10,150	184.3	48.17	13,068	290.2	18.36	150,618	247.0	253.35	1,026
	1991	229.2	2.27	9,910	182.9	48.07	13,138	261.7	16.56	150,685	215.6	220.78	1,024
	1992	221.9	2.25	10,142	177.6	46.55	13,103	244.9	15.53	151,019	206.1	213.89	1,020
	1993	222.9	2.35	10,583	169.0	43.87	12,974	259.8	16.49	151,156	259.2	270.31	1,043
Middle Atlantic	1990	216.2	2.22	10,262	161.4	40.22	12,457	359.8	22.32	147,719	269.5	277.89	1,031
	1991	207.7	2.14	10,319	167.1	41.85	12,520	319.0	20.14	150,360	261.1	267.23	1,023
	1992	195.2	2.00	10,225	160.8	40.34	12,541	308.4	19.51	150,617	274.7	281.79	1,026
	1993	193.9	2.00	10,310	157.4	39.35	12,499	316.2	19.86	149,514	290.4	298.75	1,029
East North Central	1990	160.3	1.65	10,275	158.7	34.61	10,905	377.3	23.15	146,066	225.0	120.28	535
	1991	160.7	1.65	10,242	158.7	34.68	10,928	341.9	21.20	147,624	229.9	161.41	702
	1992	155.2	1.59	10,257	153.3	33.46	10,913	324.9	19.90	146,440	233.2	169.09	725
	1993	154.4	1.59	10,316	152.1	32.93	10,825	327.1	20.03	145,773	266.1	208.56	784
West North Central	1990	119.2	1.31	11,002	117.2	20.57	8,774	427.3	25.11	139,890	196.8	195.72	995
	1991	118.4	1.29	10,893	116.0	20.02	8,633	427.2	25.14	140,085	180.3	178.51	990
	1992	118.7	1.31	11,020	114.6	19.96	8,710	381.1	22.17	138,492	201.0	200.80	999
	1993	111.9	1.22	10,893	108.8	18.37	8,444	411.2	24.21	140,174	246.5	244.27	991
South Atlantic	1990	193.3	1.92	9,933	177.2	43.68	12,327	308.5	19.43	149,963	253.5	257.60	1,016
	1991	188.5	1.88	9,952	176.7	43.67	12,359	264.3	16.68	150,314	214.7	216.60	1,018
	1992	184.8	1.83	9,910	174.4	43.17	12,376	249.0	15.78	150,036	233.3	236.48	1,014
	1993	180.0	1.82	10,131	166.8	41.34	12,393	241.2	15.27	150,752	247.9	251.62	1,015
East South Central	1990	152.5	1.54	10,112	150.6	35.96	11,937	322.4	20.02	147,833	181.4	186.99	1,031
	1991	148.2	1.52	10,236	147.3	35.29	11,977	338.8	21.10	148,287	160.7	164.35	1,022
	1992	142.9	1.48	10,331	141.3	33.89	11,992	399.7	24.76	147,498	186.9	191.03	1,022
	1993	147.6	1.48	10,008	145.0	34.87	12,023	203.0	12.98	152,290	246.7	251.67	1,020
West South Central	1990	179.2	1.91	10,653	150.3	24.01	7,986	481.1	28.96	143,304	213.9	221.91	1,038
	1991	174.8	1.93	10,483	153.1	23.35	7,626	511.7	30.56	142,188	201.9	208.49	1,037
	1992	182.6	1.93	10,543	152.7	23.30	7,628	557.6	33.10	141,333	227.1	228.67	1,030
	1993	190.7	2.00	10,509	145.0	22.53	7,768	391.9	24.43	148,381	250.0	256.92	1,028
Mountain	1990	118.6	1.27	10,695	113.6	22.22	9,774	417.6	25.00	142,552	210.6	216.89	1,030
	1991	122.0	1.29	10,556	117.6	22.84	9,710	478.5	28.47	141,682	191.8	193.76	1,010
	1992	122.1	1.29	10,554	117.1	22.83	9,746	442.4	26.45	142,335	201.5	203.82	1,027
	1993	122.3	1.28	10,471	117.0	22.79	9,740	455.0	27.35	143,118	226.9	231.97	1,023
Pacific	1990	274.4	2.89	10,521	148.1	24.00	8,104	348.6	21.44	146,467	287.7	298.31	1,037
	1991	255.0	2.67	10,465	134.2	21.31	7,940	365.3	22.31	145,396	282.5	289.64	1,025
	1992	246.7	2.56	10,359	132.1	22.32	8,445	498.2	29.75	142,190	266.4	273.91	1,037
	1993	265.6	2.74	10,319	130.6	21.93	8,398	338.7	20.64	145,070	294.6	303.70	1,041
Alaska	1990	148.1	1.84	12,403	184.4	29.06	7,881	639.0	37.06	138,091	112.2	113.01	1,003
	1991	158.1	1.86	11,788	193.7	30.30	7,821	445.2	25.53	136,513	118.0	118.34	1,003
	1992	160.9	1.91	11,891	199.1	31.14	7,823	446.7	26.07	138,961	115.0	115.32	1,003
	1993	211.3	2.43	11,512	210.7	33.10	7,853	407.0	23.42	138,732	184.7	183.37	999
Hawaii	1990	316.7	4.30	11,424				376.7	24.83	146,912			
	1991	313.4	4.04	10,780				374.4	23.16	147,241			
	1992	317.8	3.46	10,887				317.8	19.72	147,272			
	1993	340.9	3.70	10,856				340.9	21.11	147,479			

(a) Coal includes bituminous and anthracite coal and relatively small amounts of lignite.

(b) Oil includes fuel oil, crude oil, and small amounts of kerosene and petroleum coke.

(c) Gas includes natural and manufactured gas and waste gas.

SAVINGS TO BLACK HILLS EXISTING CUSTOMERS

(in thousands)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
REVENUE FROM SHERIDAN SALE	\$8,164	\$8,445	\$8,844	\$9,206	\$9,597	\$9,920	\$10,219	\$10,503	\$10,825	\$11,241
INCREASE IN FUEL EXPENSE	(1,377)	(1,247)	(1,248)	(905)	(1,008)	(762)	(687)	(605)	(529)	(361)
INCREASE IN PURCHASED POWER COSTS	(3,322)	(4,348)	(4,751)	(6,260)	(1,730)	(5,211)	(5,054)	(5,359)	(4,810)	(9,508)
COMBUSTION TURBINE CAPACITY PAYMENT TO MDU					(2,401)	(2,405)	(2,408)	(2,411)	(2,415)	(2,419)
INCREASE IN DEPRECIATION EXPENSE RELATED TO BLACK HILLS INVESTMENT IN COMBUSTION TURBINES					(768)	140	140	140	140	1,182
INCREASE IN O & M EXPENSE RELATED TO BLACK HILLS INVESTMENT IN COMBUSTION TURBINES					(271)	(120)	(123)	(126)	(128)	43
INCREASE IN PROPERTY TAXES RELATED TO BLACK HILLS INVESTMENT IN COMBUSTION TURBINES					(426)	110	115	122	128	847
INCREASE IN INTEREST EXPENSE RELATED TO BLACK HILLS INVESTMENT IN COMBUSTION TURBINES					(697)	162	156	150	144	1,084
REVENUE REQUIREMENT FOR RETURN RELATED TO BLACK HILLS INVESTMENT IN COMBUSTION TURBINES					(1,222)	285	274	263	252	1,901
	\$3,465	\$2,850	\$2,845	\$2,041	\$1,074	\$2,119	\$2,632	\$2,677	\$3,607	\$4,010

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DIRECT TESTIMONY OF GARY R. FISH
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION
BLACK HILLS POWER AND LIGHT COMPANY
APPLICATION FOR AN INCREASE IN ELECTRIC RATES
DOCUMENT NO. EL95-003

1 Q. Please state your name, position with the Company,
2 and business address.

3 A. My name is Gary R. Fish. I am the Controller for
4 Black Hills Corporation doing business as
5 Black Hills Power and Light Company. My business
6 address is 625 9th Street, Rapid City,
7 South Dakota.

8 Q. Please describe your professional background and
9 qualifications.

10 A. I earned a Bachelor of Science Degree in Business
11 Administration with a major in Accounting from the
12 University of South Dakota in 1981. I am a
13 Certified Public Accountant and a Certified
14 Internal Auditor. I am a member of the American
15 Institute of Certified Accountants, Institute of
16 Management Accountants and the South Dakota
17 Society of Certified Public Accountants. I have
18 been the Controller for the Company since 1988.
19 Before being named Controller, I was the Manager,
20 Auditing for approximately two years. Before
21 coming to work for the Company, I was employed
22 with McGladrey & Pullen, Certified Public
23 Accountants, a multi-regional accounting firm from

1 1981 to 1986.

2 Q. What are your current responsibilities?

3 A. I am the principle accounting officer for
4 Black Hills Corporation. I am responsible for the
5 consistent application of generally accepted
6 accounting principles and regulatory accounting
7 principles and related financial reporting for the
8 Company.

9 Q. Are you familiar with the books and records of the
10 Company and the manner in which they are kept?

11 A. Yes, I am. The financial statements and
12 records have been prepared on the accrual
13 basis in conformity with generally accepted
14 accounting principles and in accordance with
15 accounting requirements of the Federal Energy
16 Regulatory Commission as set forth in its
17 applicable Uniform System of Accounts.

18 Q. Have you prepared or supervised the preparation of
19 a series of schedules, statements and workpapers
20 which were filed as a part of this Application
21 which are filed in Applicant's Volume 1?

22 A. Yes. Applicant's Statements and Schedules A
23 through R and related workpapers.

24 Q. Please refer to the exhibits and explain them to
25 the Commission.

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1 A. We have chosen as our historical test period for
2 this Application, the twelve-month period ended
3 September 30, 1994. These exhibits reflect the
4 total utility company's operations.

5 All Rate Base and Rate of Return Calculations are
6 based on the average original cost plant balances
7 adjusted for known and measurable changes.

8 Black Hills Power and Light Company has prepared
9 all statements and schedules in accordance with
10 the classifications as set forth in the Federal
11 Energy Regulatory Commission's Uniform System of
12 Accounts for electric utilities as adopted and
13 amended and in accordance with rate filing rules
14 currently in effect.

15 Q. Would you explain these Statements and Schedules A
16 through R.

17 A. Yes. Statement A is the comparative balance sheet
18 as of September 30, 1994 and 1993 which
19 corresponds to the beginning and ending of the
20 test period. The most recently available balance
21 sheet as of December 31, 1994, is also included on
22 this schedule. The footnotes included in
23 Schedule A represent the footnotes included in the

1 Company's PERC Form 1 for the year ended
2 December 31, 1993. Substantially all of the
3 accounting policies described in the footnotes are
4 applicable for the test period.

5 Statement B includes the income statement for the
6 test period (year ended September 30, 1994) and
7 the most recently available income statement (year
8 ended December 31, 1994).

9 Statement C is the retained earnings statement for
10 the test period and most recently available
11 retained earnings statement for the twelve month
12 period ended December 31, 1994.

13 Statement D, Page 1, is a statement disclosing in
14 summary form the beginning balance, additions,
15 retirements, transfers/adjustments, and ending
16 balance for the Company's electric plant accounts.
17 Electric plant accounts included in this schedule
18 are Account 101, 106, 107, and 114.

19 Statement D, Page 2, discloses the calculation of
20 the average adjusted plant in service for the test
21 period. The column entitled "Subsequent and

1 Expected Closures & Retirements" reflects the
2 known and expected subsequent property additions
3 or closures from Account 107 - Construction
4 Work-In-Progress to Account 106 - Completed
5 Construction - Not Classified since the end of the
6 test period or September 30, 1994. The workpapers
7 to support this adjustment are labeled Exhibit A
8 in the workpaper section of Volume 1. The column
9 entitled "Annualized Account 106" calculates the
10 annualized impact of all non-revenue producing
11 property additions during the test year. This
12 adjustment calculates the increase in the average
13 plant in service balance if all such additions or
14 closures to Account 106 had occurred at the
15 beginning of the year. The Company has defined
16 non-revenue producing property as capital
17 additions that are not directly related to
18 servicing a new customer or group of new
19 customers. The workpapers to support this
20 adjustment are labeled Exhibit B in the workpaper
21 section of Volume 1. The column entitled
22 "Neil Simpson II" represents the capitalized cost
23 of constructing the Company's new coal fired plant
24 near Gillette, Wyoming. Mr. Ohlmacher will
25 provide additional testimony on the construction

1 cost of Neil Simpson II.

2 Schedule D-1 is a schedule of the detailed plant
3 accounts in columnar form similar to Statement D
4 for each of the plant accounts prescribed by the
5 FERC's Uniform System of Accounts for Public
6 Utilities with subtotals by functional
7 classification for the test period.

8 Schedule D-2, Pages 1 through 4, discloses the
9 major plant additions and retirements to
10 Account 101 - Electric Plant in Service for the
11 test period including brief descriptions thereof,
12 approximate dates of commercial operation or
13 retirement from service, and cost. To eliminate
14 unnecessary detailed information, the minor
15 additions and retirements to Account 101 have been
16 grouped together as other additions or
17 retirements. Pages 5 and 6 of Schedule D-2
18 disclose the major projects recorded in
19 Account 106 - Completed Construction - Not
20 Classified as of September 30, 1994, that are yet
21 to be classified to Account 101.

22 Schedule D-3, Pages 1 through 4 is the work paper

1 disclosing the plant accounts on a monthly and
2 average basis for the test period. This schedule
3 calculates the average of the 13 monthly book
4 balances during the test period for each detailed
5 plant account.

6 Schedule D-4, Pages 1 through 20, discloses the
7 major individual additions and retirements for the
8 last five calendar years (1993, 1992, 1991, 1990
9 and 1989).

10 Schedule D-5 is a summary of methods and
11 procedures followed by the Company in capitalizing
12 interest and other overheads during construction.

13 Schedule D-6 discloses the changes in intangible
14 plant for the last five years. The significant
15 portion of this asset is the Wyodak Plant
16 acquisition adjustment. Black Hills Corporation
17 received Commission approval for the inclusion in
18 rates of an acquisition adjustment of \$4,870,308
19 related to the buyout of the Wyodak Power Plant
20 Lease in Docket No. EL90-25.

21 Schedule D-7 sets forth that the Company does not
22 have any plant that is recorded on the Company's
23 books which is not used and useful in rendering
24 service.

1 Schedule D-8 describes the continuing property
2 records maintained by the Company and the methods
3 and procedures used to record retirements.

4 Statement E, Page 1, discloses the month-end
5 accumulated provision for depreciation balances by
6 functional classification for 13 months as of the
7 beginning of the test period and as of the end of
8 the test period and calculates a 13 month average.

9 Statement E, Page 2, discloses the month-end
10 accumulated provision for amortization for
11 13 months as of the beginning of the test period
12 and as of the end of the test period and
13 calculates a 13 month average.

14 Schedule E-1 discloses the annual summary of
15 changes to accumulated depreciation for each
16 functional classification set forth in
17 Statement E, Page 1.

18 Schedule E-2 includes a description of the methods
19 and procedures followed in depreciating or
20 amortizing plant.

21 Schedule E-3 is a statement of the method used in

1 making the allocation of depreciation expense to
2 the various functional groups of plant.

3 Statement F discloses the computation of working
4 capital claimed as part of the Company's rate
5 base, including the expected increase in materials
6 and supplies associated with the Neil Simpson II
7 plant. Additional testimony related to the
8 materials and supplies associated with the
9 Neil Simpson II plant will be provided by
10 Mr. Ohlmacher.

11 Schedule F-1 discloses the monthly balances for
12 fuel stocks, materials and supplies, and prepaid
13 expenses and calculates a 13 month average.

14 Schedule F-2 discloses the monthly balances of
15 materials and supplies for two years preceding the
16 test period.

17 Schedule F-3 is a supporting schedule which
18 computes the cash working capital included in the
19 Company's rate base. Additional testimony related
20 to the calculation of the Company's cash working
21 capital has been provided by Mr. White.

1 Schedule F-4 discloses the basis the Company used
2 in determining the increase in material and
3 supplies associated with the construction of
4 Neil Simpson II.

5 Statement G, Page 1, discloses the cost of
6 long-term debt and common equity and the resulting
7 overall rate of return claimed.

8 Statement G, Page 2, calculates the weighted
9 average cost of long-term debt.

10 Statement G, Page 3, discloses that the Company
11 did not have any preferred stock outstanding
12 during the test period.

13 Statement G, Page 4, discloses the sales of common
14 stock for the period from January 1990 to
15 December 31, 1994.

16 Schedule G-1 discloses the stock dividends, stock
17 splits, and changes in par or stated value from
18 January 1, 1990, to December 31, 1994.

19 Schedule G-2 discloses information on the
20 Company's outstanding common stock for the years

1 ended December 31, 1989, 1990, and 1991, 1992,
2 1993 and 1994. The calculation of Black Hills
3 Corporation's dividends as a percent of earnings
4 includes the earnings of non-utility operations.
5 Page 2 of Schedule G-2 discloses common stock
6 information by month for the test period.

7 Schedule G-3, Page 1 discloses the bonds refunded
8 during the 18 months prior to filing.

9 Schedule G-3, Page 2 discloses the sinking fund
10 requirements for its other bonds for 1993 and
11 1994.

12 Schedule G-4 discloses the earnings per share of
13 common stock which the claimed rate of return
14 would yield.

15 Schedule G-5, Page 1 discloses the forecasted cost
16 of capital used to calculate the Company's revenue
17 requirement.

18 Schedule G-5, Page 2 calculates the Company's
19 forecasted weighted average cost of long-term debt
20 of 8.41%.

1 Schedule G-5. Page 3 supports the Company's
2 forecasted common equity balances as of
3 November 15, 1995.

4 Statement H. Pages 1 to 5, discloses the Company's
5 electric operation and maintenance expenses per
6 books and related adjustments according to each
7 account of the FERC's Uniform System of Account.
8 Adjustments to the Operations and Maintenance
9 expense account are explained on Statement H,
10 Page 5. Page 5 of Statement H discloses the basis
11 for such adjustments and refers to Mr. Ohlmacher
12 and Mr. White's testimony for additional
13 information on such adjustments.

14 Schedule H-1 discloses the distribution of payroll
15 expense to the applicable functional
16 classifications. Included on this schedule is the
17 allocation of the past and future wage increase
18 adjustment reflected on Statement H.

19 Schedule H-2 discloses the cost of purchased power
20 for the test period.

21 Schedule H-3, Page 1 discloses the 12 months of
22 expenses for advertising for Account 909 and 913.

1 Schedule H-3, Pages 3 to 14 are detailed
2 workpapers to support such expenses.

3 Schedule H-3, Page 2 discloses detailed
4 information regarding the expenses recorded in
5 Account 926, 928 and 930.

6 Schedule H-4 discloses the expenses allocated from
7 Black Hills Corporation to its subsidiary's
8 operations during the test period. Expenses
9 directly related to subsidiary operations are
10 charged directly to that subsidiary including
11 internal labor. Expenses that benefit all of
12 companies within the consolidated group and are
13 not conducive to charging directly to the
14 subsidiary are allocated based on the ratio of
15 operating expenses per individual company to
16 consolidated operating expenses. The Board of
17 Directors of Black Hills Corporation approved this
18 methodology.

19 Statement I, Page 1, details the Operating Revenue
20 for the test period. The proforma adjustments
21 that were necessary included:

- 22 1) A reduction of \$141,300 for non-firm sales
23 revenue for sales during to the test year.

1 2) An additional \$54,800 of South Dakota revenue
2 related to an increase to miscellaneous
3 customer charges.

4 Mr. White has provided additional testimony
5 on these adjustments.

6 Statement I, Page 2 calculates the total
7 annualized revenue for the Company's South Dakota
8 jurisdiction.

9 Statement I-1, Pages 1 through 8, provides the
10 bill frequency data by class of customer and
11 related rate design information.

12 Schedule I-2, Page 1, discloses the monthly
13 revenue by customer classification.

14 Schedule I-2, Page 2, discloses the monthly energy
15 sales by month.

16 Statement J discloses the depreciation expense for
17 the test period by functional classification
18 including the claimed adjustments and total
19 adjusted depreciation expense claimed.

20 Schedule J-1 discloses the amortization expense

1 included in the test period related to the
2 acquisition adjustment recorded as a result of the
3 purchase of generating and transmission assets
4 that were formally leased.

5 Statement K, Page 1, calculates the federal income
6 tax expense based on the annualized adjustments
7 and claimed rate of return applied to the overall
8 utility rate base. The proforma adjustment to
9 accelerated depreciation represents the impact of
10 putting Neil Simpson Unit #2 into service in
11 November, 1995.

12 Statement K, Page 2, calculates the amount of
13 interest expense related to the annualized
14 adjustments to the Company's rate base.

15 Statement K, Page 3, describes proforma
16 adjustments necessary to fairly reflect income tax
17 expense for the test period.

18 Schedule K-1 is a reconciliation of book net
19 income with taxable net income as reported to the
20 Federal Internal Revenue Service for 1990, 1991,
21 1992, and 1993.

1 Schedule K-2 discloses the differences between
2 book and tax depreciation for the most recent tax
3 year ended December 31, 1993.

4 Schedule K-3 discloses the net taxable income for
5 each company included in Black Hills Corporation's
6 1993 consolidated income tax return.

7 Schedule K-4 states the basis for the calculation
8 of federal income tax as shown on Statement K.

9 Schedule K-5 discloses the amount of state income
10 taxes for the test period.

11 Statement L discloses taxes other than income
12 taxes for the test period including proforma
13 adjustments necessary to properly reflect such
14 expenses for the test period.

15 Schedule L-1 is the supporting work paper for
16 adjustments to taxes other than income taxes and
17 payroll taxes.

18 Statement M discloses the adjusted overall cost of
19 service for the test period including the proforma
20 adjustments. Exhibit E in the workpaper section

013227.469
1 details each proforma adjustment and supports the
2 proforma adjustment totals on Statement M.

3 Schedule M-1 calculates an unadjusted cost of
4 service per the books.

5 Schedule M-2 discloses other rate base deductions
6 that are included on Statement M and M-1. Included
7 in the proforma adjustments on Statement M is the
8 estimated average deferred income tax liability
9 balance related to accelerated tax depreciation
10 associated with Neil Simpson Unit #2. Exhibit D
11 in the workpaper section supports the calculation
12 of this amount.

13 Statement N represents the per books cost of
14 service analysis. Mr. White has provided
15 additional testimony on this statement.

16 Statement O presents the individual class
17 rate of returns under the proposed rates.

18 Statement P, Page 1 discloses the calculation of
19 the base unit cost of fuel and purchased power per
20 books.

1 Statement P, Page 2 discloses the calculation of
2 the base unit cost of fuel and purchased power for
3 the adjusted test year. Mr. White discusses in
4 detail the Fuel and Purchased Power Adjustment
5 tariff.

6 Statement Q is a general description of utility
7 operations.

8 Statement R has been prepared from the financial
9 records of Wyodak Resources Development Corp.
10 which records were prepared in accordance with
11 generally accepted accounting principles.
12 Additional testimony related to the Statement R
13 calculation has been provided by Ms. Basham.

14 Q: Will the acceleration of the in-service date
15 of the Neil Simpson Unit #2 plant from
16 November 15, 1995 to September 1, 1995 change
17 the overall revenue requirement as reflected
18 on Schedule M?

19 A: The acceleration of the in-service date of
20 Neil Simpson Unit #2 will not significantly
21 change the revenue requirement of the
22 Company. Changing the in-service date of the
23 plant would increase the tax depreciation

1 expense of the Company in 1995. Increased
2 tax depreciation in 1995, would increase the
3 deferred tax liability balance, thus reducing
4 the Company's average rate base by
5 approximately \$180,000. The reduced revenue
6 requirement associated with the reduced rate
7 base would be approximately \$28,000.

8 Q. Does this conclude your testimony?

9 A. Yes.

ONPL EXHIBIT
GRF-1

**The Statments and Schedules which Mr. Fish testifies to
can be found in Volume 1, Section 4 of this Applcation.**

DIRECT TESTIMONY OF DANIEL P. LANDGUTH
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION
BLACK HILLS POWER AND LIGHT COMPANY
APPLICATION FOR AN INCREASE IN ELECTRIC RATES
DOCKET NO. EL95-003

1 Q: Please state your name and business address.

2 A: Daniel P. Landguth, 625 Ninth Street, Rapid City,
3 South Dakota.

4 Q: What is your position with Black Hills Corporation
5 and its subsidiaries?

6 A: I am the Chief Executive Officer, President and
7 Chairman of the Board of Black Hills Corporation,
8 Wyodak Resources Development Corp. (Black Hills'
9 wholly-owned coal subsidiary), Western Production
10 Company (a wholly-owned subsidiary of Wyodak
11 Resources engaged as an oil and gas exploration
12 and development company) and WYGEN, Inc. (a
13 subsidiary of Wyodak Resources that was recently
14 organized to engage in the independent power
15 producer business).

16 Q: Please briefly tell the Commission your
17 educational background and the various career
18 positions you have held.

19 A: I am a graduate of the South Dakota School of
20 Mines and Technology in electrical engineering.
21 After graduation I spent approximately two years
22 with Pacific Gas and Electric Company in San
23 Francisco, California as a commercial

1 representative. I started my career with Black
2 Hills approximately 26 years ago and have had
3 numerous positions including the jobs of sales
4 engineer, Manager Power Use, Manager Rates and
5 Regulation, Assistant Power Plant Superintendent,
6 Vice President Administration, Senior Vice
7 President and Chief Operating Officer and
8 President of the utility.

9 Q: What is the purpose of your testimony?

10 A: The purpose of my testimony is as follows:

- 11 1. Inform you of Black Hills' sale of power to
12 Montana-Dakota Utilities Co. and the effect
13 on the rates of other customers.
- 14 2. Inform you of Black Hills' plans to engage in
15 the independent power producer business
16 through WYGEN, Inc., a subsidiary of Wyodak
17 Resources and the possible benefits to our
18 customers.

19 Q: Are you familiar with Black Hills' sale of power
20 to Montana-Dakota Utilities Co.?

21 A: Yes. I helped negotiate the contract. A copy of
22 the agreement with MDU is submitted as Black Hills
23 Exhibit DPL-1.

24 Q: How did that sale come about?

0132-27-473

1 A: In February of 1994, MDU sent out a widely
2 circulated request for proposals to serve
3 wholesale power for its Sheridan, Wyoming service
4 territory commencing January 1, 1997. Black Hills
5 submitted a proposal and made the short list.
6 Negotiations followed, and we entered into the
7 contract.

8 Q: Is the contract now final?

9 A: It is subject to approval or acceptance for filing
10 by the Federal Energy Regulatory Commission. We
11 filed the contract with the FERC on January 17,
12 1995. FERC action on the filing is pending.

13 Q: Had Black Hills planned to serve the Sheridan load
14 prior to the commencement of construction of
15 NS #2?

16 A: No. We were not aware of MDU's power needs or
17 their plans for the future until receiving the
18 solicitation in 1994.

19 Q: Was serving the MDU load a part of your integrated
20 resource plan?

21 A: No.

22 Q: Why did Black Hills want the MDU sale?

23 A: Firstly, we bid the Sheridan load because when a
24 utility builds a new base load resource, a surplus
25 of energy results. As the base loads grow, this

1 energy will be utilized, along with new peaking
2 resources until the next base load resource is
3 required. However, if the utility can find an
4 opportunity to make a sale commencing shortly
5 after the commercial date of a new base load
6 resource, excess energy can be utilized along with
7 some peaking resources. This opportunity allows a
8 more efficient utilization of resources and will
9 serve to lower the rates of your regular customers
10 to whom you have a long-term commitment. Unlike
11 our permanent commitment to serve our franchised
12 retail customers, our commitment to MDU terminates
13 in ten years. The MDU contract was almost a
14 perfect fit with Black Hills' resource planning.
15 It would have been perfect if it would have
16 commenced one year earlier.

17 Secondly, the MDU contract allows Black Hills
18 to construct a larger, more efficient combustion
19 turbine when required. MDU will pay for half of
20 that turbine. This is an example of utilities
21 working together through alliances to cut costs
22 for both parties.

23 Thirdly, Black Hills is looking for sales
24 beyond its service territory because we believe
25 that Black Hills will be able to keep its rates to

1 its regular customers lower over the long term if
2 we can seize opportunities to enlarge our electric
3 business. Further sales and joint ventures with
4 others not only increase shareholder value but
5 also allow us more opportunities to better market
6 our present resources, become involved in large,
7 more efficient projects, and in the end reduce the
8 cost of power for our service territory.

9 Fourthly, Black Hills serves some large
10 customers, such as Homestake Mining, State Cement
11 Plant, Merillat Industries and Pope & Talbott
12 Lumber. While not serving Ellsworth Air Force
13 Base directly, Black Hills' sales are
14 significantly affected by Ellsworth's presence.
15 Any one single event that would adversely affect
16 any of these institutions would have a significant
17 adverse effect on Black Hills' sales. The sale to
18 MDU is to some degree a hedge to a loss of sales
19 arising from such event. The MDU sale would in
20 effect replace any of these losses if it occurs.

21 Q: What are the benefits to your regular customers
22 arising from the MDU sale?

23 A: Roxann Basham will analyze this. The estimate is
24 that the MDU sale will result in \$27,320,000
25 savings to our customers over the ten-year term of

1 the contract. The present value of the savings is
2 estimated to be \$16,600,000 discounted at 10
3 percent.

4 Q: How will these benefits be reflected in the South
5 Dakota rates?

6 A: Everett Hoyt, the President and Chief Operating
7 Officer of Black Hills Power and Light Company,
8 will testify to the Company's offer to settle this
9 case. The rate increase we request to go into
10 effect when NS #2 comes on line this fall will
11 reflect the savings from the MDU sale, but Black
12 Hills will not realize the savings until the MDU
13 service commences in 1997.

14 Q: What will be the nature of the wholesale market
15 going forward?

16 A: Because of new federal laws mandating open
17 transmission access for wholesale electric power,
18 the wholesale market is highly competitive.
19 Contracts are based on the market value of
20 electricity, not cost of service as we are
21 applying in this case.

22 Q: What corporate structure will Black Hills use in
23 the wholesale market?

24 A: Black Hills Corporation (BHPL) as a regulated
25 operating utility will continue to market sales of

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1 any surplus energy as it did in the MDU sale.
2 However, as Black Hills sees opportunity to expand
3 into the wholesale market business through newly
4 acquired resources, it will do so through an
5 exempt wholesale generator as defined by the
6 Energy Policy Act of 1992. Wyodak Resources has
7 formed a new Wyoming corporation named WYGEN,
8 Inc., whose sole purpose is to engage in the
9 wholesale electric business.

10 Q: What is an exempt wholesale generator?

11 A: This is a company that operates exclusively in the
12 wholesale electric business and files as an EWG
13 with the FERC. Black Hills can engage in the
14 wholesale electric business through an EWG without
15 becoming a holding company under the Public
16 Utility Holding Company Act.

17 Q: Is the EWG regulated?

18 A: Yes. The EWG must file all electric sale
19 contracts with the FERC for approval or acceptance
20 as a rate schedule. However, FERC will allow the
21 contract to go into effect on market based rates
22 if the EWG can prove that the contract was
23 competitively bid and the EWG or an affiliate of
24 the EWG did not have market power over the buyer.
25 In that event, the EWG does not have to justify

1 the rates on a cost-of-service basis. In other
2 words, the EWG is allowed to earn whatever the
3 market will bear. On the other hand, the EWG
4 bears a high degree of risk, just like any
5 business. If the contract rates won't pay the
6 EWG's cost of fulfilling the contract, the EWG has
7 no regulator to turn to for an increase in rates.
8 The EWG also, unlike utilities, has no duty to
9 serve a territory. It can choose its market and
10 compete where it decides to do so.

11 Q: Will Black Hills Corporation invest in the EWG or
12 guarantee debt? Please explain.

13 A: Our plan is that all investments and guarantees of
14 debt of WYGEN, if required, will come from Wyodak
15 Resources, just as Wyodak invests in oil and gas
16 production. It is not our intent that Black Hills
17 Corporation will make any investment in WYGEN or
18 guarantee debt.

19 Q: Will Black Hills' retail customers take on any
20 risk of rate increases because of the activities
21 of its affiliates engaging in the wholesale
22 electric power market?

23 A: No. Neither WYGEN's assets nor its operating
24 costs will be a part of Black Hills' rate base and
25 operating costs. If WYGEN incurs losses, those

1 losses will not be passed on to Black Hills'
2 retail customers.

3 Q: Will Black Hills' retail customers obtain benefits
4 from WYGEN building plants? Please explain.

5 A: Very possibly, yes. If WYGEN is able to develop a
6 project such as a plant next to NS #2, certain
7 efficiencies would result from the use of common
8 facilities with the result that Black Hills and
9 its customers would save costs. Secondly, if
10 WYGEN can finance the construction of facilities
11 at or near the Wyodak site through sales to
12 others, opportunities could arise for WYGEN to
13 sell lower cost power to Black Hills, whose
14 transmission system is strategically located to
15 take power from that facility. We believe that a
16 utility with an affiliate in the wholesale power
17 business will present many opportunities for
18 transactions benefiting both shareholders and
19 retail customers. Thirdly, we believe that
20 entering the competitive market presents an
21 excellent discipline for Black Hills that will be
22 reflected throughout its organization.

23 Q: What benefits would Black Hills' retail customers
24 receive if WYGEN purchases power for resale?

1 A: Here again, it is possible that if WYGEN were able
2 to purchase power for resale, Black Hills'
3 customers could benefit. If WYGEN is able to
4 create a market for power either from generating
5 facilities it may build or through purchased
6 power, Black Hills will have a subsidiary in the
7 wholesale electric business that is not limited to
8 a restricted franchised service territory. WYGEN
9 is small but is able to form alliances with other
10 utilities or IPPs on projects located anywhere.
11 The success of both Black Hills and its subsidiary
12 is mutually beneficial. A successful WYGEN could
13 develop many opportunities for its parent company
14 in finding lower-cost power.

15 Q: Is an EWG allowed to enter into transactions with
16 an affiliated operating utility?

17 A: Yes, if state regulatory and FERC approvals are
18 obtained. Black Hills and WYGEN would be charged
19 with the burden of proof that proper cost
20 allocations between the two companies are
21 maintained, that Black Hills would be receiving
22 power at or below its market value, and Black
23 Hills has mitigated any market power such as
24 adopting open access transmission tariffs with
25 comparability standards so that no other supplier

1 would have been foreclosed from competing with
2 WYGEN for the sale to Black Hills.

3 Q: Does entering the wholesale electric business
4 posture the Company for retail wheeling and
5 competition at the retail level?

6 A: It certainly does. We have no idea if competition
7 will come to South Dakota in the retail electric
8 market. But if it does, Black Hills will be ready
9 to compete. We are replacing small generators
10 with plants at a more optimum size. We are
11 enlarging our customer base where permitted under
12 current law. We are learning to compete in the
13 open market. When and if retail wheeling comes,
14 Black Hills intends to be in a position to also
15 enlarge its retail base.

EXHIBIT

BHPL
DPL-1

POWER INTEGRATION AGREEMENT

between

Black Hills Corporation,
doing business as Black Hills Power and Light Company

and

Montana-Dakota Utilities Co.,
A Division of MDU Resources Group, Inc.

Dated: September 9, 1994

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POWER INTEGRATION AGREEMENT

This Power Integration Agreement, dated as of September 9, 1994, is entered into by and between BLACK HILLS CORPORATION, a South Dakota corporation, doing business as Black Hills Power and Light Company, and Montana-Dakota Utilities Co., a Division of MDU RESOURCES GROUP, INC., a Delaware corporation.

1. RECITALS AND DEFINITIONS.

1.1 Definitions. The following capitalized words and phrases when used in this Agreement shall have the respective meanings as follows:

"Agreement" is this Power Integration Agreement including all exhibits attached hereto.

"Annual Fixed Costs" of either party are the levelized fixed costs as determined under Exhibit A.

"BHC" is Black Hills Corporation, a South Dakota corporation, doing business as Black Hills Power and Light Company.

"BHC Furnished Capacity" is 60 percent of the peak load of the MDU Sheridan Service Territory during each calendar month of the Service Term.

"Black Hills' System" has the same meaning as set forth in the Pacific Contract and, pursuant to this Agreement, also includes a Black Hills contracted transmission path from Pacific's System to the Pacific/MDU Interconnection.

"Combustion Turbine" is a combustion turbine to be fired either with fuel oil and/or natural gas of an approximate name plate size of 70 MW to be constructed at a time and place as provided at Section 3.1 and the CT Agreement.

"Commercial Date" is the date the Combustion Turbine is in commercial operation under Prudent Utility Practice. The Commercial Date shall be the first day of a calendar month.

01322-2274808

"CT Agreement" is the Construction, Ownership and Operating Agreement between BHC and MDU, a copy of which is attached as Exhibit B.

"CT Term" is a period of time commencing with the Commercial Date and terminating ten years thereafter.

"FERC" is the Federal Energy Regulatory Commission of the United States.

"MDU" is Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., a Delaware corporation.

"MDU Furnished Capacity" is 40 percent of the peak load of the MDU Sheridan Service Territory during each calendar month of the Service Term.

"MDU Sheridan Service Territory" is MDU's existing service territory in the City of Sheridan and Sheridan County, Wyoming as it exists at this time and includes any modifications thereof during the Service Term.

"Notice of Intent to Construct" is the notice to be given under Section 3.1 of this Agreement.

"Pacific" is PacifiCorp, an Oregon corporation.

"Pacific Contract" is the Power Sales Agreement, dated as of the 31st day of December, 1983, entered into by and between Pacific and BHC as may be amended from time to time. The Pacific Contract expires December 31, 2023.

"Pacific/MDU Interconnection" is the interconnection where Pacific delivers electric energy from Pacific's System at 230 kV to MDU's 230/46 kV substation situated in Sheridan County, Wyoming.

"Prudent Utility Practice" at any particular time means either (a) any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry prior thereto or (b) any of the practices, methods or acts, which, in the exercise of reasonable judgment in the light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition. Prudent Utility Practice is not intended to be limited to the optimum practice, method or act, to the exclusion of all others, but rather to be a

spectrum of possible practices, methods or acts. Prudent Utility Practice shall also include those practices, methods and acts that are required by applicable laws and final orders or regulations of regulatory agencies having jurisdiction.

"Remaining CT Term" is that period of time commencing at the end of the Service Term and ending on the last day of the CT Term.

"Service Term" shall commence at 12:00 a.m. on January 1, 1997 and shall terminate at 12:00 midnight on December 31, 2006.

"Term" means the same as defined in the CT Agreement.

Other capitalized terms and phrases used in this Agreement that are not otherwise defined herein but are defined in the CT Agreement shall have the meaning as set forth in the CT Agreement.

1.2 Recitals. During the Service Term, MDU requires a supply of electric capacity and energy to serve the needs of its electric retail customers in its MDU Sheridan Service Territory. BHC will have system energy and capacity available to meet MDU's requirements, but BHC anticipates that Black Hills' System will at some future time require a combustion turbine as an additional peaking resource. MDU desires to participate in the construction of the Combustion Turbine to meet the capacity requirements of its MDU Sheridan Service Territory at such time BHC's integrated resource planning requires the Combustion Turbine in its resources. The parties enter into this Agreement to integrate resources of Black Hills' System and the MDU Sheridan Service Territory by providing from Black Hills' System the capacity and

energy requirements of MDU and, at such time the Combustion Turbine is constructed, by providing capacity for MDU from MDU's interest in the Combustion Turbine.

2. DELIVERY OF CAPACITY AND ENERGY.

2.1 System Capacity and Energy. During the Service Term, BHC shall provide and MDU shall acquire at 230 kV all of the electric capacity and energy requirements to serve MDU's retail customers in the MDU Sheridan Service Territory except where MDU purchases capacity and associated energy in excess of 55 megawatts as provided at Section 4.6.

2.2 Points of Delivery. By scheduling capacity and energy under the Pacific Contract, BHC shall cause Pacific to deliver at no wheeling charge to MDU all of the MDU capacity and energy requirements as set forth in Section 2.1 over Pacific's System to the Black Hills' System at the Pacific/MDU Interconnection.

2.3 Control Area Services. BHC shall be responsible for area control service to the MDU Sheridan Service Territory at no cost to MDU. BHC will provide, at no cost to MDU, telemetry equipment and a communication channel from the Pacific/MDU Interconnection to BHC's system control. All costs incurred by BHC to provide control area services, including, but not limited to, load following, telemetry, regulation, reserves, and control area accounting, shall be paid by BHC.

2.4 Sheridan-Johnson REA. Deliveries of electric power and energy for Sheridan-Johnson Rural Electrification Association ("Sheridan-Johnson") at the Pacific/MDU Interconnection shall not be included in determining deliveries to MDU under Section 4.0, nor shall transformer and distribution line losses incurred between the Sheridan-Johnson meters on MDU's system and the Pacific/MDU Interconnection be included in determining deliveries to MDU.

2.5 Monthly Accounting. MDU shall read meters at the Pacific/MDU Interconnection and provide a printout of all data required by BHC. Meters shall be read and such data shall be supplied to BHC on a timely basis in coordination with the Western Area Power Administration schedule in Wyoming.

3. COMBUSTION TURBINE.

3.1 Time and Place of Construction of Combustion Turbine. At its sole discretion, BHC shall determine the time and the place of the construction of the Combustion Turbine as provided in the CT Agreement; provided, the place of construction shall be within BHC's service territory as it exists on the date of this Agreement, or within a 20-mile radius thereof, or MDU Sheridan Service Territory. At such time BHC has made the decision to accept proposals for the construction of the Combustion Turbine, BHC shall give MDU a written Notice of Intent to Construct disclosing the place of the construction of the Combustion Turbine and the estimated Commercial Date of the

Combustion Turbine. The period of time between the Notice to Construct and the estimated Commercial Date shall be at least 24 months. While BHC anticipates the need for the Combustion Turbine before the end of the Service Term, BHC reserves the right in its sole discretion to determine that the Combustion Turbine is not needed and will not be constructed during the Service Term. BHC further reserves the right to construct combustion turbines at any time at locations other than those locations specified in the first sentence of this Section 3.1; and in that event, none of such turbines shall constitute the Combustion Turbine described in this Agreement.

3.2 Ownership Interest in Combustion Turbine. If the Commercial Date is scheduled during the Service Term, MDU and BHC shall each acquire and own an undivided 50 percent interest in the Combustion Turbine.

3.3 Use of Turbine Output. Operation, control and use of the output of the Combustion Turbine is set forth in the CT Agreement.

4. PRICES AND PAYMENTS.

4.1 Payments for BHC Furnished Capacity. For the BHC
Furnished Capacity MDU shall pay BHC monthly the following rates:

<u>Calendar Year</u>		Capacity Charge (\$KW/Mo)
1997		13.60
1998		13.70
1999		13.80
2000		13.90
2001		14.00
2002		14.10
2003		14.20
2004		14.30
2005		14.40
2006		14.50

4.2 Payments for MDU Furnished Capacity. Prior to the Commercial Date, MDU shall pay BHC monthly the following rates for the MDU Furnished Capacity:

<u>Calendar Year</u>		Capacity Charge (\$KW/Mo)
1997		5.461
1998		5.468
1999		5.477
2000		5.485
2001		5.493
2002		5.502
2003		5.511
2004		5.520
2005		5.529
2006		5.539

After the Commercial Date, MDU Furnished Capacity shall be deemed furnished from MDU's ownership interest in the Combustion Turbine.

4.3 Fixed Cost Payments and Operating Expenses for Combustion Turbine During Service Term. Commencing on the Commercial Date and continuing for the balance of the Service Term, the following payments shall be made each month:

- (a) If the name plate megawatts in the Combustion Turbine owned by MDU are in excess of MDU Furnished Capacity for that month, BHC shall pay MDU one-twelfth of MDU's Annual Fixed Costs per megawatt for such excess megawatts.
- (b) If the name plate megawatts in the Combustion Turbine owned by MDU are less than MDU Furnished Capacity for that month, MDU shall pay to BHC one-twelfth of BHC's Annual Fixed Costs per megawatt for such deficiency.
- (c) BHC shall pay all Operating Expenses and Fuel Costs of the Combustion Turbine during the Service Term.
- (d) The CT Agreement in Section 5 thereof sets forth the responsibility for the Operating Expenses and Fuel Costs following the Service Term.

4.4 Payments for Energy. For all energy delivered to serve the MDU Sheridan Service Territory during the Service Term, MDU shall pay BHC monthly the following megawatthour rates:

<u>Calendar Year</u>	<u>Energy Charge</u> <u>(\$/MWh)</u>
1997	15.66
1998	16.28
1999	16.94
2000	17.61
2001	18.32
2002	19.05
2003	19.81
2004	20.61
2005	21.43
2006	22.29

4.5 New Direct Taxes Adjustment. If BHC experiences increased costs during the Service Term from its generating facilities and power and energy purchase contracts, as such facilities and contracts exist from time to time, due to new

legislation adopted after the date of this Agreement authorizing a governmental authority or authorities to impose a direct tax or taxes (whether a transaction tax, CO₂ or other emissions tax or energy tax) on electric generation fueled by coal, natural gas or other hydrocarbons, the rates under Section 4.4 shall be increased to reflect MDU's pro rata share of those costs. MDU's share of these costs for each billing month shall be the product of (i) BHC's actual costs per megawatthour incurred by BHC as a result of such new taxes from all generated energy from BHC's electric generating plants (including BHC's interest in jointly owned plants) and energy purchased during that billing month, times (ii) the megawatthours of energy delivered by BHC to MDU during that month.

4.6 Adjustment for Additional Capacity. If the MDU Sheridan Service Territory requires capacity in excess of 55 megawatts during the Service Term, the rates in Section 4.1, 4.2 and 4.4 shall be increased to just and reasonable rates for that capacity and associated energy delivered by BHC in excess of 55 megawatts to reflect BHC's costs to serve that additional capacity; provided, MDU at its option may purchase any capacity in excess of the 55 megawatts and associated energy and transmission service from others. If BHC and MDU are unable to agree on the amount of BHC's costs in delivering capacity in excess of 55 megawatts and associated energy, the dispute shall be settled by arbitration under Section 6.

4.7 Payment Schedule During Service Term. Commencing on the fifth working day of February 1997 and continuing on the fifth working day of each month thereafter until and including the fifth working day of January, 2007, BHC shall send to MDU by telephone facsimile and by mailing, first class postage prepaid, an invoice for the capacity and energy delivered to MDU under this Agreement for the previous month. Each invoice shall also set forth any payments due from BHC to MDU pursuant to Section 4.3 as credits to the amount owed by MDU. MDU shall pay each invoice by the 10th working day of the month by wire transfer. Simple interest shall accrue on any amount not paid when due at a rate of 125 percent of Chemical Bank's prime rate in effect during the period of delinquency.

5. GOVERNMENTAL REGULATION.

5.1 Filing. The parties shall submit this Agreement for filing to the FERC. If the FERC issues an order not accepting this Agreement, including the CT Agreement, for filing in its entirety and without change, the parties shall:

(i) exercise best efforts to amend this Agreement to comply with such FERC order, or (ii) terminate this Agreement.

5.2 Fixed Contract. The terms, conditions, and formulae for prices for service specified in this Agreement and the CT Agreement shall remain in effect for the terms therein and shall not be subject to change through application to the FERC pursuant to the provisions of Section 205 of the Federal Power

Act absent the agreement of the parties. The parties covenant that neither shall request relief from any of the provisions of this Agreement pursuant to the provisions of Section 206 of the Federal Power Act absent the agreement of the parties. The foregoing statutory references are intended to include any subsequent similar enactments.

6. ARBITRATION.

If any dispute arises under this Agreement as to any factual matter, the parties shall submit the factual dispute to a board of three arbiters, one to be selected by each party and the parties to agree on the selection of a third arbiter. If the parties are unable to agree on the third arbiter, the parties shall request the senior district judge of the United States District Court of the District of Wyoming to submit a list of five (5) persons. Each party shall alternately strike one name from the list, the first exercise to be determined by lot. The last person remaining on the list shall serve as the third arbiter. Except as otherwise set forth herein, the arbitration shall be held under the rules of the American Arbitration Association. The arbiters shall render their decision in writing not later than thirty days after the matter has been submitted to them, and the decision of a majority of the board of arbiters of the factual dispute shall be binding on the parties. Each party shall bear the expense of preparing and presenting its own case,

and the expense of the arbitrators shall be equitably divided between the Owners by the arbitrators.

7. UNCONTROLLABLE FORCES.

Neither party to this Agreement shall be considered to be in default in performance of any obligation hereunder if failure of performance shall be due to uncontrollable forces. The term "uncontrollable forces" means any cause beyond the control of the party affected, including, but not limited to, failure of facilities, flood, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance, labor disturbance, sabotage, and restraint by court order or public authority, which by exercise of due foresight such party could not reasonably have been expected to avoid, and which by exercise of due diligence it shall be unable to overcome. A party shall not, however, be relieved of liability for failure of performance if such failure be due to causes arising out of its own negligence or to removable or remediable causes which it fails to remove or remedy with reasonable dispatch. Any party rendered unable to fulfill any obligation by reason of uncontrollable forces shall exercise due diligence to remove such inability with all reasonable dispatch. Nothing contained herein, however, shall be construed to require a party to prevent or settle a strike against its will.

8. NOTICES.

Any notice, demand, or request provided for in this Agreement shall be deemed properly served, given, or made if delivered in person or sent by registered or certified mail, postage paid and return receipt requested, to the person so designated as its authorized representative. The titles and addresses of the authorized representatives hereunder are as follows:

For BHC: President
Black Hills Corporation
625 Ninth Street
P. O. Box 1400
Rapid City, South Dakota 57709

For MDU: President
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, ND 58501

By giving written notice to the other party, a party may change the title and address for the purpose of receiving notice hereunder.

9. WAIVER.

Any waiver by a party of its rights with respect to default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not be deemed to be a waiver with respect to any subsequent default or matter. No delay in asserting or enforcing any right hereunder shall be deemed a waiver of such right.

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10. SEVERABLE OBLIGATIONS.

Except where specifically stated in this Agreement to be otherwise, the duties, obligations, and liabilities of the parties are intended to be several and not joint or collective. Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership, or joint venture or to impose a trust or partnership duty, obligation, or liability on or with regard to either party. Each party shall be individually and severally liable for its own obligations under this Agreement.

11. AMENDMENTS.

No amendment of this Agreement shall be effective without written approval of each party.

12. ASSIGNMENT.

This Agreement shall not be assigned to any third party without the written consent of the other, and such consent shall not be withheld unreasonably; provided, this Agreement shall inure to and be binding upon the successors in interest of substantially all of the electric properties of the respective parties and, if just MDU's electric system serving the MDU Sheridan Service Territory is sold or transferred to another entity, or condemned through the exercise of eminent domain, to the successor in interest to MDU's electric system serving the MDU Sheridan Service Territory.

13. CHOICE OF LAW.

The parties in their performance of their obligations hereunder shall conform to all applicable laws, rules and regulations and, to the extent that their operations may be subject to the jurisdiction of state or federal regulatory agencies, subject to the terms of valid applicable orders of any of such agencies. This Agreement shall be subject to and be construed under the laws of the State of Wyoming.

IN WITNESS WHEREOF, the parties have executed this Agreement as of the date set forth in the first paragraph hereof.

BLACK HILLS CORPORATION

By Alfred R. Lindquist
Its Chairman, President & CEO

MONTANA-DAKOTA UTILITIES CO., a
Division of MDU RESOURCES GROUP,
INC.

By Joseph R. Meichel
Its President & CEO

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Exhibit A

ANNUAL FIXED COSTS

Introduction

This Appendix sets forth the elements and techniques to calculate the annual fixed costs of the Combustion Turbine under Section 4.3 for the Service Term and Section 5.2(b) of the CT Agreement for the Remaining CT Term.

The Annual Fixed Cost is the per-MW sum of: (a) initial levelized annual fixed cost, (b) subsequent levelized annual fixed costs (if any), and (c) other fixed annual charges, including but not limited to property taxes, insurance, and taxes other than income tax.

Section A1: Discussion of Methodology

Levelized fixed charges are the basis of annual fixed costs hereunder. While actual capital-related charges associated with an investment may vary considerably from year to year, the levelized fixed charge translates these charges into a level annual amount which remains constant over time. The present values of the two streams (varying versus constant) are equal.

The levelized fixed charge includes three basic components: (a) return on investment, given a specific capital structure and cost of capital; (b) recovery of investment, given the appropriate depreciation period related to the investment; and (c) income tax requirements, given tax law considerations. These components are commonly expressed as: (a) interest expense on

debt and return required by shareholders; (b) book depreciation; and (c) income taxes incorporating the effects of investment tax credits and tax depreciation.

An initial levelized annual charge rate will be applied to the original investment of the Combustion Turbine. The rate will be recalculated effective each January 1 only in the event of a change during the preceding calendar year in any of the following: (a) the common equity or (b) income tax law, but not to be applied retroactively.

Subsequent levelized annual fixed charge rates will be calculated each year to reflect the most current information and will be applied each year to the amount of capital additions, replacements (less credit for net salvage and insurance proceeds, if any) and betterments of the Combustion Turbine completed through the end of the preceding calendar year.

Section A2: Determination of Annual Fixed Costs

Annual Fixed Costs will be determined by (a) adding the amounts calculated under Sections A2.1 through A2.5 and (b) dividing the total by the name plate rating of the Combustion Turbine in MW.

A2.1. The initial levelized annual fixed charge rate determined annually in accordance with Section A3 of this Exhibit, multiplied by the party's original investment to complete the Combustion Turbine.

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A2.2. The sum for such year of each of the subsequent levelized annual fixed charges determined for each year from the Commercial Date to date. Each subsequent annual levelized fixed charge shall be determined by multiplying (a) the subsequent levelized annual fixed charge rate, as calculated in accordance with Section A3, below, by (b) the party's dollar investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments of the Combustion Turbine, completed during the calendar year immediately preceding establishment of such subsequent levelized annual fixed charge.

A2.3. All ad valorem taxes imposed upon the Combustion Turbine.

A2.4. Any tax, assessment, payment in lieu of taxes, or other charge imposed by any governmental body assessed or charged against the parties relating to the Combustion Turbine, excluding ad valorem taxes and state and federal income taxes and taxes covered under Section 4.5 of the Agreement.

A2.5. All insurance premiums incurred related to the Combustion Turbine.

Section A3: Elements of Levelized Annual Fixed Charge Rates

A3.1 Capital Structure: For purposes of calculating initial levelized annual fixed charge rates and subsequent levelized annual fixed charge rates, the capital structure will remain constant for the duration of this Agreement. The capital structure is:

Long-Term Debt	55%
Preferred Stock	5%
Common Stock Equity	<u>40%</u>
Total Capital	100%

A3.2 Cost of Capital:

A3.2.1 Long-Term Debt: Bond interest applicable in the calculation of each initial levelized annual fixed charge rate will be the Utility Long Bond Rate in effect within the 12-month period prior to the Commercial Date. Bond interest applicable in the calculation of each subsequent levelized annual fixed charge rate for future capital additions, replacements, or betterments shall be the Utility Long Bond Rate, in effect during the twelve-month period prior to the date of the completion of construction of the capital additions, replacements or betterments for which the subsequent levelized annual fixed charge rate is calculated. For the purposes herein, the Utility Long Bond Rate is the average interest charge on A-rated first mortgage bonds of a term of 20 to 25 years being issued by electric utilities during the period of time for which the calculation is being determined.

A3.2.2. Preferred Stock. Return on preferred stock applicable in the calculation of each levelized annual fixed charge rate shall be 50 basis points above the Utility Long Bond Rate used to calculate that rate.

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A3.2.3. Common Stock Equity. Return on common stock equity applicable in the calculation of each initial levelized annual fixed charge rate and each subsequent levelized annual fixed charge rate shall be as agreed to by the parties from time to time. In the event the parties are unable to agree to the return on common stock equity, either party may apply to the FERC for resolution of the dispute.

A3.3 Book Depreciation: Book depreciation charges shall be at a straight-line rate based on a twenty-five (25) year life in calculating the initial levelized annual fixed charge rates. Book depreciation charges for subsequent levelized annual fixed charge rates shall be based on the estimated service life.

A3.4. Income Tax Requirements: Income tax requirements applicable in calculating both initial and subsequent levelized annual fixed charge rates shall be based on the following items; provided, subsequent changes in tax laws shall be incorporated in computing levelized annual fixed charge rates for periods following such tax law change:

A3.4.1. The federal corporate income tax rate (currently thirty-five percent (35%)).

A3.4.2. A state corporate income tax rate. Any state corporate income tax rate shall be applied on a composite revenue weighted average in each state in which retail service is provided by the party for which the rate is being determined.

A3.4.3. Use of Modified Accelerated Cost Recovery System (MACRS) method of tax depreciation.

A3.4.4. Investment Tax Credits allowed, if any, in accordance with the provisions of the Internal Revenue Code, as amended, regardless of whether a party is able to use such credits.

A3.4.5. Income taxes shall be computed using the normalization method of accounting.

A3.4.6. The tax basis will be the actual percentage relationship between book basis and tax basis of the Combustion Turbine.

CONSTRUCTION, OWNERSHIP AND OPERATION AGREEMENT

between

Black Hills Corporation

and

Montana-Dakota Utilities Co.,
a Division of MDU Resources, Inc.

Dated: September 9, 1994

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CONSTRUCTION, OWNERSHIP AND OPERATION AGREEMENT

This Construction, Ownership and Operation Agreement, dated as of September 9, 1994, is entered into between BLACK HILLS CORPORATION, a South Dakota corporation, doing business as Black Hills Power and Light Company, and Montana-Dakota Utilities Co., a Division of MDU RESOURCES GROUP, INC., a Delaware corporation.

1. RECITALS AND DEFINITIONS.

1.1 Definitions. The following capitalized words and phrases when used in this Agreement shall have the respective meanings as follows:

"Additions and Replacements" are additions and replacements of portions or all of the Combustion Turbine as the Operator may determine during the Term in the application of Prudent Utility Practice to cause the Combustion Turbine to be operational and in compliance with law. Additions and Replacements are those additions and replacements which would under generally accepted accounting principles be capitalized.

"Agreement" is this Construction, Ownership and Operation Agreement.

"BHC" is Black Hills Corporation, one of the parties to this Agreement.

"Capital Additions" means additions, betterments and replacements to the Combustion Turbine necessary to assure design capability and reliability or that are required by law, or by order or regulation of a governmental agency having jurisdiction.

"Capital Retirements" means those physical elements of the Combustion Turbine removed from service or used with the intent that the item so removed will not be placed back into service.

"Combustion Turbine" is a combustion turbine to be fired either with fuel oil and/or natural gas of an approximate name plate size of 70 megawatts.

"Commercial Date" is the date the Combustion Turbine is in commercial operation under Prudent Utility Practice. The Commercial Date shall be the first day of a calendar month.

"Construction" means all activities necessary for planning, engineering, acquisition and erection of the Combustion Turbine and of Capital Additions and Elective Capital Additions thereto.

"Costs of Construction" are all costs allocable to Construction (excluding costs of fuel and allowance for funds used during construction), after giving appropriate consideration to credits relating to such costs and proceeds from dispositions of surplus property. Without limiting the generality of the foregoing, such costs shall include:

- (a) All costs of preliminary site investigation and development costs, land acquisition, architectural and engineering services, labor, materials, equipment, supplies, operator and other personnel training, testing, permits and licenses, legal services, Capital Additions and Elective Capital Additions;
- (b) Payroll of Operator's employees, including fringe benefits, allocated on an actual time basis including related fringe benefits and payroll taxes;
- (c) Traveling expenses including use of Operator's transportation equipment;
- (d) All costs of insurance obtained pursuant to Section 9 hereof and applicable to Construction;
- (e) All costs relating to injury and damage claims arising out of Construction less proceeds of insurance maintained in accordance with Section 9 hereof or insurance under any contract for Construction entered into pursuant to Section 2 or Section 10 hereof; and
- (f) All federal, state and local taxes and payments in lieu of taxes legally required to be paid in

connection with Construction, except any tax or payment in lieu of taxes assessed or charged directly against any individual Owner unless such tax or payment was assessed or charged to the individual Owner on behalf of the Combustion Turbine.

"CT Term" is a period of time commencing with the Commercial Date and terminating ten years thereafter.

"Elective Capital Additions" means additions, betterments and replacements to the Combustion Turbine that are not Capital Additions.

"Fuel Costs" are the costs of fuel oil or natural gas acquired to fuel the Combustion Turbine.

"MDU" is Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., one of the parties to this Agreement.

"Net Generating Capability" is the total amount of electrical energy which the Combustion Turbine is capable of generating, due allowance being made for legal, regulatory or physical constraints then obtaining, less the amount used in the production thereof, as determined at any time by the Operator.

"Operating Expenses" are all expenses incurred in or relating to the operation and maintenance of the Combustion Turbine, including, but not limited to:

- (a) Payroll of Operator's employees (including fringe benefits), allocated on an actual time basis including related fringe benefits and payroll taxes;
- (b) Materials and supplies, including related purchasing and handling costs, spare parts inventory and costs of acquiring and maintaining fuel oil inventory;
- (c) Traveling expenses, including use of Operator's transportation equipment;
- (d) All costs relating to injury and damage claims arising out of operation and maintenance of the Combustion Turbine less

proceeds of insurance maintained in accordance with Section 9 hereof.

- (e) Auxiliary power costs;
- (f) All federal, state or local taxes and payments in lieu of taxes (legally required to be paid in connection with the operation of the Combustion Turbine) except any tax, or payment in lieu of taxes, assessed or charged directly against an individual Owner unless such tax or payment was assessed or charged to the individual Owner on behalf of the Combustion Turbine; and
- (g) Administrative and general expenses in an amount equal to a percentage of the total expenses detailed in paragraphs (a) through (g), but not including premium cost for insurance procured pursuant to Section 9. The applicable percentage shall be established annually on the basis of the previous year's actual expenses. The percentage shall be a ratio, the numerator of which is the Operator's administrative and general expenses and the denominator of which is the Operator's utility direct expenses to which such administrative and general expense applies.

"Operator" is BHC or MDU if BHC sells its interest in the Combustion Turbine, and MDU exercises the option to become the Operator as provided at Section 3.3.

"Owners" are BHC and MDU.

"Owners Committee" is a committee composed of two persons, one to be designated to serve from time to time by each party to this Agreement.

"Percentage Share" is each party's respective ownership interest in the Combustion Turbine as set forth at Section 2.1.

"Power Agreement" is the Power Integration Agreement, dated as of the same date of this Agreement and entered into between BHC and MDU.

"Prudent Utility Practice" at any particular time means either (a) any of the practices, methods and acts

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engaged in or approved by a significant portion of the electric utility industry prior thereto or (b) any of the practices, methods or acts, which, in the exercise of reasonable judgment in the light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition. Prudent Utility Practice is not intended to be limited to the optimum practice, method or act, to the exclusion of all others, but rather to be a spectrum of possible practices, methods or acts. Prudent Utility Practice shall also include those practices, methods and acts that are required by applicable laws and final orders or regulations of regulatory agencies having jurisdiction.

"Remaining CT Term" is that period of time commencing at the end of the Service Term and ending on the last day of the CT Term.

"Term" commences with the Commercial Date and terminates at a date the Combustion Turbine as originally constructed, reconstructed, or added to is not, or cannot be made, capable of producing electricity consistent with Prudent Utility Practice or the requirements of governmental agencies having jurisdiction, plus any time required for ending the Combustion Turbine pursuant to Section 22; provided, the Term shall end earlier at the close of the sale transaction if BHC purchases MDU's interest in the Combustion Turbine under Section 24 or by agreement of the parties.

If the duration of any term or condition of this Agreement shall be subject to the rule against perpetuities or a similar or related rule, then the effectiveness of such term or condition shall not extend beyond (a) the maximum period of time permitted under such rule or (b) the specific applicable period of time expressed in this Agreement, whichever is shorter. For purposes of applying the rule against perpetuities or a similar or related rule, the measuring lives in being shall be those of the officers and directors of BHC and MDU shown in their respective 1993 annual reports, together with all such listed persons' children and grandchildren living on the date of execution of this Agreement. As used herein, the terms "children" and "grandchildren" shall have their primary generally accepted meaning of descendants, including persons who are legally adopted.

Other capitalized terms and phrases used in this Agreement that are not otherwise defined herein but are defined in the Power Agreement shall have the same meaning as set forth in the Power Agreement.

1.2 Recitals. The Power Agreement provides for BHC supplying electric capacity and energy to MDU for its MDU Sheridan Service Territory, and under the terms thereof, the Combustion Turbine may be constructed at a time to be determined by BHC to provide for capacity to Black Hills' System and to allow MDU to provide a portion of the capacity for its MDU Sheridan Service Territory from an interest in the Combustion Turbine. This Agreement sets forth the terms of the construction, ownership and operation of the Combustion Turbine.

2. OWNERSHIP AND CONSTRUCTION OF COMBUSTION TURBINE.

2.1 Ownership. Each party shall own as its Percentage Share an undivided 50 percent interest in the Combustion Turbine.

2.2 Determination of Site and Construction Term. BHC shall determine the site of the Combustion Turbine; provided, the site shall be within the service territory of BHC as it exists at this time, or within a 20-mile radius thereof, or the MDU Sheridan Service Territory. In its sole discretion, BHC shall determine the time the Construction is to take place and the Commercial Date.

2.3 Determination of Design and Engineering. BHC shall determine the design and engineering of the Combustion

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Turbine; provided, that the design and engineering shall first be presented to the Owners Committee in time for a thorough review by both parties. BHC shall take into consideration all comments of members of the Owners Committee before determining the final design and engineering of the Combustion Turbine and shall make its decision based on Prudent Utility Practices.

2.4 Construction Budget. As soon as BHC determines the timing of the Construction of the Combustion Turbine, BHC shall submit to the Owners Committee for its comments a budget setting forth an estimate of amounts expected to be expended for Costs of Construction and an estimated cash flow schedule for each calendar quarter during Construction.

2.5 Payments for Construction. The Operator shall periodically notify MDU a reasonable period of time in advance, as determined from time to time by the Operator, or in the event of an emergency as soon as practicable, of expenditures for Costs of Construction and the required payment schedule. Whether or not such amounts are specified in a budget, each Owner shall pay its Percentage Share of such amounts as needed so that the Operator will have funds available to pay Construction Costs.

2.6 Accounting. On or before the 26th day of each month, the Operator shall render to MDU a statement showing for the preceding calendar month all Costs of Construction incurred by the Operator during such preceding month. Any variance between such statement of actual Costs of Construction and the

amounts deposited by the Owners in the previous month shall be added to or deducted from the respective Owner's obligations for such Costs of Construction in the month or months succeeding the issuance of such statement.

2.7 Close of Account. Within a reasonable time after the Commercial Date as is reasonably possible, the Operator shall make a final accounting of all Construction Costs for the initial Construction.

3. OPERATOR.

3.1 BHC Operator. BHC shall be the Operator of the Combustion Turbine on behalf of and for the account of Owners subject to the terms, conditions and covenants contained in this Agreement. Except as otherwise herein provided, the Operator, as agent for and on behalf of Owners, shall construct, operate and maintain the Combustion Turbine, hire all Combustion Turbine personnel, and pay all Costs of Construction and Operating Expenses.

3.2 Operator's Obligations. BHC accepts the appointment as Operator and agrees that it will construct, operate and maintain the Combustion Turbine in accordance with Prudent Utility Practice, and any applicable laws, regulations, orders, permits and licenses, now or hereafter in effect, of any governmental authority.

3.3 No Assignment of Operator's Duties. Unless MDU shall give its consent in writing, the Operator shall not assign

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its responsibility as Operator to any person except in connection with an assignment of its entire Percentage Share. In the event BHC sells its interest in the Combustion Turbine to another entity, BHC shall give written notice to MDU of such sale, and MDU shall thereupon have the option to become the Operator of the Combustion Turbine and thereby enure to all rights and assume all obligations of the Operator under this Agreement. MDU may exercise the option by giving BHC written notice thereof within 60 days of the receipt of notice of the sale.

3.4 Agency Authority. Operator is hereby granted and shall have the power to exercise authority to do everything necessary, proper and usual, in the ordinary course of business, for effecting the purpose of its agency, including, but not limited to, the power to enter into contracts with third parties for and on behalf of the Owners, the power to make and receive payments, the power to initiate, compromise or settle claims with third parties, the power to act as agent in its own name, and the power to appoint subagents. The grant of such agency powers to Operator shall remain in effect until the end of the Term.

3.5 Work Force. The Operator shall maintain a force of able and efficient manpower. The work force will be employed in the classifications necessary to construct, operate and maintain the Combustion Turbine. The Operator shall negotiate any contracts entered into with unions and set wage scales for nonunion personnel.

3.6 Training Program. Operator shall maintain a training program to assure the availability of qualified personnel for Construction, operation and maintenance of the Combustion Turbine. If such training program utilizes facilities of the Operator other than Combustion Turbine, the costs of such training shall be allocated on an equitable basis to either Costs of Construction or Operating Expenses.

3.7 Liens. Operator shall pay promptly all sums due employees or due any governmental or other agency on their behalf or on account of their employment and shall not permit any material or labor claims to be filed against the property of the Owners, other than claims that are being contested in good faith.

3.8 Remedy and Release. Except for Operator's gross negligence, the sole remedy of MDU for failure by BHC to operate and maintain the Combustion Turbine in accordance with this Section 3 shall be to obtain specific performance of the obligations set forth herein. MDU waives all rights for damages for any such failure, except for Operator's gross negligence, and releases BHC from all liability caused directly or indirectly from such failure.

4. USE OF COMBUSTION TURBINE.

4.1 During Service Term. During the Service Term as set forth in the Power Agreement, BHC is entitled to schedule for its purposes all capacity and energy from the Combustion Turbine, and MDU shall have no rights to such capacity and energy but

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shall be entitled to payments as provided at Section 4.3 of the Power Agreement.

4.2 During Remaining CT Term. MDU shall have an option, to be exercised before December 31, 2006 by written notice to BHC, to have the right to schedule for its purposes during the Remaining CT Term up to, but not to exceed, its Percentage Share of the Net Generating Capability; and BHC shall have the right to schedule for its purposes its Percentage Share. If MDU fails to exercise that option, BHC is entitled to schedule all capacity and energy from the Combustion Turbine during the Remaining CT Term, and MDU shall have no rights to such capacity and energy but shall be entitled to payments as provided at Section 5.2(b)(ii).

4.3 After the CT Term. After the CT Term and for the balance of the Term of this Agreement, each party shall have the right to schedule for its purposes up to, but not to exceed, its Percentage Share of the Net Generating Capability.

4.4 Failure of MDU to Schedule. During the Term, BHC shall have the right to schedule for its purposes any Net Generating Capability MDU could have scheduled, but did not, under Sections 4.2 and 4.3.

4.5 Notification. MDU shall provide BHC through its dispatchers its estimated hourly schedule of generation up to its authorized amount in a timely fashion as normally required by Prudent Utility Practice.

4.6 Black Hills' System Capacity in Lieu of MDU Schedule. At any time MDU schedules capacity and energy as authorized herein, BHC may as an alternative to operating the Combustion Turbine furnish MDU the scheduled capacity and energy from Black Hills' System delivered at the Combustion Turbine. In that event, MDU shall pay BHC the Fuel Costs that would have been consumed to comply with MDU's schedule.

4.7 Capability Limits. The Operator shall determine the operating limits and operating capability of the Combustion Turbine and shall promptly notify MDU of any change therein.

4.8 Operations. The Operator shall, subject to unscheduled outages, operate the Combustion Turbine as scheduled by the Owners and shall hold deviations from schedule to a minimum. Unless otherwise agreed among the Owners, actual generation shall be apportioned between the Owners in proportion to the generation schedules of the respective Owners.

5. PAYMENTS.

5.1 During the Service Term. During the Service Term, the obligations of each party are set forth in Section 4.3 of the Power Agreement.

5.2 During the Remaining CT Term. During the Remaining CT Term, the obligation of each party to pay costs are as follows:

- (a) If MDU exercises its option granted at Section 4.2, each of the Owners shall pay its respective Percentage Share of

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the Operating Expenses, and the Fuel Costs for the fuel consumed to generate the capacity and energy scheduled by it.

- (b) If MDU does not exercise its option granted at Section 4.2, BHC shall pay (i) all Operating Expenses and Fuel Costs; and (ii) MDU Annual Fixed Costs per megawatt for MDU's interest in the Combustion Turbine.

5.3 After the CT Term. After the CT Term and during the balance of the Term of this Agreement, each of the Owners shall pay its respective Percentage Share of the Operating Expenses and shall pay the Fuel Costs for the fuel consumed to generate the capacity and energy scheduled by it.

5.4 Oil and Spare Parts Inventory. MDU shall pay Black Hills its Percentage Share of the fuel oil and spare parts inventory maintained for the Combustion Turbine at the following time:

- (a) If MDU exercises its option granted at Section 4.2, the payment shall be made on the first day of the Remaining CT Term.
- (b) If MDU does not exercise its option granted at Section 4.2, the payment shall be made on the last day of the Remaining CT Term.

5.5 Payment Schedule. During those months MDU is obligated to pay its Percentage Share of Operating Expenses and Fuel Costs and based upon invoices rendered by BHC, MDU shall pay the Operator by the 15th day of each month an amount equal to the estimated obligation for MDU that month for Operating Expenses and Fuel Costs.

On or before the fifth business day of each month, the Operator shall render to MDU an invoice showing for the preceding calendar month all Operating Expenses and Fuel Costs incurred by the Operator during such preceding month and the amounts thereof MDU is obligated to pay. Any variance between such statement and the estimated amounts previously paid by MDU for that month shall be added to or deducted from MDU's obligation for succeeding months. MDU shall pay the invoice by the 15th day of the month the invoice is rendered. Interest at Chemical Bank's prime rate shall be added to underpayments and deducted from overpayments of estimated amounts. During those months BHC is obligated to pay MDU Annual Fixed Costs, BHC shall pay MDU one-twelfth of the Annual Fixed Cost each month by the 15th day of the month for which the payment is being made.

6. OPERATION AND MAINTENANCE.

6.1 Operating Budget. On or before October 1 of each year, the Operator shall submit to the Owners Committee for its comments a budget of its estimate of Operating Expenses by calendar months for the operating year beginning January 1 next following. Such comments shall be provided no later than December 1 in any such year. After taking into account all comments of both members of the Owners Committee, the final budget shall be determined by BHC. Each budget shall include such items of expenditures for replacement and repair of the Combustion Turbine as are normal to projects of a similar

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character and shall provide an adequate contingency item for emergency repairs and replacements. BHC will submit to the Owners Committee any budget revision which changes the budget by 10% or more during any calendar year which MDU shall promptly consider. After taking into account all comments of both members of the Owners Committee, the final budget revision shall be determined by BHC.

The Owners recognize that it will be necessary for continued operation of the Combustion Turbine, or to maintain the Combustion Turbine in operable condition, that the Operator be in a position to meet commitments for payroll, repairs and replacements, materials and supplies, services and other expenses of a continuing nature in order that it may fulfill its obligations as Operator under this Agreement. Accordingly, notwithstanding any of the provisions of this Section, the Operator, on behalf of the Owners, may make all expenditures in the normal course of business or in an emergency, as necessary for the proper and safe operation and maintenance of the Combustion Turbine and the Owners will advance or reimburse their respective Percentage Share of such expenditures when provided in this Agreement.

6.2 Additional Expenses. To the extent not set forth in the annual budget, the Operator will provide, not later than the first of each month, a schedule of payments to be made of Operating Expenses in such month. The Operator may, during the

month, notify MDU of additional dates or additional amounts, if unanticipated obligations are incurred.

7. SCHEDULING OF OUTAGES.

7.1 Scheduled Outages. Scheduled outages for maintenance shall be as required by the manufacturers' applicable conditions of sale and delivery of the affected facilities and equipment. Maintenance shall be in such month and year and for such periods of time as shall be determined by (i) the Operator during the period of time that MDU has no right to schedule capacity and energy from the Combustion Turbine, and (ii) by the agreement of both members of the Owners Committee during that period of time that MDU has the right to schedule capacity and energy from the Combustion Turbine. The Operator shall submit all proposed scheduled maintenance outage periods to the Owners Committee at least once a year with a sufficient lead time to allow both members of the Owners Committee to respond to BHC before the final maintenance schedule is determined.

7.2 Emergency Outages. In the event of emergency outages, or forced outages, or reductions in Combustion Turbine for any reason, the Operator shall determine a normal schedule for repair or replacement or other restoration.

8. ACCOUNTING AND REPORTS.

8.1 Records. The Operator shall keep adequate records of Project Construction and operations, including records

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necessary to reflect the efficiency of Project operations and maintenance programs, and to record generation of power, and shall keep other records as required by regulatory authorities. All records shall be made available for inspection by the Owners as desired and copies shall be furnished the Owners upon request.

8.2 FERC Accounting. All accounts shall be kept so as to permit conversion to the system of accounts prescribed for electric utilities by the FERC, or any successor commission, but the manner in which accounts are kept pursuant to this Agreement is not intended to be determinative of the manner in which they are treated in the books of account of the Owners.

8.3 Audits and Contract Limitation to Make Claim. MDU may request the Operator from time to time, but no more than once a year, to cause all books and records to be audited by MDU's internal auditing staff or by independent Certified Public Accountants of national reputation selected by Operator with the approval of MDU, which approval shall not be unreasonably withheld. Copies of such audits shall be supplied to each Owner. The cost of such independent auditors shall be shared equally by the parties.

Each party waives any claim against the other party for any incorrect payments under this Agreement if notice of such claim is not given the other party within two years after the incorrect payments were made.

8.4 Subchapter K IRC Exclusion. Operator shall prepare and the Owners shall make the appropriate election under regulations promulgated under Section 761 of the Internal Revenue Code to have the organization which the Owners may be deemed to comprise excluded from the provisions of Subchapter K of the Code.

9. INSURANCE.

9.1 Procurement. The Operator shall procure at the earliest practicable time and thereafter maintain in effect at all times hereinafter provided, to the extent available at reasonable cost and in accordance with standards prevailing in the utility industry for projects of similar size and nature, adequate insurance coverage of the Combustion Turbine with responsible insurers, with each Owner as a named assured as its respective interests may appear, to protect and insure against: employer's liability, public liability for bodily injury and property damage, all risks of physical damage to property or equipment, including transportation and installation perils, and such other insurance as the Owners deem necessary, with reasonable limits and subject to appropriate exclusions, and deductibles.

9.2 Waiver of Subrogation. Each Owner shall ensure that each of its policies of insurance that may be applicable to any claims arising in connection with the Project shall include broad-form contractual coverage or contain a waiver of the

insurer's rights of subrogation against, or name as additional assureds, the other Owner and its respective agents and employees. To the extent permitted by its insurance policies, each Owner waives any rights of subrogation against the other Owner, its agents and employees, for losses, costs, damages, or expenses arising out of the Construction, operation, maintenance, reconstruction or repair of the Project.

10. CAPITAL ADDITIONS.

10.1 Determination of Capital Additions. After timely notifying the Owners Committee and taking into account all comments from both members of the Owners Committee, BHC shall determine the necessity of a Capital Addition or an Elective Capital Addition. The Operator shall prepare and deliver to the Owners Committee a cost estimate of such Capital Addition, or Elective Capital Addition.

10.2 Construction of Elective Capital Addition. If the Owners agree, the Operator shall proceed with construction of an Elective Capital Addition, with the costs thereof to be borne by the Owners in proportion to their Percentage Shares. Without Agreement the Operator shall proceed with an Elective Capital Addition at the request of an Owner at such Owner's sole cost; provided that such Elective Capital Addition does not diminish the entitlement or increase the costs of the other Owner.

10.3 Construction of Capital Addition. The Operator shall proceed with construction of a Capital Addition with the

costs thereof to be borne by the Owners in proportion to their Percentage Shares.

10.4 Payment. The Operator shall notify MDU not less than 20 days in advance of a required Capital Addition payment, and MDU shall make payments to the Operator at the time when the Operator needs such funds to pay the costs of Construction of the Capital Addition.

10.5 Budget for Additions. On or before October 1 of each year, Operator shall submit to the Owners Committee a budget of its estimate of expenditures required to be made for Capital Additions or Elective Capital Additions pursuant to this section, for the calendar year beginning January 1 next following. Issuance and receipt of such budget shall not obligate either Owner to proceed with construction of such additions or bear the costs thereof, other than pursuant to the provisions of this Section 10.

11. LICENSES AND PERMITS.

Upon the expiration of any licenses or permits required for the operation of the Combustion Turbine, or should any additional or further licenses or permits be required, the Owners agree to file timely applications for a new or further license or permit, as the case may be, to be held as tenants in common in the undivided interests set forth hereinabove.

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12. LIABILITIES.

12.1 Mutual Release. Each of the Owners releases the other and its agents and employees from liability for any claims for loss or damage, including claims for consequential loss or damage, arising out of the ownership, Construction, operation, maintenance or repair of the Combustion Turbine, due to negligence, excluding gross negligence, including but not limited to loss of use and loss of profit.

12.2 Construction Damage Losses. Any loss, cost, liability, damage and expense to the Owners or either of them, arising out of the Construction of the Combustion Turbine and based upon injury to or death of persons or damage to or loss of property including the Combustion Turbine or other property of Owners and other persons, to the extent not covered by collectible insurance, shall be charged to Costs of Construction.

13. DEFAULTS.

13.1 Written Demand. Upon failure of an Owner to make or cause to be made any payment when due, or to perform or cause to be made or performed any other obligation to be made or performed, the other Owner may make written demand upon said Owner for such payment or performance.

13.2 Default. If the failure of an Owner is to make a payment when due and such failure is not cured within five (5) days from the date of a demand made pursuant to Section 13.1, it shall constitute a default at the expiration of such period.

13.3 Dispute Notification. If an Owner shall dispute a default asserted against it, then such Owner shall timely make or cause to be made payment of any sums in dispute or perform the obligation in dispute but may do so under protest. Such protest shall be in writing, shall specify the reasons upon which the protest is based and a copy thereof shall be mailed to the other Owner. Upon resolution of such dispute, the payments advanced or made between Owners, as in this paragraph provided, shall be adjusted appropriately.

13.4 Arbitration of Disputes. All disputes referred to in Section 13.3 above shall be submitted to arbitration pursuant to Section 18 to determine the extent, if any, of the obligation of the Owner disputing such default. If payment or performance is timely made under protest, an act of default shall not be deemed to have occurred.

13.5 Remedy for Default. In the event that an Owner is in default because of failure to make payments when due, then the following shall occur during the period such Owner is in default unless the nondefaulting Owner elects otherwise in writing:

The defaulting Owner's Percentage Share of the output of the Project shall be deemed to be assigned to the Operator on behalf of the nondefaulting Owner during the period of default and may be sold by the Operator and the proceeds applied to the amounts owed by the defaulting Owner pursuant to the Project Agreements.

In the event of a default, the nondefaulting Owner is authorized to execute, deliver and file such notices, demands, agreements,

consents, financing statements, applications and other documents as are necessary or appropriate to implement the provisions of this subsection to the full extent legally possible. In the event that any of the provisions of this subsection are waived by the nondefaulting Owner or are held to be unenforceable by competent authority, then the remaining provisions shall be severable and in full force and effect.

13.6 Interest. Payments not made when due by an Owner may be advanced by the other Owner and, if so advanced, shall bear simple interest at the rate of 125% of Chemical Bank's prime rate in effect during the period of delinquency.

13.7 Additional Remedies. In addition to the rights granted in this Section 13, any nondefaulting Owner may take any action, at law or in equity, including an action for specific performance, to enforce this Agreement and to recover for any loss, damage or payment advances, including attorneys' fees in all trial and appellate courts and collection costs incurred by reason of such default.

13.8 Section 13.5 shall not create an encumbrance prior to the lien of any existing mortgage, loan or credit agreement of either Owner except to the extent permitted thereunder.

14. UNCONTROLLABLE FORCES.

No Owner shall be considered to be in default in the performance of any of its obligations hereunder, other than

obligations of such Owner to pay costs and expenses, if failure of performance shall be due to uncontrollable forces. The term "uncontrollable forces" shall mean any cause beyond the control of the Owner failing to perform, and which, by the exercise of reasonable diligence, such Owner is unable to overcome, and shall include but not be limited to an act of God, fire, flood, explosion, strikes, labor disputes, labor or materials shortages, sabotage, an act of the public enemy, civil or military authority, including court orders, injunctions, and orders of government agencies with proper jurisdiction prohibiting acts necessary to performance hereunder or permitting any such act only subject to unreasonable conditions, insurrection or riot, an act of the elements, failure of equipment, inability to obtain or ship materials or equipment because of the effect of similar causes on suppliers or carriers or failure of any governmental agency to timely act. Nothing contained herein shall be construed so as to require an Owner to settle any strike or labor dispute in which it may be involved. Any Owner rendered unable to fulfill any obligation by reason of uncontrollable forces shall exercise due diligence to remove such inability with all reasonable dispatch.

15. WAIVER OF RIGHT TO PARTITION.

So long as the Combustion Turbine or any part thereof as originally constructed, reconstructed or added to is used or useful for the generation of electric power and energy, or to the

end of the period permitted by applicable law, whichever first occurs, the Owners waive their right to partition whether by partition in kind or sale and division of the proceeds thereof, and agree that they will not resort to any action at law or in equity to partition and further waive the benefit of all laws that may now or hereafter authorize such partition of the properties comprising the Combustion Turbine. It is agreed that this covenant shall be deemed to run with the land.

16. TRANSFER AND ASSIGNMENTS; SECURED INTERESTS.

All or any part of the interest of each Owner in the Combustion Turbine or any part thereof may be transferred and assigned as follows, but not otherwise:

(a) To any mortgagee, trustee, or other secured party, as security for bonds or other indebtedness of such Owner, present or future, and such secured party may transfer or assign the interest given as security pursuant to or in lieu of, a foreclosure of the lien (or the exercise of power of sale) held by such secured party, provided that the transferee or assignee assumes all the duties and obligations of the Owner making the transfer or assignment.

(b) To any person in the electric utility business into which or with which the Owner making the transfer may be merged or consolidated or to which the Owner transfers substantially all of its assets.

(c) To any person the stock or ownership of which is wholly owned by the Owner making the transfer.

(d) To any other person with a written consent of the other Owner.

(e) By MDU to any person after complying with the conditions of Section 24.

17. OBLIGATIONS ARE SEVERAL.

The duties, obligations and liabilities of the Owners hereunder are intended to be several and not joint or collective and no Owner shall be jointly or severally liable for the acts, omissions, or obligations of the other Owner. Nothing herein contained shall be construed to create an association, joint venture, partnership, or impose a partnership duty, obligation or liability, between the Owners. No Owner shall have a right or power to bind the other Owner without its express written consent, except as expressly provided in this Agreement.

18. ARBITRATION.

If any dispute arises under this Agreement as to any factual matter, the parties shall submit the factual dispute to a board of three arbiters, one to be selected by each party and the parties to agree on the selection of a third arbiter. If the parties are unable to agree on the third arbiter, the parties shall request the senior district judge of the United States District Court of the District of Wyoming to submit a list of

five (5) persons. Each party shall alternately strike one name from the list, the first exercise to be determined by lot. The last person remaining on the list shall serve as the third arbiter. Except as otherwise set forth herein, the arbitration shall be held under the rules of the American Arbitration Association. The arbiters shall render their decision in writing not later than thirty days after the matter has been submitted to them, and the decision of a majority of the board of arbiters of the factual dispute shall be binding on the parties. Each party shall bear the expense of preparing and presenting its own case, and the expense of the arbitrators shall be equitably divided between the Owners by the arbitrators.

19. APPLICABLE LAW AND REGULATIONS.

The Owners in their performance of their obligations hereunder shall conform to all applicable laws, rules and regulations and, to the extent that their operations may be subject to the jurisdiction of state or federal regulatory agencies, subject to the terms of valid and applicable orders of any such agencies. This Agreement shall be subject to the laws of the State of South Dakota.

20. NOTICES.

Any notice, demand, or request provided for in this Agreement shall be deemed properly served, given, or made if delivered in person or sent by registered or certified mail,

postage paid and return receipt requested, to the person so designated as its authorized representative. The titles and addresses of the authorized representatives hereunder are as follows:

For BHC: President
Black Hills Corporation
625 Ninth Street
P. O. Box 1400
Rapid City, South Dakota 57709

For MDU: President
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, North Dakota 58501

By giving written notice to the other party, a party may change the title and address for the purpose of receiving notice hereunder.

21. ADDITIONAL DOCUMENTS.

Each Owner, upon request by the other Owner, shall make, execute and deliver any and all documents reasonably required to implement the terms of this Agreement.

22. END OF COMBUSTION TURBINE.

When in the agreement of both members of the Owners Committee the Combustion Turbine can no longer be made capable of producing electricity consistent with Prudent Utility Practice or the requirements of governmental agencies having jurisdiction, or when part or all of the Combustion Turbine is removed from service, Operator shall sell all salable parts of the portion of the Combustion Turbine being removed from service to the highest

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bidders; provided, however, if the entire Combustion Turbine is being removed from service and if Operator should determine that the Combustion Turbine will bring a greater amount at salvage if sold as a unit than it would if it were dismantled and the salable parts removed and sold, then Operator may sell the Combustion Turbine as a unit to the highest bidder. After deducting all costs of ending the Combustion Turbine, including, without limiting the generality of the foregoing, the cost of decommissioning, razing all structures and disposing of the debris and meeting all applicable requirements of law, Operator shall close any remaining Combustion Turbine accounts and, if there are net proceeds, distribute to each Owner its Percentage Share of such proceeds. In the event such costs of ending the Combustion Turbine exceed available funds, each Owner shall pay its Percentage Share of such excess as incurred.

23. TERM.

This Agreement shall continue for the Term.

24. OPTION AND RIGHT OF FIRST REFUSAL.

24.1 Right to Cause BHC to Purchase Combustion Turbine.

MDU shall have an option to cause BHC to purchase MDU's interests in the Combustion Turbine as of the last date of the CT Term. The purchase price to be paid by BHC to MDU shall be the original cost depreciated of MDU's interests therein (including any fuel oil and spare parts inventory owned by MDU) as determined by

generally accepted accounting principles. MDU may exercise its option by giving BHC written notice thereof on or before the last day of the Service Term. Upon the payment of the purchase price, MDU shall transfer to BHC title to its interests in the Combustion Turbine free of any liens or encumbrances caused or created by MDU through its mortgage indentures or otherwise.

24.2 BHC's Right of First Refusal. If MDU does not exercise its option to cause BHC to purchase its interest in the Combustion Turbine as of the end of the CT Term as provided in Section 24.1, MDU may sell its interest therein at any time after the CT Term; provided, before MDU may sell its interest to an entity other than BHC, MDU must first offer BHC in writing a right of first refusal. Within 90 days following the receipt of the right of first refusal, BHC shall have an option to acquire MDU's interest in the Combustion Turbine at a purchase price equal to MDU's original cost depreciated as determined by generally accepted accounting principles. BHC's option shall be exercised by written notice to MDU. If BHC fails to exercise its option, MDU may sell its interest in the Combustion Turbine to any other entity.

24.3 Sale Subject to Agreement. The purchaser of MDU's interest in the Combustion Turbine shall be bound by the terms and provisions of this Agreement, and BHC shall retain all of its rights to the operation, control and capacity and energy output of the Combustion Turbine as set forth in this Agreement.

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25. MISCELLANEOUS.

25.1 Headings. The headings of the Sections of this Agreement are inserted for convenience of reference only and shall not affect the meaning or construction thereof.

25.2 Singular/plural. The singular of any term in this Agreement shall encompass the plural and the plural the singular, unless the context otherwise indicates.

25.3 No Third-Party Beneficiaries. This Agreement is made solely for the benefit of the Owners, and is not, and shall not be construed to be, made for the benefit of any person not a party hereto.

25.4 Amended Only By Executed Writing. This Agreement shall not be amended except by written instrument executed, acknowledged and delivered by each of the Owners.

IN WITNESS WHEREOF, the Owners have executed this Agreement in duplicate.

BLACK HILLS CORPORATION

By Arnold R. Lundquist
Its Chairman, President & CEO

MONTANA-DAKOTA UTILITIES CO., a
Division of MDU RESOURCES GROUP,
INC.

By Joseph R. Marchet
Its President & CEO

DIRECT TESTIMONY OF EVERETT E. HOYT
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION
BLACK HILLS POWER AND LIGHT COMPANY
APPLICATION FOR AN INCREASE IN ELECTRIC RATES
DOCKET NO. EL95-003

1 Q: Please state your name and business address.

2 A: Everett E. Hoyt, 625 Ninth Street, Rapid City,
3 South Dakota 57709.

4 Q: What is your position with Black Hills Power and
5 Light Company?

6 A: I hold the position of President and Chief
7 Operating Officer of Black Hills Power and Light
8 Company ("BHP" or "Company"). I have
9 responsibility for electric utility operations.

10 Q: What is your educational and business background?

11 A: Following my graduation from South Dakota School
12 of Mines and Technology, where I received a
13 Bachelor of Science degree in Mechanical
14 Engineering in 1961, I spent three years in
15 management positions in South Dakota with
16 Northwestern Bell Telephone Company (now a part of
17 U. S. West) and two years on active duty as a line
18 officer in the U. S. Army Corps of Engineers in
19 Fort Belvoir, Virginia. In 1966, I entered law
20 school at the University of South Dakota and was
21 awarded a Juris Doctor degree in 1969. After one
22 year as a law clerk to a United States District
23 Judge in South Dakota, I began private law

1 practice in Huron, South Dakota. In 1973, I was
2 offered a position on the legal staff of
3 Northwestern Public Service Company, an electric
4 and gas utility serving in eastern South Dakota
5 and which has its general offices in Huron. When
6 I left NWPS on October 1, 1989, to join BHP, I was
7 Senior Vice President-Legal and Corporate
8 Secretary, and a member of the NWPS Board of
9 Directors.

10 Q: Please describe the issues presented in the
11 present application.

12 A: To meet customer needs for electricity, BHP is
13 constructing a solely-owned 80 MW electric
14 generating plant called Neil Simpson Unit #2
15 (NS #2), which we expect to be completed by
16 September 1, 1995. When completed at a cost of
17 approximately \$121,000,000, this additional
18 investment in utility plant will increase BHP's
19 rate base by 65 percent. The NS #2 unit, together
20 with BHP's 20% interest in the 330 MW Wyodak
21 electric generating plant, will form the nucleus
22 of BHP's electric power production system,
23 providing low-cost coal-fired generation for years
24 to come. The plant will include state-of-the-art
25 equipment to minimize pollutant discharge.

0132-27-15009

1 In this application, BHP is requesting that
2 the Commission authorize BHP to increase electric
3 revenue levels by 9.96% effective when NS #2
4 becomes operational in generating electricity for
5 BHP's South Dakota customers.

6 Q: Please describe BHP's present retail electric
7 rates for South Dakota customers.

8 A: BHP's last general rate increase approved by this
9 Commission was in 1982. BHP's retail electric
10 rates have been fairly stable since 1988, when
11 phase-in of the costs associated with the 75 MW of
12 power purchased from Pacific Power & Light Company
13 was completed. Since 1987, the Consumer Price
14 Index (CPI) has increased by 25.8%. In BHPL
15 Exhibit EEH-1, we have graphed the CPI against BHP
16 electric rates since 1974. As the graph
17 indicates, BHP rates during the past twenty years
18 have increased considerably less than the increase
19 in the CPI during the period.

20 Q: Please describe some of the cost-containment
21 efforts by BHP which have reduced the revenue
22 requirement in this Application.

23 A: We monitor our costs very closely and utilize
24 compensation incentives to encourage all BHP
25 employees to control operations and maintenance

1 expenses. In BHPL Exhibit EEH-2, I have shown the
2 annual percentage increase over the past five
3 years in several key indicators for BHP. As you
4 will observe, our controllable operations and
5 maintenance expense has increased by only 0.7% per
6 year during this period while the Consumer Price
7 Index has increased by 3.5% per year during this
8 period.

9 Through our "Gainshare" program, all
10 employees are eligible for a compensation bonus of
11 up to 3% of their compensation if the Company,
12 their department, and their work group attain
13 certain safety, productivity, customer service,
14 and cost containment goals. We feel that the
15 Gainshare program has been very effective in
16 educating and motivating BHP employees to conduct
17 our business efficiently. A copy of the Gainshare
18 Plan for 1995 is attached as Exhibit EEH-3.

19 In addition to Gainshare, all nonbargaining
20 unit employees began in 1994 to participate in
21 BHP's "Results Compensation Program" in which all
22 employees are eligible for bonus compensation if
23 BHP meets certain operating income goals
24 encouraging the reduction of BHP operating
25 expenses, and if Black Hills Corporation meets

1 certain corporate earnings goals. A copy of the
2 summary plan description for the 1995 Results
3 Compensation Program is included as BHPL Exhibit
4 EEH-4.

5 Because wages constitute a significant part
6 of BHP's operating costs, staffing at BHP is
7 carefully evaluated. With each position opening
8 created through retirement or termination, the
9 first approach is to determine whether those job
10 duties can be distributed equitably through the
11 remaining work force. We continually evaluate
12 whether a reorganization of the work unit can be
13 accomplished so that electric operations can be
14 carried out more effectively. The total number of
15 BHP employees has remained relatively stable for
16 the past ten years, while the number of customers
17 and energy sales have increased significantly.

18 Compensation levels at BHP are established by
19 comparison with like positions and
20 responsibilities in the utility industry and in
21 other industries. The Company does not utilize a
22 cost-of-living adjustment in establishing wage
23 increases but relies on the market for the
24 particular position or skill. Annual increases in
25 compensation for nonbargaining unit employees are

1 established as a part of the employee's annual
2 performance review in which accomplishment of
3 performance goals is reviewed. A part of each
4 employee's annual compensation is dependent upon
5 attainment of goals in the Gainshare and Results
6 Compensation programs previously described. Wage
7 increases and fringe benefits for bargaining unit
8 employees are established through the collective
9 bargaining process, with reference to the wages
10 and benefits prevailing in the BHP market.

11 Q: Please explain BHP's approach to rate design by
12 customer class as presented in this Application.

13 A: In this Application, BHP proposes that the
14 additional revenue requirement of 9.96% be
15 realized by an "across-the-board" increase of that
16 amount (give or take a small fraction of one
17 percent) from all customer classes. While the
18 customer class cost of service would indicate that
19 the required revenue increase would differ from
20 class to class and within customer classes if
21 there were strict adherence to equal class return
22 principles, we believe that it is more equitable
23 in this instance for all customers to experience
24 like percentage increases in their electric costs.

013327-511
1 Q: Please explain the Company's proposal to provide
2 discounts to large customers which are willing to
3 enter into long-term contracts for service.

4 A: BHP's larger customers provide a substantial
5 benefit to the customer group through very
6 efficient utilization of BHP's electric system;
7 most BHP industrial customers with requirements
8 greater than 2000 KW have load factors which are
9 higher than the system average. As we plan our
10 system to meet capacity (demand) requirements of
11 our customers, we can better plan capacity
12 additions and utilization if we have assurance
13 that our larger customers will remain BHP
14 customers. At present, self-generation is an
15 option which might be evaluated by BHP's large
16 customers if BHP's industrial rates do not remain
17 competitive. Under our present regulatory
18 framework, loss of large customers will result in
19 a shift of costs to residential and other customer
20 groups. BHP's proposal to offer discounts to
21 large customers which are willing to enter into
22 long-term contracts is one way to encourage large
23 customers to remain committed to BHP for a
24 reasonable planning horizon in return for reduced
25 energy costs. BHP witnesses White and Smith have

1 offered support for the large customer long-term
2 contract discount from the perspective of
3 experienced utility cost-of-service analysts.

4 Q: Does BHP have any programs which might assist
5 customers in adjusting to the increased rates?

6 A: Yes. BHP encourages its managers and customer
7 account representatives to work closely with
8 customers on an individual basis to encourage
9 efficient energy use and to arrange bill payment
10 plans which assist residential customers in
11 budgeting their payments for electric service to
12 avoid significant seasonal variations in their
13 billings. In addition, our managers and customer
14 account representatives work closely with the
15 Energy Assistance Program and with other agencies
16 and social groups which provide financial
17 assistance to deserving customers.

18 Our customer account representatives receive
19 interpersonal relations training which enables
20 them to better interact with customers on a
21 problem-solving basis. While our account
22 delinquency and charge-off rates are good (to the
23 benefit of our customer group), we attempt to work
24 with customers to tailor bill payments to their
25 personal budgets.

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1 Our largest 160 customers are visited at
2 their business location by a BHP supervisor at
3 least once each year to evaluate their energy use
4 and billing options. Our industrial service
5 engineers, all graduate electrical engineers with
6 experience in industrial situations, are available
7 to assist industrial customers in evaluation of
8 more energy efficient applications for their
9 business operations.

10 Q: How much of an increase in revenue is justified in
11 this case?

12 A: In my opinion, the Company's cost of service
13 presented in this case justifies an increase in
14 revenue from our South Dakota customers of
15 \$13,199,300, a 15.58% increase.

16 Q: Are you asking this Commission to approve that
17 increase in this case?

18 A: No. We are requesting this Commission to
19 authorize designed rates and filed tariffs that
20 would result in increased revenues from our South
21 Dakota customers of \$8,338,650, or a 9.96%
22 increase. However, as Kyle White has explained to
23 you in his testimony, we are asking this
24 Commission to include a clause in the Fuel and
25 Purchased Power Adjustment rate schedule that will

1 one, exclude the incremental cost of additional
2 energy and peaking capacity required to serve the
3 Montana-Dakota Utilities Co. (MDU) Sheridan,
4 Wyoming load under our new 10-year contract with
5 MDU commencing January 1, 1997, and two, also
6 exclude the energy sales (KWH) from that sale so
7 as to neutralize the effect of the MDU sale from
8 the Fuel and Purchased Power Adjustment. In
9 effect this MDU clause will allow BHP to retain
10 the benefit from the MDU sale commencing in 1997
11 to make up for the deficiency in revenue from the
12 time NS #2 goes on line (expected to be
13 September 1, 1995) and January 1, 1997, a period
14 of 16 months.

15 Q: If the MDU clause is allowed, do you forecast that
16 BHP will receive sufficient revenue in 1997 to
17 yield a fair return on rate base?

18 A: Our forecast indicates that the requested MDU
19 clause will result in a fair return in 1997, but
20 the deficiency we are willing to take during the
21 16 months prior to January 1, 1997 may not be
22 restored.

23 Q: Why are you willing to take less than what you
24 believe is fair and reasonable during the 16
25 months?

1 A: We are sensitive to the effect of a large increase
2 in rates. The resulting "rate shock" to our
3 customers can result in several negative effects
4 to this Company, including deterioration of
5 Company-customer relationships, negative reactions
6 of customers making it difficult to communicate
7 understanding, negative reaction of this
8 Commission creating negative perceptions of the
9 investment community, long, drawn-out and costly
10 rate proceedings and litigation, a lag in
11 obtaining adequate rate relief, loss of electric
12 sales resulting from negative reactions of
13 contractors and customers, political reactions
14 resulting in onerous laws and regulation and
15 assaults upon the free enterprise system.

16 During my tenure at Northwestern Public
17 Service Company, I experienced these negative
18 reactions to applications for large rate
19 increases. I know of what I speak.

20 This is why Black Hills sponsored legislation
21 to allow a phased-in rate stability plan to be
22 invoked when a utility is about to experience a
23 large rate base increase.

24 Q: Why didn't you request a phase-in through a rate
25 stability plan?

1 A: You will recall that we did file such a plan
2 before this Commission when we anticipated rate
3 increases totalling over 20 percent. We had
4 applied for four phased-in rate increases for a
5 total of 17.9%. This would have negated the
6 capitalization of AFUDC for NS #2. However, we
7 withdrew that application as we gained more
8 confidence in a positive forecast of revenues and
9 costs. Our construction schedule of NS #2 was so
10 short that we decided to file a regular
11 application at a time that would allow rate
12 increases to come into effect at the same time NS
13 #2 became commercial. We had also been challenged
14 by a proposed qualifying facility under PURPA to
15 replace NS #2 and accepted that challenge by
16 guaranteeing the cost of NS #2 and lowering the
17 incremental cost of coal. We concluded that we
18 would take a more competitive approach to the
19 problem of obtaining rate relief and find ways to
20 minimize rate increases as much as possible.

21 Q: Do you believe now that taking this more
22 competitive approach was correct? Why?

23 A: We certainly do. What this Company has been able
24 to accomplish during this period is incredible.
25 Who would have thought, even five years ago, that

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1 a utility would step up to the plate by
2 guaranteeing to its regulatory commissions that it
3 would construct a necessary addition that would
4 increase its rate base by 65 percent, complete
5 that addition 4 months early and 3 percent under
6 budget, and require a rate increase of only 9.96
7 percent.

8 This competitive approach led BHP to compete
9 vigorously for the off-system opportunity sale to
10 MDU. This new sale results in savings in costs
11 that give us this opportunity to keep the rate
12 increase under 10% while we wait 16 months for the
13 savings to the Company. The MDU sale presented an
14 opportunity to offer our customers what is in
15 effect a phased-in approach.

16 I also believe that if the Commission allows
17 the treatment of the MDU sale in the fuel and
18 power adjustment tariff, the investment community
19 will see that as a reinforcement by the regulatory
20 community of Black Hills' more competitive
21 approach.

22 Q: How long are you proposing that the MDU clause
23 remain in the fuel and purchased power adjustment
24 tariff?

1 A: This tariff, like all of the tariffs of the
2 Company, is subject to change by this Commission
3 in response to initiatives of either the Company
4 or Commission. Changes in revenues and costs
5 require changes in tariffs. To the extent that
6 BHP realizes positive revenue flows from the MDU
7 sale is the extent that BHP need not request rate
8 increases to its customers. We would anticipate
9 that at the next rate case, the cost of service
10 would reflect all of the costs of serving MDU and
11 the revenues would be credited against revenue
12 requirements as is usually done for off-system
13 opportunity sales. Lee Smith supports this
14 eventual treatment in her testimony.

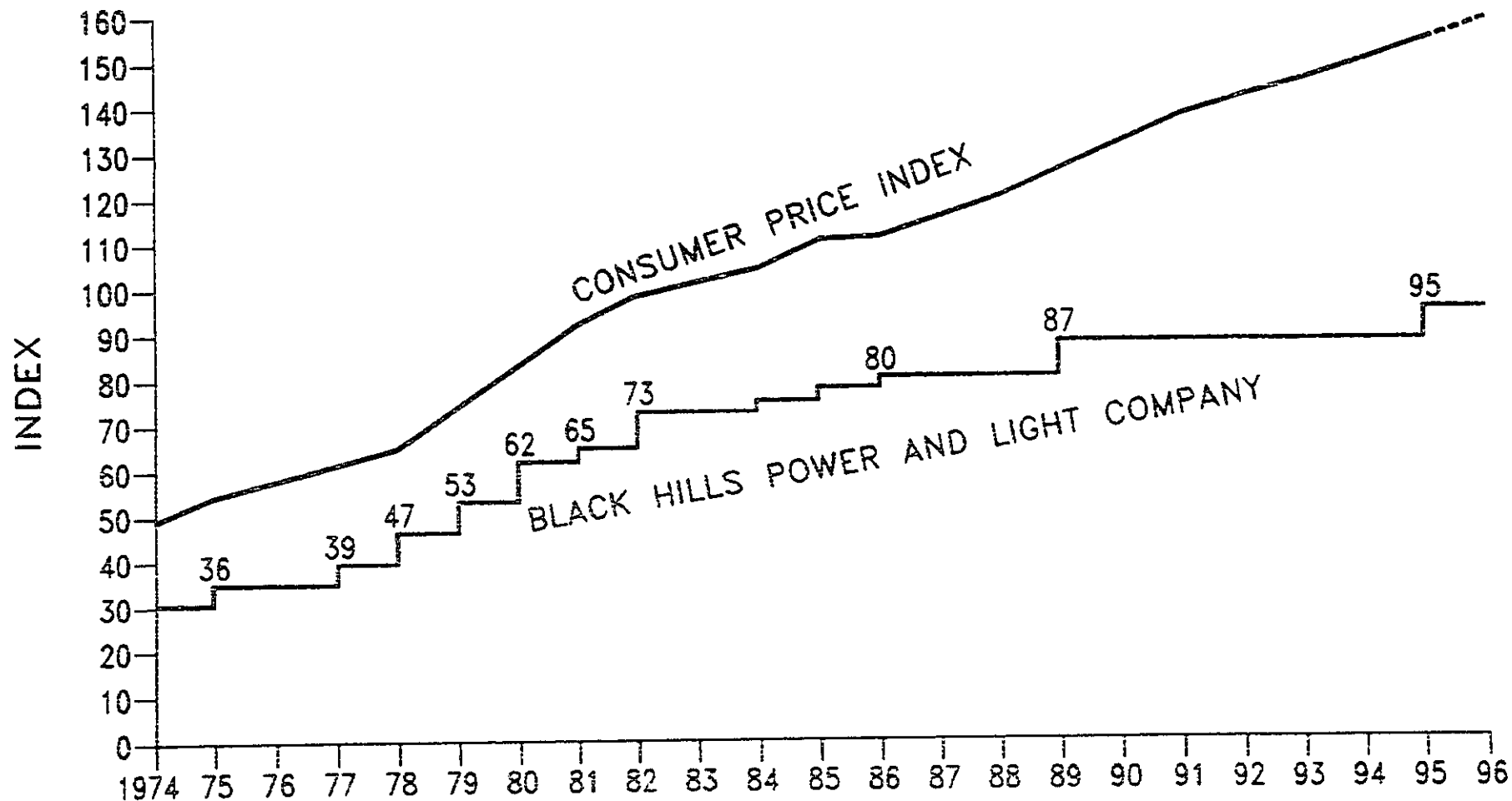
15 Q: When do you expect your next rate case?

16 A: The uncertainties of the future always make it
17 difficult to answer this question.

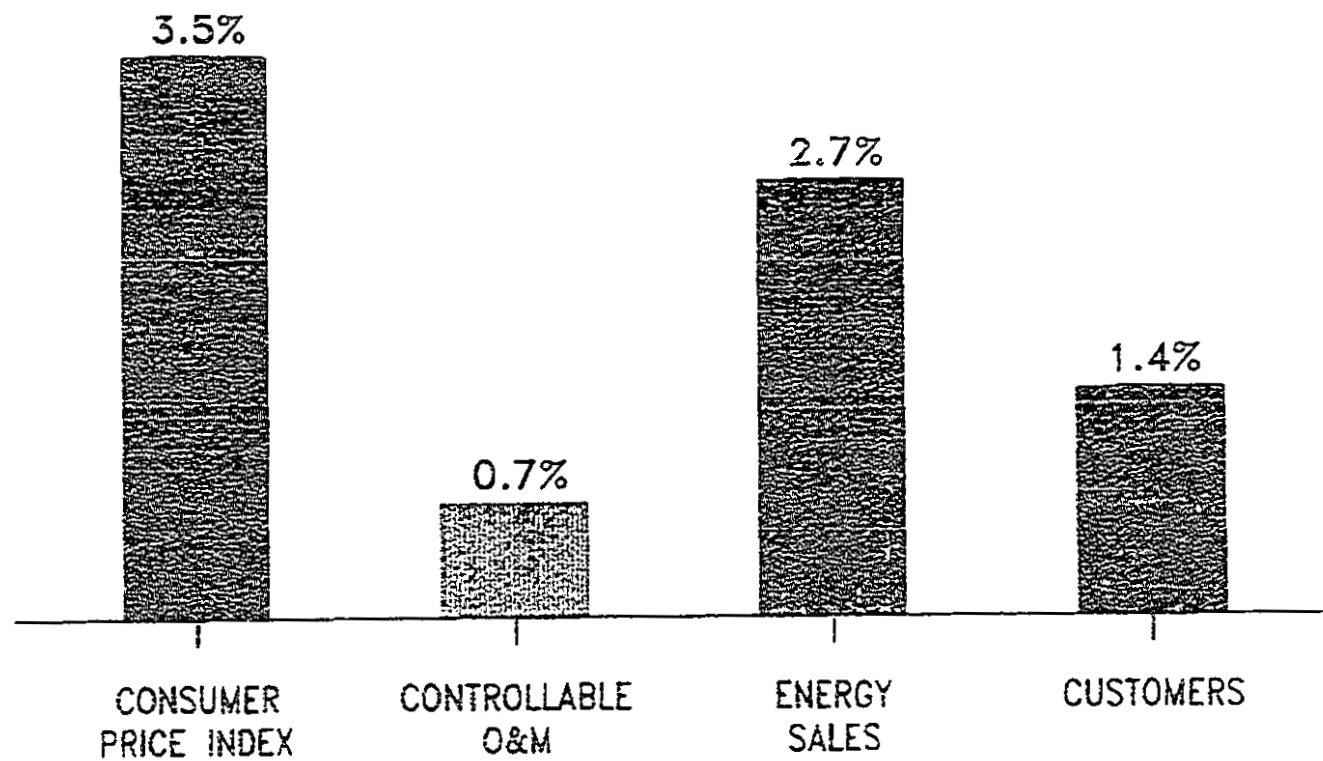
18 As a part of our offer we are willing to
19 agree to a moratorium on rate increases, other
20 than as a result of the fuel and purchased power
21 adjustment, until January 1, 1998. The moratorium
22 would not apply to rate increases caused by
23 increased taxes or other material new governmental
24 impositions or other unexpected events as I have
25 described.

1 We anticipate that barring higher than
2 expected inflation, increased taxes or unexpected
3 events having a material effect on revenues or
4 costs, and assuming we obtain the rate increase
5 and MDU sale treatment as requested, that we
6 should be able to stabilize rates for several
7 years.

ELECTRICITY PRICE COMPARED WITH CONSUMER PRICE INDEX



5 YEAR ANNUAL COMPOUND INCREASE (IN PERCENT)



1995

**BARGAINING UNIT
GAINSHARING PROGRAM**

SUMMARY PLAN DESCRIPTION

BARGAINING UNIT

DIVISION A

1995 GAINSHARING PROGRAM

As competition for our customers' energy dollars continues to increase, we must all strive to approach our jobs with the elements that have made us successful in the past--creativity and innovation with the responsibility to complete our work in a productive, cost-conscious, and safe manner. The 1995 Gainsharing Program is designed to motivate us toward this objective.

Basic Program principles and guidelines:

- Program awards should be directly linked with pro-active work unit activities and goals that are **challenging, yet obtainable**, and activities that improve Company financial performance.
- Pro-active activities should be linked to the strategic plan and include cost and/or waste reduction and/or improvement of productivity, efficiency, customer service, quality, etc. -- primarily in the areas of operation and maintenance.
- Goals must be results based and measurable.
- Ultimately, these activities must affect the improvement of Company financial performance before there is any payout.

Division A plan participants includes all bargaining unit employees who are involved in the operation and maintenance of the power plants. In order to promote greater work unity, all plant personnel will be associated with their respective work units. This includes the plant manager, plant supervisor, results engineer, materials coordinator, and support staff plan participants.

Safety is an important aspect of our plan to increase productivity and contain costs. Working safely protects us and the public from the pain and expense related to personal injuries and property damage. Finding ways to continue to cost-effectively provide reliable and high quality service for our customers will provide long-term benefits for our customers and shareholders.

The Gainsharing Program is funded by achieving certain **Company-Wide Goals** which include:

- * If at the end of the fiscal year **Company OSHA Recordable and Motor Vehicle Accident** rates are below the NCEA rates, a 1% of payroll award will be funded in the "Bank".
- * If at the end of the fiscal year **Company Operation and Maintenance Expenses** are 1% below budget, a 1% of payroll award will be funded in the "Bank".
- * If at the end of the fiscal year **Company Operation and Maintenance Expenses** are reduced by an additional 1%, an additional 1% of payroll award will be funded in the "Bank".

Awards are based on the percent funded in the "Bank" (0 to 3%) and the successful achievement of **Individual Safety and Plant and Division O & M Expenses Reduction and Productivity Goals** that include:

- * Achieve work unit goal(s).
- * Reduce individual Plant budgeted controllable O&M expense by 1%
- * Reduce Division A budgeted controllable O&M expense by 1%.
- * Meet plant availability goals:

Neil Simpson	91%
Ben French	89%
Osage	92%
Kirk	92%

- * Conduct pro-active work safety activities and work safely.

Stop Loss: The basic goal of gainsharing is to reduce costs. Therefore, employees who have a MVA, LTA, public liability, operations or property damage loss in excess of \$10,000 and are found to be at fault will be ineligible for any gainshare award that year. An incident that occurs in one year but accumulates expenses in more than one year would affect an employee's gainsharing award in the year expenses reach \$10,000. The Gainsharing Committee will address special situations and determine effect.

BARGAINING UNIT

DIVISION B

1995 GAINSHARING PROGRAM

As competition for our customers' energy dollars continues to increase, we must all strive to approach our jobs with the elements that have made us successful in the past -- creativity and innovation with the responsibility to complete our work in a productive, cost-conscious, and safe manner. The 1995 Gainsharing Program is designed to motivate us toward this objective.

Basic Program principles and guidelines:

- Program awards should be directly linked with pro-active work unit activities and goals that are **challenging, yet obtainable**, and activities that improve Company financial performance.
- Pro-active activities should be linked to the strategic plan and include cost and/or waste reduction and/or improvement of productivity, efficiency, customer service, quality, etc. -- primarily in the areas of operation and maintenance.
- Goals must be results based and measurable.
- Ultimately, these activities must affect the improvement of Company financial performance before there is any payout.

Division B plan participants include all Division B bargaining unit employees. In order to promote greater work unity, all first level non-bargaining unit supervisors will be associated with their respective work units.

Division B work units are as follows:

- Northern Hills Area
- Southern Hills Area
- Newcastle District
- Rapid City District
- Line Crews
- Rapid City Line Service
- Line Clearance Tree Trimmers and Transformer Shop
- Motor Vehicle Shop
- Special Services
- Electricians
- Meter Lab
- Rapid City Warehouse

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Safety is an important aspect of our plan to increase productivity and contain costs. Working safely protects us and the public from the pain and expense related to personal injuries and property damage. Finding ways to continue to cost-effectively provide reliable and high quality service for our customers will provide long-term benefits for our customers and shareholders.

The Gainsharing Program is funded by achieving certain **Company-Wide Goals** which include:

- * If at the end of the fiscal year **Company OSHA Recordable and Motor Vehicle Accident** rates are below the NCEA rates, a 1% of payroll award will be funded in the "Bank".
- * If at the end of the fiscal year **Company Operation and Maintenance Expenses** are 1% below budget, a 1% of payroll award will be funded in the "Bank".
- * If at the end of the fiscal year **Company Operation and Maintenance Expenses** are reduced by an additional 1%, an additional 1% of payroll award will be funded in the "Bank".

Awards are based on the percent funded in the "Bank" (0 to 3%) and the successful achievement of **Individual Safety and Work Unit and Division O & M Expenses Reduction, and Productivity** goals that include:

- * Achieve work unit goal(s).
- * Reduce individual work unit budgeted controllable O&M expense by 1%.
- * Reduce Division B budgeted controllable O&M expense by 1%.
- * Customer outage time is less than (to be determined) minutes. (Developed on a basis which precludes success or failure based upon transmission outage or major storm.)
- * Conduct pro-active work safety activities and work safe.

Stop Loss: The basic goal of gainsharing is to reduce costs. Therefore, employees who have a MVA, LTA, public liability, operations or property damage loss in excess of \$10,000 and are found to be at fault will be ineligible for any gainshare award that year. An incident that occurs in one year but accumulates expenses in more than one year would affect an employee's gainsharing award in the year expenses reach \$10,000. The Gainsharing Committee will address special situations and determine effect.

BARGAINING UNIT GAINSHARING PROGRAM ELIGIBILITY AWARD FORMULA

This is how the "the Door to the Bank is opened".

Goals	Number of Points Eligible to Earn	Earned
Complete one work unit goal.	12	
Complete a second work unit goal.	11	
Complete a third work unit goal.	11	
Reduce individual applicable Power Plant (Division A) or Work Unit (Division B) O & M Expenses by 1%.	11	
Reduce applicable Division O & M expenses by 1%.	11	
Achieve Division A Plant Availability Goal or Division B Customer Outage Goal.	11	
If individual employee safety rating is 10 points.*	33	
If individual employee safety rating is 5 to 9 points.*	17	
If individual employee safety rating is 1 to 4 points.*	-0-	
If individual employee safety rating if 0 to minus 4 points.*	minus 34	
If individual employee safety rating is minus 5 or more points.*	minus 67	
Total Earned:		
Award Formula: Divide total number of points earned by 100 to determine percentage. (Example 67 divided by 100 equals 67%) Multiply the percentage funded in the "Bank" by the percentage earned. (Example: 67% times 3% equals 2%) Two percent (2%) is the amount of the individual employee's Gainsharing Award.		

* See Bargaining Unit Gainsharing Safety Goals Program.

BARGAINING UNIT SAFETY GAINSHARING GOALS FOR 1995

INDIVIDUAL SCORING

Each employee will begin the year with a safety rating of plus six. Proactive safety efforts will increase the score and the occurrence of an accident will decrease the score as follows:

· Complete a self-study safety course*	+2
· Conduct a Safety Meeting for the work group	+1
· Teach a safety-related class on or off the job	+1
· Submit one near-miss incident report that occurred in the work group this year	+1
· Complete a S.T.O.P. contact and document	+0.5
· Operations Accident	-3.5
· Public Liability Accident	-3.5
· Medical Case Accident	-3.5
· Vehicle Accident	-5
· Violation of a safety rule	-5
· Lost Time Accident	-10

NOTE: * Following are the three self-study safety courses available:

- Holding Effective Safety Meetings
- Hazards and Safety Procedures
- Hazard Awareness

(Study shall be done on personal time.)

SUPERVISORS and FOREMEN

Employees who directly supervise other employees are in a position to influence the proactive safety effort of employees they supervise. Therefore, direct Supervisors and Foremen will be tied to the performance of the employees they supervise.

The safety points applied to the award formulas of Supervisors and Foremen will be equal to the average of their work unit. Supervisors and Foremen will earn points just like the other employees and their points will be included in the work unit average.

NOTES:

- Each employee will maintain their own score card.
- Positive points added to the score must be initialed by the employee's supervisor.
- Near miss reports must be approved by the Supervisor and the Manager of Safety and Loss Control and may be submitted only once by one employee.
- To achieve S.T.O.P. points, contact cards must be approved by the employee's supervisor.
- Proactive activities to gain positive points must be above and beyond normal assigned performance.

Stop Loss: The basic goal of gainsharing is to reduce costs. Therefore, employees who have a MVA, LTA, public liability, operations or property damage loss in excess of \$10,000 and are found to be at fault will be ineligible for any gainshare award that year. An incident that occurs in one year but accumulates expenses in more than one year, would affect an employee's gainsharing award in the year expenses reach \$10,000. The Gainsharing Committee will address special situations and determine effect.

SAFETY GAINSHARE SCORE SHEET

Employee:

POINTS EARNED	
Category	
Beginning Balance	6
Complete a self-study course - plus 2 points	
Conduct a Safety Meeting for the Work Group - plus 1 point	
Teach a safety-related class on or off the job - plus 1 point	
Submit one near miss incident report - plus 1 point	
Complete a S.T.O.P. contact and document - plus 0.5 point	
POINTS LOST	
Lost Time Accident - minus 10 points	
Vehicle Accident - minus 5 points	
Violation of a Safety Rule - minus 5 points	
Medical Case accident - minus 3.5 points	
Operations Accident - minus 2 points	
Public Liability Accident - minus 2 points	
TOTAL	

GUIDELINES

The Gainsharing Program will consist of a one-year period starting January 1, 1995, through December 31, 1995. The Program calculations and payout checks, if appropriate, will be issued in the first quarter of the following year.

An individual employee's gainsharing bonus, if any, will be paid on gross pay as it appears on the employee's W-2. This includes regular, overtime, paid time off, shift differential and other forms of premium pay.

An employee who transfers between one of the three gainshare programs as defined in the Program will have their gainshare bonus, if appropriate, based upon where the greatest amount of time work occurred. The maximum gainsharing award an employee may receive is 3%.

Anyone terminated from employment with Black Hills Corporation before the completion of the program will not be eligible for any gainsharing bonus. Exceptions would be death, permanent disability or retirement.

Board of Directors Retain Discretion

This Program is not a contract of employment. The Company reserves the right to change this Program whenever and in whatever manner it deems appropriate. Irrespective of changes in the Program, no rights are vested. All awards are earned only when and if finally approved by the Board of Directors notwithstanding anything contained in the Program that may be construed to be to the contrary.

The Board of Directors, in its sole absolute discretion, may decline to approve any award, though the participant may have achieved or exceeded threshold and target levels of performance. Setting a threshold or target of performance for any participant does not constitute a promise to pay an award even if the participant meets the threshold or target of performance. In determining whether to make an award and the amount of the award, the Board of Directors may consider criteria other than or in addition to the threshold and target performance determined under this Program. Nothing in this Program is a promise by the Company or any of its subsidiaries to continue to employ any participant for any period of time.

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1995

STAFF

GAINSHARING PROGRAM

SUMMARY PLAN DESCRIPTION

1995 STAFF GAINSHARING PROGRAM

As competition for our customers' energy dollars continues to increase, we must all strive to approach our jobs with the elements that have made us successful in the past -- creativity and innovation with the responsibility to complete our work in a productive, cost-conscious, and safe manner. The 1995 Gainsharing Program is designed to motivate us toward this objective.

Basic Program principles and guidelines:

- Program awards should be directly linked with pro-active work unit activities and goals that are **challenging, yet obtainable**, and activities that improve Company financial performance.
- Pro-active activities should be linked to the strategic plan and include cost and/or waste reduction and/or improvement of productivity, efficiency, customer service, quality, etc. -- primarily in the areas of operation and maintenance.
- Goals must be results based and measurable.
- Ultimately, these activities must affect the improvement of Company financial performance before there is any payout.

Included in this Program are plan participants in the following departments: Finance/Accounting, Human Resources, Information Services, Governmental and Public Affairs, and staff employees of the Rapid City District, Customer Services, Engineering and Operations, General Services, and Rates and Demand Side Management.

Safety is an important aspect of our plan to increase productivity and contain costs. Working safely protects us and the public from the pain and expense related to personal injuries and property damage. Finding ways to continue to cost-effectively provide reliable and high quality service for our customers will provide long-term benefits for our customers and shareholders.

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The **Gainsharing Program** is funded by achieving certain **Company-Wide Goals** which include:

- If at the end of the fiscal year **Company OSHA Recordable and Motor Vehicle Accident** rates are below the NCEA rates, a 1% of payroll award will be funded in the "Bank".
- " If at the end of the fiscal year **Company Operation and Maintenance Expenses** are **1% below budget**, a 1% of payroll award will be funded in the "Bank".
- " If at the end of the fiscal year **Company Operation and Maintenance Expenses** are **reduced by an additional 1%**, an additional 1% of payroll award will be funded in the "Bank".

Department Goals: Each Department must develop a minimum of four (4) goals. The Gainsharing Committee recommends one set of goals for the entire department. However, the department may have more than one set of goals for defined work units within the department or goals for an individual within the department.

Award Formula: Awards are based on the successful completion of work unit goals. Awards are determined by multiplying the percentage funded in the "Bank" by the percentage of the work unit goals that were achieved by the work unit. **For example:**

If there is 3% funded in the "Bank" and if the work unit achieves four of four work units goals, multiply 3% by 100%, which equals a 3% award payout.

If there is 2% funded in the "Bank" and if the work unit achieves two of four work unit goals, multiply 3% by 50%, which equals a 1% award payout.

Note: For each MVA, LTA, or public liability an individual employee has, the equivalent of a 1% award will be deducted from their award as previously calculated. (An employee could lose the entire 3% potential award should they incur three of the above mentioned incidents.)

Stop Loss: The basic goal of gainsharing is to reduce costs. Therefore, employees who have a MVA, LTA, public liability, operations or property damage loss in excess of \$10,000 and are found to be at fault will be ineligible for any gainshare award that year. An incident that occurs in one year but accumulates expenses in more than one year would affect an employee's gainsharing award in the year expenses reach \$10,000. The Gainsharing Committee will address special situations and determine effect.

GUIDELINES

The Gainsharing Program will consist of a one-year period starting January 1, 1995, through December 31, 1995. The Program calculations and payout checks, if appropriate, will be issued in the first quarter of the following year.

An individual employee's gainsharing bonus, if any, will be paid on gross pay as it appears on the employee's W-2. This includes regular, overtime, paid time off, shift differential and other forms of premium pay.

An employee who transfers between one of the three gainshare programs as defined in the Program will have their gainshare bonus, if appropriate, based upon where the greatest amount of time work occurred. The maximum gainsharing award an employee may receive is 3%.

Anyone terminated from employment with Black Hills Corporation before the completion of the program will not be eligible for any gainsharing bonus. Exceptions would be death, permanent disability or retirement.

Board of Directors Retain Discretion

This Program is not a contract of employment. The Company reserves the right to change this Program whenever and in whatever manner it deems appropriate. Irrespective of changes in the Program, no rights are vested. All awards are earned only when and if finally approved by the Board of Directors notwithstanding anything contained in the Program that may be construed to be to the contrary.

The Board of Directors, in its sole absolute discretion, may decline to approve any award, though the participant may have achieved or exceeded threshold and target levels of performance. Setting a threshold or target of performance for any participant does not constitute a promise to pay an award even if the participant meets the threshold or target of performance. In determining whether to make an award and the amount of the award, the Board of Directors may consider criteria other than or in addition to the threshold and target performance determined under this Program. Nothing in this Program is a promise by the Company or any of its subsidiaries to continue to employ any participant for any period of time.

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1995

EXECUTIVE

GAINSHARING PROGRAM

1995 EXECUTIVE GAINSHARING PROGRAM

The Executive Gainsharing Program is one of three sections of a Company-wide gainsharing program. Other work units participating in the Company-wide program are the Bargaining Unit and a program for the Staff. Each of the three work units have goals established in which participants can directly influence the results. The maximum award that any participant may receive is three percent.

This program is designed for the officers in the following positions: Chairman, President and CEO; President and COO; Sr. Vice President, Finance; Vice President, Administration; Vice President, Power Supply; Secretary/Treasurer, and Controller.

Black Hills Corporation 1995 Executive Gainsharing Program Goals

I. Safety Goal (1%)

This category has a total award value of 1%. The category is comprised of safety goals dependent on each other. The goals are:

- A. Motor Vehicle Accidents
- B. OSHA Lost Time Accidents

To receive a 1% award, the Company average must be less than the NCEA average at year-end in each respective area.

II. O&M Expense Reduction Goal (1%)

This category has a total award value of 1%. For an award to be paid in this category, a reduction in the O&M budget must occur. A payout to the participants will be equal to one-third of the average company-wide participant gainshare payout.

Example: If the average 1995 gainshare award payout per participant is 2.5%, each participant (officer) in this specific program would receive a payout equal to .825%.

III. Rate Case Goals (1%)

The goal has a total award value of 1%. Each participant will develop a goal representing their respective area of responsibility in relation to successful South Dakota and Wyoming rate cases. At year-end, the CEO will determine to what degree the goal has been achieved. Awards for each participant can be made in 1/4% increments not to exceed 1%.

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Note: For each MVA, LTA, or public liability an individual employee has, the equivalent of a 1% award will be deducted from their award as previously calculated. (An employee could lose the entire 3% potential award should they incur three of the above mentioned incidents.)

Stop Loss: The basic goal of gainsharing is to reduce costs. Therefore, employees who have a MVA, LTA, public liability, operations or property damage loss in excess of \$10,000 and are found to be at fault will be ineligible for any Gainshare Award that year. An incident that occurs in one year but accumulates expenses in more than one year would affect an employee's Gainsharing Award in the year expenses reach \$10,000. The Gainsharing Committee will address special situations and determine effect.

GUIDELINES

The program will be comprised of a one year period starting January 1, 1995, through December 31, 1995. The gainshare program calculations and payout checks, if awarded, will be issued in the first quarter of the following year.

An individual employee's gainsharing bonus, if any, will be paid on gross pay as it appears on the employee's W-2. This includes regular, paid time off, and other forms of compensation.

An employee who transfers between one of the three gainshare programs as defined in the 1995 Gainsharing Program will have their gainshare bonus, if awarded, based upon where the greatest amount of time worked occurred. The maximum gainsharing award an employee may receive is 3%.

Anyone terminated from employment with Black Hills Corporation before the completion of the program will not be eligible for any gainsharing bonus. Exceptions would be death, permanent disability or retirement.

Board of Directors Retain Discretion

This Plan is not at any time a contract of employment. The Company reserves the right to change this Plan whenever and in any manner it deems appropriate. Irrespective of changes in the Plan, no rights are vested. All awards are earned only when and if finally approved by the Board of Directors notwithstanding anything contained in the Plan that may be construed to be to the contrary.

The Board of Directors, in its sole and absolute discretion, may decline to approve any award, though the participant may have achieved or exceeded threshold and target levels of performance. Setting a threshold or target of performance for any participant does not constitute a promise to pay an award even if the participant meets the threshold or target of performance. In determining whether to make an award and the amount of the award, the Board of Directors may consider criteria other than or in addition to the threshold and target performance determined under this Plan. Nothing in this Plan is a promise by the Company or any of its subsidiaries to continue to employ any participant for any period of time.

1995

RESULTS

COMPENSATION

PROGRAM

Black Hills Power and Light Company

Wyodak Resources Development Corp.

Western Production Company

RESULTS COMPENSATION PROGRAM

In 1995, we are continuing the Results Compensation program which was implemented in 1994. This program has significantly enhanced the Corporation's compensation philosophy and practice.

The Results Compensation program is designed to recognize and reward the contribution that group performance makes to corporate success. Results Compensation can pay financial rewards up to 8 percent of your earnings.

Group Performance

There are several elements that go into determining the success of the Corporation. Some of these elements include: the contributions employees make to achieve goals; both on an individual basis and as part of a work unit, in addition to the market, general economic conditions, quality of management, strategic plans, and regulatory agencies.

In general, the current merit/base pay system provides individual pay opportunities that are competitive in our respective industry and geographic location coupled with each company's ability to pay. The emphasis of the Results Compensation program is on rewarding group or business unit performance.

Results Compensation Program Objectives

The Results Compensation program is designed to meet the following objectives:

- Enhance and broaden the current compensation philosophy and pay practice.
- Share the results of the Corporation and the business unit with the people who contribute to that success.
- Motivate work performance and behavior that supports the Corporate and business unit financial goals.
- Increase the employee's understanding of the business.

Results Compensation Guidelines

- The program encompasses a one-year period; January 1, 1995, through December 31, 1995. Results Compensation awards, if approved, will be paid out in the first quarter of the following year.
- Regular full-time and regular part-time employees are eligible to participate in this program.
- An individual employee's Results Compensation award, if any, will be paid on gross pay as it appears on the employee's W-2 form. This includes regular, overtime, paid time off and other forms of premium pay.
- An employee who transfers between one of the three participating companies (BHP, WRDC, WPC) during the program year will have the Results Compensation award, if approved, based upon where the greatest amount of time worked occurred.
- The local union IBEW, 1250, elected not to participate in the 1994 Results Compensation program. It is unknown at this time if they will elect to participate in the 1995 program.
- If the bargaining unit does not participate, an employee who transfers to or from a bargaining unit position will receive a pro-rated Results Compensation award, if approved, relative to the amount of time worked in the non-bargaining unit position and gross pay earned in the non-bargaining unit position.
- The maximum Results Compensation bonus and award an employee may receive is 8 percent.
- In determining the bonus percentage to be paid, calculations will be rounded to two decimal places (e.g., 1.43%) not rounded to the nearest whole percentage amount.
- Any participating employee whose employment relationship with the Corporation is terminated voluntarily or involuntarily prior to the end of the program year will not be eligible for any Results Compensation award. Exceptions would be death, permanent disability or retirement.

Determining Results Compensation Awards

The Results Compensation program has two key financial goals. The financial goals consist of a business unit goal and a corporate goal. Whether a program award is paid and how much any award will be depends on how well and to what degree the goals were obtained as evaluated by the Board of Directors.

Goal 1. Financial performance of the individual business unit (BHP, WRDC and WPC) based on operating income.

Operating income is all unit revenue, less operating expense, before corporate income taxes and interest charges. This measures the financial results of operations.

Participants can receive up to four percent of their total Results Compensation award from this goal; specifics are attached. Specific goals will be determined and communicated to each employee of the respective business unit upon finalization of the budget process.

Goal 2. Corporate consolidated earnings per share (EPS) goal.

Earnings per share are equal to the total profit divided by the number of shares of Black Hills Corporation common stock owned by shareholders.

Participants can receive up to four percent of their total Results Compensation award from the goal. Since this is a consolidated Corporate goal, all employees in the different business units will have the same goal; specifics are attached. The specific goal will be determined and communicated to each employee upon finalization of the budget process.

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Board of Directors Retain Discretion

This program is not at any time a contract of employment. The Company reserves the right to change this program whenever and in any manner it deems appropriate. Irrespective of changes in the program, no rights are vested. All awards are earned only when and if finally approved by the Board of Directors notwithstanding anything contained in the program that may be construed to be to the contrary.

The Board of Directors, in its sole and absolute discretion, may decline to approve any award, though the participant may have achieved or exceeded threshold and target levels of performance. Setting a threshold or target of performance for any participants does not constitute a promise to pay an award even if the participant meets the threshold or target of performance. In determining whether to make an award and the amount of the award, the Board of Directors may consider criteria other than or in addition to the threshold and target performance determined under this program. Nothing in this program is a promise by the Corporation to continue to employ any participant for any period of time.

**PROPOSED 1995 RESULTS COMPENSATION PROGRAM - BLACK HILLS POWER AND LIGHT
GENERAL RELATIONSHIPS BETWEEN EARNINGS AND BONUS PERCENTAGES**

	OPERATING INCOME	% BONUS	% WEIGHTED	WEIGHTED BONUS
OPERATING INCOME BONUS GOAL:				
BUDGETED 1995 OPERATING INCOME-BHPL	\$25,284,000	0.0%		
TARGET GOAL (5% OVER BUDGET)	\$26,548,200	0.0%	50.0%	0.00%
EXCEED TARGET BY:				
1.0%	\$26,801,040	1.0%	50.0%	0.50%
2.0%	\$27,053,880	2.0%	50.0%	1.00%
3.0%	\$27,306,720	3.0%	50.0%	1.50%
4.0%	\$27,559,560	4.0%	50.0%	2.00%
7.0%	\$28,318,080	5.0%	50.0%	2.50%
10.0%	\$29,076,600	6.0%	50.0%	3.00%
13.0%	\$29,835,120	7.0%	50.0%	3.50%
16.0%	\$30,593,640	8.0%	50.0%	4.00%

	CONSOLIDATED EPS	% BONUS	% WEIGHTED	WEIGHTED BONUS
EARNINGS PER SHARE BONUS				
BUDGETED 1995 EARNINGS PER SHARE-BHC	\$1.66	0.0%		
TARGET GOAL (5% OVER BUDGET)	\$1.74	0.0%	50.0%	0.00%
EXCEED TARGET BY:				
1.0%	\$1.76	1.0%	50.0%	0.50%
2.0%	\$1.78	2.0%	50.0%	1.00%
3.0%	\$1.79	3.0%	50.0%	1.50%
4.0%	\$1.81	4.0%	50.0%	2.00%
7.0%	\$1.86	5.0%	50.0%	2.50%
10.0%	\$1.91	6.0%	50.0%	3.00%
13.0%	\$1.95	7.0%	50.0%	3.50%
16.0%	\$2.01	8.0%	50.0%	4.00%

**PROPOSED 1995 RESULTS COMPENSATION PROGRAM - WYODAK RESOURCES DEVEL
GENERAL RELATIONSHIPS BETWEEN EARNINGS AND BONUS PERCENTAGES**

	OPERATING INCOME	% BONUS	% WEIGHTED	WEIGHTED BONUS
OPERATING INCOME BONUS GOAL:				
BUDGETED 1995 OPERATING INCOME-WRDC:	\$12,193,572	0.0%		
TARGET GOAL (5% OVER BUDGET):	\$12,803,251	0.0%	50.0%	0.00%
EXCEED TARGET BY:				
1.0%	\$12,925,186	1.0%	50.0%	0.50%
2.0%	\$13,047,122	2.0%	50.0%	1.00%
3.0%	\$13,169,058	3.0%	50.0%	1.50%
4.0%	\$13,290,993	4.0%	50.0%	2.00%
7.0%	\$13,656,801	5.0%	50.0%	2.50%
10.0%	\$14,022,608	6.0%	50.0%	3.00%
13.0%	\$14,388,415	7.0%	50.0%	3.50%
16.0%	\$14,754,222	8.0%	50.0%	4.00%

	CONSOLIDATED EPS	% BONUS	% WEIGHTED	WEIGHTED BONUS
EARNINGS PER SHARE BONUS				
BUDGETED YTD EARNINGS PER SHARE-EHC	\$1.66	0.0%		
TARGET GOAL (5% OVER BUDGET):	\$1.74	0.0%	50.0%	0.00%
EXCEED TARGET BY:				
1.0%	\$1.76	1.0%	50.0%	0.50%
2.0%	\$1.78	2.0%	50.0%	1.00%
3.0%	\$1.79	3.0%	50.0%	1.50%
4.0%	\$1.81	4.0%	50.0%	2.00%
7.0%	\$1.86	5.0%	50.0%	2.50%
10.0%	\$1.91	6.0%	50.0%	3.00%
13.0%	\$1.96	7.0%	50.0%	3.50%
16.0%	\$2.01	8.0%	50.0%	4.00%

PROPOSED 1995 RESULTS COMPENSATION PROGRAM - WESTERN PRODUCTION COMP
GENERAL RELATIONSHIPS BETWEEN EARNINGS AND BONUS PERCENTAGES

	OPERATING INCOME	% BONUS	% WEIGHTED	WEIGHTED BONUS
OPERATING INCOME BONUS GOAL:				
BUDGETED 1995 OPERATING INCOME-WPC	\$2,292,633	0.0%		
TARGET GOAL (5% OVER BUDGET)	\$2,407,265	0.0%	50.0%	0.00%
EXCEED TARGET BY 1.0%	\$2,430,191	1.0%	50.0%	0.50%
2.0%	\$2,453,117	2.0%	50.0%	1.00%
3.0%	\$2,476,044	3.0%	50.0%	1.50%
4.0%	\$2,498,970	4.0%	50.0%	2.00%
7.0%	\$2,567,749	5.0%	50.0%	2.50%
10.0%	\$2,636,528	6.0%	50.0%	3.00%
13.0%	\$2,705,307	7.0%	50.0%	3.50%
16.0%	\$2,774,086	8.0%	50.0%	4.00%

	CONSOLIDATED EPS	% BONUS	% WEIGHTED	WEIGHTED BONUS
EARNINGS PER SHARE BONUS				
BUDGETED YTD EARNINGS PER SHARE-EHC	\$1.66	0.0%		
TARGET GOAL (5% OVER BUDGET)	\$1.74	0.0%	50.0%	0.00%
EXCEED TARGET BY 1.0%	\$1.76	1.0%	50.0%	0.50%
2.0%	\$1.78	2.0%	50.0%	1.00%
3.0%	\$1.79	3.0%	50.0%	1.50%
4.0%	\$1.81	4.0%	50.0%	2.00%
7.0%	\$1.86	5.0%	50.0%	2.50%
10.0%	\$1.91	6.0%	50.0%	3.00%
13.0%	\$1.96	7.0%	50.0%	3.50%
16.0%	\$2.01	8.0%	50.0%	4.00%

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