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IDAHO PUBLIC
UTILITIES COMMISSION

RANDALL C. BUDGE
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April 23, 2015

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
PO Box 83720
Boise, Idaho 83720-0074

Re: IPUC Case No. PAC-E-14-10

Dear Ms. Jewell:

Enclosed you will find the original and seven (7) copies of both redacted and confidential *Joint Comments of the Monsanto Company and the PacifiCorp Idaho Industrial Customers*. The confidential Joint Comments are subject to the Protective Agreement and should be filed under seal with those copies distributed only to those who have signed the Protective Agreement.

Thank you for your assistance. If you have any questions, please don't hesitate to call.

Sincerely,

RANDALL C. BUDGE

RCB:ts
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cc: Service List

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR APPROVAL OF A TRANSACTION TO CLOSE DEER CREEK MINE AND FOR A NOTICE OF APPLICATION DEFERRED ACCOUNTING ORDER	)	**CASE NO. PAC-E-14-10** **JOINT COMMENTS OF THE MONSANTO COMPANY AND THE PACIFICORP IDAHO INDUSTRIAL CUSTOMERS**

I. INTRODUCTION

COMES NOW intervenors, the Monsanto Company and the PacifiCorp Idaho Industrial Customers ("PIIC") (collectively, the "Joint Parties"), by and through the above counsel, and hereby, jointly submits these comments in response to the Application for Approval of Transaction and for a Deferred Accounting Order (the "Application") filed by Rocky Mountain Power ("RMP" or the "Company") on December 15, 2014. The Monsanto Company's Petition to

Intervene was granted March 19, 2015 by Order No. 33254. PIIC's Petition to Intervene was granted March 19, 2015 by Order No. 33255.

The Application contained an array of accounting and ratemaking requests related to the Company's disposition of its investment in the Deer Creek Mine, including agreements to sell certain mining assets to Bowie Energy Resource Partners, LLC ("Bowie"), a long-term coal supply agreement for the Huntington facility ("Huntington CSA"), costs related to the expected withdrawal from the United Mine Workers of America ("UMWA") 1974 Pension Trust, and a loss on the settlement of the UMWA Retiree Medical liability (collectively, the "Transaction"). In total, the Company expects that these components of the Transaction will result in costs or losses approximating $[redacted] on a total-Company basis—with the majority, including the write-off of the undepreciated investment in mining assets, being recognized in calendar years 2014 through 2016.[1] On an Idaho-allocated basis, these costs or losses will amount to approximately $17.4 million, all of which the Company requests be passed on to customers through several deferred accounts accruing a carrying charge based on RMP's authorized rate of return.

These comments are in response to the Commission Order 33221, giving notice of the Application, and that this matter will proceed under Modified Procedure, authorizing interested persons to file written comments in support or opposition, and providing rights of participation by filing a Petition to Intervene.

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[1] *See* Application at 13.

II. COMMENTS

a. <u>Summary</u>

The Joint Parties have reviewed the Application and have developed a number of recommendations and adjustments to the Company's accounting and ratemaking proposals. Specifically, the Joint Parties' main recommendations and conclusions with respect to the Transaction are as follows:

- **Transaction Prudence.** It is premature for the Commission to make a prudence finding now in this proceeding, outside a general rate case and prior to all of the Transaction costs being known.

- **Depreciation Reserve Methodology.** The Commission has historically required the use of the depreciation reserve methodology to allocate gains from the disposition of Electric Plant used to provide public service to Idaho ratepayers. Based on this method, Idaho ratepayers should be responsible for 62.2% of losses associated with the Deer Creek Mine disposition, with the Company responsible for the remaining 37.8%.

- **Amortization Period.** The Company justified its deferral request based on benefits expected to accrue well after the original useful life of the Deer Creek Mine. Accordingly, the Commission should amortize the deferred account balance over a period commensurate with the benefits received by ratepayers, or approximately seven years.

- **Carrying Charge.** There should be no carrying charge approved, as the Company should not be allowed to earn a return on assets that are no longer in ratebase. If a carrying charge is approved, it should be, at a maximum, no greater than the carrying charge approved for the Energy Cost Adjustment Mechanism ("ECAM"), which accrues interest at the customer interest on deposit rate.

- **Pension Withdrawal Deferral.** It is not necessary in this proceeding for the Commission to approve any deferred accounting related to the withdrawal from the 1974 Pension Trust. Notwithstanding, the Company should not be allowed to recover a lump-sum settlement amount that exceeds the current perpetuity value to ratepayers of the annual withdrawal payments at the current authorized rate of return, or $37.6 million.

- **Return on Mine Assets.** The Company did not propose to deduct the return on the mining assets already reflected in rates from the amounts that it proposes to amortize in the ECAM. Removing these costs will reduce the amounts amortized in the ECAM by $0.7 million on an Idaho allocated basis, until the Company's next general rate proceeding.

- **Construction Work in Progress / Preliminary Survey & Investigation Expenditures.** The Company is seeking to defer $3.5 million in Construction Work in Progress ("CWIP") expenditures (Total Company) associated with the Deer Creek Mine, $0.5 million in CWIP (Total Company) associated with the Preparation Plant, and $1.6 million in Preliminary Survey and Investigation ("PS&I") expenditures. None of these expenditures are recovered in current rates. As the CWIP expenditures have never been—and never will be—used and useful, these costs should not be included in any deferral mechanism approved for the Company. Similarly, with the closure of the Deer Creek Mine, the PS&I expenditures do not now and will never provide customer benefits and also should be excluded from the regulatory asset.

- **Facilities Used for the Benefit of Non-RMP Owners of Hunter Generating Units.** The Hunter generating facilities served by the Deer Creek Mine and Mining Assets are not owned exclusively by the Company. The portion of any regulatory assets established due to the Transaction should be adjusted to remove the share attributable to non-Company ownership.

- **Royalty Costs.** Company is seeking deferral of royalty costs associated with mine closure. Given the highly uncertain nature of the Company's estimates of these costs, the Joint Parties recommend that the Commission require that any ultimate recovery of these costs should be based on the royalties actually charged to the closure costs, rather than on the Company's estimate.

- **Waiver of Sharing Bands in the Energy Cost Adjustment Mechanism.** The Joint Parties are supportive of a one-time, non-precedential exception that would grant RMP's request to flow the change in coal supply costs associated with the Transaction through the ECAM without the 90/10 sharing mechanism, as well as the amortization expense associated with the Deer Creek Mine and the Mining Assets, but only for the portion of the Mining Assets that represents the loss on the sale of those assets.

- **Union Supplemental Unemployment and Medical Costs, Non-Union Severance Costs, and Miscellaneous Closing Costs, Including Labor.** The Joint Parties object to granting deferred accounting treatment to these expenses, estimated at [redacted] million, which are within the discretion of the Company, were not unforeseen, are not yet fully known and measurable, and do not have a material impact on the Company's financial integrity.

- **Inventory Write-Offs / Fuel Inventory Benefits.** RMP is proposing to defer and recover certain inventory write-offs it will experience as a result of the Transaction. The Joint Parties do not object to deferral treatment for the inventory write-offs so long as the Commission *also* recognizes the reduction in fuel inventory that RMP is projected to experience during 2015 as a result of the Transaction, the return on which is estimated to be approximately $6 million (Total Company).

- **Retiree Medical Obligation, Regulatory Asset – Income Tax, and Unrecovered ARO Costs.** The Joint Parties do not object to RMP's proposed deferral of these items up to the amounts specified in the Application.

b. <u>Transaction Prudence.</u>

Contrary to the Company's request, it is not necessary or desirable for the Commission to make a prudence finding in this proceeding, outside a general rate case and prior to all of the Transaction costs being known. While the booking of deferred costs generally carries with it a reasonable expectation of later recovery, it does not presume that such recovery *must* occur, nor does it require that a prudence determination be made at the time authorization of cost deferral occurs. That said, the Joint Parties are not challenging in this proceeding the prudence of the Company's actions with respect to moving forward with the Transaction.

c. <u>Single-Issue Ratemaking</u>

RMP's request for deferral in this proceeding is an exercise in single-issue ratemaking, which occurs when utility rates are adjusted or deferred in response to a change in cost or revenue items considered in isolation. Single-issue ratemaking ignores the multitude of other factors that otherwise influence rates, some of which could, if properly considered, move rates in the opposite direction from the single-issue change.

When utility regulatory commissions determine the appropriateness of a cost that a utility seeks to recover from its customers, the standard practice is to review and consider all relevant factors as part of a general rate case, rather than just certain factors in isolation. Considering some costs or revenues in isolation might cause a commission to allow a utility to increase rates or defer costs in the area singled out for attention without recognizing counterbalancing savings in another area.

When faced with an application like this, it is important to bear in mind that utility ratemaking is not an exercise in expense reimbursement. The opportunity for utility cost recovery is established in the *rates* approved by the Commission. In reality, costs and revenues are almost certain to differ from what was projected at the time rates were set. The simple fact that a utility incurs a cost that differs from what was anticipated when rates were set does not create an obligation on the part of the regulator to establish a mechanism for reimbursement. By law, the Commission is only authorized to change rates upon a determination that existing rates are unjust, unreasonable, discriminatory, preferential or insufficient. *Idaho Code* § 61-502. There are limited situations, such as a change in federal tax rates[2] or significant changes in fuel costs[3], in which singling out certain items for immediate rate recovery, tracker-increases or deferred recovery is appropriate. As a general matter however, such cases involve costs which are beyond its control of the utility, not costs incurred as a result of actions initiated by the utility. As this Commission has recognized, financial situations that are under the control of and initiated by a utility do not create a good case for deferred accounting treatment. *See* Commission Order No. 32766 (Commission denial of an application by Idaho Power to immediately recover energy efficiency incentive payments in rates wherein the Commission said "The Company has established a regulatory asset account [] and the Commission will address recovery of that account when issues affecting all customers and their rates are reviewed in a general rate case."). [4]

In conclusion, because single-issue ratemaking focuses on specific costs in isolation, the Commission should view single-issue deferral proposals with great caution.

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2 IPUC Case No. U-1500-164, Order No. 21640, (December, 1987) *In the Matter of the Investigation of the Effects of Revisions of the Federal Income Tax Code Upon the Cost of Service of Regulated Utilities.*

3 *Simplot v. Intermountain Gas Co.*, 102 Idaho 341, 630 P.2d 133 (1981);

4 IPUC Case No. IPC-E-12, 24, Order No. 32766, p.9 (March 2013), *In the Matter of the Application of Idaho Power Company for Authority to Implement Rates to Include Capitalized Custom Efficiency Incentive Payments.*

d. Deer Creek Mine Background

The Company originally invested in the Deer Creek Mine land and facilities in 1977 in connection with the construction of the second Huntington Generation Unit. The Company's investment was intended to supply fuel to the entire Huntington Facility located adjacent to the mine. The Deer Creek Mine assets were originally included in the Company's rate base in Idaho following the appeal of the Company's 1976 general rate case, where the Idaho Supreme Court set aside the Commission's decision to exclude the Huntington Generation Unit 2 and Deer Creek Mine from rate base and required the inclusion of those investments as a known and measurable adjustment to the historical 1976 test period.[5]

Since that time, the Company has earned substantial amounts of return on its investment. While the cost of operating the mine is recovered as a cost of coal and included in net power costs, Idaho rates presently provide the Company with a return on rate base of approximately $744,321 per year, on an Idaho-allocated basis, in connection with its investment in the Deer Creek Mine assets and other assets involved in the Transaction. Over the approximate 37 year period that the assets have been included in rate base, the Company has earned returns on its investment in the Deer Creek Mine that likely far exceed the losses that it proposes to pass onto ratepayers in this proceeding.

The returns that shareholders have received in connection with the investment in the Deer Creek Mine have compensated for investment risk. This investment risk reflected, among other things, the probability that the Company would ultimately have to dispose of the mining assets for a loss. In recognition of this investment risk, it is critical that Commission employ an

[5] *See Utah Power & Light v. Idaho Publ. Util. Com'n,* 102 Idaho 282 (1981).

equitable methodology to allocate the losses associated with the Transaction between shareholders and ratepayers.

e. The Depreciation Reserve Methodology

For purposes of allocating gains and losses associated with the disposition of utility property between shareholders and ratepayers, the Commission has historically relied on the depreciation reserve methodology, a method that the Company, itself, originally proposed in Case No. PAC-E-99-2.[6] In that proceeding, the Company argued that shareholders should be entitled to a portion of the gain associated with the sale of the Centralia Generating Facility because, at the time of the sale, shareholders continued to bear the risk of recovering the undepreciated portion of the generating facility.[7] As applied to the Deer Creek Mine Transaction, the depreciation reserve methodology will result in the below split of losses between shareholders and ratepayers.

Table 1
Transaction Sharing Percentages Using Depreciation Reserve Methodology ($000)

1		Gross Plant	Depr. Res.	Net Plant	Shareholder %	Ratepayer %
2		(a)	(b)	(c)	(d) = (c) ÷ (a)	(e) = 1 - (d)
3	Deer Creek Mine*	218,888	(136,100)	82,788	37.8%	62.2%
4	Prep Plant**	40,915	(21,072)	19,360	47.3%	52.7%
5	*Percentage to be applied to unrecovered investment, direct closure costs, UMWA medical Settlement, and 1974 pension trust withdrawal payments					
6	** Percentage to be applied to loss on the sale of prep plant					

6 *See In re the Application of PacifiCorp for an Order Approving the Sale of its Interest in (1) the Centralia Steam Electric Generating Plant, (2) the Rate Based Portion of its Centralia Coal Mine, and (3) Related Facilities; for a Determination of the Amount of and the Proper Ratemaking Treatment of the Gain Associated with the Sale; and, (4) an EWG Determination,* Case No. PAC-E-99-2, Order 28296 at 6 (Mar 2000).

7 *Id.*

The depreciation reserve methodology relies on the relationship between net plant and gross plant to allocate gains and losses between shareholders and ratepayers. It is calculated by multiplying the gain or loss by the percentage of capital associated with an asset that has been paid for in rates by ratepayers through depreciation allowance. This percentage of capital repaid by ratepayers is representative of the public's ownership interest in the disposed asset and has historically been used by the Commission to allocate gains and losses associated with the disposition of utility property.

The principle behind the depreciation reserve methodology is that over time ratepayers gradually repay shareholders for the capital used to acquire utility plant through a depreciation allowance. This concept has been recognized by the Idaho Supreme Court, which has stated that "[o]ne way of looking at a depreciation allowance on a utility's personal property is that the public buys that property from the utility as it is used up."[8] As ratepayers reimburse shareholder capital in utility property, the property becomes vested in the public and provides ratepayers with a degree of tenancy in the utility property. Once the utility property is fully depreciated, for example, ratepayers have a right to the full benefit of utility property without having to pay to use it. Prior to the full repayment of the asset, however, ratepayers are only vested in a percentage of the utility plant. The goal of the depreciation reserve methodology is to allocate the gains and losses from the disposition of utility property between shareholders and ratepayers in accordance with this percentage interest.

This Commission has applied the depreciation reserve methodology in several instances. For example, in Case No. Case No. PAC-E-99-2, the Commission agreed with the Company's proposal that the gain from sale of the Centralia plant should be shared between shareholders and

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[8] *Boise Water Corporation v. Idaho Public Utilities Commission*, 99 Idaho 158, 161, 578 P.2d 1089, 1092 (1978).

ratepayers using the depreciation reserve methodology, finding that "the depreciation reserve methodology proposed by the Company to be a reasonable method for distribution of gain associated with the sale of the Centralia plant."[9] Similarly, the Commission rejected Avista's arguments that Avista should be entitled to the entirety of the gain from the sale of its share of Centralia, instead holding that, notwithstanding the present value revenue requirement benefits to ratepayers associated with the sale, the depreciation reserve methodology was the most appropriate method to allocate the gain from the disposition of the plant between shareholders and ratepayers.[10]

Now, in this proceeding, where the disposition of utility plant results in a loss, the Company proposes to pass 100% of losses onto customers. As a matter of equity, the Commission should reject the Company's one-sided approach of allocating Transaction losses to ratepayers and uniformly apply the depreciation reserve methodology, allocating a portion of losses to the Company, just as it has been used to allocate gains to the Company in the past.

Any other methodology, including the Company's proposal for ratepayers to bear 100% of the loss, would be unfair to ratepayers, who have been foreclosed from recognizing prior gains based on the application of the methodology. Accordingly, the Joint Parties request that the losses associated with the Deer Creek Mine disposition be allocated 37.8% to the Company and 62.2% to ratepayers, as detailed in Table 1 above.

f. <u>Amortization</u>

The Company proposes to amortize the deferred account balances requested in this proceeding in a manner consistent with the current rates of depreciation for the Deer Creek

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9 *Id.* at 11.

10 *In re Application of Avista Corporation for Authority to Sell Its Interest in the Coal-Fired Centralia Power Plant*, Case No. AVU-E-99-6, Order 28297 at 11 (Mar 2000).

Mine.[11] This amounts to a five year amortization period commensurate with the original useful life of the mine, which was scheduled to conclude at the end of 2019. Because, however, the Company justified its request for deferral based on benefits expected to accrue to ratepayers after the original useful life of the Deer Creek Mine, a five-year amortization period is too short and will not properly match the costs of the Transaction amortized to ratepayers with the benefits received in rates. In order to properly match the level of ratepayer costs with benefits received in rates, an amortization period of seven years is appropriate based on the application of the depreciation reserve methodology. If the depreciation reserve methodology is not used, a nine year amortization period, or longer, would be appropriate.

A seven year amortization period is appropriate because the majority benefits associated with the mine closure will not accrue to ratepayers until well after the end of the Deer Creek Mine's original useful life. Confidential Figure 1, below, details the timing of the benefits used by the Company in its calculation of the net present value revenue requirement benefits of the Transaction, used to justify its proposed deferral.[12]

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[11] Application at 15.
[12] *See* Crane, Di at 32:3-12.

Confidential Figure 1

Timing of Ratepayer Benefits Associated with the Transaction on a Total Company Basis ($m)

[redacted]

As can be seen from Confidential Figure 1, despite the fact that the Company is requesting for ratepayers to pay the entire amount of the Transaction costs over a five-year period, the majority of benefits will not begin to be recognized by ratepayers until after the end of the Deer Creek Mine's original useful life. The figure includes each of the major benefit categories in the Company's financial analysis, with the exception of the UMWA retiree medical settlement, which was a hard-coded value in the Company's analysis. If the UMWA retiree medical settlement benefits were included, it would further demonstrate that the benefits of the transaction will not be recognized fully by ratepayers until after the end of the Deer Creek Mine's original useful life. The Prep Plant Costs category includes the impacts of property tax savings and coal handling costs, which are too small to be detailed independently in the figure and largely offsetting. Finally, the benefit category related to the 1974 Pension Trust savings excludes the terminal value of the pension withdrawal annuity liability, which, if included, would result in an additional [redacted] ratepayer benefit in 2029.

Included in Attachment A is a numerical representation of the above benefits that compares the Transaction costs to the cumulative ratepayer benefits expected from the mine disposition over the period 2015 through 2029. As can be noted from the Attachment, had the economics been measured solely over the five-year period ending in 2019, the Transaction would not have produced a net benefit to ratepayers. A net benefit will only begin to accrue to ratepayers after calendar year 2021, supporting a seven year amortization period. This timing, however, is based on the assumption that the depreciation reserve methodology would be applied to reduce the amount of transaction costs allocable to ratepayers. If the depreciation reserve methodology is not applied, a net benefit will only begin to accrue to ratepayers after calendar year 2024, supporting a nine year amortization period.

A number of problems are created by the Company's proposal to amortize the Transaction costs over a period preceding the time when the majority of the benefits are to be recognized by ratepayers. Foremost, if a five-year amortization period is approved, generational inequity will occur. The ratepayers responsible for paying the upfront amortization will not be the same ratepayers that ultimately receive the benefits associated with the Transaction. Further, increases in other jurisdictions' loads may create a situation where the benefits ultimately received by ratepayers through the inter-jurisdictional allocation methodology become diluted with time. This jurisdictional inequity to Idaho customers, whose loads are not expected to grow as rapidly as other jurisdictions, must be resolved in any amortization approved by the Commission.

To solve these problems, amortization, first, must occur over the same period that benefits are received in order to ensure that the ratepayers responsible for the costs are the same ratepayers receiving the benefits. Second, any amount amortized must be dynamic, such that the amortization will be reduced in the circumstance where Idaho's jurisdictional allocation of the Transaction benefits, by virtue of its allocation of the Huntington facility, declines. An illustrative example of a dynamic amortization methodology is detailed in Table 2 below.

Table 2
Illustrative Dynamic Amortization Methodology

1			2016	2017	2018	...	2022
2	Illustrative Total Company Amortization ($m)		10.00	10.00	10.00		10.00
3	Huntington Fuel Allocator (SE)		6.0%	5.5%	5.0%		4.0%
4	Idaho Allocated Amortization ($m)	[1] * [2]	0.60	0.55	0.50		0.40

In summary, the Commission should require the Company to amortize the deferred account balance over a seven year period in order to properly match the costs borne, and benefits received, by ratepayers, as detailed in Attachment A. If the depreciation reserve methodology is not employed by the Commission, however, a nine year amortization period, or longer, should be used. Such an amortization period is critical to ensuring that generational inequity does not occur. In addition, the amortization should be dynamic, responding to changes in Idaho's share of benefits as illustrated in Table 2, above.

g. Carrying Charge

The Company has proposed a carrying charge for the unrecovered investment in the Deer Creek Mine and the Mining Assets equal to its overall rate of return.[13] It is the Joint Parties' position that there should be no carrying charge approved, as the Company should not be allowed to earn a return on assets that are no longer in ratebase. First and foremost, the Joint Parties question the legality of providing a carrying charge on what will effectively be assets no

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13 Application at 16.

longer owned by the Company and included in ratebase. Idaho Code § 61-502 prohibits the Commission (except upon an explicit finding that the public interest would be served) from "setting rates [] that grants a return on construction work in progress or property held for future use and which is not currently used and useful in providing utility service." With this statutory bar in place, the Company has a significant burden of proving that it is "in the public interest" for the Commission to establish a carrying charge, as requested.

There is a strong Commission precedent for approving deferred accounts with no carrying charge. For example, in Case No. IPC-E-06-06, Idaho Power Company sought deferral of costs incurred in an effort to develop the Grid West Regional Transmission Organization ("RTO"), the development of which was unsuccessful.[14] In that proceeding the Commission authorized a deferral but did not authorize a carrying charge on the deferred account balance because the Idaho Power Company's efforts were unsuccessful.[15] Upon reconsideration, the Commission emphasized that it retains "discretionary authority in determining whether to approve a carrying charge on a deferral account."[16]

As another example, in Case No. IPC-E-09-21, Idaho Power Company sought deferral of costs related to the under recovery of transmission revenues from legacy transmission agreements not recoverable through formula transmission rates.[17] The Commission held that no carrying charge should be allowed on the deferred account balance requested in that proceeding because "the deferral provides sufficient benefit to the Company."[18] Finally, in Case No. IPC-E-

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14 *See In re the Application of Idaho Power Company for an Accounting Order Addressing the Deferral of Costs Related to the Development of Grid West,* Case No. IPC-E-06-06, Order No. 30157 at 1.

15 *Id.*

16 Case No. IPC-E-06-06, Order 30235 at 2.

17 *In re the Application of Idaho Power company for an Accounting Order Authorizing the Deferral of Transmission Costs Associated with the Order on Initial Decision (FERC Docket No. ER06-787),* Case No. IPC-E-09-21, Order No. 30940 at 6.

18 *Id.*

92-9, the Commission adopted Staff's proposal – in which Idaho Power concurred – that losses from the sale of utility assets would be placed in a regulatory asset account and amortized over ten years, with the unamortized balance of the loss included in revenue requirement but excluded from ratebase, so as "not [to] allow the shareholders to earn a return on an asset no longer owned by the Company." [19] The Joint Parties are in accord with the Commission's announced position in the cases cited above, and in other determinations made by the Commission, that there should be no carrying charge approved in this case, as the Company should not be allowed to earn a return on assets that are no longer in ratebase.

Alternatively, should the Commission decide to compensate the Company for the time value of money associated with the recovery of the deferral, the Company should only be entitled to recover the time value of money based on a more relative risk free rate. The overall rate of return received by the Company includes a risk premium, both through the cost of equity and the cost of debt, which provides the Company with profit commensurate with the level of risk assumed in its investment in utility assets. The level of risk assumed by the Company in utility assets, however, is not the same level of risk assumed with respect to recovering the deferred accounts sought in this proceeding. Once a deferred account has been determined and approved by the Commission for amortization, the risk of recovery surrounding the account balance is much lower than other aspects of the Company's operations. As a result, the Company's overall rate of return is not an appropriate carrying charge for the deferred account balance sought in this proceeding. The Joint Parties also disagree with the Company as to "what is" the Company's current overall rate of return. [20]

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[19] Case No. IPC-E-93-20, Order No. 25241 , *Application of Idaho Power Company for Authority to Sell Certain Distribution Facilities Located on Bald Mountain.*

[20] In discovery, RMP states that it's overall pre-tax rate of return in Case No. PAC-E-11-12 was 11.616%. However, that case was resolved through a stipulation that did not specify an approved return on equity or an

If the Commission decides to allow a carrying charge, the Commission should, at a maximum, apply a carrying charge that is consistent with the carrying charge applied to the ECAM balance, based on the customer interest on deposit rate. Consistent with the power cost deferrals included in the ECAM, the deferred account balances sought in this proceeding should accrue interest at a rate not to exceed the interest on deposit rate, currently 1.0% per annum.

h. <u>Pension Withdrawal Liability</u>

Energy West Mining Company currently contributes approximately $3 million per year into the 1974 Pension Trust. These costs are currently classified as a cost of fuel and included in net power costs. When the Company closes the Deer Creek Mine and withdraws from the 1974 Pension Trust, it will have the option to continue paying the $3.0 million annual liability, in perpetuity, or settle its liability with an upfront, lump-sum settlement amount.[21] The lump-sum settlement amount would be determined in a bilateral negotiation between the Company and the 1974 Pension Trust. For the plan year ending June 30, 2014, the Company estimated that the withdrawal liability for Energy West was $96.7 million, based on a risk-free discount rate.

The Company's proposed treatment is to continue the annual contribution of $3 million until an acceptable lump-sum withdrawal payment can be determined. Accordingly, this expense should remain in net power costs, where it is currently recorded, requiring no deferral or special accounting order from the Commission. If and when the Company proposes to recover a lump-sum withdrawal payment, it should then be subject to Commission review and approval at that time.

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approved overall rate of return. *See* Case No. PAC-E-11-12, Order 32432, and Stipulation filed October 18, 2011. **The most recent post-tax rate of return approved by the Commission was 7.98%, established in Case No. PAC-E-10-07**, which translates into approximately 11.15% on a pre-tax basis. *See* Case No. PAC-E-10-07, Order 32196, at 12 and 41. The Pre-tax ROR of 11.15% was estimated by applying the approved Conversion Factor of 1.615 to the approved ROE of 9.9%.

[21] Stuver, Di at 11:4-20.

Notwithstanding, the financial exposure to ratepayers of withdrawing from the 1974 Pension Trust is currently limited to an annuity payment of approximately \$3.0 million per year.[22] Thus, to the extent that the Company negotiates a lump-sum withdrawal payment, any amount paid in excess of the perpetuity value of the \$3.0 would be harmful to ratepayers. Based on the 7.98% cost of capital approved in Case No. PAC-E-10-07 (*See* footnote 20), the perpetuity value of the \$3.0 million annuity payment to ratepayers is approximately \$37.6 million on a total Company basis,[23] or approximately \$2.4 million on an Idaho allocated basis.

The amount for which a party may be willing to settle an annuity payment is largely driven by the perpetuity value. The perpetuity value represents the present value of a fixed stream of payments made for an indefinite period of time and is calculated, simply, by dividing the payment by the periodic interest rate:

Figure 2
Perpetuity Value

$$\textbf{Perpetuity Value} = \frac{\textbf{Payment}}{\textbf{Discount Rate}}$$

Based on this formula, at a 7.98% cost of capital, any lump-sum amounts paid in excess of \$37.6 million would increase costs to ratepayers relative to the perpetuity value of the \$3.0 million annual withdrawal liability. From the ratepayer perspective, any amount of funds paid in excess of that amount would be more efficiently deployed by the Company as a permanent offset to rate base, rather than as a lump-sum payment. It follows that any amount collected in excess of that amount would only serve to eliminate any risk to shareholders and would not be appropriately included in rates.

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22 Stuver, Di at 11:4-20.
23 \$37.6 m = \$3.0 m ÷ 7.98%.

i. <u>Return on Mining Assets</u>

The Company has proposed to begin immediate amortization of the Transaction costs through the ECAM. The Company, however, is currently recovering the capital costs associated with the disposed mining assets and did not propose any adjustment to remove the return on mining assets already included in rates. The Company proposal, therefore, overstates the amount of cost incremental to base rates that ought to be recovered through the ECAM. Eliminating this return component would result in a $744,321 annual reduction to the Company's ECAM deferrals.[24]

Two categories of costs have traditionally been included in rates associated with the Deer Creek Mine. First, mine operating costs, including depreciation, are included in the cost of fuel for the Huntington facility. This fuel cost is reflected in rates as a net power cost, which is trued-up annually through the ECAM. Second, the net plant investment in the mining assets is included in rate base, separate from the net power cost calculation. The rate base amounts and associated return on the mining assets are only updated in rates in general rate case filings.

While the 'return of'—*i.e.* depreciation of—the mining assets will be trued-up as a component of net power costs in the ECAM, the 'return on' the mining assets will not be accounted for in the ECAM proceeding. Under the Company's proposal, it will continue to earn a return on the mining assets until new rates are established in a general rate proceeding. In order to properly reflect the rate impact of the Company's proposal, the Commission should require the Company to reduce the amount of Transaction costs amortized in the ECAM by the

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[24] *See* Attachment B (the Company's Supplemental Response to Monsanto Data Request ("DR") 1.22). The $744,321 return component was calculated by RMP in this data response using the 11.616% pretax return alleged by the Company. Although the Joint Parties disagree with RMP's representation of its authorized return, the return component amount depicted by RMP is referenced here for purposes of this discussion. If the Commission determines that RMP's representation of its return is incorrect, it would impact the amount of the return component.

$744,321 of Idaho-allocated return on the mining assets already reflected in rates until the return component is removed from rates in the Company's next general rate proceeding.

i. Construction Work in Progress / Preliminary Survey and Investigation Expenditures

RMP is seeking to defer $3.5 million in Construction Work in Progress ("CWIP") expenditures (Total Company) associated with the Deer Creek Mine, $0.5 million in CWIP (Total Company) associated with the Preparation Plant, and $1.6 million in Preliminary Survey and Investigation ("PS&I") expenditures, which is for a surface exploration drilling program outside the boundaries of the leases currently controlled by PacifiCorp. None of these expenditures are recovered in current rates. As the CWIP expenditures have never been – and never will be – used and useful, these costs should not be included in any deferral mechanism approved for the Company. Similarly, with the closure of the Deer Creek Mine, the PS&I expenditures do not now and will never provide customer benefits and also should be excluded from the regulatory asset. The Joint Parties do not believe that the circumstances of this Transaction warrant deviation from the Commission's typical requirement that costs can be collected from customers only for assets that are used and useful and that provide benefits to customers.

j. Facilities Used for the Benefit of Non-RMP Owners of Hunter Generating Units

The Hunter generating facilities served by the Deer Creek Mine and Mining Assets are not owned exclusively by the Company. Other parties own shares in Hunter Units Nos. 1 and 2 that together represent 14.88% of the aggregate operating capacity of the three Hunter units. Any regulatory assets established due to the Transaction should be adjusted to remove the share attributable to non-Company ownership of these units. Currently, the costs of the Deer Creek Mine and Mining Assets allocated to the other owners are recovered from the share of the cost of coal charged to the other owners.[25] With Deer Creek coal production discontinued, this vehicle for recovery of the Deer Creek Mine and Mining Assets costs from the non-RMP owners no longer exists. Instead, the Company's filing appears to contemplate fully recovering all Transaction costs from retail customers, without recognizing that a portion of these facilities also served non-RMP ownership interests. The Joint Parties disagree with such an approach and recommend that RMP be required to remove the portion of the assets that were required to serve the non-RMP-owned Hunter plant.

In discovery, RMP prepared a table that identifies the portion of the Transaction costs the Company believes is allocable to retail customers after the portion of the assets required to serve non-RMP ownership interests is removed. This adjustment results in a reduction of [redacted] applied to the proposed regulatory assets associated with the Deer Creek Mine, the loss on the Mining Assets, closure costs, and Retiree Medical settlement loss, as well as an adjustment to the 1974 Pension Trust regulatory asset.[26] The Joint Parties believe this adjustment is reasonable, with the exception of the loss on the Mining Assets, for which the adjustment should be closer to [redacted], to reflect the fact that the Preparation Plant is primarily used in support of the Hunter units. To the extent any of these regulatory assets are approved in this proceeding, the regulatory asset values should reflect these removals.

The Joint Parties note that RMP agreed to address this issue in its Utah and Wyoming Deer Creek Mine closing Settlements, agreeing to the following Settlement terms in Utah (with very similar language in the Wyoming Settlement):

> The [Utah] Parties agree that the Commission should enter an order authorizing separate accounts to be established for all joint owner elements related to the Transaction, including but not limited to the following:

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25 See RMP Response to Monsanto Data Request 2.4 (a), (b) and (d).

26 See WY PSC Docket No. 20000-464-EA-14, RMP Response to WIEC Data Request 5.3 and Confidential Attachment WIEC 5.3.

a. the Utah-allocated portion of unrecovered investment in the Deer Creek Mine and the loss on the Mining Assets;

b. the Utah-allocated portion of Deer Creek closure costs;

c. the Utah-allocated portion of loss on settlement of the Retiree Medical Obligation;

d. the Utah-allocated portion of the withdrawal from the 1974 Pension Trust; and

e. the Utah-allocated portion of total Company amount of \$3.8 million of the net Deer Creek Mine related CWIP (including PS&I and salvage).

The Company will be responsible for obtaining reimbursement of these costs from joint owners; the Company's utility customers' rates will not be impacted in the event the joint owners do not fully reimburse the Company.

k. <u>Royalty Costs</u>

The Company is seeking deferral of royalty costs associated with mine closure. The Joint Parties are concerned with the estimation of these costs provided by RMP in this case. One portion of the royalty cost estimate, abandonment royalties amounting to [redacted], appears to be purely speculative at this point.[27] The other portion of the royalty cost estimate, recovery-based royalties of [redacted], is derived by grossing up RMP's planned expenditures associated with mine closure, including the 1974 Pension Trust withdrawal and Retiree Medical settlement loss.[28] Given the highly uncertain nature of these estimates, the Joint Parties recommend that the Commission require that any ultimate recovery of these costs should be based on the royalties *actually* charged to the closure costs, rather than on the Company's estimate. In addition, in the Wyoming Settlement, RMP agreed to cap the recovery of

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27 See Utah PSC Docket No. 14-035-147, RMP Response to OCS Data Request 2.23. Abandonment royalty estimate source: RMP Response to IPUC Data Request 4, Confidential Attachment IPUC 4, EW Fin Model 12-15-14, 'EW FRF Pro Forma Closure Sale', "Royalties" tab.

28 See WY PSC Docket No. 20000-464-EA-14, RMP 1st Supplemental Response to WPSC Data Request 2.16. Recovery-based royalty estimate source: RMP Response to IPUC Data Request 4, Confidential Attachment IPUC 4, EW Fin Model 12-15-14, 'EW FRF Pro Forma Closure Sale', "Royalties" tab.

abandonment royalties at 75% of the total costs estimated in the Company's filing. The Joint Parties recommend that a similar cap be adopted for Idaho.

I. <u>Waiver of Sharing Bands in the Energy Cost Adjustment Mechanism</u>

The depreciation and operating expenses of the Deer Creek Mine and Mining Assets are currently included in net power costs, and RMP proposes that these costs, along with the costs or benefits realized for replacement coal supply, be subject to the ECAM without application of the 90/10 sharing band. The Joint Parties are supportive of a one-time, non-precedential exception that would grant RMP's request to flow the change in coal supply costs associated with the Transaction through the ECAM without the 90/10 sharing mechanism, as well as the amortization expense associated with the Deer Creek Mine and the Mining Assets.

The Joint Parties believe this treatment is reasonable because the depreciation expense associated with the Deer Creek Mine and the Mining Assets is currently included in net power cost, and thus is part of base net power cost in rates. However, at the time these assets are taken out of service they cease to be included in net power cost. Thus, actual net power cost, for the purpose of calculating the 2015 ECAM, will be reduced by the amount of the depreciation and operating expenses of the Deer Creek Mine and the Mining Assets. Absent any special ratemaking consideration, the ECAM mechanism will remove 90% of these costs currently included in base NPC from ultimate recovery from customers, as if they had gone away. In the Joint Parties' view, in the case of depreciation expense, such a result would be an unintended consequence of ratemaking mechanics that would produce an unreasonable result, thus justifying deferred accounting treatment.

The depreciation expense for these assets is currently included in rates and RMP is proposing to convert the corresponding net plant in service into a regulatory asset that would continue to be amortized on the same schedule that the plant is being depreciated. In general, it is reasonable for RMP to continue to recover its initial investment in the Deer Creek Mine and the Mining Assets at the current level until rates are reset pursuant to the next general rate case.

If this amortization expense is deferred through the ECAM as proposed by RMP, then it may also be reasonable to exempt it from the 90/10 sharing mechanism in the calculation of the 2015 ECAM (and the 2016 ECAM, to the extent that it is not included in the rate effective period following the next general rate case), in order to maintain current recovery levels. At the same time, it would also reasonable to exempt the incremental benefits of supplying the Hunter and Huntington plants through the Bowie contract from the 90/10 sharing mechanism to place this companion impact on net power cost on the same playing field as the treatment of depreciation/amortization expense. That is, it would be unreasonable to exempt the depreciation/amortization expense from the 90/10 sharing (which benefits RMP) without also exempting the incremental benefits of the Bowie contract (which, on a standalone basis, is projected by RMP to benefit customers).

This issue has also been addressed in the Utah and Wyoming Settlements, with the former providing as follows:

> The [Utah] Parties agree that the Commission should enter an order authorizing a one-time, non-precedential exception to be made to the 70/30 Energy Balance Account ("EBA") sharing band for the following items, to be recovered by flowing them through the EBA at 100% without applying the sharing band until the rate effective date of the next general rate case:
>
> a. unrecovered Deer Creek Mine investment amortization, at the current level of depreciation expense in rates, and the amortization of the loss related to the Mining Assets at the current rate of depreciation as described in the Application; and
>
> b. actual Utah fueling cost for the Hunter and Huntington plants, including:
>   i. lower replacement coal costs;
>   ii. Prep Plant operational savings;

iii. pension timing savings; and
iv. savings on Energy West retiree medical benefits as a result of the settlement of the Retiree Medical Obligation.

The Parties agree that the sharing band waiver is non-precedential, and the Company agrees to not request any change or elimination of the EBA sharing band to be effective prior to the end of the EBA pilot.

The Wyoming Settlement provides similar language and the benefits identified in section (b) are identical to that of the Utah Settlement. The Joint Parties recommend that the same benefits identified in section (b) above be recognized in the Idaho jurisdiction.

m. <u>Union Supplemental Unemployment and Medical Costs, Non-Union Severance Costs, and Miscellaneous Closing Costs, Including Labor</u>

RMP is seeking deferral of an estimated [redacted] million (Total Company) in mine closing costs associated with these items, most of which will be incurred in 2015-16. The Joint Parties object to granting deferred accounting treatment to these expenses, which are within the discretion of the Company, were not unforeseen, are not known and measurable, and do not have a material impact on the Company's financial integrity. To the extent these costs are prudently incurred, they can properly be recovered through the filing of a general rate case, depending on the timing of the filing and test period used in the case. But as utility ratemaking is not a matter of simple cost reimbursement, it should not be presumed that these costs are or will be recoverable on a single-issue basis, outside the framework of a general rate case. Consequently, the Joint Parties recommend that deferred accounting treatment for these costs be denied.

n. <u>Inventory Write-Offs / Fuel Inventory Benefits</u>

RMP is proposing to defer and recover certain inventory write-offs it will experience as a result of the Transaction, estimated to be [redacted] million (Total Company). The Joint Parties do not object to deferral treatment for the inventory write-offs so long as the Commission *also* recognizes the reduction in fuel inventory that RMP is projected to experience during 2015 as a result of the Transaction. Fuel inventory has an impact on rates because it is included in rate base and RMP earns its authorized rate of return on its value. RMP's fuel inventory for facilities impacted by the Transaction is projected to decline significantly in 2015 relative to what is included in rates (*See* Table 2 below). The Joint Parties object to the Company's failure to recommend that any reduction in fuel inventory be recognized as a benefit to customers as part of its proposed deferral. If RMP is to receive the benefit of deferred accounting for many of the costs it is incurring as a result of the Transaction, including an inventory write-off, then the savings to customers in fuel inventory carrying costs should also be reflected.

Table 2

Coal Fuel Stock Balances Related to Transaction			
Fuel Stock Site	PAC-E-11-12 Dec. 2011 Year-End Balances [29]	Current Projection 13-mo. av. Dec 14-Dec 15 [30]	Difference (Current Projection - GRC Balances)
Hunter	71,376,781	50,645,174	(20,731,607)
Huntington	28,267,756	28,594,235	326,479
Deer Creek Mine	568,214	5,298	(562,916)
Preparation Plant	32,836,497	5,091,901	(27,744,596)
Rock Garden	22,401,094	17,633,011	(4,768,083)
Total	155,450,342	101,969,619	(53,480,723)

The earnings on the reduction in fuel inventory for Calendar Year 2015, which the Joint Parties estimate to be $6 million (Total Company)[31], should be deferred and credited against the inventory write-off, and the excess credited against the remaining regulatory assets associated with the Transaction that are approved by the Commission in this case.

[29] Data Source: RMP Response to Monsanto Data Request 2.1, Attachment Monsanto 2.1.

[30] Data Source: UT PSC Docket No. 14-035-147, RMP Response to OCS Data Request 4.6, Attachment OCS 4.6.

[31] The $6 million Total Company estimate was derived using the Utah Commission Integrated Allocation Model 12-2-14 from UT PSC Docket No. 13-035-184. The Utah revenue requirement impact determined in the model (~$2.5 million) was divided by the Utah system energy (SE) factor (41.972%) to derive the estimated Total Company impact of the change in coal fuel stock balances relative to what was included in Case No. PAC-E-11-12, using the authorized rate of return in Case No. PAC-E-10-07. Although this calculation was made using a Utah model, it represents a reasonable estimation of the Total Company impact of the change in coal fuel stock balances in Idaho rates.

The Joint Parties note that a fuel inventory credit is recognized in the Utah Settlement. In that Settlement, the fuel inventory credit is recognized starting June 1, 2015. However, the Joint Parties believe that a more appropriate date for the credit to start being accrued is January 1, 2015, to reflect the benefit of the reduced fuel inventory associated with the cessation of Deer Creek mining operations at the end of 2014, rather than five months later, which is associated with the target date of the Transaction.

o. <u>Retiree Medical Obligation, Regulatory Asset – Income Tax, and Unrecovered ARO Costs</u>

RMP has requested deferral of approximately [redacted] million (Total Company) for Retiree Medical Obligation, [redacted] million (Total Company) for an income tax regulatory asset, and [redacted] million (Total Company) for unrecovered asset retirement obligation (ARO) costs. As the Retiree Medical Obligation costs would have been amortized to FAS 106 expense absent the settlement, the Joint Parties do not object to RMP's proposal for deferral of these costs. With respect to proposed income tax regulatory asset, the Joint parties are not objecting to RMP's proposal for deferral of this item to the extent it offsets what would otherwise be a duplicate tax benefit to customers, as RMP maintains in its Response to Monsanto Data Request 2.5. And because the unrecovered ARO costs are part of a long-term calculation applied to the asset retirement obligation for a long-lived asset, deferral and amortization of these costs may be appropriate.

II. <u>Conclusion</u>

In light of the approximately [redacted] million in costs associated with the Transaction, which the Company proposes to pass onto Idaho customers, the Joint Parties respectfully request that the Commission adopt the proposed recommendations outlined in these comments. The

Joint Parties appreciate the opportunity to submit these comments regarding the Transaction to dispose of the Deer Creek Mine and look forward to working with the Commission and interested parties to resolve these matters.

RESPECTFULLY SUBMITTED this 23rd day of April, 2015.

Monsanto Company	**PacifiCorp Idaho Industrial Customers**
Randall C. Budge RACINE, OLSON, NYE, BUDGE & BAILEY, CHARTERED	Ronald L. Williams WILLIAMS BRADBURY, P.C.

CERTIFICATE OF MAILING

I HEREBY CERTIFY that on this 23rd day of April, 2015, I served a true, correct and complete copy of the foregoing document, to each of the following, via the method so indicated:

Randall C. Budge

RANDALL C. BUDGE

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ATTACHMENT A
(CONFIDENTIAL)

ATTACHMENT B

PAC-E-14-10/Rocky Mountain Power
April 16, 2015
Monsanto Data Request 1.22 – 1st Supplemental

Monsanto Data Request 1.22

Please state the return on rate base included in Docket No. PAC-E-11-12 associated with each and every asset that will be sold, disposed, or retired as a result of the Deer Creek Mine Closure and the associated transaction with Bowie.

1st Supplemental Response to Monsanto Data Request 1.22

Please refer to Attachment Monsanto 1.22 1st Supplemental. It is important to note that PAC-E-11-12 was a settled case and these amounts are approximations only.

Responder: Steve McDougal
Witness: Doug Stuver

ATTACHMENT MONSANTO 1.22 1ST SUPPLEMENTAL
ASSETS SOLD, DISPOSED OR RETIRED AS A RESULT OF DEER CREEK MINE CLOSURE

PAC-E-11-12 was a settled case and these amounts are approximations only

RATE BASE[(1)]			Pre-Tax Return	Idaho Revenue Requirement
	Total Company	Idaho Portion		
Electric Plant in Service				
Coal Mine Assets				
Sold	41,762,065	2,648,142	11.62%	307,614
Retired/Disposed	241,365,560	15,305,047	11.62%	1,777,871
Intangible Assets				
Sold	11,706	742	11.62%	86
Retired/Disposed	3,431,094	217,566	11.62%	25,273
General Plant				
Sold		-		-
Retired/Disposed	-			
Distribution Plant				
Sold	966,545	-		
Retired/Disposed		-		
Accumulated Depreciation				
Coal Mine Assets				
Sold	(19,958,359)	(1,265,564)	11.62%	(147,011)
Retired/Disposed	(135,289,993)	(8,578,770)	11.62%	(996,530)
Intangible Assets				
Sold	(6,547)	(415)	11.62%	(48)
Retired/Disposed	(1,918,701)	(121,665)	11.62%	(14,133)
General Plant				
Sold		-	11.62%	-
Retired/Disposed				
Distribution Plant				
Sold	(276,842)	-		
Retired/Disposed		-		
SE Factor from PAC-E-11-12.	6.341%			
Accumulated Deferred Income Tax at 12/31/2014				
Retired/Disposed	(21,739,947)	(1,378,535)	11.62%	(160,134)
Sold	(6,607,107)	(418,958)	11.62%	(48,667)
			TOTAL IDAHO "RETURN ON" IN RATES	**744,321**

Notes

(1) PAC-E-11-12 reflected projected plant balances for the test year. ADIT for these assets from that filing is not readily available. Actual ADIT balances are reflected for purposes of this response.