COMMENTS OF

IDAHO POWER COMPANY

TO

2009 AVERAGE SYSTEM COST DRAFT REPORT (ASC-09-IP-01)

AND

2010-2011 AVERAGE SYTEM COST DRAFT REPORT (ASC-10-IP-01)

I. Introduction.

Idaho Power Company ("Idaho Power") submits comments regarding the Average System Cost ("ASC") Draft Reports pertaining to Idaho Power, prepared by Bonneville Power Administration ("BPA") for Fiscal Years 2009 and 2010-2011. (Draft Reports for Fiscal Years 2009 and 2010-2011 are referred to collectively as "Draft ASC Reports.") Comments on Specific Issues, contained in Section III., below, specifically refer to BPA's Average System Cost Draft Report for FY 2010-2011 (ASC-10-IP-01). However, the comments should be applied to similar determinations contained in BPA's Average System Cost Draft Report for FY 2009 (ASC-09-IP-01).

II. Background.

On July 14, 2008, BPA filed its proposed 2008 Average System Cost Methodology ("2008 ASC Methodology") with the Federal Energy Regulatory Commission ("FERC") for FERC's approval (FERC Accession No. 20080716-0007). FERC subsequently accepted the 2008 ASC Methodology on an interim basis on September 30, 2008, and invited all parties to submit additional comments regarding whether FERC should approve the interim rule on a final basis. Subsequently, BPA proposed various changes that it requested to be included in a Revised 2008 ASC Methodology. Various parties, including Idaho Power, filed comments recommending changes to the Revised 2008 ASC Methodology. The comments herein do not waive, supersede or replace other comments and protests by or on behalf of Idaho Power regarding the 2008 ASC Methodology and the Revised 2008 ASC Methodology, filed either with BPA or with FERC. Idaho Power contends that ASC determinations should be considered interim, until FERC issues a final rule adopting a revised ASC Methodology.

III. General Comments.

The review processes for FY 2009 and FY 2010-2011 have been conducted in tandem and on an expedited basis. With respect to many items, Idaho Power has not had the time to conduct studies or analysis sufficient to compile, establish or verify all the information that it provided or that is relied upon in determining ASCs, and has provided to BPA what information could be gathered given severe time constraints. In other instances, Idaho Power does not agree with the treatment of certain costs by the Draft ASC Reports, but the expedited time schedule has not allowed for a thorough review of the costs, so as to enable Idaho Power to present specific recommendations as to how all such costs should properly be treated.

Idaho Power has participated in joint comments and submitted its own comments and urges consideration or reconsideration of those comments to the extent that they differ from the proposed determinations contained in the Draft ASC Reports. (*See* IOU Generic Issues List Proposal at Attachment "A", Idaho Power FY 09 ASC Issues and Clarification List at Attachment

"B", and Idaho Power FY 2010 Issues and Clarification List at Attachment "C", all of which are attached hereto.)

An absence of comment, herein, should not be treated as a concurrence or waiver on any topic. Idaho Power reserves the right to furnish more current or accurate data for ASC purposes and propose more accurate or appropriate methods of allocation with respect to future ASC determinations. If BPA proposes additional changes to the Draft ASC Reports, or adopts changes to the final ASC Reports which changes have not been commented upon, Idaho Power should have the right to comment on such changes.

IV. Comments on Specific Issues.

4.2.1. Account 303, Intangible Plant - Miscellaneous, CIS+ and General Software

Draft Decision:

Without additional documentation, BPA is unable to justify the use of the PTD ratio for General Software and will adjust the functionalization of General Software to the default of Distribution (DIST). Furthermore, BPA will adjust the functionalization of CIS+ software to Distribution (DIST).

Idaho Power Response: It is unreasonable for the Draft ASC Reports to penalize Idaho Power, because Idaho Power does not utilize an accounting system that allocates the costs of General Software Costs to production, distribution or transmission functions. It is also unreasonable and arbitrary for the Draft ASC Reports to assume that all such costs should be assigned to the distribution function.

Other regional utilities may have, for their own corporate or regulatory purposes, implemented accounting practices that functionalize General Software Costs by function. Idaho

Power does not follow such accounting practices, and in any event would have been unable to complete a study to functionalize the costs of General Software that has been already acquired.

Idaho Power has compiled of at least a partial list of general software utilized within the company, as of December 31, 2006 (the basis for the FY 2009 ASC) which is set forth, below:

Description:	*Sum Cost:*
DES OSM Project	2,194,646.17
Purchase ZAI*NET Energy Transaction/Acctg System Software	2,000,000.00
2000 Phoenix Project	1,495,739.02
Phoenix Project-Data Conversion	1,442,119.86
EMS Phase 1	1,421,468.55
1999 Phoenix Project	1,056,754.94
Wire Vision Implementation	983,426.63
CPU Upgrade	949,353.11
Meter Data System Software & Interfaces - Phase One AMR	841,431.41
Feeder Fielding Project 2001	835,974.88
Mobile GIS Project	724,215.00
Enviromental Database: WQ, Fish and Invertebrate Modules	661,569.19
Water Forecasting Model	608,534.40
Hydro Optimization Model	556,732.73
Feeder Fielding Project	511,085.88
Nexus Energy Software Implementation	475,047.10
Mainframe Upgrade	450,224.37
INDUS Connect Framework	435,260.19
MW Streamflow Forecast Model Phase 3	432,074.50
ARCFM Project	372,203.51
Cost Center 342-Build Feeder Model Database	368,869.28
Phase One AMR - IT & CIS Interfaces and Data Storage	361,078.53
Upgrade to Training Server	344,205.06
Web Support	319,889.59
Customer Care Intiative 2004	283,335.34
Sims Software and Maintenance	272,971.50
Fleet Anywhere Management Software	258,127.62
Forecast Software with Setup and Instruction	238,759.61
IVRU Replacement/Upgrade	220,634.28
Hydrologic Database	214,358.10

Environmental Database - 2005	195,303.81
Mike-11 Swan Falls, Phase 1	181,098.24
CPU Upgrade	178,450.75
2002 ITRON Project	176,253.33
Software Licenses for TIM Project	173,351.88
Additional Licenses for Seagate Info	171,560.81
Consulting Fees for Meridian Project	170,880.38
ABM Software with Setup and Instruction	165,895.85
Network Servers	154,136.95
EDMSAPI Interface to link Passport to Document Mgmt	150,000.00
RF Inventory Purchase Software	150,000.00
Media Mosaic E-Learning Project	147,608.54
Passport ICF BO'S:MR, Catalog, MWFM Wishbone, CIS Banner	146,412.50
Remote Access / Monitoring	145,841.42
SOX Software Project	143,466.42
DB2 Connect for S/W (IVRU)	142,048.62
Instant Messageing Gateway	126,785.93
Data Warehouse Development	126,710.20
Storage Management Software	126,013.97
AEGIS	123,900.00
Commvault Backup	121,200.00
Client Services Manager-Microsoft Project Svr 2002 Implementation	115,892.92
GIS Database Development	115,289.54
Phoenix Project: AM/FM/OMS	113,660.87
PPPS Software Loan	112,142.38
OMS Project - DORD, Sentry, Web Call	109,015.04
Technical Opperations-Map Board	104,132.65
Mosaix Upgrade	103,111.05
Power Mart Purchase	100,000.00
CISCO Works Upgrade	96,035.24
Mobile GIS Project	95,772.50
Reliability Performance Software-Update Performance Threshold	95,000.00
Facilities Data Cleanup	90,972.11
E-Mail Encryption Project-ASLC	88,309.21
Portal Management Software	87,670.67
Internet Filtering & Monitoring	87,061.96
Mike - 11HCC, Phase 1 (Replaces 27137496 Task 01)	83,415.93
Upgrade Webmethods	82,669.04

Loadstar Contract Renewal	81,825.00
Mapframe Site License	80,523.62
CC852	76,381.40
Aud Logic File Creation	75,000.00
N 20 Source Code Management for Natural	74,386.05
Webmethods License Agreement	73,778.25
Convert Joint Use Records to Electronic Database	73,538.50
Water Mgmt: Hydrologic Database	73,046.65
Call Manager Upgrade	71,128.88
SQL Srvr 2000 Test Prod Servers	70,276.06
Snapshot	70,000.00
PGP Universal Software Licenses	66,710.00
Security Software	64,850.56
Business Service Manager-Other Intangibles (Regional W/S Techs)	64,844.20
Geodatabase Conversion Tools Development	64,520.44
Function Contingency	64,404.85
T&D Development (CC342) - Phoenix Project GIS (Y2000)	61,929.60
Transmission Inspection and Maintenance Program	61,369.58
ADIC Upgrade	60,596.27
GIS System Upgrade	59,800.00
Map R2 & R3 Upgrades and VIP Subscriptions	58,977.63
OSI-PI Licenses and Interfaces	53,550.00
AUD/Passport API	50,904.54
Dolphin MSDS Intranet Software	50,375.81
T&D Development CC342-Phoenix Project GIS Support	50,313.55
Mecury Tools (Web Team)	48,371.48
DB2 Utilities	46,806.90
Imaging Software and Services for Phase III of AP Imaging	45,108.42
Scheduling Agents	45,000.90
Purchase Annual Copies of PLS CADD and PLS Pole Software	44,619.80
Purchase 175 Additional Seagate Info Client Licenses	43,930.95
OMS Project - DORS, Sentary, Web Call	43,324.38
Purchase and implement 1099 Reporting System	42,289.77
New CMFX Software Licenses	40,433.48
Hydrologic Database	40,395.14
Phoenix Hardware Purchases and Upgrades	39,592.15
Plateau Software License for Performance Management	38,711.37
Purchase and Install Faxgate Software and Server	38,619.41
Substation Reliability Software	38,443.91

Mainframe Upgrade	37,587.73
Push SQL Server Enterprise License	37,477.95
Software/Server needs for PQ staff, Eng & Techs	37,472.98
ESRI to Autocad Interface	37,283.86
Asset Management	37,159.50
Purchase of Cybermation Peoplesoft Agent	36,787.50
RSCAS Software Development	35,338.11
Jim Stout-MV90 Software Order	35,122.50
NSM Advanced Analystics - SIMS Project	33,454.00
Aperture (Documentation)	33,349.33
E-Talk License & Install for Support Center	30,606.18
Enterprise Storage DASD Upgrade	30,163.11
Sharepoint Compliance System Software Costs - Capital	29,997.52
Commvault	29,818.95
Upgrade Centre-VU	29,668.13
Arcview and Misc Software Line Services - Development	28,967.15
Mobile Computing Pilot Project	28,944.31
OATI Enhancements	28,810.97
Cybermation	28,556.50
Printers for Customer Service Centers	28,549.38
Data CenterADSM Tape	28,432.27
Customer Care Dev/Test Servers	26,375.33
Incident Response-Laptop, Hardware, Software, Misc Items	25,651.40
AM Meridian Software, Maintenance & Telephone Tech Support	25,507.92
GIS API for PassPort Purchase	25,000.00
Voice Network Contingencies	24,897.42
Portal Server Software	24,137.86
Install Enterprise SQL Server Ouster-Data DMZ	23,158.73
Centre VU Upgrade - Security Driven	22,776.26
Purchase Teammate Software for Internal Audit	21,000.00
Company Street Light Process Improvements	20,767.80
Stations D & C	20,734.26
ASLC-Temperature and DO Monitoring Software-Capital-2005	20,621.98
Transfer Real Time Trading Function to CHQ	20,303.81
Hydrologic Database	20,256.63
Consulting Fees for Records Management Project	20,120.00
META Data	19,950.00
CEMS Software Upgrade Unit #2 and #3 Training	18,934.28
Annual Software Support for MV90	18,032.49

Anti-Spam Project	18,015.16
Marketing Purchases for Y2000	17,994.70
ARCSDE Server w/Processor for SQL Server-Frank Mynar	16,950.00
ESRI ARC/INFO Licenses	16,884.00
New Network Servers	16,570.62
Geographic Data Technology - Dynamap/Transportation	16,001.25
1999 Sentry Software, Hardware	15,937.44
IBM ISPF Software VM Racf	15,004.50
Server Management Software	14,980.01
Purchase Software: Composer, Autodesk, Support Software	14,101.62
CC855 (2005) Ariel Image Archive	13,552.06
Consulting Fees for Records Management Project-2002	13,480.90
Verint/Loronix Web Review Site License for Security Cameras	13,364.01
Dispatch Center Mapping	13,278.75
E-Mail Redundancy	12,718.81
Building a Redundant Network of Internet Reliability	11,966.59
Building a Redundant Network of Internet Reliability	11,966.59
Autocad Map and Civil Series Relicensing with Eterra	11,510.44
Dell Poweredge 2450 Servers	11,362.82
Erwin/Modelmart Licenses	11,235.00
Building a Redundant Network of Internet Reliability	11,140.00
Building a Redundant Network of Internet Reliability	11,140.00
Software Purchase for T&D Design	10,494.75
Software Purchase for T & D Design	10,450.00
Site License for IPRAX Course	10,000.00
APOS Report Package Consolidation for CE 10 & XI	10,000.00
Encrypted E-mail	9,778.24
Intrusion Detection System Update-Labor (CC 820)	9,508.30
The Upline Group, Inc.	9,426.79
Call Center Team SVR	9,200.75
Purchase Monitoring Equipment	8,912.69
Guardian for Scanning Vault Project (AMWF/CADNET)	8,370.00
GIS Software for GIS Applications Group	7,718.64
Power Mart Purchase	7,499.70
Kevin Wartman Chem Lab Software	7,056.85
Purchase of Omicron Software	6,850.32
Aces & Oasis Upgrade	6,700.51
Purchase SQR-Runner	6,520.50
CHQ-8 Unclaimed Property Reporting Software	5,772.98

Electronic Vault Protection - Network Space, Hardware & Software	5,647.77
Guardian AMWF 5 Alp for Engineering Vault Scanning Project	5,339.50
Redundant Servers and Software	5,298.78
Load Profile Software Development	5,245.00
GIS Software for the GIS Group	5,010.46
Maplex for Arcgis Concurrent Use Licenses	3,981.44
Spicer for Engineering Vault Project	3,465.27
AM View Engineering Vault Scanning Project - Field Reps	3,088.00
Imagine Orthobase for Windows	3,000.00
Weather System Software Development	2,310.00
Aspect Communications	1,054.50
WM Hydrologic Forecast Model	633.07
Phoenix Project AM/FM and OMS Hardware Upgrades	546.43
Crystal Reports V 8.0	224.52
TOTAL	30,055,875.69

Even a superficial review of the list indicates many software titles related to generation. For instance, "ZAI*NET Energy Transaction/Acctg System Software" is related to recording keeping for wholesale purchases and sales of electricity. Other software is related to hydroelectric generation, such as "Water Forecasting Model," "Hydro Optimization Model," "Hydrologic Database," and " Mike-11 Swan Falls, Phase 1." Other software implicates information systems software, which may cover many aspects of the company's operations.

It is unreasonable to assume that all of the costs associated with these titles relate to distribution. It is also unfair to assume, as do the Draft ASC Reports, that Idaho Power could have conducted a study within the time constraints of the ASC review process to functionalize costs of particular software titles, or to allocate costs to particular functions where particular titles are shared among functions.

For Idaho Public Utilities Commission purposes, General Software Costs are accounted for using a PTD-type allocation method. For FERC purposes, these costs are accounted for using a LABOR method. Therefore, either LABOR or PTD are appropriate and approved allocation methods for Idaho Power to allocate General Software Costs. Therefore it is reasonable for the allocation of all General Software Costs in Account 303 for ASC purposes to be functionalized utilizing a LABOR or PTD method. It is unreasonable and arbitrary for the Draft ASC Reports to adjust the allocations so that all General Software Costs are assigned to the default of Distribution (DIST).

4.2.2. Amortization Reserve, Amortization of Other Utility Plant – Account 303, CIS+ and General Software

Draft Decision:

Without additional documentation, BPA is unable to justify the use of the PTD ratio for General Software and will adjust the functionalization of amortization reserves of General Software to the default of Distribution (DIST). Furthermore, BPA will adjust the functionalization of amortization reserves of CIS+ software to Distribution (DIST).

Idaho Power Response: For the same reasons as stated in Idaho Power's Response to item 4.2.1., it is reasonable to utilize a LABOR or PTD method of allocation for the treatment of amortization reserves in Account 303 and unreasonable and arbitrary for the Draft ASC Reports to adjust the functionalization of amortization reserves of General Software to the default of Distribution (DIST).

4.2.6. Account 182.3 Other Regulatory Assets: Power Cost Adjustment Deferral and Prior Year PCA Deferral

Draft Decision:

Without additional documentation from IPC, BPA is unable to justify the use of the PTD ratio for PCA Deferral and Prior PCA Deferral. BPA will adjust the Power Cost Adjustment Deferral (PCA) and Prior Year PCA Deferral and functionalize them to the default of Distribution (DIST).

Idaho Power Response: The Draft ASC Report erroneously states that, "[t]he lack of supporting rate order language from IPC did not allow a clear justification for the functionalization of PCA Deferral and Prior PCA Deferral using the PTD ratio." This account reflects actual net power expense and recovery of the balance in this account is authorized by the IPUC through rates charged to the Company's customers (IPUC Order No. 30047). This Order was provided to BPA in PDF format, as an email attachment on October 22, 2008, and is attached hereto. (*See* Attachment 'D", attached to these comments.) A requirement to provide more specific "rate order language" than contained in IPUC Order No. 30047 would be unfair and unreasonable.

4.2.7. Account 182.3, Other Regulatory Assets: Idaho DSM

Draft decision:

Without additional documentation from IPC, BPA is unable to justify the use of the PTD or Production ratios for DSM in rate base, and will adjust the functionalization of the Idaho DSM to the default of Distribution (DIST).

Idaho Power Response: The Draft ASC Report erroneously states, "[u]pon further analysis, BPA notes that IPC did not provide supporting rate order language to show that either the IPUC or the OPUC allowed this Demand Side Management in IPC's rate base." (Emphasis added). In fact, the amount in this account is recovered from the Company's customers through retail rates. The account includes Idaho Power Company DSM (Conservation) expense. This account was authorized for recovery in IPUC Order No. 27660. This Order was provided to BPA in PDF format, as an email attachment on October 22, 2008, and is attached hereto. (*See* Attachment "E", attached to these comments.) A requirement to provide more specific "rate order language" than contained in IPUC Order No. 27660 would be unfair and unreasonable.

<u>4.2.13. Account 254, Other Regulatory Liabilities: Fixed Cost Adjustment</u>

Draft Decision:

> *Account 254, Other Regulatory Liabilities: Fixed Cost Adjustment should not be included in ASC rate base. BPA will adjust the Fixed Cost Adjustment and functionalize it to the default of Distribution (DIST).*

Idaho Power Response: The Draft ASC Reports allocate costs in the account to distribution. The rationale is that, "[t]he lack of supporting rate order language from IPC did not allow a clear justification for the functionalization of DSM Idaho using either the PTD ratio or Production (PROD)."

However, the amount in this account is passed through as a cost in the rates charged to Idaho Power's customers. This ratemaking treatment was authorized in IPUC Order No. 30267 and is attached hereto. (*See* Attachment "F", attached hereto.) The mechanism for recovery of these costs contains a functionalization component that is reset with each of the Company's General Rate proceedings that functionalizes costs. Idaho Power's proposed functionalization follows the order and should be utilized.

<u>4.5.1. Account 404, Amortization of Intangible Plant – Account 303, CIS+ and General Software</u>

Draft decision:

Without additional documentation, BPA is unable to justify the use of the PTD ratio for General Software and will adjust the amortization expense of General Software and functionalize it to the default of Distribution (DIST). Furthermore, BPA will adjust the amortization expense of CIS+ software and functionalize it to Distribution (DIST).

Idaho Power Response: For the same reasons as stated in Idaho Power's Response to item 4.2.1., it is reasonable to utilize a LABOR or PTD method of allocation for the treatment of amortization expense of General Software in Account 404 for ASC purposes.

5.7. ASC Forecast Model: New Large Single Loads

Draft Decision: The Draft ASC Reports characterize the issue as being, "[w]hether IPC may withhold information necessary to calculate the cost of serving its New Large Single Loads (NLSLs) from BPA." Because Idaho Power furnished responsive information under protest, the Draft ASC Reports state that the issue is resolved.

Idaho Power Response: Idaho Power disagrees that it is reasonable to calculate the costs of serving New Large Single Loads by using costs that are developed utilizing the assumption that peaking generating plants are baseload resources.

The Pacific Northwest Electric Power Planning and Conservation Act states that a utility's ASC shall not include, "the cost of additional resources in an amount sufficient to serve any new large single load of the utility." Pacific Northwest Electric Power Planning and Conservation Act, Sec. 5(c)(7); 16 U.S.C. § 839c(c)(7). Therefore, the 2008 ASC Methodology provides for determining the cost of resources used to serve new large single loads, and then subtracting those costs from the utility's average system costs.

The practical result of the manner of the proposed implementation of the Revised 2008 ASC Methodology in determining Idaho Power's ASC is that the Draft ASC Reports disregard the very limited number of actual hours that Idaho Power's peaking facilities actually generate. For instance, Idaho Power's Bennett Mountain and Danskin simple cycle gas generating facilities had actual capacity factors of 3% during 2006. The 3% capacity factor only allowed for 263 hours of operation of each of these facilities in 2006. Because of the limited actual capacity factors, the Bennett Mountain and Danskin simple cycle gas generation plants should be disregarded for purposes of calculating the cost of service to new large single loads.

To the extent that "Endnote d" of the Revised 2008 ASC Methodology is intended, or interpreted by to mean that gas fired peaking resources are utilized by a retail utility to serve new large single loads, such intention or interpretation is fundamentally flawed and arbitrary. The interpretation of "Endnote d" set forth in the the Draft ASC Reports does not take into account how service to a new large single load is planned for, or regularly provided by a utility, or how Idaho Power actually operated its Bennett Mountain and Danskin simple cycle gas generating facilities during 2006.

New large single loads are typically large manufacturing facilities with relatively high load factors. These manufacturing facilities typically maintain relatively flat continuous loads. Peaking plants are built to serve loads that vary significantly on an hourly basis. Residential and irrigation loads are examples of these loads, while large manufacturing facilities are not.

Idaho Power's Bennett Mountain and Danskin simple cycle gas generating facilities had actual capacity factors of 3% during 2006. The 3% capacity factor only allowed for 263 hours of operation of each of these facilities in 2006. By contrast, a new large single load draws power from the utility nearly every hour of the year. BPA's method of including costs for peaking facilities, disregards the actual generation of the facility, and arbitrarily assumes that the facilities generated power during every hour during the year that a new large single load takes service from Idaho Power. This assumption is simply wrong.

If Idaho Power Company were to serve New Large Single Load customers based upon the addition of a simple cycle combustion turbine (or more specifically, the cost of the Danskin plant, Bennett Mountain plant, or any combination thereof), the resulting rates would likely preclude any New Large Single Load customer from making an economic decision to locate within the Idaho Power Company service territory, because the average annual cost to serve the entire load of a new customer from either plant would be above the average annual market price of electricity available to Idaho Power Company or other utilities in the Pacific Northwest region.

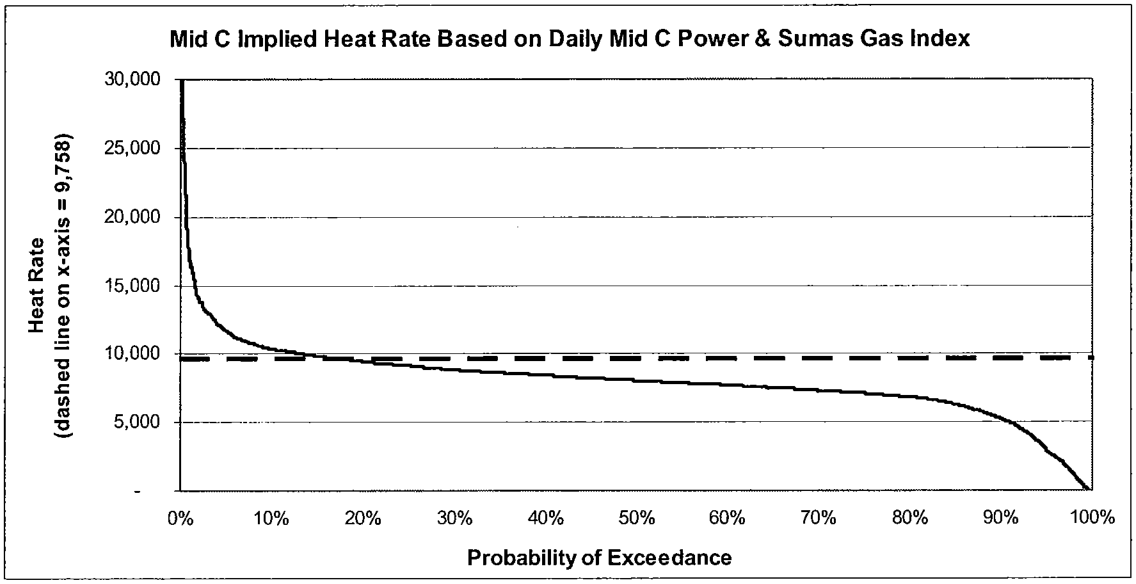
In support of the determination that electricity from the Danskin and Bennett Mountain facilities would be above the average annual market price during the majority of the year, the implied market heat rates can be extracted by dividing the daily Mid-Columbia (Mid-C) price index, a relevant electric price index for the Pacific Northwest by the daily Sumas gas index, a relevant natural gas price index for the Pacific Northwest, and comparing these implied market heat rates to both the Danskin and Bennett Mountain heat rates.

Heat Rates (Optimal, at 59°)

Bennett Mountain: 10,096 BTU per Kilowatt-hour

Danskin: 9,758 BTU per Kilowatt-hour

Implied Market Heat Rate Curve (2001-2008):



As shown in the above chart, during the majority of the time the heat rate of a resource would need to be below 9,758 BTU per Kilowatt-hour in order to dispatch economically into the market. Idaho Power Company would not plan, nor build a higher heat rate peaking plant to serve New Large Single Load customers or as a baseload resource for any customer class. Reasonable and economical use of these types of plants is for peaking activity and system reliability, which is limited in the above figure to the 0-15% probability range.

Idaho Power plans to serve any new large single load on a continuous and economical basis. A peaking unit may add reliability to Idaho Power's system; however, Idaho Power does not plan to, and it is not considered economical in the utility industry as a whole, to dedicate a peaking resource to serve a continuous load. Moreover, air quality, warranty and other requirements may preclude use of a peaking resource to provide continuous service, except under emergency conditions.

The assumption that Idaho Power's Bennett Mountain and Danskin, or similar peaking resources, are planned to serve, or actually serve, new single large loads on a kilowatt hour per kilowatt hour basis is erroneous, results in an over allocation of costs to peaking resources, and therefore exaggerates the costs of resources required to serve new large single loads. To the extent that the Draft ASC Reports interpret "Endnote d" of the 2008 ASC Methodology to require that the costs of Idaho Power's peaking generating plants must be assumed to generate every hour that a new large single load operates, the Draft ASC Reports are predicated upon a factually erroneous and arbitrary assumption, and should be revised, accordingly.

DATED this 11th day of May, 2009.

Respectfully submitted

PAINE HAMBLEN LLP

By *_/s/ R. Blair Strong_*

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CERTIFICATE OF SERVICE

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/s/ R. Blair Strong
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Attachment A
IOU Generic Issues List
Proposal

IOU Generic Issues List Proposal

Issue 1
Schedule 1
Account 303

Issue-Generic Direct Analysis Issue

Should BPA adopt common functionalization for similar types of software assets?

Discussion

Inconsistency between how the IOUs functionalize certain types of software, i.e. metering, customer information systems, work management, etc. The issue is whether BPA should maintain consistency in the functionalization of these common types of programs amongst utilities when calculating ASC.

IOU Response

BPA should maintain consistency in the functionalization of these common types of programs, with costs greater than an identified threshold value, amongst utilities when calculating ASC. In our initial Appendix 1 filings the IOUs have not functionalized certain software the same, we are all in agreement that given a determination by BPA on the proper functionalization of these items the IOUs will support a consistent treatment.

Issue 2
Schedule 1
Account 182.3 and Account 254

Issue-Generic Direct Analysis Issue

Should BPA adopt common functionalization for similar types of regulatory assets and liabilities?

Discussion

Inconsistency in the way the IOUs functionalize Deferred Pension, Pay and other labor related Assets and Liabilities. PGE and Avista and NW use the Labor Ratio. IPC uses PTD. PSE and PAC functionalize these assets to Distribution. The issue is whether BPA should maintain consistency in the functionalization of deferred pension, pay and other labor related assets and liabilities amongst utilities when calculating ASC.

Response

BPA should maintain consistency in the functionalization of deferred pension, pay and other labor related assets and liabilities amongst utilities when calculating ASC. All of the IOUs agree that it is appropriate for purposes of determining a utility's ASC to functionalize these accounts by the LABOR ratio.

Issue 3
Schedules 1 & 3
Accounts 182.3, 186, 253, and 254

Issue-Generic Direct Analysis Issue

Should BPA require that asset accounts that have a corresponding liability account have a common functionalization? For example, should pension costs in Accounts 182.3 and 254 have the same functionalization?

Discussion

Direct analysis is required in the functionalization of Other Regulatory Assets (Account 182.3), Miscellaneous Deferred Debits (Account 186), Other Deferred Credits (Account 253), and Other Regulatory Liabilities (Account 254). Direct analysis should include maintaining a consistency in functionalization where there is an asset in either Account 182.3 or 186 and offsetting liabilities in either Account 253 or 254. Direct analysis also requires showing how the assets and liabilities flow through the Income Statement

Response

The IOUs agree that BPA should require that accounts that have a corresponding asset and liability account have the same functionalization.

Issue 4
Schedule 3, Schedule 3B, 3-yr pp & OSS
Account 555 & 447

Issue-Generic Issue - Purchased Power Expense, Sales for Resale, and Price Spread

How should book-outs and trading adjustments be treated for calculations of purchased power expense and sales for resale revenue and the price spread calculation?Should the treatment be consistent across utilities.

Discussion

PacifiCorp is reducing the amount of its purchased power expense and sales for resale revenue by book-outs and trading adjustments. It appears that the other utilities do not. The inclusion or exclusion of book-outs and trading adjustments in purchased power and sales for resale numbers affects the price spread calculation. BPA is considering whether it is appropriate to remove these adjustments when performing the price spread calculation and the ASCs.

Response

The IOUs support a consistent reporting of purchase power expenses and sales for resale among the exchanging utilities for the determination of price spread. If Bonneville determines the amounts used to calculate each company's price spread and reported in the FERC Form 1 should be without bookouts the IOUs agree to report and calculate accordingly.

Issue 5
ASC Forecast Model

Issue-Generic Issue - New Plant Additions – Natural Gas Prices

Should BPA adopt a common natural gas price forecast in the ASC Forecast Model for all *new* natural gas-fired plant additions?

Discussion

Forecasted natural gas prices vary significantly between utilities forecasting natural gas burning new additions. None of the utilities submitted documentation on long term firm natural gas supply contracts, so it is assumed that the differences are a result of different natural gas price forecasting techniques.

Response

The IOUs propose that it is reasonable to use a third party gas price forecast in the determination of an exchanging utility's ASC. The IOUs believe that the third party gas price forecast that BPA uses would be appropriate or another publicly available gas price forecast. In addition, if a given exchanging utility desires to use a different gas price for their new resource it is understood that they will have to supply all necessary data in support of their alternative gas price forecast.

Issue 6
ASC Forecast Model

Issue-Generic Issue - New Plant Additions - Capacity Factor

Should BPA use common representative capacity factors in the ASC Forecast model for estimating the operating costs and expected energy output for plant additions of similar type?

Discussion

Projected capacity factors vary significantly between utilities for similar types of new resources

Response

The IOUs propose that they will use a capacity factor within the range of capacity factors listed below for new resources coming online during the rate period.

Resource Type	Capacity Factor
Combined Cycle CT	45% to 75%
Simple Cycle CT	1% to 30%
Wind	25% to 45%
Geothermal	greater than 90%

Again, it is understood that if a utility chooses to use capacity factor outside the above range for a given new resource that utility will have to supply complete justification for such capacity factor.

Issue 7
Schedule 1, Income Statement
Various Accounts

Issue-Generic Issue – Inclusion - Other Regulatory Assets and Liabilities

What should be the functionalization of Other Regulatory Assets and Liabilities that are not included in rate base by the regulatory authority? What should be the functionalization of the corresponding income statement accounts for the Regulatory Assets and Liabilities that are not included in rate base by the regulatory authority?

Discussion

There is inconsistency between utilities in the functionalization of Regulatory Assets and Liabilities when not included in rate base. For example, PAC functionalized all Other Regulatory Assets and Liabilities that are not in its retail rate base to distribution. Idaho functionalized several items in these same accounts, also not included in its retail rate base, to PTD. Many of these accounts are included in working capital for ratemaking purposes. There is concern that the treatment of the income statement accounts for Other Regulatory Assets and Liabilities are not consistent with the asset and liability treatment for ASC purposes.

Response

There should be consistency between utilities in the functionalization of Regulatory Assets and Liabilities when not included in rate base. Regulatory Assets and Liabilities not included in Rate Base have no effect on the Company's income statement. All entries affect only the balance sheet.

Attachment B
Idaho Power FY 09 ASC Issues and Clarification List

BPA Issues and Clarification List for FY 2009 ASC Filing: Idaho Power Company (IPC)

No.	Schedule	Account	Issue	Discussion	Response
1	Sch-1	303	**Generic Direct Analysis Issue** Should BPA adopt common functionalization for similar types of software assets?	There is inconsistency between how the IOUs functionalize certain types of software, i.e. metering, customer information systems, work management, etc. The issue is whether BPA should maintain consistency in the functionalization of these common types of programs amongst utilities when calculating ASC.	Idaho Power supports similar functionalization across all utilities with the provision to direct assign as applicable.
2	Sch-1	182.3, 254	**Generic Direct Analysis Issue** Should BPA adopt common functionalization for similar types of regulatory assets and liabilities?	There is inconsistency in the way the IOUs functionalize Deferred Pension, Pay and other labor related Assets and Liabilities. PGE and Avista and NW use the Labor Ratio. IPC uses PTD. PSE and PAC functionalize these assets to Distribution. The issue is whether BPA should maintain consistency in the functionalization of deferred pension, pay and other labor related assets and liabilities amongst utilities when calculating ASC.	Idaho Power supports similar functionalization across all utilities with the provision to direct assign as applicable.
3	Sch-1 Sch-3	182.3, 186, 253, 254	**Generic Direct Analysis Issue** Should BPA require that asset accounts that have a corresponding liability account have a common functionalization? For example, should pension costs in Accounts 182.3 and 254 have the same functionalization? Should the functionalization of the amortization match the functionalization of the corresponding assets and liabilities?	Direct analysis is required in the functionalization of Other Regulatory Assets (Account 182.3), Miscellaneous Deferred Debits (Account 186), Other Deferred Credits (Account 253), and Other Regulatory Liabilities (Account 254). Direct analysis should include maintaining a consistency in functionalization where there is an asset in either Account 182.3 or 186 and offsetting liabilities in either Account 253 or 254. Direct analysis also requires showing how the assets and liabilities flow through the Income Statement.	Idaho Power supports similar functionalization across all utilities with the provision to direct assign as applicable.
4	Sch-1	303, 111, 404, 108	**Intangible Plant – Miscellaneous Software** Does IPC's direct analyst support the use of PTD to functionalize software costs?	IPC completed a DIRECT analysis to its software and functionalized all software using the PTD ratio. IPC has not provided software titles, product description/purpose (with the exception of CIS+), or specific cost allocations.	For State of Idaho retail regulation, this account, in its entirety, is allocated based upon a PTD-like allocation method. For the Company's FERC jurisdiction, this account is allocated using a LABOR-like allocation method. Both methods include the CIS+ software within Production and Transmission functions, which is appropriate as the

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Date Issued: January 28, 2009

					Company uses the CIS+ software in support of all of the Company's functions. Idaho Power suggests that either LABOR or PTD is an appropriate allocation method for an integrated utility which has been authorized to use this method by both FERC and State Commissions in the last 10+ years of rate recovery filings. Because Idaho Power has hundreds of software titles that change annually, and are not functionalized within any sort of account management system, Idaho Power supports DIRECT analysis for items greater than a specified multi-million dollar threshold value. Idaho Power supports either PTD or LABOR for balance of the account.
5	Sch-1	182.3	**Other Regulatory Assets** Is IPC justified to include *SFAS 109, Regulatory Unfunded Acc Def Inc Tax* in its ASC?	IPC included SFAS 109, Regulatory Unfunded Acc Def Inc Tax and functionalized to PTD. As a general rule, the ASCM does not allow taxes to be included in ASCs, with exception of federal employment and ASC calculated federal income taxes, and property and unemployment taxes.	The Company is planning to review all functionalization of accounts in next year's ASC filing. However, because of the quick turnaround required for the review process in this year's filing, the Company will accept suggested functionalization.
6	Sch-1	182.3	**Other Regulatory Assets** Is IPC justified to include *LT&ST Mark to Market* in its ASC:	IPC included LT&ST Mark to Market and functionalized to PTD. As a general rule, the ASCM does not allow derivative instruments to be included in ASC.	IPC accepts distribution functionalization for this item.
7	Sch-1	182.3	**Other Regulatory Assets** Is IPC justified to include the following items in its ASC: *Professional Fees* *Minor Items*	IPC identified Professional Fees and Minor items as costs attributed to work in its general rate cases. As a general rule, the ASCM does not allow regulatory expenses to be included in ASC.	Professional fees are a result of bringing in consulting expertise to the Company to perform various tasks. These are not fees assessed by a regulatory commission. It is the Company's position that Professional fees should be functionalized as LABOR. For purposes of functionalization of Minor Items, it is the Company's position that a standard method be applied (PTD or LABOR).
8	Sch-1	182.3	**Other Regulatory Assets** Did IPC correctly functionalize *Idaho DSM* account?	IPC functionalized these conservation measures to PTD. The explanation of the items was not sufficiently clear for BPA understand why IPC is functionalizing this account to PTD. ASCM allows all conservation to be functionalized to PROD.	Idaho Power supports re-allocation of DSM account to PROD.

9	Sch-1	186	**Miscellaneous Deferred Debits** Does IPC's direct analysis support the use of PTD to functionalize the *PeopleSoft/Passport* software cost?	IPC used the PTD ratio to functionalize this software. IPC did not include supporting documentation or justification for the use of the PTD functionalization for this software.	Idaho Power supports a similar treatment for these systems across all facilities. PeopleSoft is the Company's GL, tracking all of the Company's assets including Generation facilities, Transmission facilities, etc. Passport includes functionality to assist with payroll, purchasing, inventory (for generation, transmission, distribution, etc). The two software tools have too many functions to identify.
10	Sch-1	186	**Miscellaneous Deferred Debits** Is IPC justified in including the following *Minor items & Job Orders* in its ASC: CIS+ Allow Bad Debt Cust Service Financing Prog Allow Bad Debt – Cust Serv Shelf Registration Valmy PP	IPC completed a Direct analysis on these items and functionalized all to PTD. Their supporting documentation does not provide complete details of the items nor does it show justification towards the production or transmission costs. It is unclear if PTD is the appropriate functionalization.	It is IPC's position that the items in this account are below a significant dollar amount and therefore, a functionalization process for each individual item would be inefficient. IPC would prefer PTD functionalization applied to the account as the items included support all of the Company's functions. There are no items of a value large enough to impact Idaho Power's ASC on any significant level.
11	Sch-1	253	**Miscellaneous Deferred Credits** Is IPC justified to include the *City of Eagle – Taxes* and fee in ASC?	IPC functionalized this item using the PTD ratio. As a general rule, the ASCM does not allow taxes to be included in ASCs, with exception of federal employment and ASC calculated federal income taxes, and property and unemployment taxes.	This is a liability account showing that the Company owes the City of Eagle, for Transmission related investment. The Company suggests a change from PTD to Transmission.
12	Sch-1	254	**Miscellaneous Deferred Debits** Is IPC justified to include the *Regulatory Unfunded Acc Def Inc Tax* in ASC?	IPC included Regulatory Unfunded Acc Def Inc Tax and functionalized to PTD. As a general rule, the ASCM does not allow taxes to be included in ASCs, with exception of federal employment and ASC calculated federal income taxes, and property and unemployment taxes.	Please see 5.
13	Sch-1	254	**Miscellaneous Deferred Debits** Did IPC correctly functionalize *DSM Rider* and *DSM Rider, OR* accounts?	In data response BPA-IP-11, IPC functionalized these revenues to "support analysis and implementation of new DSM programs" and functionalizes each using the PTD ratio. In data response BPA-IP-28, IPC listed the DSM expenses. The explanation of the items was not sufficiently clear for BPA understand how the riders are integrated into the conservation program or why IPC is functionalizing this account to PTD.	The Company accepts a change to PROD for this account.

14	Sch-1	254	**Miscellaneous Deferred Debits** Did IPC correctly functionalize *Emission Sales Interest ID*?	In the data response, BPA-IP-11, IPC described this item as "The balance in this account represents the tax portion of the Idaho Jurisdiction surplus emission allowance sales." However, for this same line item, IPC then described the regulatory treatment as the "Interest on the sale of the Company's emissions credits is provided to the Company's customers through its annual Power Cost Adjustment (PCA) mechanism." These statements appear to be in conflict with each other. In addition, the purpose of the liability is unclear. IPC functionalized this account using the PTD ratio.	This account captures additional refunds to customers for the sale of emission credits through the Company's Power Cost Adjustment mechanism. The Company is planning to review all functionalization of accounts in next year's ASC filing. However, because of the quick turnaround required for the review process in this year's filing, the Company will accept suggested functionalization.
15	Sch-1	254	**Miscellaneous Deferred Debits** Did IPC correctly functionalize *Other Def Credit – PCA*	The explanation of the items was not sufficiently clear to allow an understanding of the purposes of this account and therefore the applicability of the functionalization.	This account was set up to conform to GAAP reporting requirements in the event a Regulatory Asset – 182.3 has a credit balance, to re-class that balance on a quarterly basis to a Regulatory Liability.
16	Sch-1	111	**Amortization of Intangible Plant** Is IPC's direct analysis of this account justified for all line items?	IPC places costs for Amortization of Intangible Plant into *Amortization of Other Utility Plant*. However, IPC states "…intangible plant is excluded from this account." It is unclear whether or not Intangible Plant is included in Account 111. And if not included in this account, where is the amortization of account 303, including American Falls Dam Rebuild and all software accounts?	The data response supplied by Idaho Power was in error, this account includes the accumulation of amortization expense on intangible plant; retirements for intangible plant are processed against this account.

17	Sch-1	123.1	**Investment in Associated Company** Did IPC provide all relevant data for this account?	IPC includes costs of its investment in Idaho Energy Resource Company in this account; however, it is unclear if dividends or interests associated with this investment are recorded.	In the past, IERCo had paid dividends to IPC when it had excess cash. The last dividend was in 2002. IPC and IERCo have an interest-bearing intercompany note. The balance is currently a receivable on IPC's books and should be disclosed elsewhere on the Form 1. Any interest that has been charged on the note would affect IERCo's net income and thus IPC's investment in IERCo. The interest for this account is recorded in 123.1. The Company is planning to review all functionalization of accounts in next year's ASC filing. However, because of the quick turnaround required for the review process in this year's filing, the Company will accept suggested functionalization.
18	Sch-3	908	**Customer Assistance Expenses** Did IPC provide all relevant data for this account and did IPC functionalize this account correctly?	IPC functionalized subaccount 908.011 (conservation) to PTD, and functionalized additional conservation costs in sub-account 908.000 to DIST. The ASCM allows all conservation to be functionalized to PROD.	Please see response to number 8.
19	Sch-3	403	**Common Plant-Electric** Why does IPC show an entry for this account?	IPC shows a distribution cost (negative) in this account. IPC does not have a common plant. BPA does not understand the reason for this entry.	IPC does not have a common plant nor an actual physical asset associated with this account. The 403.400 account is recording a regulatory write-off of disallowed costs as a counter to costs in account 108/403.200.

20	Sch-3B	421	**Miscellaneous Non-Operating Revenues** Does IPC's direct analysis support the use of PTD to functionalize the Rabbi Trust compensation plan?	The Rabbi Trust accounts hold compensation elected to be deferred by senior management. These accounts are excluded for ratemaking purposes. IPC functionalizes these accounts to PTD. It is unclear if these accounts should functionalized using this ratio. The following are the account descriptions: 421050: reflects interest and dividend income 421051: reflects gains on the sales of investment assets 421052: reflects unrealized gains on investment assets	IPC recommends PTD, but will accept LABOR for this account.
21	Sch-3B	456	**Other Electric Revenues** Did IPC correctly functionalize *Standby Charges* and *Standby Services*?	IPC provided a description of *standby charges* (two separate line items in this account) in data response BPA-IP-18. Through a clarification in data response BPA-IP-26, IPC corrected the second identification as a *standby service* and corrected the descriptions of both sub-accounts. Each is functionalized to PTD. Based on the descriptions, it is unclear why IPC is functionalizing revenue from Standby Charges and Standby Services to DIST when they appear to be production costs.	These are revenues received for the provision of bundled services delivered to retail customers. IPC believes that it is appropriate to functionalize these revenues to distribution (DIST) but would accept the use of PTD since the bundled services are delivered at the customers' premises. This service is applicable to customers utilizing on-site generation and not applicable to service for re-sale, to serve where on-site generation is used for only emergency supply or to co-generators or small power producers who have contracted to supply power and energy. The type of service provided is three-phase at approximately 60 cycles. If the customer opts for parallel operations, Idaho Power Company will install a system protection package at the Customer's expense, prior to the start of the parallel operations. The customer will also pay a Maintenance charge of 0.7 percent per month times the investment in the protection package. Charges under this tariff include Standby Reservation, Standby Demand, Excess Demand and Minimum ("Customer") Charges. Under Idaho Power's State Commission, this account has been directly assigned to Idaho Retail Customer(s) and functionalized as Distribution (similar to DIST functionalization). This account is not included for purposes of FERC jurisdictional ratemaking (i.e. Transmission).

22	**ASC Forecast Model**		**Retail Load Forecast Data** Correction to Load Forecast Data in Forecast Model	IPC inadvertently submitted Load Forecast data in Forecast Model in calendar year (CY). The requirement was fiscal year (FY). IPC is aware of the discrepancy and the error will be corrected.	IPC accepts BPA's informal offer to transform the calendar year data into the appropriate fiscal years. Idaho Power will submit the missing months for BPA's calculations at its earliest convenience.
23	NLSL		**New Large Single Load Data** Whether IPC may withhold information necessary to calculate the cost of serving its NLSL from BPA.	IPC has not submitted all requested data for its NLSLs or resource costs to serve the NLSLs. Through discovery requests and responses, IPC has neglected to address BPA's request to complete, clarify, and review *all* necessary information included in the NLSL worksheet. BPA submitted three separate data requests: BPA-IP-21, BPA-IP-29, and BPA-IP-30. IPC submitted some but not all information and did so under protest (response to BPA-IP-21). BPA has not received responses to either BPA-IP-29 or BPA-IP-30. If IPC does not submit answers to these requests, BPA may, in its discretion, make its own assessment of the costs to exclude from IPC's ASC.	Attached, please find IPC's data responses to BPA-21 and 29. Idaho Power does not support BPA's methodology to include peaking plants (which cannot for multiple reasons service a NLSL) in the NLSL calculation. Idaho Power has attached the requested BPA-IP-30 data, but is doing so under protest. Please see Attachment 1 to this response.
24	**Sch-3B, 3-YR PP & OSS**	**555, 447**	**Generic Issue - Purchased Power Expense, Sales for Resale, and Price Spread** How should book-outs and trading adjustments be treated for calculations of purchased power expense and sales for resale revenue and the price spread calculation? Should the treatment be consistent across utilities?	PacifiCorp reduced the amount of its purchased power expense and sales for resale revenue by book-outs and trading adjustments. It appears that the other utilities, such as IPC, do not. The inclusion or exclusion of book-outs and trading adjustments in purchased power and sales for resale numbers affects the price spread calculation. BPA is considering whether it is appropriate to remove these adjustments when performing the price spread calculation for the ASCs.	Idaho Power supports similar functionalization across all utilities with the provision to direct assign as applicable.
25	**ASC Forecast Model**		**Generic Issue - New Plant Additions – Natural Gas Prices** Should BPA adopt a common natural gas price forecast in the ASC Forecast Model for all *new* natural gas-fired plant additions??	Forecasted natural gas prices vary significantly between utilities forecasting natural gas burning new additions. None of the utilities submitted documentation on long term firm natural gas supply contracts, so it is assumed that the differences are a result of different natural gas price forecasting techniques.	Idaho Power supports similar functionalization across all utilities with the provision to direct assign as applicable.

26	**ASC Forecast Model**		**Generic Issue - New Plant Additions - Capacity Factor** Should BPA use common representative capacity factors in the ASC Forecast model for estimating the operating costs and expected energy output for *new* plant additions?	Projected capacity factors vary significantly between utilities for similar types of new resources.	Idaho Power supports similar functionalization across all utilities with the provision to direct assign as applicable.
27	**Sch. 1, Income Statement**	**Various**	**Generic Issue – Inclusion - Other Regulatory Assets and Liabilities** What should be the functionalization of Other Regulatory Assets and Liabilities that are not included in rate base by the regulatory authority? What should be the functionalization of the corresponding income statement accounts for the Regulatory Assets and Liabilities that are not included in rate base by the regulatory authority?	There is inconsistency between utilities in the functionalization of Regulatory Assets and Liabilities when not included in rate base. Many of these accounts are included in working capital for ratemaking purposes. There is concern that the treatment of the income statement accounts for Regulatory Assets and Liabilities are not consistent with the asset and liability treatment for ASC purposes.	Idaho Power supports similar functionalization across all utilities with the provision to direct assign as applicable.

Attachment C
Idaho Power FY 2010
Issues and Clarification
List

BPA Issues and Clarification List for FY 2010 ASC Filing: Idaho Power Company (IPC)

No.	Schedule	Account	Issue	Discussion	Response
1	Sch-1	303	**Generic Direct Analysis Issue** Should BPA adopt common functionalization for similar types of software assets?	There is inconsistency between how the IOUs functionalize certain types of software, i.e. metering, customer information systems, work management, etc. The issue is whether BPA should maintain consistency in the functionalization of these common types of programs amongst utilities when calculating ASC.	Idaho Power supports similar functionalization across all utilities with the provision to direct assign as applicable.
2	Sch-1	182.3, 254	**Generic Direct Analysis Issue** Should BPA adopt common functionalization for similar types of regulatory assets and liabilities?	There is inconsistency in the way the IOUs functionalize Deferred Pension, Pay and other labor related Assets and Liabilities. PGE and Avista and NW use the Labor Ratio. IPC uses PTD. PSE and PAC functionalize these assets to Distribution. The issue is whether BPA should maintain consistency in the functionalization of deferred pension, pay and other labor related assets and liabilities amongst utilities when calculating ASC.	Idaho Power supports similar functionalization across all utilities with the provision to direct assign as applicable.
3	Sch-1	182.3, 186, 253, 254	**Generic Direct Analysis Issue** Should BPA require that asset accounts that have a corresponding liability account have a common functionalization? For example, should pension costs in Accounts 182.3 and 254 have the same functionalization? Should the functionalization of the amortization match the functionalization of the corresponding assets and liabilities?	Direct analysis is required in the functionalization of Other Regulatory Assets (Account 182.3), Miscellaneous Deferred Debits (Account 186), Other Deferred Credits (Account 253), and Other Regulatory Liabilities (Account 254). Direct analysis should include maintaining a consistency in functionalization where there is an asset in either Account 182.3 or 186 and offsetting liabilities in either Account 253 or 254. Direct analysis also requires showing how the assets and liabilities flow through the Income Statement.	Idaho Power supports similar functionalization across all utilities with the provision to direct assign as applicable.

Analyst: J Shaughnessy
Date Issued: February 11, 2009

No.	Schedule	Account	Issue	Discussion	Response
4	Sch-1 Sch-3	303, 111, 108 404	**Intangible Plant – Miscellaneous Software** Does IPC's direct analysis support the use of PTD to functionalize software costs?	IPC completed a DIRECT analysis to its software and functionalized all software using the PTD ratio. IPC stated the CIS+ is used for billing and all of the services provided to retail customers. IPC has not provided software titles, product description/purpose (with the exception of CIS+), or specific cost allocations.	For State of Idaho retail regulation, this account, in its entirety, is allocated based upon a PTD-like allocation method. For the Company's FERC jurisdiction, this account is allocated using a LABOR-like allocation method. Both methods include the CIS+ software within Production and Transmission functions, which is appropriate as the Company uses the CIS+ software in support of all of the Company's functions. Idaho Power suggests that either LABOR or PTD is an appropriate allocation method for an integrated utility which has been authorized to use this method by both FERC and State Commissions in the last 10+ years of rate recovery filings. Because Idaho Power has hundreds of software titles that change annually, and are not functionalized within any sort of account management system, Idaho Power supports DIRECT analysis for items greater than a specified multi-million dollar threshold value. Idaho Power supports either PTD or LABOR for balance of the account.
5	Sch-1	182.3	**Other Regulatory Assets** Is IPC justified to include *SFAS 109, Regulatory Unfunded Acc Def Inc Tax* in its ASC?	IPC included SFAS 109, Regulatory Unfunded Acc Def Inc Tax and functionalized to PTD. As a general rule, the ASCM does not allow taxes to be included in ASCs, with exception of federal employment and ASC calculated federal income taxes, and property and unemployment taxes.	The Company is planning to review all functionalization of accounts in next year's ASC filing. However, because of the quick turnaround required for the review process in this year's filing, the Company will accept suggested functionalization.
6	Sch-1	182.3	**Other Regulatory Assets** Did IPC correctly functionalize *Idaho LT&ST Mark to Market* Should BPA functionalize *Idaho LT&ST Mark to Market* to DIST, the same functionalization as all other derivative instruments account?	IPC included LT&ST Mark to Market and functionalized to PROD. As a general rule, the ASCM does not allow derivative instruments to be included in ASC.	IPC accepts distribution functionalization for this item.

No.	Schedule	Account	Issue	Discussion	Response
7	Sch-1	182.3	**Other Regulatory Assets** Is IPC justified to include *Fin 48 Unfunded-Noncurrent* in its ASC?	IPC included FIN 48 Unfunded-Noncurrent (tax) and functionalized to PTD. In data response BPA-IP-06, IPC described this account as a tax liability for "Uncertain Tax Positions." As a general rule, the ASCM does not allow taxes to be included in ASCs, with exception of federal employment and ASC calculated federal income taxes, and property and unemployment taxes. The explanation of the items was not sufficiently clear for BPA understand why IPC is functionalizing this account to PTD.	The Company is planning to review all functionalization of accounts in next year's ASC filing. However, because of the quick turnaround required for the review process in this year's filing, the Company will accept suggested functionalization.
8	Sch-1	182.3	**Other Regulatory Assets** Does IPC's direct analysis support the use of PTD to functionalize *PCA Deferral* and *Prior Year PCA Deferral*?	IPC included these PCA (Power Cost Adjustments) and functionalized to PTD. PCA is an accumulation of excess power purchase costs. The explanation of the items was not sufficiently clear for BPA understand the reason these items should be functionalized to PTD.	The Company is planning to review all functionalization of accounts in next year's ASC filing. However, because of the quick turnaround required for the review process in this year's filing, the Company will accept suggested functionalization.
9	Sch-1	182.3	**Other Regulatory Assets** Did IPC correctly functionalize *Idaho DSM* account? Should BPA functionalize *Idaho DSM* to PROD as allowed for conservation measures?	IPC functionalized these conservation measures to PTD. The explanation of the items was not sufficiently clear for BPA understand why IPC is functionalizing this account to PTD. ASCM allows all conservation to be functionalized to PROD.	Idaho Power supports re-allocation of DSM account to PROD.
10	Sch-1	182.3	**Other Regulatory Assets** Is IPC justified to include *PS&I Coal Plant* in its ASC? Should BPA functionalize *PS&I Coal Plant* to DIST, as stated in the 2008 ASCM?	IPC functionalizes this account to PROD and states that this asset represents the preliminary survey and investigation of a coal plant that was proposed in its 2006 IRP As a general rule, Preliminary Surveys and Investigations are not allowed to be included in ASC.	The Company is planning to review all functionalization of accounts in next year's ASC filing. However, because of the quick turnaround required for the review process in this year's filing, the Company will accept suggested functionalization.

No.	Schedule	Account	Issue	Discussion	Response
11	Sch-1	253	**Other Deferred Credits** Is IPC justified to include either *Fin 48 Unfunded-Noncurrent* or *Fin 48 Interest* in its ASC?	IPC included FIN 48 Unfunded-Noncurrent (tax) and functionalized to PTD. In data response BPA-IP-06, IPC described this account as a tax liability for "Uncertain Tax Positions." As a general rule, the ASCM does not allow taxes to be included in ASCs, with exception of federal employment and ASC calculated federal income taxes, and property and unemployment taxes.	Please see no. 7
12	Sch-1	254	**Other Regulatory Liabilities** Is IPC justified to include the *Regulatory Unfunded Acc Def Inc Tax* in ASC?	IPC included Regulatory Unfunded Acc Def Inc Tax and functionalized to PTD. As a general rule, the ASCM does not allow taxes to be included in ASCs, with exception of federal employment and ASC calculated federal income taxes, and property and unemployment taxes.	Please see no. 5
13	Sch-1	254	**Other Regulatory Liabilities** Did IPC correctly functionalize *DSM Rider* and *DSM Rider, OR* accounts? Should BPA functionalize *Idaho DSM* to PROD as allowed for conservation measures?	In data response BPA-IP-11, IPC functionalized these revenues to "support analysis and implementation of new DSM programs" and functionalizes each using the PTD ratio. In data response BPA-IP-9, IPC listed the DSM expenses. The explanation of the items was not sufficiently clear for BPA understand how the riders are integrated into the conservation program or why IPC is functionalizing this account to PTD.	Idaho Power supports re-allocation of DSM account to PROD.
14	Sch-1	254	**Other Regulatory Liabilities** Did IPC correctly functionalize *FAS 133 Market to Market ST?*	IPC functionalizes FAS 133 Market to Market using the PTD ratio. As a general rule, the ASCM functionalizes all derivative instruments to DIST.	IPC accepts distribution functionalization for this item.
15	Sch-1	254	**Other Regulatory Liabilities** Did IPC correctly functionalize *Fixed Cost Adjustment*	In data response BPA-IP-09, IPC defined this account as a "true-up mechanism for residential and small general service customers." The explanation of the items was not sufficiently clear for BPA understand the reason this should be functionalized to PTD. This item appears to relate directly to distribution. The ASCM does not allow distribution costs to be included in ASCs.	The Fixed Cost Adjustment is the provision that was put in place to remove disincentives for Company performed Conservation measures. The FCA allows the Company to recover fixed Production, Transmission and Distribution plant investment even in the event that Conservation programs lower Company sales. The Company is in support of either PTD or PROD (Conservation) functionalization for this account.

No.	Schedule	Account	Issue	Discussion	Response
16	Sch-1	123.1	**Investment in Associated Company** Did IPC provide all relevant data for this account?	IPC includes costs of its investment in Idaho Energy Resource Company in this account; however, it is unclear if dividends or interests associated with this investment are recorded.	In the past, IERCo had paid dividends to IPC when it had excess cash. The last dividend was in 2002. IPC and IERCo have an interest-bearing intercompany note. The balance is currently a receivable on IPC's books and should be disclosed elsewhere on the Form 1. Any interest that has been charged on the note would affect IERCo's net income and thus IPC's investment in IERCo. The interest for this account is recorded in 123.1. The Company is planning to review all functionalization of accounts in next year's ASC filing. However, because of the quick turnaround required for the review process in this year's filing, the Company will accept suggested functionalization.
17	Sch-3	908	**Customer Assistance Expenses** Did IPC provide all relevant data for this account and did IPC functionalize this account correctly?	IPC functionalized subaccounts to 908 to PTD, PROD, and DIST. The ASCM allows all conservation to be functionalized to PROD. The explanation of the items was not sufficiently clear for BPA understand why IPC functionalized this account to PTD, DIST, and PROD.	The Company accepts PROD.
17	Sch-3	930.1	**General Advertising Expenses** Does IPC's direct analysis support the use of PTD to functionalize these advertising expenses?	IPC included General Advertising Expenses and functionalized to PTD. IPC described the expenses in data response BPA-IP-10. In general the ASCM does not include general advertising expenses, with the exception of conservation-related advertising and promotion costs. The explanation of the items listed was not sufficiently clear for BPA to understand if any of these expenses were used for conservation measures.	Currently, the Company books all DSM and Conservation related advertising to a separate account. However, in the calendar year 2007, and included in the Company's FERC Form 1 data, there is the possibility that some of the advertising booked to 903.1 was for DSM or Conservation related programs. The Company is planning to review all functionalization of accounts in next year's ASC filing. However, because of the quick turnaround required for the review process in this year's filing, the Company will accept suggested functionalization.

No.	Schedule	Account	Issue	Discussion	Response
18	Sch-3B	421	**Miscellaneous Non-Operating Revenues** Does IPC's direct analysis support the use of PTD to functionalize the *MSC NONOP INC?*	IPC describes *MSC NONOP INC,* in data response BPA-IP-17, as "interest charges accrued on certain program and regulatory deferrals. It also includes miscellaneous refunds received for activities that are recorded outside of utility operating income." The explanation of the items was not sufficiently clear for BPA understand why IPC is functionalizing this account to PTD.	The Company is planning to review all functionalization of accounts in next year's ASC filing. However, because of the quick turnaround required for the review process in this year's filing, the Company will accept suggested functionalization.
19	Sch-3B	421	**Miscellaneous Non-Operating Revenues** Does IPC's direct analysis support the use of PTD to functionalize the Rabbi Trust compensation plan?	The Rabbi Trust accounts hold compensation elected to be deferred by senior management. These accounts are excluded for ratemaking purposes. IPC functionalizes these accounts to PTD. It is unclear if these accounts should functionalized using this ratio. The following are the account descriptions: 421001: reflects gains on the sale of investment assets from a Rabbi Trust used for payment of benefits under a non-qualified pension plan 421050: reflects interest and dividend income 421051: reflects gains on the sales of investment assets 421052: reflects unrealized gains on investment assets	Idaho Power Company accepts either PTD or LABOR to be consistent with all of the other IOU ASC filings.
20	Sch-3B	407.4	**Regulatory Credits** Did IPC correctly functionalize *Reg CR-FCA DEFORDER 30267*	In date response BPA-IP-15, IPC defined this account as a "true-up mechanism for residential and small general service customers." The explanation of the items was not sufficiently clear for BPA understand the reason this should be functionalized to PTD. This item appears to relate directly to distribution.	The Fixed Cost Adjustment is the provision that was put in place to remove disincentives for Company performed Conservation measures. The FCA allows the Company to recover fixed Production, Transmission and Distribution plant investment even in the event that Conservation programs lower Company sales. The Company is in support of either PTD or PROD (Conservation) functionalization for this account.
21	Sch-3B	407.3	**Regulatory Debits** Is IPC justified to include *Reg DR-ORD 29509-Amort Prof Fee* in its ASC? Should BPA functionalize *Reg DR-ORD 29509-Amort Prof Fee* to DIST?	IPC stated in data response BPA-IP-16 that this account was for the amortization of "professional fees paid to experts to participate in three different [rate] cares" and functionalized to PTD. As a general rule, the ASCM does not allow regulatory costs or fees to be included in ASCs.	Professional fees are a result of bringing in consulting expertise to the Company to perform various tasks. It is the Company's position that Professional fees should be functionalized as LABOR. For purposes of functionalization of Minor Items, it is the Company's position that a standard method be applied (PTD or LABOR).

No.	Schedule	Account	Issue	Discussion	Response
22	Sch-3B	456	**Other Electric Revenues** Did IPC correctly functionalize *Standby Charge*?	In IPC's description of *standby charge* in data response BPA-IP-18, it is unclear why IPC is functionalizing revenue from Standby Charge to DIST when it appears to be a production cost.	These are revenues received for the provision of services delivered to retail customers. IPC believes that it is appropriate to functionalize these revenues to distribution (DIST) but would accept the use of PTD since the service is delivered at the customers' premises. This service is applicable to customers utilizing on-site generation and not applicable to service for re-sale, to serve where on-site generation is used for only emergency supply or to co- generators or small power producers who have contracted to supply power and energy. The type of service provided is three-phase at approximately 60 cycles. If the customer opts for parallel operations, Idaho Power Company will install a system protection package at the Customer's expense, prior to the start of the parallel operations. The customer will also pay a Maintenance charge of 0.7 percent per month times the investment in the protection package. Charges under this tariff include Standby Reservation, Standby Demand, Excess Demand and Minimum ("Customer") Charges. Under Idaho Power's State Commission, this account has been directly assigned to Idaho Retail Customer(s) and functionalized as Distribution (similar to DIST functionalization). This account is not included for purposes of FERC jurisdictional ratemaking (i.e. Transmission).
23	Sch-3B	456	**Other Electric Revenues** Did IPC correctly functionalize *Alt. serv.chg-Rate 46* and *Alternate Distribution Service*?	In data response BPA-IP-18, IPC functionalized these revenues to "the provision of local service to the Lucky Peak generation project" and functionalizes each using the DIST. The explanation of the items was not sufficiently clear for BPA understand why IPC is functionalizing these accounts to DIST.	This charge recovers the cost of a secondary distribution circuit to a customer, which backs up the Customer's regular distribution circuit. This account has been functionalized as Distribution for both State and FERC regulatory purposes.

No.	Schedule	Account	Issue	Discussion	Response
24	**Sch-3B**	456	**Other Electric Revenues** Did IPC correctly functionalize *PV Rate?*	In date response BPA-IP-18, IPC defined this account as charges for the use of "photovoltaic equipment" and functionalized to DIST. In data response BPA-IP-08, IPC functionalizes the partial fees paid for the Photovoltaic Generator to PROD. The explanation of this item was not sufficiently clear for BPA understand why IPC is functionalizing this (photovoltaic) account to DIST and the related photovoltaic equipment to PROD.	The Company is planning to review all functionalization of accounts in next year's ASC filing. However, because of the quick turnaround required for the review process in this year's filing, the Company will accept suggested functionalization.
25	**ASC Forecast Model**		**Retail Load Forecast Data** Correction to Load Forecast Data in Forecast Model	IPC inadvertently submitted Load Forecast data in Forecast Model in calendar year (CY). The requirement was fiscal year (FY). IPC is aware of the discrepancy and the error will be corrected.	This information will be provided at the Company's earliest convenience.
26	**NLSL**		**New Large Single Load Data** Whether IPC may withhold information necessary to calculate the cost of serving its NLSL from BPA.	IPC inadvertently omitted certain requested data for its NLSLs resource costs to serve the NLSLs. IPC submitted some but not all information and did so under protest (response to BPA-IP-21). If IPC does not submit answers to these requests, BPA may, in its discretion, make its own assessment of the costs to exclude from IPC's ASC.	Idaho Power does not support BPA's methodology to include peaking plants (which cannot for multiple reasons service a NLSL) in the NLSL calculation. Idaho Power will provide the requested data at its earliest convenience, but is doing so under protest.
27	**Sch-3B, 3-YR PP & OSS**	555, 447	**Generic Issue - Purchased Power Expense, Sales for Resale, and Price Spread** How should book-outs and trading adjustments be treated for calculations of purchased power expense and sales for resale revenue and the price spread calculation? Should the treatment be consistent across utilities?	PacifiCorp reduced the amount of its purchased power expense and sales for resale revenue by book-outs and trading adjustments. It appears that the other utilities, such as IPC, do not. The inclusion or exclusion of book-outs and trading adjustments in purchased power and sales for resale numbers affects the price spread calculation. BPA is considering whether it is appropriate to remove these adjustments when performing the price spread calculation for the ASCs.	Idaho Power supports similar functionalization across all utilities with the provision to direct assign as applicable.

No.	Schedule	Account	Issue	Discussion	Response
28	**ASC Forecast Model**		**Generic Issue - New Plant Additions – Natural Gas Prices** Should BPA adopt a common natural gas price forecast in the ASC Forecast Model for all *new* natural gas-fired plant additions?	Forecasted natural gas prices vary significantly between utilities forecasting natural gas burning new additions. None of the utilities submitted documentation on long term firm natural gas supply contracts, so it is assumed that the differences are a result of different natural gas price forecasting techniques.	Idaho Power supports similar functionalization across all utilities with the provision to direct assign as applicable.
29	**ASC Forecast Model**		**Generic Issue - New Plant Additions - Capacity Factor** Should BPA use common representative capacity factors in the ASC Forecast model for estimating the operating costs and expected energy output for *new* plant additions?	Projected capacity factors vary significantly between utilities for similar types of new resources.	Idaho Power supports similar functionalization across all utilities with the provision to direct assign as applicable.
30	**Sch. 1, Income Statement**	**Various**	**Generic Issue – Inclusion - Other Regulatory Assets and Liabilities** What should be the functionalization of Other Regulatory Assets and Liabilities that are not included in rate base by the regulatory authority? What should be the functionalization of the corresponding income statement accounts for the Regulatory Assets and Liabilities that are not included in rate base by the regulatory authority?	There is inconsistency between utilities in the functionalization of Regulatory Assets and Liabilities when not included in rate base. Many of these accounts are included in working capital for ratemaking purposes. There is concern that the treatment of the income statement accounts for Regulatory Assets and Liabilities are not consistent with the asset and liability treatment for ASC purposes.	Idaho Power supports similar functionalization across all utilities with the provision to direct assign as applicable.

Attachment D
IPUC
Order No. 30047

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO IMPLEMENT POWER COST ADJUSTMENT (PCA) RATES FOR ELECTRIC SERVICE FROM JUNE 1, 2006 THROUGH MAY 31, 2007	)	**CASE NO. IPC-E-06-7** **ORDER NO. 30047**

On April 12, 2006, Idaho Power Company filed its annual power cost adjustment (PCA) Application. Since 1993 the PCA mechanism has permitted Idaho Power to adjust a portion of its rates upward or downward to reflect the Company's annual "power supply costs." Because of its predominant reliance on hydroelectric generation, Idaho Power's actual cost of providing electricity (its power supply cost) varies from year-to-year depending on changes in Snake River streamflow and the market price of power. The annual PCA surcharge or credit is combined with the Company's "base rates" to produce a customer's overall energy rate.

In this year's PCA Application, Idaho Power calculated that its annual power costs have decreased $46.8 million below the normalized PCA rates. The Company estimated that this represents a $123.5 million decrease in revenues from existing rates, or an average reduction in the PCA rates of 19.34%. Exhibit 8.

On April 18, 2006, the Commission issued a Notice of Modified Procedure soliciting public comments regarding the PCA Application. Only the American Association of Retired Persons (AARP) and the Commission Staff filed written comments. They urged the Commission to approve the proposed PCA rate reductions. After reviewing the Application and the comments, we approve the PCA Application and direct Idaho Power to implement the PCA rate credits to be effective on June 1, 2006.

BACKGROUND

A. The PCA Mechanism

The annual PCA mechanism is comprised of three major components. First, PCA rates are adjusted to compensate for the forecast in Snake River streamflows and storage. In years of abundance of streamflows with correspondingly plentiful and relatively inexpensive hydro-generation, the Company's power supply costs are usually lower. Conversely, when streamflows or snow packs are low, Idaho Power must rely increasingly upon its other thermal generating resources and power purchased from the regional market. The Company's other thermal generating resources (coal and gas plants) and purchased power, are typically more costly than the Company's hydro-generation. Under the PCA mechanism, the Company may recover 90% of the difference between the projected power costs and the "normalized" power costs. Order No. 25880.

Second, because the PCA includes forecasted costs, the preceding year's estimated costs are "trued-up" to account for actual costs. Third, is the "true-up of the true-up." Idaho Power uses normalized power sales (measured in kilowatt hours (kWh)) from the ensuing PCA year as the denominator to computing the true-up of the true-up. Over or under recovery is balanced with the following year's true-up. Thus, ratepayers will pay for the actual amount of power sold by Idaho Power to meet native load requirements – no more or no less. Order No. 29334 at 4. In summary, ratepayers receive a rate credit when power costs are low, but are assessed a surcharge when power costs are high.

B. The Recent Rate Case

As mentioned above, a customer's overall energy rate is comprised of the PCA rate and base rate. In Order No. 30035, the Commission approved a settlement Stipulation entered into by the parties in Idaho Power's recently completed general rate case, Case No. IPC-E-05-28. Order No. 30035 increased base rates by an average of 3.2%. Consequently, the proposed PCA decrease in this case will offset the increase in base rates.

THE 2006 PCA APPLICATION

This year's PCA Application included the forecasted costs based on water condition; a true-up of last year's forecasted costs to reflect actual costs; and the true-up of the 2005-2006 PCA year true-up (the true-up of the true-up). This year's water forecast for April through July inflows at Brownlee Reservoir was 8.3 million-acre feet (maf). The 30-year average inflows at Brownlee are 6.3 maf (1971-2000). This year's water forecast is roughly 33% above the 30-year average.

1. <u>The Water Forecast</u>. Based upon the projected water inflows to Brownlee Reservoir, the Company calculated projected power supply costs of $63,316,436 for the 2006-2007 PCA year (June 1, 2006 to May 31, 2007). The projected power costs equal 0.4691¢ per kWh. The 0.4691¢ per kWh cost estimate is 0.2786¢ per kWh lower than the Commission's approved base of 0.7477¢ per kWh. Consequently, the Company proposed a credit of 0.2507¢

per kWh (90% of 0.2786¢) for the power cost projection component. Application at 3; Schwendiman Dir. at 5.

2. The True-Up. Idaho Power reported in its Application that the difference between last year's forecast costs and actual costs (the true-up) is a credit to customers of $39,513,704. *Id.*, Exhibit 3. The PCA true-up component included several additional items previously approved by the Commission. Application at 4. These additional items included the customer benefits associated with settlement of the Valmy plant outage, reduced power costs as a result of the new Bennett Mountain power plant, non-recurring tax credit issues (Order No. 29600), and one year of interest (Order No. 29789). Schwendiman Dir. at 5-7. This amount is then divided by the normalized total jurisdictional sales in CY 2005 of 12,695,163 MW. Idaho Power witness Schwendiman calculated that the true-up portion of the PCA rate is a rate credit of 0.3113¢ per kWh. *Id.* at 7-8, 9.

3. The True-Up of the True-Up. The Company stated that last year it collected all but $24,513,298 of the PCA deferral balance. This deferral balance is included in the carry-over from last year's PCA case and the recovery of "lost revenue" from Case No. IPC-E-01-34. *Id.* at 8. Dividing this amount by the 2005 Idaho jurisdictional sales results in a PCA true-up of the true-up rate element of 0.1931¢ per kWh. Combining the three components – the projected power costs credit of 0.2507¢, the true-up component credit of 0.3113¢, and the true-up of the true-up surcharge of 0.1931¢ – results in a PCA rate credit for the 2006-2007 PCA year of 0.3689¢ per kWh. This represents a net decrease of 0.9728¢ from the existing PCA surcharge rate of 0.6039¢ per kWh.

4. The Rate Proposal. Idaho Power proposed to implement the PCA credit rates on June 1, 2006 to coincide with the approved change in base rates. The Company calculated an average decrease in PCA rates of 19.34% but each customer class will receive a different percentage decrease due to the PCA fixed cents adjustment. The Company proposed the following PCA rates for the major customer classes and calculated the percentage decreases in the PCA rates by customer class:

Customer Group (Schedule)	Current PCA Surcharge Rate	Proposed PCA Credit Rate	Percentage PCA Rate Decrease
Residential (1)	0.6045¢	0.3689¢	15.4%
Small Commercial (7)	0.6039¢	0.3689¢	12.8%
Large Commercial (9)	.06039¢	0.3689¢	21.9%
Industrial (19)	0.6039¢	0.3689¢	27.0%
Irrigation (24-25)	0.6052¢	0.3689¢	19.4%

The PCA rates for Idaho Power's three special contract customers would also decrease to a credit of 0.3689¢ per kWh. Their PCA rates would decrease: 30.59% for Micron; 32.40% for Simplot; and 31.93% for the Department of Energy (INL). Schwendiman Exh. 8. The Company's Application included the proposed PCA tariff in Schedule 55.

THE COMMENTS

1. Staff Comments. The Staff conducted an audit of all actual revenues and expenses that occurred during the PCA year. The Staff sought to verify the revenues and costs associated with the cloud seeding program, fuel expenses for coal, fuel expenses for natural gas and power purchases/sales. The Staff also examined the settlement agreement credits contained in Order No. 29600, the IDACORP energy credits, and the risk management operating plans. Staff's analysis did not find any unreasonable transactions. Staff also determined that the Company's power transactions were made with an assortment of credit-worthy partners on a timely basis, and there were no transactions conducted with an Idaho Power affiliate. Staff Comments at 4.

The Staff's calculations for the three PCA components agreed with Idaho Power's calculations. Staff calculated that the 2006-2007 PCA rate credit should be 0.3689¢ per kWh as shown in Staff Attachment C, line 16. The Staff recommended that the Commission approve the PCA rates as filed by the Company.

2. AARP. AARP-Idaho also supported Idaho Power's proposal to reduce the PCA rates. AARP noted that the proposed PCA rate credits represent a real benefit for residential customers living on fixed or low incomes. Comments at 2-3. AARP asserted that the proposed overall "rate reduction will help a number of customers to better afford their electricity bills as we begin the summer months." *Id.* at 3.

COMMISSION FINDINGS

Based upon our review of the PCA Application and the two comments, we find it is reasonable to grant Idaho Power's Application to reduce the PCA rates. More specifically, we find the proposed PCA rate credit of 0.3689¢ per kWh is reasonable. In addition, the Commission approves the proposed PCA rate credits for the three special contract customers. The PCA rate decreases approved in this Order will offset the recent base rate increases approved in Order No. 30035.

Given the abundance of snow pack and Snake River streamflow, we are pleased to decrease rates after six years of PCA surcharges. The significant decrease in the PCA rate this year demonstrates the fairness and value of the PCA mechanism. This year the Company is able to meet its expected loads with less expensive hydro-generation. All customers will see their overall electric rates decrease effective June 1, 2006.

ORDER

IT IS HEREBY ORDERED that Idaho Power Company's Application to reduce its PCA rates is approved.

IT IS FURTHER ORDERED that from June 1, 2006 through May 31, 2007, the PCA rate credit shall be 0.3689¢ per kWh for all customer classes and the three special contract customers.

IT IS FURTHER ORDERED that the PCA rate credits contained in this Order shall be effective for service on June 1, 2006. The Company's proposed PCA tariff Schedule 55 is approved.

THIS IS A FINAL ORDER. Any person interested in this Order (or in issues finally decided by this Order) or in interlocutory Orders previously issued in this Case No. IPC-E-06-7 may petition for reconsideration within twenty-one (21) days of the service date of this Order with regard to any matter decided in this Order or in interlocutory Orders previously issued in this case. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 25th day of May 2006.

PAUL KJELLANDER, PRESIDENT

MARSHA H. SMITH, COMMISSIONER

DENNIS S. HANSEN, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

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Attachment E
IPUC
Order No. 27660

Office of the Secretary
Service Date
July 31, 1998

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES TO RECOVER DEMAND SIDE MANAGEMENT/ CONSERVATION EXPENDITURES.	**CASE NO. IPC-E-97-12** **ORDER NO. 27660**

SYNOPSIS

On November 26, 1997, the Idaho Power Company (Idaho Power; Company) filed an Application for authority to increase its rates to allow for the accelerated recovery of its outstanding Demand Side Management (DSM) expenditures. By this Order, we authorize Idaho Power to increase its rates to reflect an amortization of 12 years with a carrying charge of 7.25%. The resulting revenue requirement increase shall be allocated to all of the Company's customer classes under the existing methodology and shall be recovered through a uniform percent increase to customers' bills except for special contract customers who will pay a fixed fee. We deny from recovery, the Company's investment in its Commercial Lighting Program incurred after the 1995 calendar year. Idaho Power's rates shall be reduced to reflect a decrease in the amount of its authorized annual DSM administration expense. The first 6 months of amortization related to the Company's 1994 DSM investment shall be reflected as if amortized through June, 1998. Finally, we award intervenor funding to the Rate Fairness Group in the amount of $4911.37, the Idaho Irrigation Pumpers Association in the amount of $14,727.94 and the Idaho Citizens Coalition in the amount of $5360.68.

BACKGROUND

In its Application, Idaho Power states that as a result of Commission Order No. 25880 issued in Case No. IPC-E-94-5, the Company began amortizing $19,863,300 of deferred DSM program expenditures incurred prior to 1994 at a rate of $68,970 per month for 24 years. The Company contends that a 24 year amortization period for that deferred investment is too long; it proposes to amortize the outstanding DSM investment ($17,449,400 for the Idaho jurisdiction as of December 31, 1997) over five years. In addition, the Company wishes to begin amortizing all DSM expenditures made after 1993 over five years. The Idaho jurisdictional amount of these expenditures (as of August 31,1997) was $16,239,800. The Company wishes to also recover carrying charges on deferred DSM amounts and to recover for the income tax impacts on those carrying charges.

Idaho Power states that, based upon changing the amortization period for deferred DSM expenditures made prior to 1994 from 24 to 5 years, the Idaho jurisdictional revenue requirement to be recovered in this five year period is $13,311,200. The Company states that the carrying charges for the Idaho jurisdictional revenue requirement associated with the deferral of DSM made after 1993 are $7,794,000. The Company states that carrying charges during the years 1996 and 1997 have not been shown because of their treatment in the revenue sharing cases. Idaho Power anticipates that revenue sharing for 1997 will exceed the carrying charges that will accrue on deferred DSM program expenditures in 1997. If that is correct, Idaho Power states, the Company will request that the Commission offset DSM carrying charges in the 1997 revenue sharing proceeding in the same manner as it offset those costs against shared revenues in 1996. To the extent that there is carrying charge recovery, there will be an income tax impact on the recovery of those carrying charges. The income tax impact of the Idaho jurisdictional revenue requirement associated with the carrying charges on deferral of DSM, Idaho Power contended in its Application, was $5,003,700.

In summary, the Idaho jurisdictional balances purportedly associated with pre-1994 deferred DSM expenditures is $13,311,200 and deferred DSM program expenditures made after 1993 is $16,239,800. The Idaho jurisdictional revenue requirement associated with carrying charges on deferred DSM amounts is $7,794,000 and the Idaho requirement associated with income taxes on carrying charges is $5,003,700. Idaho Power sought to recover the total amount of $42,348,700.

The Company proposes that the Commission treat the 5 year Idaho jurisdictional revenue requirement amount as two separate amounts to be allocated to customer classes by separate methods. The Company recommends that the first amount, $13,311,200, which is the incremental revenue requirement associated with accelerating amortization of deferred DSM expenditures made prior to 1994, be allocated to customer classes using the same allocations used in Case No. IPC-E-94-5; the Company's last general rate case.

Idaho Power recommends that the remainder of the revenue requirement, which includes deferred program expenditures made after 1993, including carrying charges and income taxes, be allocated to customer classes based upon the "ability of the customer class to participate" in DSM programs.

allocated to customer classes based upon the "ability of the customer class to participate" in DSM programs.

Following the filing of Idaho Power's Application, the Industrial Customers of Idaho Power (ICIP), Micron Technology, Inc. (Micron) and the Rate Fairness Group (RFG) filed motions to dismiss the Company's Application on the basis that it constituted a general rate increase in violation of the rate moratorium agreed to by Idaho Power and adopted by this Commission in Order No. 26216 issued in Case No. IPC-E-95-11; it is inappropriate to grant the Application without considering other issues that would affect the Company's earnings, and that the Idaho Legislature, rather than this Commission, should determine whether Idaho Power should be allowed accelerated recovery of its DSM investment. On April 30, 1998, this Commission issued Order No. 27493 in this case denying all three motions to dismiss and the matter proceeded to hearing on May 26-27, 1998. The following appearances were made at the hearing.

Idaho Power Company	Larry D. Ripley, Esq.
Commission Staff	Brad M. Purdy, Deputy Attorney General
Industrial Customers of Idaho Power	Peter J. Richardson, Esq.
Micron Technology, Inc.	Allan R. Richey, Esq.
Rate Fairness Group	Paul L. Jauregui, Esq.
Idaho Irrigation Pumpers Association, Inc.	Randall C. Budge, Esq.
Idaho Citizens Coalition	Al Fothergill
U.S. Department of Energy	Lawrence A. Gollomp, Esq.
FMC Corporation	Conley Ward, Esq.

FINDINGS

Amortization of DSM

The only party supporting Idaho Power's proposed acceleration of its DSM recovery is the Commission Staff. All others advocate that recovery remain at the current 24 years. The arguments advanced by the various parties in opposition to Idaho Power's proposal largely overlap. Primarily, the parties contend that Idaho Power provides no justification for its selection of 5 years as an appropriate amortization period. Certain parties contend that Idaho Power is attempting to avoid stranded investments on a piecemeal basis without netting all of the Company's resources. Micron argues that this is an issue that lies within the exclusive province of the Idaho Legislature. Others, such as the ICIP, argue that the concept of "matching" revenues with expenses requires that amortization match the expected useful lives of the resources. The ICC points out that most utility analysts predict that the transmission and distribution functions of electric utilities will remain regulated thus minimizing or negating the possibility that Idaho Power will not recover its DSM investments. FMC contends that, in some respects, DSM is simply another form of a generating resource and there is no greater justification for accelerating the recovery of conservation resources than there is for accelerating the recovery of investment in a hydro or thermal facility. FMC also notes that although DSM is expensive by today's market standards (because of low gas prices and sophisticated gas generation technologies), it allowed Idaho Power to avoid the acquisition of relatively high cost hydro and thermal resources during the 1970's and 1980's.

In rebuttal, Idaho Power argues that other regulatory jurisdictions are trending toward a shorter amortization of DSM. The Company also posits that shortening the recovery of DSM better ensures that customers who received the benefits of the DSM measures will pay for them. Idaho Power also notes that resource planning horizons have changed. Utilities are no longer planning for the acquisition of base load generating plants so DSM is not simply another form of generation. The Company further asserts that DSM is unlike generating assets owned by the utility. In the event of market or regulatory changes, the Company can sell the latter in the market. The benefits of the actual DSM measures, however, remain with those customers in whose facilities they were installed.

We find:

This Commission has expressed concern for some time regarding the amount of DSM deferral that Idaho Power has been accumulating. This is evidenced by the three year limit we imposed on Idaho Power as of August, 1994 in Order No. 25880 to begin amortizing its DSM balances. It is also evidenced by the fact that we specifically approved the provision in the rate moratorium allowing the Company to seek a modification to the manner in which it recovered its DSM expenditures. We also find significant the changes that are sweeping through the electric industry and the unpredictability that has resulted.

We also agree with Idaho Power that conservation measures are different, in at least one important aspect, from other generating resources. They are not owned by the Company as are base load generating plants. Clearly, the Company is at somewhat greater risk with respect to DSM cost recovery in the event of market and regulatory changes. We also find persuasive that by shortening the recovery period of DSM, it is more likely that those customers who reaped the benefit of cost effective resources, will pay for them. In short, we find that a 24 year recovery period for Idaho

Power's DSM expenditures is too long. Consequently, we find that it is reasonable to allow the Company to shorten the period in which it may recover its DSM.

Idaho Power was widely criticized in this case for purportedly failing to provide a tangible basis for its selection of a five year amortization period. The fact is, the matter requires some degree of discretion. This Commission, by virtue of the authority vested in it pursuant to Chapter 5, Title 61, of the Idaho Code, has the power and, indeed, the charge, to exercise that discretion. In defense of its proposal, Idaho Power notes that it currently relies on a five year planning horizon for the acquisition of resources. The Company also leans on the unpredictability of the regulatory world in which it operates as further justification for a dramatically shortened recovery. Perhaps, we view the future regulatory paradigm from a different perspective, or with greater assuredness. In any event, as the ICC posits, it is very likely that in five years' time, there will still be regulation of at least some aspect of Idaho Power's operations in this state. We find, therefore, that a five year amortization is too short.

We find that reducing the established DSM recovery period by one half (to12 years) will considerably lessen the risk that the Company will not recover some portion of its expenditures while, at the same time, shift more cost responsibility on those customers who benefitted from the acquisition of DSM without unduly burdening ratepayers. Thus, we believe that a 12 year amortization period is a just and reasonable compromise of all interests concerned.

Recovery of expenditures in Commercial Lighting Program

Staff proposes that all of the Company's investment made after the 1995 calendar year in the Commercial Lighting Program (CLP) be disallowed. Staff notes that unlike most of the Company's other DSM programs, there was never a formal impact evaluation conducted for the CLP at any time during the course of the program to determine how many program participants would have made lighting improvements without the program or whether the improvements they did make were likely to persist for the assumed 12 year life. Thus, there is no reasonable assurance that the expenditures being made by Idaho Power were resulting in energy savings and, if so, to what extent. Staff argues, it was not possible to determine if the CLP was cost effective and, therefore, prudent for the Company to continue beyond the first two plus years.

Idaho Power argues, in rebuttal, that the Company conducted "site verifications" in which an unspecified number of CLP installations were examined to determine what the energy savings were and whether the measures and the program were proving to be economically cost-effective.

We find:

Idaho Code § 61-502 requires that before this Commission may change a utility's rates, it must find the existing rate "unjust, unreasonable, discriminatory or preferential." Rates previously approved by the Commission must, therefore, be presumed to be fair unless and until the Commission, whether by its own action or the action of another party, has before it evidence to the contrary. Consistent with *Idaho Code* § 61-502's mandate of reasonableness, the Idaho Supreme Court ruled long ago that before changing a public utility's rates, the Commission must first find that existing rates are "unreasonable." See, *Murray v. Public Utils. Comm'n*, 27 Idaho 603, 150 P. 47 (1915). Also, in Case No. U-1500-165, Order No. 22299, the Commission stated that "care must be taken to pay only for measurable conservation benefits and for those conservation benefits not otherwise available." *Order No. 22299 at p. 17.*

In this case, Idaho Power filed an Application seeking to increase its rates on the basis that they are insufficient. Because the Company is usually the only party in possession of the information necessary to determine whether a cost was prudently incurred, it carries an obligation to support its rate filings with information sufficient to establish that prudence. We find that Idaho Power has not shown that its CLP met these criteria. In its Production Request No. 9, Staff requested "copies of any management, monitoring, or evaluation plans prepared or utilized for. . .the Commercial Lighting Efficiency Programs. . . ." In response, Idaho Power stated:

> The management and status reports for the programs are included in the Conservation Plans of Idaho Power that are published annually. A copy of Conservation Plans for the years 1989 through 1997 has been provided. The Company will soon release its 1998 Conservation Plan, and a copy will be provided. References to the particular program years are set forth below.
>
> . . .
>
> (c) Commercial Lighting Program, 1993 through 1997 (Staff Exhibit No. 105)

In its production request No. 10, Staff requested "copies of any progress reports, program evaluations, impact assessments, performance summaries or similar documents prepared for. . .the Commercial Lighting Efficiency programs. . . ." In response, Idaho Power stated:

> In response to Requests 10(a), 10(b) and 10(c), all progress reports, program evaluations and impact assessments conducted by or for Idaho Power are included in the Plan or the Technical Appendices by program. . . .

Idaho Power's responses to Staff's Production Request Nos. 9 and 10 were dated April 15, 1998. In the rebuttal testimony of Idaho Power witness Gregory Said, the Company stated:

> In addition to the fact that it was relatively easy to determine that the Commercial Lighting Program was cost effective without conducting an in-depth evaluation, the Company did perform field evaluations to determine if the electricity savings in the Commercial Lighting Program had persisted over time.

Tr. Vol. V, p. 597.

Witness Said's rebuttal testimony, filed May 20, 1998, 3 working days prior to the hearing, is apparently the first time during the course of this proceeding that Idaho Power identified any type of evaluation it performed on the CLP notwithstanding that Staff had clearly requested such information more than two months earlier. We find that Idaho Power's failure to accurately and fully respond to Staff's production request rendered it impossible for Staff to conduct a prudence review of the Company's CLP expenditures. Moreover, the Company failed to produce as a witness to this proceeding any Idaho Power employee with first hand knowledge of the CLP. The following is an excerpt of testimony given by Company witness Said live during the hearing:

> Q. Where did you get your information that you utilized in preparing your testimony on the CLP, Mr. Said? Did you get that from Ms. Nemnich?
> A. Yes, I did.
> Q. And Idaho Power did not call her as a, present her as a, witness to this proceeding in support of its application, did it?
> A. No.

Tr. Vol. VI at p. 649.

Perhaps our concern with the CLP is best reflected in the following testimony of Mr. Said also given at the hearing:

> Q. Okay. Would you agree with my characterization of Ms. Nemnich's testimony that she testified, her deposition testimony that she testified, that the Company had not performed an impact evaluation of the CLP?
> A. I think that's true and that's consistent with her response in the data request.

Tr. Vol. VI, pp. 647-648.

In conclusion, Mr. Said testified:

> Q. And that's the extent of the evaluation that you did, that the Company did, of the CLP [referring to the "field" evaluations]?

A. Yes. We were in the process of looking into discontinuance of the program and were of the opinion that if you were going to discontinue a program that it wasn't reasonable to put a lot of time and effort into a written report whose sole purpose would be to propose modifications or discontinuance of the program.

Id. at p. 650.

Regarding the CLP, we find that Idaho Power failed to offer proof that the expenditures made by the Company were reasonable and, in fact, failed to conduct the impact evaluation that it said it was going to do in its 1995 Conservation Plan filed with this Commission. Moreover, we find that actions taken by Idaho Power rendered it difficult if not impossible for Staff to conduct an independent review of the prudence of the Company's CLP expenditures. We cannot impose upon the Company a burden of proof that is unnecessarily onerous. Neither can we countenance, however, Idaho Power's apparent lack of concern for, and cooperation in, the efforts of Staff to fully analyze the prudence of this particular expenditure. Consequently, we find that until Idaho Power demonstrates that its deferred expenditures in the CLP program after 1995 were prudently incurred, given that it failed to perform the impact evaluation that it had told the Commission it was planning, then those expenditures will be disallowed as proposed by Staff.

Carrying charge on outstanding DSM balances

Idaho Power proposes collecting a carrying charge on outstanding DSM balances at the rate of 9.199% which reflects the Company's overall rate of return established in Order No. 25880. Staff contends that this rate was appropriate to reflect the 24 year amortization period and the possible risks of not recovering the full amount. Staff argues, however, that a shorter recovery period results in significantly less risk for Idaho Power. Since the payment of the accumulated DSM costs would be reasonably assured due to the shorter repayment time frame, the DSM deferred asset should be considered more like a receivable from the ratepayers with a correspondingly lower risk. Staff proposes using the Company's medium term cost of debt as a carrying charge. Rounded off, this equates to 7%. Staff's proposal is based upon the presumption that the Company's request to recover DSM over 5 years is granted. A different carrying charge might be appropriate if some other time period is ultimately adopted by the Commission.

The ICIP proposes that the Commission assume, for rate setting purposes, that current unamortized DSM balances be financed with 5 year bonds and that rate adjustments be calculated

In rebuttal, Idaho Power contends that absent the front-end recovery securitized by an actual bond issue, the hypothetical elimination of the common equity and the preferred components of the overall cost of capital is inappropriate as proposed by Staff and the ICIP. The Company states that it does not apportion its rate base and assign different capital costs to the portions. Idaho Power states that the DSM deferred balance was financed or funded by the existing capital structure of the Company and would be financed with short term debt only if the DSM balance was securitized.

We find:

Idaho Power witness Gale conceded that "[v]iewed in isolation there is a minimal risk reduction related to the shortening of the amortization period. . . ." This understates the reduction in risk that Idaho Power apparently perceives it will enjoy as a result of a faster recovery period.

Mr. Gale further testified that "Idaho Power's overall rate of return has been traditionally set in the context of a general rate case where all the factors impacting risk can be examined." The Company advocates against singling out the interest on deferred DSM balances without a full assessment of all factors impacting the Company's risk. This precise logic was in fact used by other parties in this case who suggest that it is inappropriate to accelerate the recovery of DSM without netting it against all of Idaho Power's resources. We have already found that circumstances unique to DSM and to Idaho Power warrant a different treatment of the Company's investment in DSM. By the same token, we find that it would be consistent and reasonable for us to consider the reduction in risk attributable to a shorter DSM recovery period in selecting a carrying charge. Because we have decided to allow the Company to shorten DSM recovery to 12 years, we find that a carrying charge of 7.25% based on utility bond rates would be appropriate.

Level of future DSM expense

Staff and other parties recommend that the amount of annual DSM expense embedded in rates should be reduced to reflect the fact that Idaho Power has terminated all but one of its DSM programs (Agriculture Choices-Currently being considered for termination) and, therefore, the Company should experience significantly reduced costs in administering DSM as a whole. Staff proposes reducing the amount of DSM expense embedded in Idaho Power's rates in Idaho for future recovery from $1,060,909 to $212,534, which constitutes the average level of 1996 and 1997 actual recorded expenses.

Idaho Power contends that actual DSM expenditures will remain higher than Staff and other parties suggest due to commitments made to the Low Income Weatherization Assistance program (LIWA) but concedes that there will be a "slight" reduction in administrative DSM related costs. The Company counters that administrative costs it actually booked do not reflect on going or actual costs experienced by Idaho Power, including costs relating to the Company's involvement in the Northwest Energy Efficiency Alliance (NEEA) and the Agricultural Choices program. Adopting Staff's recommendation, Idaho Power asserts, will lock in unreasonably low expense levels into future years.

The Company concedes that its organizational structure makes it difficult to measure the on going DSM administrative costs because both corporate and field personnel were and are involved in these activities. Consequently, Idaho Power proposes that its future DSM administrative expense be decreased by the annual salaries of the four individuals who left the Company and who spent the majority of their time working on DSM programs. This would result in a $337,362 reduction to the annual DSM expense level.

We find:

The amount of annual DSM expense embedded in rates must be reduced to reflect reductions that all parties, including the Company, acknowledge. The appropriate amount of the reduction is disputed. We find that the appropriate treatment must use the Company's actual booked costs in lieu of speculative amounts that cannot be quantified. Merely eliminating the expense related to four employees is not sufficient to recognize the complete termination of nearly all DSM programs. We find that Staff's proposed expense level of $212,534 reasonably represents the cost of on-going programs and is the only amount for which there is solid evidence. If, in the future, the Company actually experiences significantly higher DSM expenditures, we would certainly entertain a filing to revisit the matter.

Gross-up for interest on taxes

Idaho Power grossed up the full carrying charge amount in its DSM revenue requirement. Staff proposes that only the equity portion from the Company's capital structure should be grossed up. The Company agrees in concept but argues that the actual ratio would be 60% for total equity (a weighted ratio). Idaho Power grossed up the full carrying charge in the DSM balance deferred, the prospective carrying charges and all adjustments for revenue sharing. Staff grossed up the carrying charge in the DSM balance deferred and the accrued interest in the revenue sharing adjustments. Staff argues that the prospective interest should not be grossed up.

We find:

Staff's rationale and methodology is reasonable. Idaho Power agreed in concept that the equity portion is the amount that would be grossed up but that the appropriate ratio is the weighted ratio of 60%. No party objected to the use of the 60% ratio. Therefore, we adopt this ratio to determine the gross up for taxes. The deferred amounts should be grossed up for taxes, however, we can not accept grossing up the prospective interest amount.

Proposed adjustment to reflect 1998 amortization of 1994 DSM deferrals

Staff proposes that the first six months of amortization of Idaho Power's 1994 DSM expenditures be reflected for January through June 1998, reducing the DSM balance because the Company should have begun amortizing those expenditures, at the latest, by January, 1998 as per Order No. 25880.

We find:

In Case No. IPC-E-94-5, Order No. 25880, Idaho Power was directed to begin amortizing its DSM balances no later than 3 years from the date of deferral. In that Order, we stated:

> We are also concerned with the length of time that DSM program expenses were allowed to accumulate prior to the filing of this rate case, resulting in accrued expenses in excess of $20 million. We decline to adopt Staff's proposal to order immediate amortization of DSM costs. We find it reasonable to require that commencement of amortization begin after no more than three years. In the future, IPCo must begin amortization of accumulated DSM costs after a three year period.

Order No. 25880 at p. 18.

Based on the foregoing, Staff argues that the 1994 deferred DSM balances would begin to be amortized January 1998. Because it is now mid-year, Staff proposes reflecting 6 months of that amortization by reducing the balance remaining. Idaho Power argues because it filed its case in late November of 1997, prior to the end of the third year following deferral of 1994 expenditures, it complied with the intent of the Commission's Order.

We agree with Staff. When we issued Order No. 25880, we were clearly concerned with the level of deferred DSM that Idaho Power had accrued and desired that the Company make some type of filing to begin recovery of those balances over time. We find the fact that Idaho Power filed its Application in this case in late 1997, slightly before the end of the three year limit, does not satisfy the spirit and intent of Order No. 25880. The Company has sufficient experience with proceedings before this Commission to know that a filing of this complexity and magnitude could not be processed and finally resolved prior to the end of the three year limit. During the hearing in this case, Idaho Power could offer no reason why it could not or did not file this case sooner. Given the concern we have repeatedly expressed, at least as long ago as 1995, regarding the need to begin amortizing Idaho Power's DSM, we find that our previous Order requiring amortization to begin should remain in effect. We find, therefore, that it is reasonable to reflect the first six months of amortization of the Company's 1994 deferred balances as a reduction to the balance remaining for recovery.

Allocation of revenue requirement

Idaho Power proposes that its pre-1994 DSM balances be allocated on the basis of system load factor. All post-1993 balances are proposed to be allocated on the basis of a class's "ability to participate" in DSM. Idaho Power's stated rationale for changing the allocation methodology for post-1993 expenditures is that "DSM is currently viewed from the perspective of the direct benefits" received.

The parties to this proceeding were split on the issue of revenue allocation. The Irrigators object to allocation on the basis of ability to participate noting that there has never been an equal ability to participate on the part of all customers in a given class and it is impossible to determine those who could or could not participate. The Irrigators point out that cost effective DSM has benefitted all of Idaho Power's customers and should continue to be allocated as it always has. Moreover, the Irrigators argue that the DSM programs they were qualified to participate in were limited because of their late implementation. Under Idaho Power's allocation methodology, the Irrigators will pay for DSM programs when they could not participate in the programs and now will pay more for post-1993 DSM because they can participate in those programs.

The ICC argues that there is absolutely no support for changing the allocation methodology. According to the ICC, Idaho Power's proposal places the bulk of cost responsibility on residential and irrigation customers and relatively little on larger, industrial customers. The ICC characterizes this as "retroactively changing the rules of the game."

Staff argues that DSM was a cost effective surrogate for generating resources when implemented and there is simply no reason to allocate it in a different manner. Staff also notes that while participating customers may have benefitted more from the actual DSM measures, they often had to pay up front costs and assume the risk that the conservation measures would produce the expected savings. In lieu of Idaho Power's proposal, Staff suggests that customers' total electricity bills be increased by a uniform percentage. Staff notes that this methodology offers the benefit of simplicity and will not unreasonably distort class revenue responsibility.

The RFG opposes the "ability to participate" allocation noting that not all customers within a class could even qualify for a DSM program supposedly designed for that class. For instance, the Company's Manufactured Home Acquisition Program would be allocated to all residential customers. Only those customers who purchased a manufactured home, however, could have participated in that program.

Micron argues in favor of the ability to participate methodology but argues that it was not able to participate in any post-1993 DSM, including the Partners in Industrial Efficiency program and should not be allocated any costs for that time period.

FMC argues that none of Idaho Power's post 1993 DSM programs were cost effective and, thus, the ability to participate is the only meaningful method of allocation.

We find:

In Case No. IPC-E-94-5, we chose to allocate the recovery of DSM to all of Idaho Power's customer classes using the DSM allocation methodology adopted in the last rate case. Our rationale for doing so was that the acquisition of cost effective DSM benefitted all of the Company's customers because it allowed the Company to avoid the construction or acquisition of more expensive resources. We find that the original logic upon which we selected an allocation methodology for DSM remains sound. No party to this proceeding offered persuasive arguments in favor of abandoning our chosen method of allocation. To the extent that Idaho Power's DSM constituted a cost effective acquisition of resources when implemented, then the rationale for allocation of the cost of those resources remains unchanged.

Idaho Power's premise that those who benefit from DSM should pay for it has conceptual merit. Indeed, that is the very logic that led us to allocate DSM along with other system resource costs. The flaw in Idaho Power's "ability to participate" allocation, however, is one of a practical nature. In fact, we find that the term "ability to participate" is somewhat misleading. As the Company's witness readily agreed, the fact that a given DSM program might have been targeted for a given customer class does not mean that every member of that class truly had the ability to participate in the program. For instance, although the Manufactured Home Acquisition program was designed for customers who were served under the residential class schedule, that program was available, as a practical matter, to only a small percentage of the residential class customers. Furthermore, there was also considerable debate over whether and to what extent Micron could or did participate in the PIE program. Adoption of the Company's proposed allocation would require this Commission to make findings regarding the nature of Micron's business operations and the interplay and business relationship between Micron Technology and Micron Electronics. Similar difficulties exist in determining the extent of FMC's ability to participate in DSM programs.

We find that such speculative analysis is needless considering that DSM represents a system resource and should be allocated as such. We view Staff's "uniform percent" class allocation proposal as a much simpler alternative to the Company's proposal, but note that the Staff offered no compelling reason to deviate from the previously approved allocation method. We also find that spreading DSM costs uniformly across all customer classes as proposed by Staff would improperly allocate DSM costs and unreasonably alter the class revenue responsibility established in the last rate case.

We commend the Company for its effort to craft an allocation that it believed falls somewhere in the middle of the various parties' interests. Nonetheless, for the foregoing reasons, Idaho Power is directed to allocate the revenue requirement increase resulting from this Order to all customer classes on the basis of system load factor, as previously required by Order No. 25880.

Rate design

Idaho Power proposes that the revenue requirement increase allocated to each customer class be recovered using a uniform percentage increase. For its special contract customers, however, the Company proposes a flat monthly fee designed to recover that allocation.

Staff disagrees with Idaho Power's proposal of a flat monthly fee for all special contract customers except for FMC. For those three other special contract customers, Staff proposes a uniform percentage increase based on monthly bills as proposed by Idaho Power for its other customer classes. For FMC, Staff proposes a different rate design. Staff notes that under FMC's recently approved contract with Idaho Power, the second block of FMC's consumption is tied to market conditions and is lower. To ensure that FMC pays its allocable share of the DSM revenue requirement increase, Staff proposes that the revenue requirement allocation be recovered through a fixed fee based upon a uniform percentage increase of normalized revenues received from FMC in 1996.

We find:

As noted above, we have chosen to allocate the increased revenue requirement based on the existing allocation method adopted in Case No. IPC-E-94-5 (Idaho Power's last general rate case). The Company is directed to collect the revenue requirement of each non-special contract class by applying the uniform percentage increase to all rate components within that class. For special contract customers, the Company's proposal of a fixed fee is accepted. The resulting rate increases applicable for each customer class, including the special contract customers, are shown in Attachment "A" to this Order.

Intervenor funding

Intervenor funding requests were submitted by the RFG ($12,084.92), the ICC ($5,360.68) and the Irrigators ($15,174.89). We find that each of the three intervenors seeking funding contributed materially to the Commission's final decision in this case and that the positions taken by them differed sufficiently from those taken by the Commission Staff to warrant the award of intervenor funding to all three applicants. We further find that the requests of all three applicants otherwise satisfy all of the procedural and substantive requirements set forth in the *Idaho Code* § 61-617A and Rules 161 through 165 of the Commission Rules of Procedure, IDAPA 31.01.01. We do note, however, that the Application of the Irrigators fails to itemize the hourly fees and number of hours worked of its attorney and consultant. Such information is necessary for us to determine whether the costs incurred and amount of funding sought is "reasonable in amount" as required by *Idaho Code* § 61-617A and Commission Rule 165. Without such itemization, future requests by the Irrigators will not be approved.

Initially, we believe it is justifiable to award the entire $25,000 available, in total, to the participants to this proceeding pursuant to *Idaho Code* § 61-617A. First, we award the ICC's entire request of $5,360.68. For the Irrigators, we award costs in the amount of $1,276.49, consultant fees in the amount of $8,850 and attorney's fees in the amount of $4,601.45 for a total award of $14,727.94. Regarding the request of the RFG, we award costs in the amount of $320.92. We limit our award of attorney's fees, however, to $4,601.45 for a total award of $4,911.37. The $4,601.45 awarded to each of the attorneys for the RFG and the Irrigators was calculated by splitting in half the remaining amount of intervenor funds available after satisfying the ICC's entire request and costs and consulting fees for the RFG and the Irrigators.

Prepayment of DSM allocation

Staff proposes that because special contract customers each are a class of one for whom we have allocated a fixed amount, they should be given the option of prepaying their allocation to avoid carrying charges. No party opposed Staff's proposal.

We find:

It is reasonable to allow special contract customers the option of prepayment. We note that this will in no way affect the amount of recovery assessed or otherwise prejudice the Company's other customer classes.

Timing of recovery

Our decision in this case results in an annual revenue requirement increase to Idaho Power in the amount of $3,054,672. Staff witness Carlock proposes that any revenue requirement increase approved by this Commission be deferred from recovery by offsetting it against the Company's 1997 revenue sharing adjustment. Staff proposes, therefore, to use the sharing amount to cover the additional monthly revenue requirement until it is exhausted. Staff further proposes that the actual increase for DSM reflected on customer bills coincide with the 1999 PCA change and 1998 revenue sharing review on May 15, 1999 or when those rates are to be effective. Idaho Power, on rebuttal, recalculated the 1997 earnings sharing to reflect the adjustment proposed by Staff in the gross up for taxes. The recalculated amount is $5,353,405.

We find:

No party objected to Staff's proposal which we hereby adopt. The Company is directed to utilize the 1997 earnings sharing amount to offset the DSM revenue requirement until the 1999 PCA rate change is effective. Since the annual DSM revenue requirement is less than the 1997 revenue sharing adjustment, the unused balance shall accrue interest at the 6% interest rate established for payments on customer deposits. Any offsets to the remaining balance will be evaluated and the true up determined coincident with the 1998 revenue sharing review. The disposition of any remaining balance associated with the 1997 earnings sharing will be determined in the 1998 earnings sharing review.

ORDER

IT IS HEREBY ORDERED that the application of Idaho Power Company for accelerated amortization of its outstanding DSM investment is approved subject to the terms and conditions set forth in the body of this Order.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 31st day of July 1998.

Dennis S. Hansen

DENNIS S. HANSEN, PRESIDENT

Commissioner Nelson Dissented

RALPH NELSON, COMMISSIONER

Marsha H. Smith

MARSHA H. SMITH, COMMISSIONER

ATTEST:

Myrna J. Walters

Myrna J. Walters
Commission Secretary

O:IPC-E-97-12.bp7

IPC-E-97-12
Customer Class Cost Allocation and Rate Increases

Sch.	Customer Class	IPC-E-94-5 Allocation	Share of $254.556/mo.	Intervenor Funding	Total New Mo. Rev. Req.	1996 Norm. Monthly Rev.	% Rate Increase
1	Residential	33.58%	$85,489	$417	$85,906	$16,146,000	0.532%
7	Small General	2.24%	5,691		5,691	1,311,900	0.434%
9	Large General	18.63%	47,432		47,432	7,097,800	0.668%
15	Lighting, Dusk/Dawn	0.03%	86		86	120,400	0.071%
19	Large Power	13.04%	33,198		33,198	4,026,700	0.824%
24	Irrigation	14.22%	36,197	625	36,822	5,151,400	0.715%
26	Micron Tech.	2.21%	5,628		5,628	907,200	0.620%
28	FMC Corp.	12.56%	31,963		31,963	2,800,700	1.141%
29	J.R. Simplot Co.	1.96%	4,995		4,995	552,100	0.905%
30	U.S. Dept. of Energy	1.36%	3,475		3,475	407,900	0.852%
40	Unmetered General	0.04%	94		94	30,800	0.305%
41	Munic. Street Light.	0.07%	189		189	137,100	0.138%
42	Munic. Traffic Signal	0.05%	119		119	17,800	0.669%
	Total, All Classes	100.00%	$254,556	$1,042	$255,598	$38,707,800	0.660%

DISSENT OF
COMMISSIONER RALPH NELSON
CASE NO. IPC-E-97-12

While I agree with my colleagues on the major thrust of this order, there are two points on which I cannot agree.

The first is the carrying charge for the DSM balance. While a shorter amortization period will reduce risk to the Company slightly, it is not risk free. I would allow the return that was approved in Idaho Power's last rate case.

The second point which I do not agree is the decision to disallow some amortization because the Company's case was not filed timely. The case was filed in time to comply with my understanding of the Commission's intent in Order No. 25880, when we said that Idaho Power Company couldn't accumulate DSM costs for more than three years without applying for recovery of those costs, or they would have to begin amortization without recovery in rates. In this instance, they applied for recovery within the three years.

Ralph Nelson, Commissioner

Attachment F
IPUC
Order No. 30267

Office of the Secretary
Service Date
March 12, 2007

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE INVESTIGATION OF FINANCIAL DISINCENTIVES TO INVESTMENT IN ENERGY EFFICIENCY BY IDAHO POWER COMPANY.	))))	**CASE NO. IPC-E-04-15** **ORDER NO. 30267**

On August 10, 2004, the Idaho Public Utilities Commission (Commission) in Order No. 29558 established Case No. IPC-E-04-15 to investigate financial disincentives to investment in energy efficiency by Idaho Power Company (Idaho Power; Company). On January 27, 2006, Idaho Power filed an Application requesting authority to implement a Fixed Cost Adjustment (FCA) decoupling or true-up mechanism for residential and small general service customers. On December 18, 2006, a Joint Motion was filed with the Commission requesting approval of a negotiated Stipulation and implementation of the FCA as a three-year pilot program. The Commission in this Order approves the Stipulation and the FCA pilot program.

Background

On August 10, 2004, the Idaho Public Utilities Commission in Order No. 29558 established this case to investigate financial disincentives to investment in energy efficiency by Idaho Power Company. In that Order the Commission approved a series of workshops and directed the participants to provide a written report no later than December 15, 2004 to update the Commission on the status of the workshops.

On December 15, 2004, workshop participants in Case No. IPC-E-04-15 filed a Status Report with the Commission. A Final Report on workshop proceedings was filed on February 14, 2005. The Final Report called for two actions: (1) the development of a true-up simulation to track what might have occurred if a decoupling or true-up mechanism had been implemented for Idaho Power at the time of the last general rate case, and (2) advocacy for filing a pilot energy efficiency program that would incorporate both performance incentives and "lost revenue" adjustments.

Application to Implement a Decoupling Mechanism

On January 27, 2006, Idaho Power filed an Application requesting authority to implement a rate adjustment mechanism that would adjust the Company's rates upward or downward to recover the Company's fixed costs independent from the volume of the Company's energy sales. This type of ratemaking mechanism is commonly referred to as a "decoupling mechanism." However, Idaho Power in its Application believes that a more accurate description of what the Company is proposing is a "true-up mechanism." The true-up mechanism, entitled "Fixed-Cost Adjustment" (FCA) would be applicable only to Residential Service (Schedule 1, Schedule 4 and Schedule 5) and Small General Service (Schedule 7) customers.

As reflected in the Company's decoupling proposal, the fixed-cost portion of the Company's revenue requirement would be established for these two customer classes at the time of a general rate case. Thereafter, the FCA would provide the mechanism to true-up the collection of fixed costs per customer to recover the difference between the fixed costs actually recovered through rates and the fixed costs authorized for recovery in the Company's most recent general rate case.

The Company represents the FCA would work identically for both the residential and small commercial classes. For each class, the actual number of customers would be multiplied by the fixed cost per customer rate (calculated as a part of determining the Company's allowed revenue requirement in a general rate case). This product would represent the "allowed fixed-cost recovery" amount. This pro forma amount would be compared with the amount of fixed costs actually recovered by the Company. To determine this "actual fixed-cost recovered amount," the Company would take weather-normalized sales for each class and multiply that by the fixed-cost per kilowatt-hour rate (again, established in the Company's general rate case). The difference between these two numbers (the "allowed fixed-cost recovery" amount minus the "actual fixed-cost recovered" amount) would be the fixed-cost adjustment for each class. The FCA could be either positive or negative.

The FCA is proposed to change rates coincidentally with Idaho Power's Power Cost Adjustment (PCA) and Idaho Power's seasonal rates. Although the FCA would be timed to adjust on the same schedule as the PCA, the accounting for the FCA will be completely separate from the PCA. Additionally, the Company proposes to include a discretionary cap of 3% as a potential rate mitigation tool for the Commission's use.

The purpose of the FCA, the Company contends, is to remove the financial disincentive in current rate design to the Company's investing fully in energy efficiency activities. Limiting implementation to only residential and small general service customers, the

Company states, provides an incremental approach for evaluating a new type of mechanism for the Company and its customers.

The Company's Application details proposed FCA accounting entries for monthly deferrals plus interest. The Company in its Application has filed the supporting testimony and exhibits of Ralph Cavanagh, Michael J. Youngblood, and John R. Gale.

On March 6, 2006, the Commission issued a Notice of Application in Case No. IPC-E-04-15 and established a March 17, 2006 deadline for intervention. Intervenor status was granted to the Industrial Customers of Idaho Power (ICIP) and the NW Energy Coalition (NWEC). In its Notice, the Commission acknowledged the intention of the Company and Commission Staff (together with other parties of record) to initiate and engage in settlement discussions. Reference Commission Settlement Rules of Procedure, IDAPA 31.01.01.272-276.

Joint Motion for Approval of Stipulation

Based on settlement negotiations a Joint Motion for Approval of Stipulation was filed with the Commission on December 18, 2006 by Idaho Power, Commission Staff and the NW Energy Coalition. Reference Commission Rule of Procedure 274. Although a party to this proceeding and a participant in settlement negotiations, the Industrial Customers of Idaho Power (ICIP), did not sign the Stipulation.

Terms of Stipulation

The Stipulation parties agree that it would be in the public interest for the Company to implement, as a pilot program, the FCA mechanism proposed by the Company in its Application with the following conditions and provisions:

a. Any differences between Schedules 1 and 7 class revenue requirements and the corresponding fixed cost per customer approved by the Commission in Case No. IPC-E-05-28 (2005 general rate case) must be reconciled with the fixed cost per customer and fixed cost per energy utilized in the approved FCA mechanism.

b. To determine the actual number of customers determined by class on a monthly basis, the Company will utilize the same customer count methodology used in the Company's 2005 rate case filing.

c. The methodology used to weather-normalize actual monthly energy used in the FCA will be the same weather normalization methodology used in the Company's filing in the 2005 rate case.

d. The FCA mechanism will be implemented on a pilot basis for a three-year period beginning January 1, 2007 and running through December 31, 2009 plus any carryover. The first rate adjustment will occur June 1, 2008, coincident with the 2008-2009 PCA and subsequent rate adjustment will occur on June 1 of each year during the term of the pilot.

e. Calculation of the monthly FCA deferral will be recorded as a separate line item in the monthly PCA report provided to the Commission. The Commission-approved FCA adjustment will be combined with the Conservation Program Funding Charge for purposes of customer bill presentation. There will be no separate line item for the FCA on customers' billing statements.

f. The Company will file its FCA adjustment request on March 15th of each year. Staff's audit of the FCA adjustment request will include review of deferral balances, comparison of actual energy savings to DSM energy savings estimates as normally provided in the DSM Annual Report and load growth forecasts and verification of the resulting FCA adjustment.

g. Either Staff or the Company can request the Commission to authorize discontinuance of the pilot program during the three-year period. Requests to discontinue the pilot program, with supporting justification, must be filed with the Commission during the March 15 to June 1 review period.

The Company agrees to provide with its annual March 15 filing a detailed summary of energy efficiency and demand-side management (DSM) activities that demonstrate an enhanced commitment resulting from implementation of the FCA mechanism and removal of the financial disincentive to energy efficiency and DSM. Evidence of enhanced commitment will include, but not be limited to, a broad availability of efficiency and load management programs, building code improvement activity, pursuit of appliance code standards, expansion of DSM programs, pursuit of energy savings programs beyond peak shaving/load shifting programs and third party verification. As part of this commitment, the Company's 2008 Integrated Resource Plan will include an evaluation of the costs and potential for energy savings that would occur if the appliance and equipment efficiency standards adopted by the State of Oregon were applicable in the State of Idaho. In addition, the Company makes the following specific commitments in regard to building code improvements and enforcement of such standards:

a. The Company will promote the adoption of energy codes to achieve improved levels of efficiency in new commercial and residential construction and appliance standards in Idaho consistent with the Model Conservation Standards released by the Northwest Power and

Conservation Council or that exceed the 2003 IECC and ASHRAE 90.1 codes.

b. As part of its enhanced commitment to DSM described above, the Company will promote and support appropriate energy code training programs and advocate the enforcement of energy codes. Idaho Power will identify ways to support energy code implementation and enforcement in all jurisdictions in Idaho Power's service territory.

The parties to the Stipulation agree that the Stipulation represents a compromise of the positions of the parties of the case. The Stipulation is supported by the filed testimony of the Stipulation parties. Those testimonies can be summarized as follows:

Idaho Power – Testimony of John R. (Ric) Gale

In supplemental testimony, Ric Gale notes the previously filed supporting testimony of himself, Ralph Cavanagh and Michael Youngblood in support of a Fixed Cost Adjustment (FCA) rate mechanism.

Gale notes that in his previously filed testimony, Company witness Cavanagh advocated for a pilot energy efficiency program that might contain incentive elements. In a separate filing, but related to this proceeding and its genesis, Gale states that the Company is proposing to implement a performance based incentive (and penalty) pilot for an energy efficiency program targeted to new residential construction. Reference Case No. IPC-E-06-32.

In support of the proposed FCA, Gale contends that if a utility recovers the material portion of its fixed costs through variable energy rates, it is not rational for the utility to embark on any programs or initiatives that reduce the amount of energy sold. The proposed FCA, he states, strikes a middle ground between sound business practice and energy efficiency. With approval of the proposed FCA, Gale contends that the utility becomes indifferent to increases or decreases in energy sales and the disincentive to promote programs and services that reduce energy consumption is eliminated.

Idaho Power proposes an incremental approach to introduction of a true-up mechanism by limiting the FCA to Schedules 1 and 7 in order to gain experience and to minimize exposure to potential unintended consequences. Schedules 1 (Residential) and 7 (Small General Service), it contends, are logical places to start in that these two customer classes present the most fixed cost exposure in percentage terms.

Two advantages of starting the accounting on January 1, 2007 are that numbers can tie directly to the numbers reported in the Company's general rate filings as opposed to split year reporting and that weather can be normalized on a calendar basis. Use of a June 1, 2008 date for changing rates allows ample time for the Company's books to close and for the FCA rate application to be filed, reviewed, and authorized. The June 1 date is especially desirable to the Company because it allows the Company to change customer rates once for the Power Cost Adjustment (PCA), the FCA and the summer season.

Idaho Power proposes a 3% cap on potential rate increases. The Commission at its discretion and judgment, however, it states, can impose the cap or let the rate change as calculated.

The FCA proposal, Idaho Power contends, provides an opportunity to conservatively test the concept of a true-up mechanism and the removal of a financial disincentive to energy efficiency activities. The FCA, it states, will make Idaho Power properly indifferent to choices between demand and supply side resources, creating an environment where load reduction activities can be pursued and balanced with Idaho Power's financial goals. The proposal incrementally addresses the customer classes that are the simplest to administer and that have the largest relative exposure to problems with fixed cost recovery. In addition, safeguards have been added to protect against the unintended consequences. The deferred aspect of the FCA, it states, is mirrored after another mechanism that has been successfully in effect since 1993, the Power Cost Adjustment mechanism. Finally, Idaho Power contends that the FCA is consistent with the National Action Plan for Energy Efficiency introduced last summer and endorsed by many entities including the National Association of Regulatory Utility Commissioners (NARUC) and the Edison Electric Institute. Company Exhibit No. 11.

Idaho Power believes that the Stipulation satisfies the criteria developed by the participants in the workshops. These criteria were:

1. Stakeholders are better off than they would be without the mechanism.
2. Cross-subsidies are minimized across customer classes.
3. Financial disincentives are removed.
4. The acquisition of all cost-effective DSM is optimized.
5. Rate stability is promoted.
6. The mechanism is simple.
7. Administrative costs and impacts of the mechanism are known, manageable, and not subject to unexpected fluctuation.
8. Short and long term effects to customers and Company are monitored.

9. Perverse incentives are avoided.
10. A close link between the mechanism and desired DSM outcomes is established.

Commission Staff – Testimony of Randy Lobb

Staff believes the filed Stipulation establishes a reasonable pilot mechanism to track the effects on fixed cost recovery of Company-provided energy efficiency and DSM programs and removes the perceived disincentive by reimbursing the Company for identified losses.

In exchange for removal of the disincentive, the three-year pilot requires measured improvement by the Company with respect to the size and availability of energy efficiency and DSM programs provided within its service territory. It also provides symmetry (surcharge/credit) when fixed cost recovery per customer varies above or below a Commission established base. Staff therefore supports the Stipulation.

Staff notes that the Parties to the underlying investigation agreed that disincentives did exist but were unable to agree that restoration of lost fixed revenues would result in additional or more effective investment in energy efficiency and DSM by Idaho Power. Nevertheless, Staff notes the parties agreed to a set of criteria that would be required for any FCA mechanism and agreed to conduct a simulation of a proposed fixed cost true-up mechanism to identify potential impacts.

As a result of the workshop process, simulation of mechanism impacts and significant additional analysis and evaluation of cost recovery between rate cases, Staff concluded that energy efficiency and DSM programs reduce fixed cost recovery over what otherwise would have occurred, creating a financial disincentive for the Company to implement such programs. To the extent these disincentives are a significant barrier to cost effective energy efficiency and DSM, Staff believes the barrier should be removed.

Staff further determined that the proposed mechanism is appropriately structured because it uses a Commission approved fixed cost recovery level and it provides symmetrical adjustment to fixed cost recovery above or below the Commission approved base. By agreeing to the mechanism as proposed in the Stipulation, Staff believes the Company has committed to embark on a significantly expanded level of energy efficiency and DSM to the benefit of all ratepayers. To the extent barriers perceived by the Company are removed, Staff expects a renewed commitment to energy efficiency and DSM including support for building codes and appliance standards that otherwise would not have occurred.

Issues of concern to Staff in evaluating the FCA mechanism included the potential impact on customer rates, recovery of assumed fixed costs associated with new customers, recovery of lost fixed costs due to reasons other than Company DSM and energy efficiency programs and whether removal of disincentives through the FCA will result in measurable improvement in Company programs. Staff concluded that approval of the mechanism in pilot form will allow the Commission and other interested parties to evaluate Idaho Power's progress after removal of the disincentive. Staff concluded that for a Company with consistent customer growth such as Idaho Power, an overall per-customer comparison is more practical than trying to adjust for changes in consumption due to customer growth. Staff ultimately concluded that the potential improvement in accuracy did not justify the additional complexity required to remove the effect of non-DSM factors for purposes of the proposed pilot mechanism.

The Stipulation includes provisions for Staff to audit FCA results annually to compare actual savings as adjusted in the mechanism to DSM savings estimates. Staff will also compare actual new customer consumption to new customer load growth estimates as provided in the Company's Integrated Resource Plan (IRP). Both the Company and Staff have reserved the opportunity to request that the mechanism be discontinued if it fails to perform as intended.

As reflected in the prefiled testimony of Company witness Youngblood in this case, the anticipated impact of the proposed mechanism on customer bills, Staff states, was evaluated by simulating the FCA true-up mechanism over the period 1994 through 2004. The Company's evaluation of the simulation showed that the mechanism could result in both customer credits and surcharges ranging from an annual reduction of less than 1% to an increase of almost 4%. The proposed mechanism includes a 3% cap on annual increases with carryover of unrecovered deferred costs to subsequent years.

Staff has evaluated the simulation methodology and has concerns about the validity of the results. Staff also recognizes that the results are highly dependent upon many variables including relative success of Company energy efficiency and DSM programs, new customer energy consumption and the timing of Company general rate cases. That is why Staff insisted upon a three-year pilot program with annual audits to evaluate the impact of the mechanism as a condition of agreeing to the Stipulation.

Staff notes to the extent energy efficiency and DSM programs are significantly expanded, it is likely that the Company will request an increase in the conservation program funding charge to recover additional program costs. The ultimate effect on individual customer bills will depend on the availability of energy efficiency and DSM programs and the level of customer participation in those programs.

Staff supports the FCA mechanism agreed to in the Stipulation because it has the potential to deliver cost-effective DSM and energy efficiency that otherwise might not occur. The pilot nature of the mechanism, the required commitment of the Company to expand its programs and the opportunity for annual audit with off-ramps to modify or terminate the mechanism all reflect uncertainty regarding the mechanism's actual impact and an appropriately cautious approach to implementation.

NW Energy Coalition – Testimony of Steven D. Weiss

By way of background, Steven Weiss notes that the Coalition was an intervenor in Idaho Power Company's 2003-04 general rate case (IPC-E-03-13). In that case, Ralph Cavanagh presented testimony for the Coalition urging the adoption of a fixed-cost adjustment mechanism to better align the interests of Idaho Power's customers and shareholders. Mr. Cavanagh also recommended an exploration of performance incentives to encourage strong performance in demand-side management (DSM) by Idaho Power Company. Pursuant to Commission Order in that case, the Coalition filed a Petition initiating this docket.

The existing regulatory paradigm, the Coalition contends, places the utility's interest (to increase sales) in conflict with the customer's interest (to reduce their total energy cost). Not only does this foster a corporate culture that opposes direct utility investments in programs that reduce energy use, but the Coalition contends that it further motivates the utility to discourage customer-financed reduction measures and to oppose efforts to tighten building codes and appliance standards.

The Coalition believes that decoupling results in a better alignment of shareholder, management and customer interests to provide for more economically and environmentally efficient resource decisions. Decoupling, it states, is essential to establishing a corporate culture that promotes strong cost-effective conservation investments.

While decoupling removes the Company's disincentive to encourage energy conservation, the Coalition contends that it does not provide a positive incentive to acquire cost-effective conservation. Decoupling, it states, is only intended to make the utility indifferent to changes in energy usage. The Coalition conditions its support on strong, incremental conservation commitments. The Stipulation provides for thorough reviews of the Company's conservation activities and includes safeguards to ensure no unintended consequences result from decoupling. These commitments, coupled with the Company's increased portfolio of DSM programs as reflected in its 2006 Integrated Resource Plan, provide the Coalition with ample assurance that decoupling will create tangible, positive results. The Commission additionally will have an opportunity to review the Company's performance annually, as well as at the end of the three-year pilot program. The Coalition recommends that the Commission approve the Stipulation.

On January 4, 2007, the Commission issued a Notice of Settlement Stipulation and Modified Procedure in Case No. IPC-E-04-15 and established a comment deadline of January 31, 2007. Comments opposing the Stipulation and Joint Motion were filed by the Idaho Community Action Network (ICAN) and a utility customer. No reply comments were filed. The Commission Staff filed comments adopting its previously filed testimony in support of the Stipulation.

Public Comments

The customer filing comments summarizes the Company's two filings in Case Nos. IPC-E-04-15 and IPC-E-06-32 (DSM Incentive Pilot Program). One, he states, would allow an annual increase to customers' electric rates if Company investments in energy efficiency programs increase Company costs. The other, he states, would give the Company financial incentives for meeting performance levels in a program to encourage energy-efficient home construction.

As the customer recalls, the most recent rate increase allowed to Idaho Power was justified by an increase in demand for electricity. Now, as he understands it, Idaho Power is seeking a rate increase if demand is decreased by conservation or efficiency measures. He concludes that ratepayers are being asked to pay more either way.

Idaho Community Action Network Comments

The Idaho Community Action Network (ICAN) opposes approval of the Stipulation and the proposed Fixed Cost Adjustment mechanism. Decoupling, it states, is contrary to the interest of Idaho Power's customers, favoring instead the utility and its shareholders. ICAN contends that the general public is completely unaware of the significant change in the way rates will be set in the future and recommends that the Commission hold public hearings before considering the Stipulation.

Contrary to the Commission's long-standing approach to ratemaking, where all revenues and expenses are on the table, ICAN states the Stipulation will authorize the Company to receive additional revenue through a decoupling mechanism without any proof of need. What makes this scheme patently unfair, unjust and unreasonable, it contends, is that it ignores the economic conditions of the utility at the time the surcharge is incurred or imposed.

In its evaluation of the Stipulation, ICAN recommends that the Commission seek answers to at least the following questions:

1. What is the actual amount of revenue lost due to Idaho Power's own energy efficiency efforts and the significance of the financial impact on the Company?

2. What proportion of declining customer use is attributable to Company conservation efforts, as compared to other causes not related to Company actions (e.g., better housing codes, appliance standards, price elasticity)?

3. What is Idaho Power's track record on energy efficiency?

4. Are there reasons why Idaho Power has pursued energy efficiency without a decoupling mechanism and can it be expected to do so in the future?

5. What specific additional energy efficiency programs will Idaho Power customers see if decoupling is adopted (separate from the program proposed in IPC-E-06-32)?

6. Are customers compensated for their increased risk and the reduction of risk to shareholders (i.e., is the shift reflected in a downward adjustment to the Company's return on equity)?

7. Are there alternatives to decoupling?

ICAN in its comments proposes some answers to the questions it poses.

Should the Commission approve the proposed decoupling mechanism, ICAN recommends that the Commission take steps to limit the potential liability of consumers and to ensure that the project accomplishes what it is intended to accomplish and to such end recommends the following:

- Establish a mandatory 3% revenue cap on the Fixed Cost Adjustment.
- Create a separate line item for the FCA on billing statements to increase transparency and public education about the program.
- Establish a clear conservation plan with real accountability.

The Stipulation, ICAN contends, does not outline clear conservation goals or accountability measures. The Company commitment it describes, ICAN contends, is extraordinarily vague; it will "support" and "promote" changes in housing codes, but has no authority to ensure that those changes occur. There are no set conservation targets or benchmarks. ICAN recommends that the Commission require Idaho Power to commission a third party to perform a conservation study; develop a conservation plan with targets and benchmarks; create an advisory group to review the conservation study and plan; issue requests for proposals to implement the plan; and demonstrate to the Commission within a year of approval of the pilot program that it will meet the plan's targets. The plan, ICAN contends, should include increased levels of low-income weatherization assistance to mitigate the impact of the FCA on low-income customers. If Idaho Power fails to meet these deadlines, ICAN recommends that the Commission terminate the pilot program.

- Extension of the decoupling program.

ICAN reports that the Washington UTC recently ordered that a decoupling mechanism in a natural gas case "may only be extended as part of a general rate case, and only after a thorough evaluation of the mechanism performed by an independent consultant." ICAN recommends that the Commission make extension of the decoupling and other pilot programs conditional on a general rate case to allow the revenue distortions caused by the FCA to be evaluated and eliminated. ICAN recommends that a third-party evaluation also be required.

- Return on equity.

ICAN recommends that the Commission reduce Idaho Power's return on equity by at least 50 basis points. Otherwise, it states, shareholders are doubly benefiting from stable revenue and a lower cost of capital at the expense of customers.

- Use of 2005 numbers for setting recovery benchmarks.

ICAN contends that the real solution is to evaluate the utility on its overall revenue instead of simply per-customer usage. However, absent that, in order to avoid the growing gap caused by using Idaho Power's 2005 general rate case established aggregated residential customer revenue and subtracting the 2005 general rate case aggregated residential customer usage, ICAN recommends that the revenue be based on actual income for residential customers and then offset by the 2005 per customer usage.

Commission Findings

The Commission has reviewed and considered the filings of record in Case No. IPC-E-04-15 including the Company's Fixed Cost Adjustment (FCA) filing and supporting testimony and the proposed Stipulation conditions and provisions and supporting testimony. We have also reviewed the filed comments and recommendations of ICAN and the Company's customer.

The proposed FCA is a three-year pilot program that will be applicable to Residential Service (Schedules 1, 4 and 5) and Small General Service (Schedule 7) customers. These two classes present the most fixed cost exposure for the Company. The FCA is designed to provide symmetry (surcharge/credit) when fixed cost recovery per customer varies above or below a Commission established base. The FCA mechanism also incorporates a 3% cap on annual increases with carryover of unrecovered deferred costs to subsequent years. Pursuant to the Stipulation, the first rate adjustment will occur June 1, 2008 coincident with the 2008-2009 PCA and subsequent rate adjustments will occur on June 1 of each year during the term of the pilot. The program envisions close review and monitoring by Staff and interested parties with reporting requirements and opportunities for discovery and comment. Either Staff or the Company can request the Commission to authorize a discontinuance of the pilot program during the three-year period.

Promotion of cost-effective energy efficiency and demand-side management (DSM), we find, is an integral part of least-cost electric service. This case was opened to identify financial disincentives to Idaho Power's investment in energy efficiency. The Company-proposed FCA mechanism removes a Company-identified financial disincentive to energy efficiency and DSM investment and is designed to reduce on a per-customer basis the utility's dependence on revenue from stable kilowatt-hour sales. The FCA methodology is a departure from traditional ratemaking and merits a cautious approach to implementation. The annual FCA true-up mechanism assures a more stable utility recovery of fixed costs that are now recovered in the energy rate component of residential and small general service customers.

Making the Company indifferent to reduced energy consumption and demand is but one half of the quid pro quo agreed to by the stipulating parties. In return for the FCA, the

Company is expected to demonstrate an enhanced commitment to energy efficiency and DSM. Evidence of enhanced commitment will include, but not be limited to, measures identified in Stipulation paragraph 8, measures including efforts to improve and enforce state building codes and appliance efficiency standards, as well as expansions and improvements to its load efficiency, load management and DSM programs.

Determining whether the FCA will operate as envisioned will require close monitoring. It remains to be seen whether sufficient performance metrics can be developed to accurately measure the extent and effectiveness of Idaho Power's efforts. This uncertainty is a good reason to adopt it now only as a pilot. A pilot will enable program corrections or cessation if it is unsuccessful or if unintended consequences develop.

The Stipulation and proposed decoupling mechanism is opposed by the Idaho Community Action Network (ICAN) and a customer of Idaho Power. The Company's customer concludes that he is being asked to pay for both kilowatt-hour increases and decreases. His position is understandable. We note by way of explanation that there are two dynamics in play. First, increases in load (new customers and increased consumption by existing customers) require additional resources, often at additional and higher cost. Second, because under traditional ratemaking a portion of the Company's fixed costs are allocated to the energy component of rates, decreases in customer usage affects the Company's ability to recover its fixed costs. To the extent energy efficiency and DSM programs are effective in reducing total load, the Company's overall costs of supply and thus the cost to customers will be less than it would otherwise be if the Company was required to meet new load growth with new supply-side resources. To the extent a customer is able to reduce his energy consumption through participation in Company energy efficiency and DSM programs or individual energy saving measures, he of course reduces his out-of-pocket cost below what it otherwise would have been.

ICAN requests that the Commission hold a public hearing prior to any consideration of the Stipulation and FCA mechanism. The Commission has reviewed the filings of record in this case including the Final Report on workshop proceedings. Parties participating in the workshops were Idaho Power, Commission Staff, the NW Energy Coalition, the Industrial Customers of Idaho Power and the Community Action Partnership of Idaho. ICAN was not a participant. The Commission finds that the concerns raised by ICAN are many of the same concerns raised by workshop participants and Settlement parties. We find most of its recommendations to be issues that will be considered in our assessment of the continuing viability of the pilot program. The recommended return on equity adjustment, however, is a general rate case issue and can be addressed in the Company's next rate case. The Commission encourages ICAN to participate in future opportunities for review, monitoring, discovery and comment. We decline to hold a hearing at this time, but retain that option for review of the FCA.

The Commission continues to find it reasonable to process this case pursuant to Modified Procedure, i.e., by written submission rather than by hearing. IDAPA 31.01.01.204. We further find it reasonable to approve the three-year Fixed Cost Adjustment pilot and Stipulation conditions and provisions.

Petition for Intervenor Funding

On December 26, 2006, a Petition for Intervenor Funding was filed by the NW Energy Coalition. Reference *Idaho Code* § 61-617A; IDAPA 31.01.01.161-165. The Coalition requests $8,342.10.

Idaho Code § 61-617A and Rules 161-165 of the Commission's Rules of Procedure provide the framework for awards of intervenor funding. Section 61-617A(1) declares that it is the "policy of this state to encourage participation at all stages of all proceedings before the Commission so that all affected customers receive full and fair representation in those proceedings." Accordingly, the Commission may order any regulated utility with intrastate annual revenues exceeding $3,500,000 to pay all or a portion of the costs of one or more parties for legal fees, witness fees and reproduction costs, not to exceed a total for all intervening parties combined of $40,000.

Rule 162 of the Commission's Rules of Procedure provides the form and content requirements of a petition for intervenor funding. The petition must contain: (1) an itemized list of expenses broken down into categories; (2) a statement of the intervenor's proposed finding or recommendation; (3) a statement showing that the cost the intervenor wishes to recover are reasonable; (4) a statement explaining why the costs constitute a significant financial hardship for the intervenor; (5) a statement showing how the intervenor's proposed finding or recommendation differed materially from the testimony and exhibits of the Commission Staff; (6) a statement showing how the intervenor's recommendation or position addressed issues of concern to the general body of utility users or customers; and (7) a statement showing the class of customer on whose behalf the intervenor appeared.

Pursuant to *Idaho Code* § 61-617A and the Commission's Rules of Procedure 161-165, NW Energy Coalition applies for intervenor funding in the amount of $8,342.10. The Coalition's Application is supported by points and authority. The itemized list of expenses is comprised of $8,090 in attorney fees, $224.60 for airfare and $27.50 for ground transport. Costs related to time expended by Coalition employees Nancy Hirsch, Ken Miller, and Steven Weiss for participating in and preparing workshops (and for Mr. Weiss) in preparing his testimony and working with counsel were not included in the Coalition's Application. In addition, the Coalition notes that it incurred other minor copying, postal and telecommunication expenses that are also not included in its Application. The Coalition contends that its recommendations and positions focused on matters which impact all utility customers and that the Coalition most directly represents the interests of residential and small commercial customers.

Commission Findings

Submitted for Commission consideration is a Petition for Intervenor Funding filed by the NW Energy Coalition. Reference *Idaho Code* § 61-617A; IDAPA 31.01.01.161-165. The Coalition requests $8,342.10. We find that the Petition for Intervenor Funding in this case was timely filed and satisfies the "procedural" requirements set forth in Rules 161-165 of the Commission's Rules of Procedure.

Idaho Code § 61-617A includes a statement of policy to encourage participation by intervenors in Commission proceedings. The Commission determines an award for intervenor funding based on the following considerations:

a. A finding that the participation of the intervenor has materially contributed to the decision rendered by the Commission;

b. A finding that the costs of intervention are reasonable in amount and would be a significant financial hardship for the intervenor;

c. The recommendation made by the intervenor differed materially from the testimony and exhibits of the Commission Staff; and

d. The testimony and participation of the intervenor addressed issues of concern to the general body of users or consumers.

We find that the Petition of the NW Energy Coalition satisfies the findings that we are required to make to justify an award. The NW Energy Coalition was principally responsible for initiating this inquiry. Its participation materially contributed to the outcome. This particular case was resolved by way of Settlement, compromise of positions and not litigation. We find that the Petition satisfies the substantive requirements of Commission Rule of Procedure 165. We find it fair, just and reasonable to award the total request of NW Energy Coalition in the amount of $8,342.10 and find that the public interest and the interests of residential and small general service customers are well served by such award. We further find that the Coalition was professional and economical in the marshalling of its time and efforts and that failure to grant its request for funding would be a significant financial hardship for the Coalition.

CONCLUSIONS OF LAW

The Idaho Public Utilities Commission has jurisdiction over this matter and over Idaho Power, an electric utility, pursuant to the jurisdiction granted under Title 61 of the Idaho Code and the Commission's Rules of Procedure, IDAPA 31.01.01.000 *et seq.*

ORDER

In consideration of the foregoing and as more particularly described above, IT IS HEREBY ORDERED and the Commission does hereby approve the December 1, 2006 Stipulation and the proposed three-year pilot program Fixed Cost Adjustment (FCA) mechanism for Residential Service (Schedule 1, Schedule 4, and Schedule 5) and Small General Service (Schedule 7) customers.

IT IS FURTHER ORDERED that the NW Energy Coalition's Petition for Intervenor Funding is granted in the amount of $8,342.10. Reference *Idaho Code* § 61-617A. Idaho Power is directed to pay said amount to Advocates for the West, counsel for NW Energy Coalition, within 28 days from the date of this Order. Idaho Power shall include the cost of this award of intervenor funding to the Coalition as an expense to be recovered in the Company's next general rate case proceeding from the Residential (Schedules 1, 4 and 5) and Small General Service (Schedule 7) customer classes.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 12th day of March 2007.

PAUL KJELLANDER, PRESIDENT

MARSHA H. SMITH, COMMISSIONER

MACK A. REDFORD, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

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