COMMENTS OF IDAHO POWER COMPANY RESPECTING THE INTERPRETATION, IMPLEMENTATION, AND REVISION OF THE AVERAGE SYSTEM COST METHODOLOGY

At the Average System Cost Methodology workshop conducted by BPA staff on October 6, 2009, at the BPA headquarters in Portland, Oregon, BPA staff invited written comments on the items discussed orally. Idaho Power Company respectfully submits the following comments this November 6, 2009, in response to that invitation:

SUMMARY OF COMMENTS

1. Proposed NLSL Rate Methodology Change: BPA staff's interpretation and implementation of the NLSL Rate Methodology creates an inaccurate representation of the cost to serve large load customers. This interpretation should be corrected and should not be applied to other rate recovery devices until it has been corrected. Idaho Power disagrees with BPA staff's assertion that this interpretation cannot or should not be corrected.

2. Proposed Software Functionalization Methodology Change: The functionalization methodology proposed by BPA is excessively rigid for a technology-driven cost category and needlessly complex for this type of rate mechanism. A single functionalization such as LABOR or PTD which capture all of the utilities' functions would be more appropriate for the functionalization of software-related accounts.

3. Proposed Change to New Resource Additions: In absence of a true-up mechanism, all plant that is operational at the time of the issuance of the final gas price forecast should not trigger a second materiality test and by definition, should be considered material. Actual information is inherently more accurate than predicted information; therefore, data known because of the actual operation of a facility at the time of the final gas forecast should replace forecast values, especially when those values are reduced to zero by application of a "materiality" test. The use of the materiality test to exclude consideration of known and actual costs of generating plant used to serve utility loads is unreasonable, lowers benefits to which residential and small farm customers would otherwise be entitled and therefore violates the Northwest Power Act. In light of the Joint Comments submitted by the Northwest Investor-Owned Utilities, Idaho Power would accept the first materiality test as the cutoff for removing resources from the utilities' ASC filings.

4. Accuracy of BPA's Forecast Model: It is Idaho Power Company's recommendation that BPA continue to pursue a more accurate means of forecasting costs in the ASC forecast model, including capturing natural growth of plant accounts and related operation and maintenance expense.

5. Confidentiality and Conservation: Idaho Power Company agrees with, and supports the Joint Comments of the Investor-Owned Utilities with respect to Confidentiality and Conservation

Proposed NLSL Rate Methodology Change

BPA staff have proposed to change the NLSL rate calculation from the existing methodology that uses actual cost values to a new methodology that uses allocated functionalized costs. During the October 6, 2009, workshop, BPA staff presented the proposed change and stated that their reason for the change was to make the process easier for BPA which would like to use a similar methodology to calculate the Rate Period High Water Mark Tier II rate for public entities. BPA staff suggested that using a uniform method for calculating the NLSL and the Rate Period High Water Mark Tier II rate would be an ideal result. Yet instead of conforming to the existing NLSL rate calculation, BPA staff proposed changing the NLSL methodology to something easier to calculate.

BPA staff provided an example of the calculation using Portland General Electric's 2007 calendar year information. The new methodology increased the NLSL rate in that instance. By increasing the NLSL Rate, BPA staff made the incorrect assumption that the cost to an IOU of providing service to a large industrial load is <u>more expensive than service to other customers</u>.

This expense is then removed from the IOU's ASC calculation, reducing Residential Exchange Program benefits. At the time of the workshop, BPA staff did not present calculations of the NLSL under its proposal for other utilities. Upon request from Idaho Power, BPA staff agreed to re-calculate each of the utilities' NLSL rates under their proposed methodology change and provide the spreadsheets to the utilities for further study. Idaho Power Company received a copy of the NLSL rate calculation under BPA's proposal on October 16, 2009. The NLSL rate as calculated for Idaho Power Company under BPA's proposal was $1.62 per megawatt hour more than under the existing methodology resulting in a reduction in Idaho Power Company's potential Residential Exchange Benefits if the proposal is adopted. With an increase of $1.62 per megawatt hour, the Company's ASC is reduced an additional $142,000 for every 10 average megawatt hours of increase in a single large customer's load, without any acknowledgment of decreases in other large customer loads. BPA's proposed methodology change would result in a significant decrease in Residential Exchange Benefits that unreasonably penalizes residential and small farm customers when the principal reason for the proposed methodological change is to make it easier to calculate the Rate Period High Water Mark Tier II rate. In this instance, ease of calculation is not a sufficient reason to penalize residential and small farm customers by using less accurate data.

In its Reply Comments to FERC respecting the approval of BPA's proposed ASC Methodology, Idaho Power noted BPA's intention to calculate "the cost of additional resources in an amount sufficient to serve any new large single load of the utility" by using the fully allocated costs of peaking resources, plus fuel costs, on a cost per kilowatt basis, and then multiplying the cost per kilowatt by the kilowatt hours of the new single large load during the year. Idaho Power pointed out that result of this interpretation is to disregard the actual usage of peaking resources on Idaho Power's system and thus distort the costs of such resources when used to calculate costs to served NLSLs. *See* Reply Comments of Idaho Power Company, FERC Docket No. EF08-2011-000, RM08-20-000 (Dec. 15, 2008) (copy attached hereto as Attachment "A").

BPA itself recognizes that large industrial loads have characteristics that make the loads beneficial, and by inference less costly to serve than other types of loads. By letter from Bonneville Power Administration, dated March 3, 2009, and later referenced throughout the *PNGC vs. BPA* Opinion by Judge Berzon, BPA contended that the cost of serving large industrial loads was beneficial to BPA because those types of loads are taken in "flat blocks that require little or no shaping". BPA also contended that these types of loads are also taken in light load hours during times when electricity is difficult to sell on the open market. *See* letter dated March 3, 2009 (copy attached hereto as Attachment "B"). Additionally, BPA contended that large customers provide power reserves and that with changes in technology there may be ways for these customers to provide value that has yet to be imagined.

BPA's factual contentions respecting the nature of large industrial customers on a hydroelectric based utility system comports with Idaho Power's understanding. In the case of a utility with a large amount of hydro resources, such as BPA or Idaho Power Company, not only do these utilities experience reduced load and reduced prices during light load hours, there are also time periods during the year when the utility is required to spill water over its dams, thereby wasting fuel. This effect is similar to dumping loads of coal into a landfill instead of using the coal to fuel a coal-fired plant. In times of combined spill conditions and light-load hours, market prices may actually invert to negative levels. In fact, with the addition of more wind projects added to the northwest's power system, the frequency of occurrences of negative market prices during light load hours and spill conditions may increase. During these times, large flat loads may prevent wasted fuel spill or plant turndowns; and some industrial customers will be able to ramp up loads mutually benefiting both the utility and the industrial customer. In those situations, the utility's ability to serve loads during times of low and negative market prices will decrease the average system costs.

The Ninth Circuit Court of Appeals did not find fault with BPA's factual contentions in this respect. Instead, the Court addressed the concern that arose out of BPA's conversion of a physical sale of power to a financial exchange type of agreement. The NLSL rate calculation as interpreted by BPA and implemented through its ASC methodology is not an accurate representation of the costs required to serve large loads. as understood by both Idaho Power and BPA. As part of BPA's effort to reformulate or reinterpret the ASC methodology to apply to BPA's regional dialogue long-term contracts, BPA should reassess the insufficient factual basis upon which BPA staff base their current understanding of how to assess the costs of service to NLSLs. In its interpretation and application of the ASC methodology, BPA staff assumes that Idaho Power's large industrial loads would be served at costs that are well above market prices because of the assumption that the full cost of new plants should be fully allocated to those customers, without taking into account the fundamentally different economics associated with base-load and peaker units which are built to serve peak loads, not large flat blocks of power.

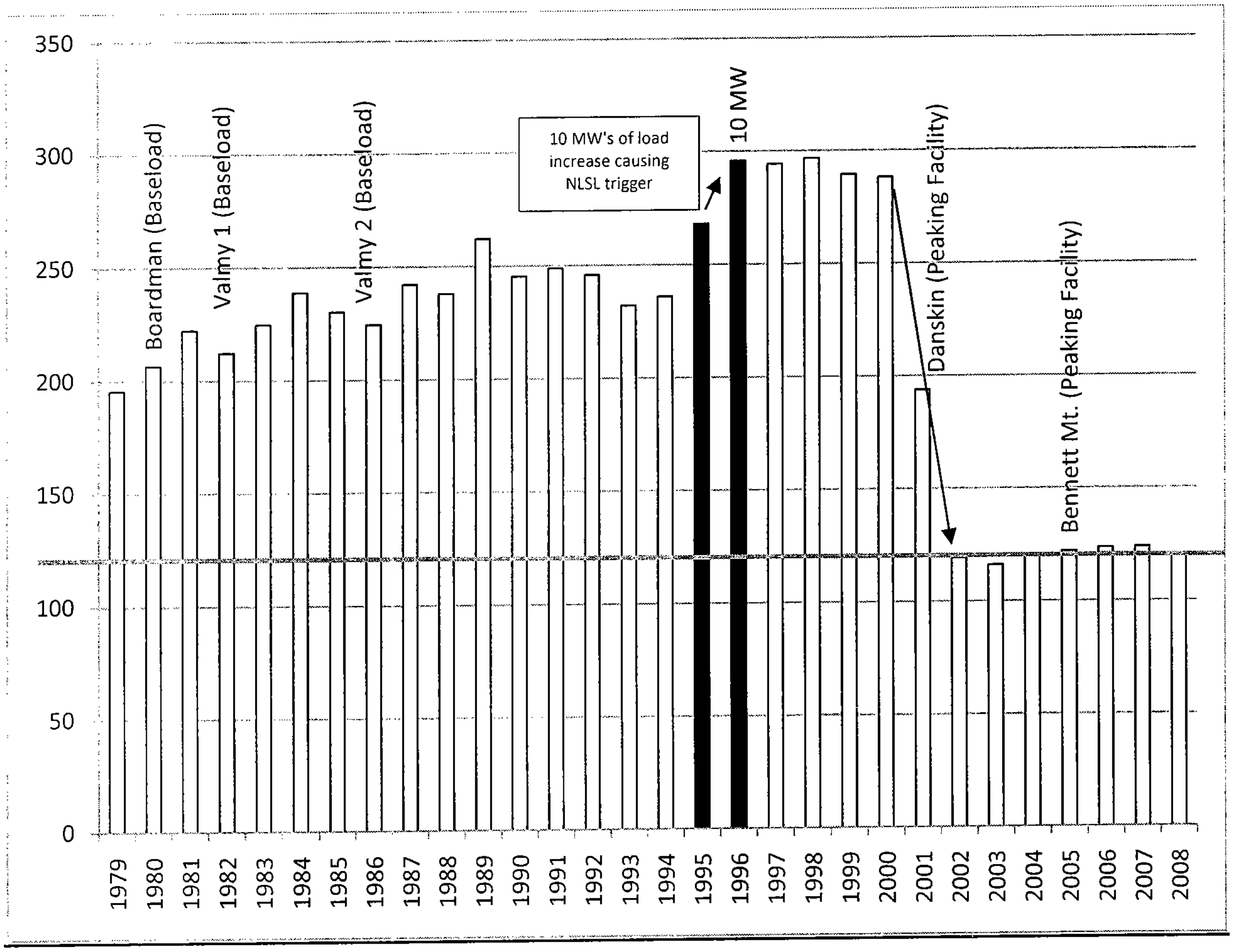
Additionally, BPA staff erroneously attribute market purchases, inclusive of purchases that are required under the Public Utility Regulatory Policies Act (PURPA). PURPA projects are plants from which Idaho Power is required to purchase output and were not necessarily planned or built to serve any specific load within the Idaho Power service territory. Congress intended that PURPA be an incentive to the development of small and renewable resources, without increasing costs to utility customers. BPA staff's interpretation and implementation of the ASC Methodology acts to frustrate the intention of Congress by isolating PURPA costs and attributing them to NLSLs in a manner that reduces the residential benefits to utility customers, thereby directly frustrating the intent of Congress. PURPA projects are a cost of serving all of Idaho Power's customers, and those costs should not be directly assigned to large industrial customers for the purpose of reducing the average system costs, and thereby diminish residential exchange benefits to the utility customers.

A solution to these errors of fact incorporated into BPA staff's interpretation and implementation of the ASC methodology would be to change the capacity factors of the plants used in the NLSL rate calculation to correct for the clear mismatch between peaking plant's' capacity factors and a the load factors associated with large flat industrial loads. In its letter dated March 3, 2009, BPA states that it used a 100% load factor in calculating the rate for a large industrial customer. If one assumes that an industrial customer is served with a peaker plant, one must also assume that the peaker plant would be run at all hours. This mismatch drives the costs of the peaker plants to levels well above market which artificially increases the costs of the NLSL, a flat load that is not necessarily driving the utility's need for peaking facilities. The artificially inflated costs are then removed from the utility's ASC, reducing Residential Exchange Benefits. Moreover, one must further assume that a utility would likely operate peaker plants in violation of air quality permits, and manufacturer's warranties. BPA staff's interpretation and implementation of the ASC methodology in this respect defies any business logic. For example, under the BPA staff's logic one must assume that Idaho Power built a peaking plant at a cost of $352.25/MWh to serve an industrial customer. However, the assumption that Idaho Power Company would willingly build a plant that costs more than $350/MWh under any current condition to serve a single 10-megawatt high load factor customer is in conflict with any sound business principle under which any regional utility, including BPA, operates.

BPA staff's interpretation and implementation of the NLSL methodology departs from reality in another respect. As pointed out in other Idaho Power filings, the NLSL reflected in Idaho Power's ASC has been offset by a much larger lost load. Yet lost load has never been considered by BPA staff. Presently, Idaho Power Company has lost an entire

240 megawatts of industrial load dwarfing the 10 megawatts of claimed NLSL that triggered the mechanism in 1996.

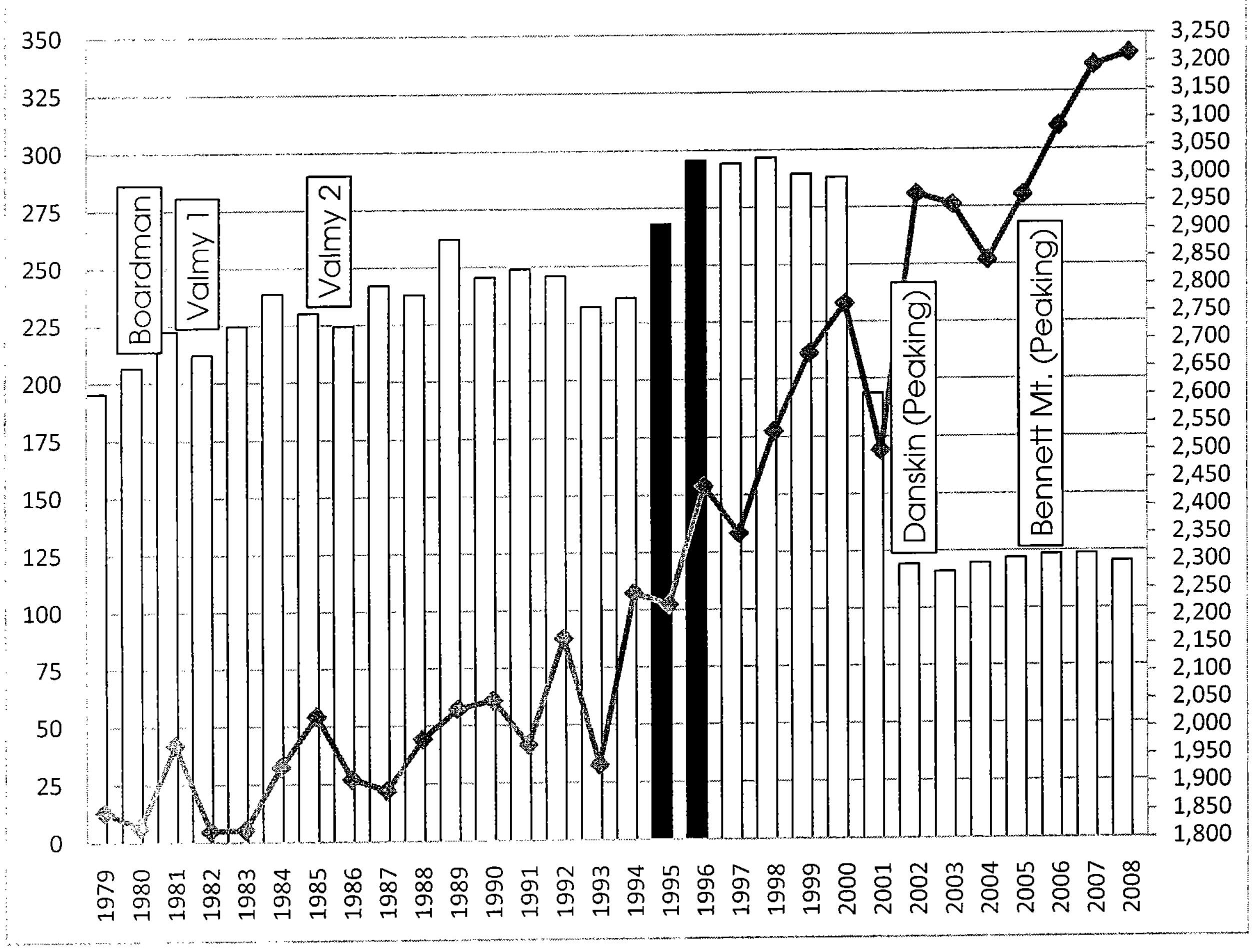
The table below illustrates the large customer loads as calculated for ASC purposes. In the table, the jump in load from 1995 to 1996 is the trigger that requires Idaho Power Company to remove $25 million dollars from its Average System Cost (see FY 2010 2011 Final ASC Report, page 2 of 89). However, the recaptured large loads after the year 2000 dwarfed the small 10 megawatts of load increase that incurred in the mid-1990's. The production plants used in the calculation of the NLSL rate are also identified by year of operation. No plants were built within three years or more of the NLSL 10 megawatt increase that triggered the mechanism in the ASC calculation for Idaho Power.



In the above chart, the columns represent Idaho Power Company's total large customer loads as calculated using the ASC methodology. The jump in a single customer's load from 1995 to 1996 (highlighted in black columns) represents the load growth to which the NLSL rate is applied. The solid red line represents the total average megawatts of large customer loads at year-end 2008. The NLSL rate multiplied by a single customer's load increase from the trigger year of 1995 to today is then applied to the overall ASC creating a cost reduction to the Idaho Power ASC and reducing potential exchange benefits. The NLSL rate is the combination of the costs, as calculated under the ASC methodology, arising from the plants that are listed in the above chart, and power purchases including 1) Boardman and Valmy (coal-fired baseload generation units), 2) Danskin and Bennett Mountain (peaking facilities), 3) market purchases, and 4) obligatory PURPA purchases.

The plants were clearly built at times other than the triggered increase in NLSL and in no way was the planning or construction of these plants caused by the minor increase in a single customer's load in 1996, followed by the overall decrease in this customer group's total load that we see today when compared to the trigger year. In fact, Idaho Power's first dedicated peaking unit was placed in operation during the years of rapid large customer load decline and the second peaker plant, during years of large customer load stability.

Under further investigation, one finds that Idaho Power Company's peak loads were rapidly increasing in the late 1990's and continue to grow today. Table 2 below shows not only the data from the previous table, but the addition of the system summer firm peak growth (the red line on the secondary axis). It is much more reasonable to suggest that the peaking units were planned to serve the increase in peak load rather than the 10 megawatts of load increase from 1995 to 1996.



This table demonstrates that the five plants used in the NLSL rate calculation were not built solely to support the small increase in a single, high load factor customer's load that incurred in 1996 (viewed in isolation from the large customer class), but that the two peaking units (Danskin and Bennett Mountain) were built for reasons different from those that are implied by the manner in which BPA applies their costs to determine the costs of resources used to serve NLSLs.

Idaho Power Company has planned a large Combined Cycle Combustion Turbine (CCCT) project to provide new baseload generation, that will be built in the year 2012. The project received preliminary regulatory approval mid-

2009 from the Idaho Public Utilities Commission. This project is envisioned to meet the demands of future load growth, including the growth from potential new large load customers. In reality, the CCCT project's variable energy rate is the most accurate rate to apply under the NLSL methodology, as the main purpose of this plant will be to provide baseload generation to supply the necessary energy to serve existing customer load growth and new customer loads within the Company's service territory. Additionally, a methodology to include a weighted portion of fixed plant costs taking into consideration the NLSL customers' high load factor would be appropriate. However, the change in the total large customer load that occurred between the years 2000 and 2002 should also be considered in the NLSL methodology prior to the application of any NLSL rate.

PROPOSED SOFTWARE FUNCTIONALIZATION METHODOLOGY CHANGE

BPA staff has proposed to change the Software Functionalization methodology for the Average System Cost calculation, from the existing methodology allowing direct assignment of costs by functional categories to a pre-determined functionalization method. During the October 6, 2009, workshop, BPA staff presented the proposed functionalization by software category because this issue became apparent when BPA staff noticed different utilities were categorizing what BPA considered to be similar software packages to different functions. Additionally, Idaho Power Company indicated that its accounting systems did not capture the detail necessary to functionalize various software packages and that functionalizing software items that were only a few thousand dollars would add a level of detail unnecessary to the process. It was suggested by Idaho Power that using a LABOR or PTD allocator for the entire account would be adequate in determining the utilities' ASCs. Additionally, a threshold value of two million dollars should be used to identify outliers which might be more easily and appropriately directly assigned to a specific function.

Not only does the method proposed by BPA staff result in unnecessary complexity to the utilities' derivation of the ASC and to the review process, the functional categories proposed by BPA staff appear both flawed and inconsistent with the motivation behind the proposed NLSL methodology.

There are several cost categories that appear to be inconsistent applied between BPA's proposed NLSL calculation and the software functionalization proposal. For example, BPA staff has proposed to capture the costs of vehicles and equipment in the NLSL calculation as a cost of production yet in its software functionalization proposal, software items related to "Fleet Management", management of vehicles and equipment, are considered distribution. By using this functionalization method, the cost of managing the utility vehicle and equipment fleet is not considered a cost of producing or transmitting power, yet conflictingly, BPA staff proposes to consider these costs a cost of serving a large industrial customer, which are used to further reduce the residential exchange benefits. This illogical and inconsistent logic results in a detriment to an exchanging utility's customers and thereby violates the Northwest Power Act.

An entire general category in the software functionalization proposal is described as containing production, transmission, and distribution costs, yet all of the items within the category are functionalized to distribution. Distribution is removed from the ASC, reducing the utility benefits. Additionally, it should be noted that Idaho Power Company uses its GIS system for hydro relicensing and for its transmission system, yet the GIS costs are considered by BPA staff to be distribution related.

Technology, by definition, is in a state of constant change and growth to meet future needs. It is highly unlikely that a static functionalization method could ever attempt to cover future technology uses that have yet to be imagined. Any attempt to design such as system would be a futile use of resources.

When viewing both the software functionalization proposal and the NLSL proposal together, the rational for proposing each is in direct conflict with the other. BPA's software methodology change would bring fine grain detail to a very small aspect of the ASC cost calculation, yet the NLSL proposed methodology change creates far less cost accuracy for a very large cost aspect of the ASC calculation which by nature, will only increase in the future in large increments as large load customers come online and without equal recognition of losses in load.

The argument for the proposed NLSL cost determination methodology change is that it would be "easier" yet the software functionalization proposal would create a tremendous amount of fine detail for a large number of small cost items, and likely lengthen the amount of time spent in the review process. This also places additionally burden on the utilities that would be required to manually functionalize hundreds of software items.

BPA staff also erroneously asserted that once a utility's software items had been functionalized, it would be easy to merely update the information the following year. However, out of the 253 software items listed in the 2008 informational report, only 161 of those had been functionalized by Idaho Power as part of the 2006 filing. Because of the nature of the reporting system, determining whether an item has been previously functionalized for a previous filing must be done individually. Additionally, the accounting system lists 12 items identified as "CPU UPGRADE". In order to functionalize each item, a work order look-up is required to identify the employee responsible for the work order. Then the employee who created each work order must be individually contacted to ascertain the location and purpose of the upgrade (e.g. central headquarters, a hydro facility, operation centers, call center, etc.). A similar system for identifying accounting entries would be required for many of the other entries that are less than obvious than those items referred to, above. These are entries that would not necessarily have the same functionalization as in a prior year and that could not be easily functionalized without extensive work order investigation. For its most recent informational filing, Idaho Power functionalized the items labeled "CPU UPGRADE" ranging in value from $1,214 to $425,217 as LABOR. Lists of Idaho Power's 2006 and 2008 account detail are attached. (See Attachments "C" and "D", hereto).

It should be noted that this same type of rigorous investigational work is required for other accounts with the option or requirement to Direct Assign costs, regardless of the size of the cost items within the account.

The ASC methodology and its manner of implementation should be logical and take into account the relative costs of implementation. Requiring a utility to utilize a fine level detail for manually functionalizing hundreds of software packages with costs of less than several thousand dollars, and penalizing the utility's customers with lower benefits if the utility fails to do so, does not comport with the Northwest Power Act.

PROPOSED CHANGE TO NEW RESOURCE ADDITIONS

BPA staff proposed setting a deadline for new resource additions, stating that there were changes in the materiality threshold test for several new resource additions during the review process--one utility's new resource addition was dropped from the ASC due to a change in materiality below threshold values and another utility saw a plant that had been previously left out, under the assumption that it did not meet materiality, subsequently pass the materiality test. To correct the situation, BPA staff proposed setting a cutoff date for the inclusion of new resources in the company's ASCs.

In the event that BPA elects to utilize a second materiality test, Idaho Power would recommend that a second materiality test not be applied to any plant that is operational on the date of the issuance of the final gas price forecast. An existing plant used to serve utility load is clearly required to be included in a utility's ASC by the Northwest Power Act, and using the materiality test to cost would violate the Northwest Power Act.

Idaho Power Company supports the Joint Comments of the Northwest Investor-Owned Utilities that the initial materiality test is the only test that should allow exclusion of a resource. The test should not be re-triggered by an updated gas price forecast adopted at any time later in the process. However, in the event that BPA does not accept the cutoff proposed in the Joint IOU Comments, BPA should allow the utilities to re-group resources at the time of any additional materiality test.

ACCURACY OF BPA'S FORECAST MODEL

BPA staff identified several problem areas in the WP10 forecast including lack of accuracy in the transmission and distribution plant. BPA staff did not forecast the natural increase in the utilities' plant accounts and noticed that by doing so, the BPA staff understated these values in their forecast--further reducing ASC benefits. Idaho Power recommends that BPA either include a true-up mechanism or to apply an index to all of the line items in the ASC calculation, because it is reasonable to assume that a utility will build and improve its plant facilities over time, causing increases in both rate base and expense items. It is unreasonable and arbitrary to assume that there would be no such increases.

CONFIDENTIALITY AND CONSERVATION

Idaho Power Company agrees with, and supports the Joint Comments of the Investor-Owned Utilities with respect to Confidentiality and Conservation.

APPENDIX A

UNITED STATES OF AMERICA
BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

United States Department of Energy **Bonneville Power Administration** **2008 Average System Cost Methodology**	Docket Nos. EF08-2011-000 RM-08-20-000

REPLY COMMENTS OF
IDAHO POWER COMPANY

Idaho Power Company ("Idaho Power") submits these reply comments pursuant to the Commission's notice of November 21, 2008. Idaho Power has also previously filed comments on its own behalf, and has joined comments and reply comments filed jointly on behalf of Avista Corporation, Idaho Power Company, PacifiCorp, Portland General Electric Company, and Puget Sound Energy, Inc. ("Joint Comments of the Pacific Northwest Investor-Owned Utilities"). The reply comments of Idaho Power filed herewith are in addition to, and are supplementary to, previously filed comments of Idaho Power and Joint Comments of the Pacific Northwest Investor-Owned Utilities.

As demonstrated by these reply comments of Idaho Power, the Commission should not adopt either

(i) the Interim Rule issued by the Commission on September 30, 2008, amending 18 C.F.R. Part 301 (the "Interim Rule") or

(ii) the new Average System Cost Methodology (the "2008 ASCM") proposed by the Bonneville Power Administration ("BPA"), as amended by the BPA Comments, for determining the average system cost ("ASC") of a utility's resources under section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839(c) (the "Northwest Power Act") for purposes of the Residential Exchange Program (the "REP"),

unless both the Interim Rule and the 2008 ASCM are revised consistent with these reply comments of Idaho Power.

I. INTRODUCTION

Subsequent to the Commission's adoption of an Interim Rule respecting the 2008 ASCM, Bonneville Power Administration ("BPA") received and reviewed average system cost filings from Idaho Power (and other utilities), and requested that Idaho Power furnish additional information to BPA pursuant to BPA's proposed Average System Cost methodology.[1] Among other data requests, BPA issued a data request to Idaho Power that Idaho Power furnish certain information for reporting year 2006, related to its simple cycle gas generation facilities that it uses for peaking generation purposes.

Attachment "A" hereto is a data request to Idaho Power from BPA, which also contains a response by Idaho Power, and a subsequent reply by BPA. Attachment "A" sets forth and illustrates BPA's apparent intention to treat peaking generating plants as baseload resources when calculating the costs of resources used to serve "new large single loads.".[2]

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

---

[1] On September 30, 2008, the Commission conditionally revised on an interim basis its regulations governing the methodology used by BPA in its residential exchange program. *See* Interim Rule, 124 FERC ¶ 61,312 (Sept. 30, 2008).

[2] "New large single load" means any load associated with a new facility, an existing facility, or an expansion of an existing facility-

(A) which is not contracted or, or committed to, as determined by the Administrator, or by a public body, cooperative, investor-owned utility, or Federal agency customer prior to September 1, 1979, and

(B) which will result in an increase in power requirements of such customer of ten average megawatts or more in any consecutive twelve-month period.

Pacific Northwest Electric Power Planning and Conservation Act, Sec. 3(13); 16 U.S.C. 839a(13).

Planning and Conservation Act, Sec. 5(c)(7); 16 U.S.C. § 839c(c)(7). Therefore, the 2008 ASCM 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.

In this connection, Attachment "A" sets forth BPA's intention to calculate "the cost of additional resources in an amount sufficient to serve any new large single load of the utility" by using the fully allocated costs of peaking resources, plus fuel costs, on a cost per kilowatt basis, and then multiplying the cost per kilowatt by the kilowatt hours of the new single large load during the year. Therefore, the practical result of BPA's implementation of the 2008 ASCM is that BPA disregards the very limited number of actual hours that Idaho Power's peaking facilities actually generated during the reporting year 2006. Idaho Power's Bennett Mountain and Danskin simple cycle gas generating facilities, as described in Attachment A, had actual capacity factors of 3% during 2006, the reporting year for which BPA was requesting data in Attachment A. 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, Idaho Power contends that its 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,. However, BPA, relying upon "Endnote d" of the 2008 ASCM, stated its disagreement with this contention. BPA stated:

> With respect to your above comment for reasons to exclude Bennett Mountain and Danskin from the NLSL resource cost data, this matter was evaluated and discussed during the 2008 Average System Cost Methodology consultation proceedings. For those NLSLs not served by dedicated resources (CF/CT prior to September 1, 1979), or at BPA's NR rate, the following shall apply, as stated in the 2008 ASCM, endnote d, page 24:

> ...To the extent that NLSLs are not served by dedicated resources plus the Utility's purchases at the NR rate, the costs of such excess load shall be determined by multiplying the kilowatt-hours not served under subsections (1) and (2) above, by the cost (annual fixed plus variable cost, including an appropriate portion of general plant, administrative and general expense and other items not directly assignable) per kilowatt-hour of **all resources** and long term power purchases (five years or more in duration)...

See **BPA's Reply to IPC's Response to data request BPA-IP-21,** contained in Attachment A.

II. COMMENTS

To the extent that Endnote d of the 2008 ASCM is intended, or interpreted by BPA, 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. BPA's understanding of Endnote d 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, as described in Attachment A, had actual capacity factors of 3% during 2006 as reported in Attachment A. 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.

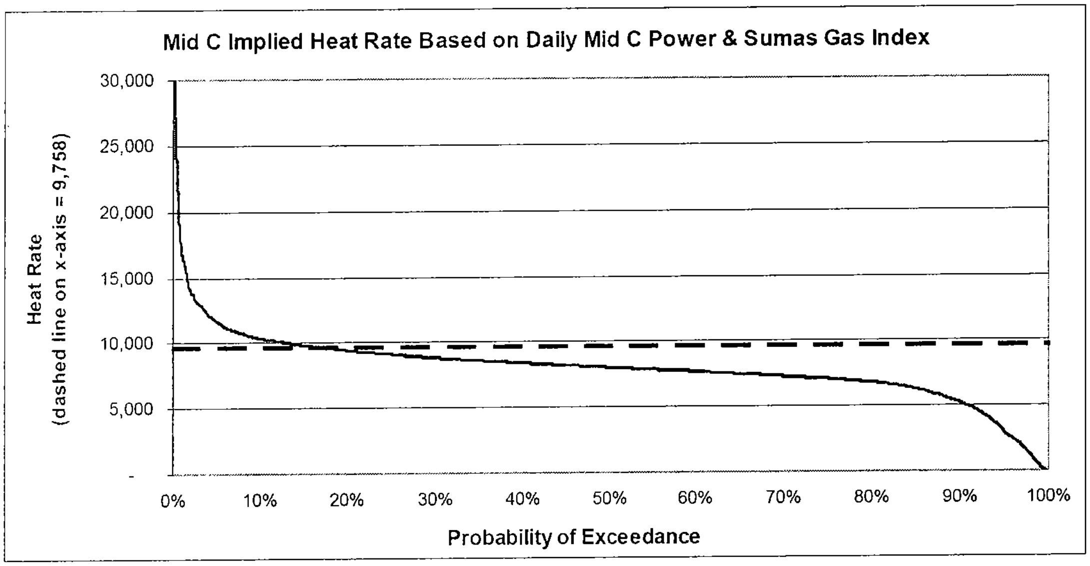
If Idaho Power Company were to serve New Large Single Load customers based upon the addition of a simple cycle combustion turbine (or more specifically, the cost of the Danskin plant, Bennett Mountain plant, or any combination thereof) the resulting rates would likely preclude any New Large Single Load customer from making an economic decision to locate within the Idaho Power Company service territory as 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.

BPA's 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 Endnote d of the 2008 ASCM requires that the costs of Idaho Power's peaking generating plants be assumed to generate every hour that a new large single load operates, Endnote d is predicated upon an erroneous assumption, and endnote d should be revised, accordingly.

III. CONCLUSION.

For the reasons discussed above, Idaho Power Company respectfully request that the Commission not adopt either the Interim Rule or the 2008 ASCM on a final basis unless both the Interim Rule and the 2008 ASCM are revised consistent with the reply comments of Idaho Power Company.

DATED: December 15, 2008.

PAINE HAMBLEN LLP

By: /S/ *R. BLAIR STRONG*
R. Blair Strong

717 West Sprague Avenue, Suite 1200
Spokane, WA 99201
Telephone: 509-455-6000
Email: r.blair.strong@painehamblen.com

CERTIFICATE OF SERVIC

I HEREBY CERTIFY that on this 15th day of December, 2008, I caused to be served a copy of the foregoing document upon each person designed on the official service list compiled by the Secretary in Docket No. EF08-2011-000 and RM08-20-000.

/S/ R. Blair Strong

00673706.DOC

APPENDIX B

Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

POWER SERVICES

March 3, 2009

In reply refer to: PT-5

To regional customers, stakeholders and other interested parties:

On February 13 the Bonneville Power Administration posted for public review and comment the draft amendment of its 2007 Block Power Sales Agreement (2007 Block Contract) with Montana-based Columbia Falls Aluminum Company and Flathead Electric Coop Inc.

We appreciate the time and effort invested by those who provided comments. I have provided BPA's responses to the comments as an attachment to this letter.

After careful consideration Bonneville has determined to proceed with the amendment to its 2007 Block Contract using the Industrial Firm (IP) power rate as the basis for a monetized arrangement directly between Bonneville and CFAC, which is virtually identical to the previous amendment agreed upon by BPA and Alcoa. We believe that both Amendments are structured in a manner that conforms with the December 17, 2008, decision by the United States Court of Appeals for the Ninth Circuit in Pacific Northwest Generating Cooperative, et al., v. Bonneville Power Administration (December Opinion). Given the existing circumstances, we also believe that monetizing the sales is appropriate and in accord with the December Opinion.

BPA will separately address the FY 2010-11 period under the 2007 Block Contract, and will engage with the public on the terms for any amendment or replacement agreement for the FY 2010-11 period. In addition, the Administrator has stated that BPA will address any look-back issues associated with payments made under the 2007 Block Contract during the FY 2007-08 period, and intends to engage the region at an appropriate time.

Sincerely,

/s/ Paul E. Norman

Paul E. Norman
Senior Vice President
Power Services

Attachment

PSBPA'S RESPONSE TO COMMENTS:
CFAC AMENDMENT
(Effective through September 2009)

Background

The December 2008 Opinion of the United States Court of Appeals for the Ninth Circuit in *PNGC v. DOE* invalidated the Bonneville Power Administration's (BPA) monetization of its surplus power sales for direct service industrial (DSI) aluminum smelter service under contracts for the FY 2007-2011 period because the monetization was not based on the Industrial Firm Power (IP) rate. *Pacific Northwest Generating Cooperative v. DOE*, Case No. 05-75638, Slip Op. 16513 -16583 (*PNGC*). In response, BPA suspended monetization payments to Alcoa and CFAC. BPA then engaged the aluminum smelter DSIs in discussions on the possibility of amendments to conform continued smelter service to the *PNGC* opinion and possibly avoid any unnecessary interruption of smelter operations. BPA has now agreed to virtually identical amendments with both Alcoa and CFAC. Comments provided in each context are also virtually identical and so the decisions reflected in this document are equally applicable to both the Alcoa and CFAC Amendments.

Public Process

Because of the need to act quickly to avoid further economic problems for the smelters, BPA could only provide a limited amount of time for public comment on the CFAC and Alcoa Amendments, which will cover slightly more than three quarters of the current fiscal year.[1] Some of the comments have suggested that the amount of time made available was inadequate for full consideration of the implications of the *PNGC* opinion and the terms of the amendments. ICNU argues the "BPA is once again refusing to allow the region adequate time to review its Proposed Amendment." CFA 090006 at 2. ICNU also states that BPA has "made any review of the contract more difficult by only providing the new provisions and not providing a complete copy of the new contract" and concluding that "BPA has simply provided an insufficient opportunity to review the Revised PSA." *Id.*

Contrary to these assertions, BPA believes that the processes provided for public consideration of BPA's proposals have been adequate. The public has had two opportunities within almost two months to comment, one for the Alcoa Amendment and then another for the CFAC Amendment. Presumably, the commenting parties could have used some part of the intervening period to consider the Amendment more fully, particularly the implications of the *PNGC* opinion. Indeed, certain parties were obviously sufficiently convinced of the meaning of *PNGC* that they filed petitions in the Ninth Circuit Court of Appeals challenging the Alcoa Amendment.

[1] BPA has committed to a more extensive public process for DSI service for FY2010 and beyond.

As to provision of the entire contract, as suggested by ICNU, BPA did provide the entire contract, specifically identifying the provisions that had been modified as a result of the amendments. Moreover, the retained terms were the subject of public processes in 2005 and 2006, and the subject of litigation for an additional three years. To suggest that they are not readily available to the public, or that BPA has provided insufficient information, is not accurate.

Some comments also argued that prior to entering into the amendments BPA should seek a remedy for any unlawfully paid benefits in FY 2007-2008. However, such a proposed sequencing would not be consistent with the need to act quickly with respect to the Amendments, since such a process, should it be initiated at this time, could be lengthy. Moreover, *PNGC* does not require any particular sequencing of events, instead remanding the issues to BPA to determine the appropriate course. *Id.* at 16582. At this time, petitions for rehearing have been filed in *PNGC*, and the Court's mandate has not issued. Consequently, the prudent approach is to address the current exigent need of DSI survivability with contract amendments that comply with the Court's opinion, and to then, if and once the Court's mandate has issued, address the issues of whether overpayments were made and, if so, what mechanism(s) may be available to recover such overpayments, such as through offset, rate adjustment, or otherwise.

Consistency with PNGC Opinion

Several parties have raised legal issues, largely in connection with the Ninth Circuit opinion issued on December 17, 2008, in *PNGC*. As discussed below, BPA believes the arguments are inconsistent with the opinion and would lead to results that would generally prevent the Administrator from implementing key elements of the opinion and other Ninth Circuit rulings, as well as require him to ignore explicit statutory rate directives.

Requirement of Initial Offer at IP Rate

Some of the commenting parties appear to believe that, even if BPA offers to sell power to DSIs at the IP rate, that rate must recover the full incremental costs of any resources obtained to support DSI contracts. PPC, for example, concludes that its legal analysis leads to the conclusion that BPA is not justified in entering into the CFAC Amendment because "BPA calculates that doing so will result in substantial costs to its preference customers" (*citing PNGC,* slip op. at 16570, which states that "BPA has voluntarily agreed to forego revenues by charging the DSI a rate below what is authorized by statute (*i.e.,* the IP rate) and below what is available on the open market . . . and renders BPA's decision to 'monetize' the DSI contracts in an amount reflective of those underlying rate decisions—albeit a capped amount—highly suspect." PPC, CFA090005 at 2 and FN 5. *See also,* NRU, CFA090001 at 2 (arguing that "DSIs have no right to continued BPA service" and a discretionary sale must be consistent with "establishing rates at the lowest possible cost consistent with sound business principles"); SUB, CFA090003; and Canby, CFA09002.

A central holding of the Court's opinion is that, if the Administrator exercises his discretion to offer to sell power to the DSIs, any initial offer must be at the IP rate. *See, e.g. PNGC*, Slip Op. at 16539 and 16550. In support of its conclusion that any initial offer of DSI service must be at the IP rate, the Court observes that the legislative history of the Northwest Power Act "contains extensive evidence that Congress intended the IP rate to be the default price for sales of power to the DSIs." *Id.* at 16559. In this connection, the Court notes that legislative history states that "Section 7(c) prescribes the rates applicable to direct service industrial customers" (H.R. Rep. No. 96-976, pt. 1, at 69) and is the rate which "applies to all 'Industrial Firm' sales to BPA's direct-service industries . . . [for] 1985-86 *and all future [sales].*" (S. Rep. No. 96-272 at 59) (emphasis added in Opinion). The Court adds that, to the extent BPA decides to exercise its discretion to offer power to the DSIs, the *Kaiser* case "supports . . . our understanding that <u>BPA does have an obligation to offer the DSIs a cost-based rate</u>—namely, the IP rate—before declaring energy as surplus under § 839c(f) and selling it to the DSIs at a market-based—or other—FPS rate." *Id.* at 16564 (emphasis added). The "cost-based rate" referred to is not one that, to paraphrase the PPC's comment, is the rate for power available on the open market, but is rather the IP rate. Thus, the Court recognized that the IP rate is a cost based rate, *i.e.,* based on BPA's total system costs, and not a rate targeted to recover the incremental costs of resources that might be needed to replace system capability in order to support all of BPA's contractual obligations.

In addition, the Court set out the applicable rate directive. *See, id.*, at 16556, *citing* 16 U.S.C. § 839e(c) (Section 7(c) of the NPA). The section 7(c) rate directive requires that the IP rate be "equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region." 16 U.S.C. § 839e(c)(1)(B). That determination of equitability is required to be based upon the rate BPA charges its preference customers, with certain adjustments. 16 U.S.C. § 839e(c)(2). It is difficult to understand, as PPC and other commenters apparently contend, how the IP rate established pursuant to section 7(c) could recover from the DSIs the incremental cost of any acquisitions required to replace system capacity in support of DSI service and still be "equitable" in relation to the rates of industrial customers of BPA's public customers, who purchase power to serve their industrial loads at the PF (preference) rates. In today's dire economy, utilities are seeking to retain industrial load, not drive it away. As the language of section 7(c) shows, it was not Congress's intent to have BPA charge the DSI customers rates that are inequitable as compared to the retail rates charged by preference customers to their industrial consumers. Rather, Congress intended to closely tie the IP rate to the PF rate.

Moreover, the criteria that Congress has required BPA to consider in developing the IP rate provide no basis for converting the IP rate to an incremental cost rate rather than a cost-based rate. Instead, the statute requires that the IP rate be based on the PF rate plus a small number of explicit adjustments, including an industrial margin less any applicable credit for the value of reserves provided by DSIs; provided that the IP rate "shall in no event be less than the rates in effect for the contract year ending on June 30, 1985." 16

U.S.C. 839e(c)(2).

This statutory rate directive specifically mandates the criteria by which the IP rate will be developed and there is no apparent legal basis to conclude that it must be set to recover the incremental cost of any acquisitions made by BPA to replace resources if needed to support DSI sales. The Court in *PNGC* understood the nature of the IP rate when it held that any initial offer of service must be at the IP rate. Slip Op. at 16539. Thus, if the comments are taken at face value, some commenting parties would require the Administrator to ignore the rate-setting directive, which would be contrary to law, or make an initial offer at a rate other than the IP rate, which is prohibited by the *PNGC* opinion. Accepting such an argument would be in direct contravention of the Court's holding in the very case being relied upon by the parties who are raising it.

The Court recognized further that BPA may make market purchases to support DSI sales: "Congress also vested BPA with the authority to acquire power, including purchasing energy on the open market, if needed to meet its contractual obligations . . . .[and] BPA has the statutory authority to sell power to DSIs at valid contract rates and to purchase at market rates the power to serve those contracts." Slip Op. at 16568. Additionally, in a separate Ninth Circuit opinion, the Court did not agree with the preference customers' assertion, now apparently recast in response to *PNGC*, that no costs associated with DSI service can be allocated to the preference rate:

> According to petitioners, "Entering contracts to sell power to the DSIs when BPA has none to sell them is unlawful.... The only way the post-2001 contracts with the DSIs can be lawfully performed is to require the DSIs to pay the full costs of service." In other words, petitioners asserted that BPA could not allocate to its preference customers any of the costs of purchasing power at market prices to serve the DSIs.

Golden Northwest Aluminum, Inc. v. Bonneville Power Admin., 501 F.3d 1037, 1044 (9th Cir. 2007). The Court rejected petitioners' arguments. Instead, the Court in *GNA* concluded that BPA can "use any remaining FBS resources—including FBS replacement resources—to supply its DSI customers" and BPA "is entitled to charge preference customers a rate that reflects the total cost of all FBS resources, including resources acquired to replace losses in the generation capabilities of BPA's primary resources." *Id.*

The *PNGC* Court also recognized that the IP rate, as mandated by Congress, might itself provide some level of subsidy. The Court refers to the IP rate as the rate that BPA "is statutorily required to offer" and reflects "the primary benefit that the class of DSI customers receives under the NWPA . . ." PNGC at 16579. Further, the *PNGC* Court invalidated the monetized FPS surplus sale, at least in part, because BPA was "subsidizing the DSIs' smelter operations beyond what it is obligated to do," *i.e.,* beyond what is provided for by Congress through the IP rate directive. *Id.* at 16572 (emphasis added). Thus, if proper application of the IP rate directives results in a benefit to the DSIs, that is simply a consequence of the NPA, and not an illegal subsidy. By the same token, if BPA acquires expensive resources to serve preference customer load growth, and those resource costs increase the PF rate, this in turn results in an increase in the IP rate due to the workings of section 7(c), which means essentially that the DSIs would share some of those expensive resource costs. That too is the way the NPA works and is not an illegal subsidy.

<u>BPA's Interest in Exercising Discretion to Serve DSIs</u>

Comments have suggested that BPA has not articulated a reason why its exercise of discretion to continue service to DSIs is "in accordance with BPA's duty to offer the lowest possible rates to its consumers, consistent with sound business principles." PPC, CFA090005 at 2. *See also* comments of ICNU, SUB, Canby, and NRU.

When section 9(b) of the Northwest Power Act instructs the Administrator to timely implement the Act in a sound and businesslike manner, it does so right after first charging that the Administrator "shall discharge the executive and administrative functions of his office in accordance with the policy established by the Bonneville Project Act of 1937, section 302(a)(2) and (3) of the Department of Energy Organization Act, and this Act." 16 U.S.C. § 839f(b). A great number of policies, some of them competing, can be discerned from examining those Acts, but one in particular warrants reciting here, and that is the purpose of the Northwest Power Act to "to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply; . . ." 16 U.S.C. § 839(2). The purpose is not simply to assure preference customers of those things, or some other customer class of those things, as if they were to be the only beneficiary of BPA's actions under the Act, but to assure "the Pacific Northwest" of those things. Achieving that goal calls for a balancing of interests.

A wide variety of benefits is provided by the Northwest Power Act, not just to customers, but also to fish and wildlife and, through the Act's preference for conservation and renewable resources, the environment. The Administrator does not act in accordance with sound business principles with the view to operating as a profit-making enterprise, but rather to act in accordance with sound business principles in carrying out his myriad of responsibilities under the law, many of which evince social policies that might be viewed as inimical to acting purely like a "business." So, in the context of providing DSIs, and others, an adequate, efficient, economical and reliable power supply, it is certainly not unwarranted that BPA considers the impact of its actions on the continued viability of its customers.

BPA has, in connection with its recently proposed 2010-11 rate increase, expressed concern about the impact of the increase on consumers, particularly given the current recession and the Administration's efforts to provide a stimulus to the economy and generate jobs. Preference and other customers have now, and certainly in the past, said BPA must be concerned about the impact of its actions on consumers. Suffice it to say, the Northwest Power Act does not single out preference customers for such concern and protection, but evidences a policy of having the Administrator's actions support an economical power supply to the entire Pacific Northwest. That he is to do so consistent with sound business principles means he should support that objective consistent with sound business principles, not that sound business principles should somehow render all of these other objectives secondary or superfluous.

As noted earlier, *PNGC* affirmed that BPA has the authority, but not the obligation, to sell power to the DSIs and clarified the proper rate directives to follow in making an initial offer. BPA believes that the proposed service plan is a proper exercise of the Administrator's discretion. The decision to serve the DSI load is consistent with BPA's statutory responsibilities, including its responsibility to act in a manner consistent with sound business principles. The DSI load has provided enormous value to BPA in the past and it is reasonable to believe that it will do so again. While the aggregate DSI load has decreased substantially over the past decade due to adverse global aluminum market forces, Alcoa and CFAC have shown remarkable resilience in the face of huge challenges to remain competitive. There is ample reason to believe that they will continue to do so, if provided the opportunity to manage their costs.

DSI loads have historically benefitted BPA by taking power in relatively flat blocks that require little or no shaping; they have taken power from BPA at light load hours, when power has historically been difficult to market; and they have provided the Administrator with additional power reserves. Perhaps more importantly, BPA has in the past found it beneficial to retain the DSI load when its other loads were decreasing.

Most recently, in the 1990's, BPA was suffering significant load loss due to public customers having access to a fluid market for power that was routinely offering prices significantly less than the preference rate. Part of BPA's strategy to resolve this decreased demand was a successful effort to retain as much of the DSI load as possible in spite of the fact that BPA's cost-based rates were higher than rates for power that could be purchased on the open market. Retention of this load supported BPA's ability to meet its financial obligations in full and on time, including its Treasury repayment obligation. As the Administrator observed at the time:

> Faced with the sudden changes in the market and the resulting high likelihood that the DSIs would exercise their contractual right to remove their load from BPA on nine months notice, BPA acted to protect its overall revenues and ability to recover its costs by negotiating block sale contracts, committing the DSIs to place a substantial amount of load on BPA for five years.

Administrator's Record of Decision, 1996 Power and Transmission Rate Proposal, § 2.2 at 18; *see also, id.* § 8. Due to the many unanticipated changes that the electricity market has seen over the last two decades, it would be short-sighted and unwise to conclude that retention of DSI load could never provide significant value to BPA in the future. Due to the current economic crisis, market prices have declined significantly while BPA has just announced a proposed rate increase. No one knows what the end result of these volatile market forces will be as the economy continues to decline, nor does anyone know with certainty what market conditions will be like when the economy begins to improve.

It should also be recognized that potential load loss is not solely a product of market prices. Poor economic conditions can cause a decrease in business activity that can lead, in turn, to relocation of business enterprises and consequent population drift. Unexpected natural disasters could also affect demand for power. Currently, adverse effects in the agricultural and forest industries are anticipated due to the severe winter storms and flooding that occurred this winter. Moreover, changing technologies in the aluminum and power industries may permit DSI smelters to provide value to BPA in ways that have not yet been imagined.

It would be unwise and imprudent, in such circumstances, to refuse to provide service to customers that may provide future value to BPA as they have done in the past. In essence, such a decision would require a blind faith belief in a static and largely predictable future. Events in the power industry over the past two decades and the current economic crisis amply illustrate the folly of taking such a course. Thus, BPA sees no compelling reason, at this time, not to offer service to this statutorily-defined customer class. This is particularly true when the DSIs currently have no viable alternative for its power needs and a decision not to sell power to DSIs would almost surely have the immediate consequence of the plants shutting down and perhaps never resuming production.

BPA is certainly aware that one of the implications of providing DSI service is the impact on other rates. For this reason, the proposed service package makes business sense only because the Amendment effectively caps BPA's cost of service, and, more importantly, in the opinion of the Administrator, will not put an unreasonable degree of upward pressure on other rates. BPA's customers have not experienced a rate increase during the last six years, and service to Alcoa and CFAC under the contract amendments will have a minimal impact on rates. BPA does not believe that the proposed amendment, which covers only a nine month period at a relatively modest cost, causes unreasonable upward pressure on other rates.

Some of the comments seem to suggest that the Court will review BPA's proposal under a "highly suspect" standard. PPC, for example states: "[T]he Court's findings apply equally to the proposed amendment, and . . . BPA is not justified in exercising its discretion to sell power (or provide a monetized transaction) to the DSIs . . . where BPA calculates that doing so will result in substantial costs to its preference customers." In support of this argument PPC cites PNGC, slip op. at 16570, which states:

> BPA has voluntarily agreed to forego revenues by charging the DSIs a rate below what is authorized by statute (*i.e.*, the IP rate and below what is available on the open market). These foregone revenues result

> in higher rates for all other customers. This outcome is in apparent and direct conflict with BPA's statutory mandate, and renders BPA's decision to "monetize" the DSI contracts <u>in an amount reflective of those underlying rate decisions</u> . . . highly suspect.

PPC at 2, FN 5 (emphasis added). The context of the Court's use of the term "highly suspect" is relevant. The Court's evaluation focused on an Agreement based on the FPS rate where the purchase price for power was less than the IP rate. Thus, the Court's use of the term "highly suspect" was in the context of a transaction where BPA had not provided a sufficient basis for not charging the rate specifically authorized by the NPA for sales of industrial firm power. That situation does not arise in the context of offering a sale at the IP rate, which the Court has mandated must be the basis for any initial offer of DSI service. Moreover, the Court explicitly recognized that the standard of review has not been changed by its opinion: "Applying appropriate deference, we uphold the agency's assessment of whether its actions 'further BPA's business interests consistent with its public mission, so long as the assessment is not unreasonable." *Id., Citing Ass'n of Pub. Agency Customers*, 126 F.3d at 1171.

Because BPA has articulated reasons for providing DSI service that are "not unreasonable," BPA does not believe the Court will view the proposal as "highly suspect." Moreover, for the same reason, the "lowest rates possible" argument posited in the comments falls by the wayside because that provision applies to all of BPA's consumers and is not targeted exclusively on the rates paid by preference customers. Thus, the provision provides equal protection to DSI load that is being lawfully served at the IP rate.

<u>Other Issues</u>

<u>Market Price Derivation</u>

Two parties commented that it was not clear how BPA determined the market price to be used for calculating benefits under the Amendment. ICNU at 2; Canby at 2. For both Alcoa and CFAC, the market prices used to recalculate benefits for December 2008, and to calculate benefits for the period January – September 2009, are the same and were derived using the same methodology.

The general approach was to determine what BPA would have done had it taken the course approved in *PNGC* and correctly monetized the sale based on the IP rate. Specifically, for the period January – September 2009 BPA determined a forecast market price of $48.05 per MWh. This forecast was established as of December 18, 2008 ("Forecast Date"), or one day following the Court's opinion in *PNGC*. BPA uses three proprietary data sources when establishing its internal mark-to-market forward curve for a flat Mid-Columbia trading hub product. BPA's mark-to-market price curve is updated on a daily basis. BPA established the forecast market price by averaging a series of these daily mark-to-market price curves over the two and one-half month period prior to the Forecast Date during which BPA was in the market making actual purchases to meet its other supply obligations for the period January – September 2009. In other words, had BPA purchased additional energy from the market to support additional system load created by its contractual obligation to serve Alcoa or CFAC load, then BPA would have, on a forecasted basis, incurred that market price to meet those obligations as well.

As for the December 2008 recalculation, BPA used the same methodology described above to derive a market price, but since forward trading for December 2008 deliveries ended on November 28, 2008, the price curves for the two-month period prior to December cover a different number of trading days than those used for the period January – September 2009, yielding a different market price, equal to $57.48 per MWh, which BPA would have paid in the market if purchasing energy to serve the load. This method accurately reflects what it would have cost to monetize the sale based on the IP rate.

Equivalent IP

Some parties questioned BPA's use of the so-called "Equivalent IP" in calculating benefits under the Amendment, and the use of a 100 percent load factor in calculating the applicable IP rate. PPC at 3; ICNU at 2. Simply stated, the "Equivalent IP" used for calculating benefits under both Amendments for the period January – September 2009 is equal to the average IP rate over those months, as specified in BPA's 2007 Supplemental Wholesale Power Rate Schedules, using a flat (or 100 percent) load factor. This was done because (1) it is consistent with the 2007 Block Agreement in which BPA agreed that the benefits calculation would be based on the applicable average Equivalent PF rate at a 100 percent load factor, and (2) applying the individual monthly differentiated rates (for both the market price and the IP rate) is more complicated, raises the prospect of errors in administration, and will not change the total amount of benefits paid to the companies over the full Amendment period.[2] Finally, flattening out payments to the companies by using an average market price and IP rate simplifies BPA's projection of the companies' decisions regarding the level of operation as it relates to its power cost, since there is no monetary advantage or disadvantage to operating in any given month compared to any other.

In addition, with respect to using 100 percent load factor, the smelter loads have a very high load factor that in many months is nearly 100 percent, and that normally exceeds 95 percent on an annual basis. But even, for example, if BPA used a 96 percent load factor to calculate the demand portion of the IP rate for the Alcoa Amendment, the total cost of IP service for the period January – September 2009 would rise only $61,000 out of $21.5 million, or less than three-tenths of one percent.

[2] In addition, it is industry practice to book blocks of forward market purchases as an average of the prices paid for such blocks. Using that flat price for purposes of billing for sales of that same energy is consistent with that practice.

Comparison of Benefit Levels

One party asked for a comparison of the benefit level that will be provided to CFAC under its Amendment compared to the benefit level it would have received under the original 2007 Block Contract. Canby at 2. The answer is that the maximum amount of benefits that CFAC can receive under the Amendment equals $5.9 million, compared to a projected level of benefits under the original 2007 Block Agreement for the same 10-month period of $13.9 million. This reduction is primarily due to the fact that the number of megawatts for which CFAC can receive benefits is reduced from 170 aMW in the 2007 Block Agreement to approximately 91.5 aMW (the prior level of projected operation) for the months December 2008 – February 2009, and then further reduced to 37.5 aMW (a fixed amount) for the months March – September 2009. It is important to keep in mind when making comparisons between the level of benefits that may have been paid under the original 2007 Block Contract and the Amendment, that these comparisons are based on projections of the companies' level of operations.

While it was possible for CFAC to receive its maximum monetary benefit payment based on an monetary benefit rate of between $12 and $24 per MWh under the original 2007 Block Contract (depending on its level of operation), that rate is now fixed at $15.35 per MWh, or the difference between the Equivalent IP rate of $32.70 per MWh and the average market price under the Amendment of $48.05. However, payments to both CFAC and Alcoa remain subject to the $59 million cost cap originally adopted by BPA in the records of decision accompanying the 2007 Block Contract. By comparison, payment of the $16.7 million maximum monetary benefit to CFAC under the 2007 Block Contract would have been possible across a spectrum of operating levels, from as little as 85 aMW to as much as 170 aMW, whereas under the Amendment, there is not an operating level that could allow CFAC to attain a similar payment.[3]

In the case of Alcoa, BPA projects that Alcoa could receive a maximum monetary benefit of $31.9 million (if it operates at its demand entitlement), for the period December 2008 through September 2009, the same maximum monetary benefit amount as BPA projected Alcoa could receive under the original 2007 Block Contract for the same period. However, payment of the maximum monetary benefit under the 2007 Block Contract would have been possible across a spectrum of operating levels, from as little as 195 aMW to as much as 390 aMW, whereas under the Amendment Alcoa must operate at approximately 305 aMW – its demand entitlement – to receive its maximum monetary benefit. While the assumption regarding Alcoa's operating level remains the same, the formula for calculating the monthly payment amount under the original 2007 Block Agreement renders a monetary benefit rate that is close to that rendered by the equation under the Amendment.[4]

[3] Pursuant to their respective 2007 Block Contracts, CFAC and Alcoa each received a share of the 100 megawatts that were unused and forfeited by Golden Northwest Aluminum. This brought CFAC's allocation to 170 aMW, and Alcoa's to 390 aMW.

However, absent the cost cap, in the event Alcoa operates at its full demand entitlement under the Amendment for each hour during the period January – September 2009, the $48.05 market price would result in a maximum monetary benefit to Alcoa of $33.9 million, or approximately $2 million above its prorated share of the $59 million cost cap. Therefore, Alcoa's monetary benefit limit is specified in Exhibit F of the Amendment as $31.9 million. In other words, there could be a number of hours of operation during the Amendment period for which Alcoa would not receive benefits.

Reserves

Two parties commented that the Amendment needed to provide a portion of BPA's reserves for firm power loads in the region. IOUs at 1; PPC at 4. BPA's transmission business line is contractually entitled to call on stability reserves from the companies. Prior to BPA's administrative separation into distinct power and transmission functions, with the attendant unbundling of power and transmission products, stability reserves were available to BPA through the DSI power sales contracts. The mere fact that these reserves are now made available to BPA through a BPA transmission contract rather than the power sales contract should not matter.

In addition, as described in the records of decision accompanying the 2007 Block Agreements, beginning with the 2002 power rate case and related DSI contracts for the period FY 2002-2006, BPA ceased crediting the IP rate for the value of reserves, and did not procure reserves from the DSIs under those contracts. This is due primarily to changes in the wholesale power markets which allow BPA to procure needed reserves cheaper and more reliably from sources other than the few remaining DSIs. In lieu of a fixed credit to the IP rate, in both the 2002 and 2007 power rate cases BPA proposed and ultimately adopted the Supplemental Contingency Reserve Adjustment, which established a formula, with a cap, for calculating amounts it could pay a DSI in the event that it wished to procure reserves from a DSI through separate contract negotiations. This approach was proposed, adopted, and has been implemented by BPA without objection in the contracts spanning the period FY 2002 through FY 2011. Furthermore, to the extent BPA and CFAC elect to enter into a physically delivered transaction during the final two-years of the 2007 Block Contract (FYs 2010 and 2011), there is no reason that

[4] The formula for calculating the monthly monetary benefit payment under the 2007 Block Agreement was the lesser of the Maximum MB Monthly Payment or the amount determined by the following equation: MB Monthly Payment = ((Monthly Plant Load) x (number of hours in the month)) x (MB Rate); where the Maximum MB Monthly Payment = ((Maximum Allocation) x (number of hours in the month)) x (lesser of $12 / MWh x 0.92 or MB Rate); and where the MB Rate is determined by subtracting Equivalent PF from Forecast Market Price. By comparison, the formula for calculating the monthly monetary benefit payment under the Amendment is: MB Monthly Payment = ((Monthly Plant Load) x (number of hours in the month)) x (MB Rate); where the MB Rate is determined by subtracting Equivalent IP from Forecast Market Price. As a consequence of other Court decisions, BPA had to reduce its Priority Firm and IP rates for FY 2009 below FY 2007-2008 levels, to reflect reduced residential exchange payments to investor owned utilities, a fact that must be taken into account when comparing benefit levels.

BPA could not apply the cap and criteria in the Supplemental Contingency Reserves Adjustment provision to any cost-effective and necessary reserves it wishes to procure from CFAC. The mere fact that BPA is not receiving any reserves from CFAC during the Amendment period does not necessarily mean BPA will not procure any reserves from CFAC under the 2007 Block Contract.

Finally, BPA does not necessarily agree with the proposition that section 5(d)(1)(A) of the Northwest Power Act requires that each and every power sales contract BPA enters into with a DSI must provide reserves. The provision requires only that sales to DSI companies as a class provide a portion of BPA's reserves for regional firm power loads.[5] There is no apparent reason why this language could not be implemented in a way such that reserves are acquired from less than all DSI customers. Whether BPA will acquire reserves from CFAC, Alcoa, and/or Port Townsend during the final two years of the 2007 Block Contract has not been determined at this time although a value of reserves credit has been calculated for the initial proposal in BPA's FY 2010 power rate proceeding. In addition, as noted above, in determining the amount of reserves to be provided, BPA does so in a manner that assures the reserves are provided at least cost to BPA and its customers. Changes in the power markets since passage of the Northwest Power Act have enabled BPA to acquire reserves at a lower cost from providers other than the DSIs, and BPA believes that doing so is consistent with the intent of the Act to provide customers an economical power supply.

[5] In the 1996 rate proceeding, for example, individual DSIs were permitted to opt out of providing reserves by essentially forfeiting the value of reserves credit: "If a DSI chooses not to provide operating reserves, a billing adjustment will be made to remove the effect of the credit." 1996 General Rate Schedule Provisions at 142.

APPENDIX C

Account 303, 2006

Category	Project	Description		Sum Cost
303	27099181	DES OSM Project	$	2,194,646.17
303	27133214	Purchase ZAI*NET Energy Transaction/Acctg System Software	$	2,000,000.00
303	27057033	2000 Phoenix Project	$	1,495,739.02
303	27015192	Phoenix Project-Data Conversion	$	1,442,119.86
303	27215851	EMS Phase 1	$	1,421,468.55
303	27038529	1999 Phoenix Project	$	1,056,754.94
303	27176071	Wire Vision Implementation	$	983,426.63
303	27136629	CPU Upgrade	$	949,353.11
303	27166352	Meter Data System Software & Interfaces - Phase One AMR	$	841,431.41
303	27085277	Feeder Fielding Project 2001	$	835,974.88
303	27177530	Mobile GIS Project	$	724,215.00
303	27165250	Enviromental Database: WQ, Fish and Invertebrate Modules	$	661,569.19
303	27108749	Water Forecasting Model	$	608,534.40
303	27123740	Hydro Optimization Model	$	556,732.73
303	27064176	Feeder Fielding Project	$	511,085.88
303	27180003	Nexus Energy Software Implementation	$	475,047.10
303	27059705	Mainframe Upgrade	$	450,224.37
303	27135594	INDUS Connect Framework	$	435,260.19
303	27189487	MW Streamflow Forecast Model Phase 3	$	432,074.50
303	27091068	ARCFM Project	$	372,203.51
303	27077207	Cost Center 342-Build Feeder Model Database	$	368,869.28
303	27159879	Phase One AMR - IT & CIS Interfaces and Data Storage	$	361,078.53
303	27161774	Upgrade to Training Server	$	344,205.06
303	27096838	Web Support	$	319,889.59
303	27166091	Customer Care Intiative 2004	$	283,335.34
303	27154759	Sims Software and Maintenance	$	272,971.50
303	27065322	Fleet Anywhere Management Software	$	258,127.62
303	27073935	Forecast Software with Setup and Instruction	$	238,759.61
303	27139677	IVRU Replacement/Upgrade	$	220,634.28
303	27085161	Hydrologic Database	$	214,358.10
303	27188653	Environmental Database - 2005	$	195,303.81
303	27217708	Mike-11 Swan Falls, Phase 1	$	181,098.24
303	27133629	CPU Upgrade	$	178,450.75
303	27109379	2002 ITRON Project	$	176,253.33
303	27148617	Software Licenses for TIM Project	$	173,351.88
303	27108399	Additional Licenses for Seagate Info	$	171,560.81
303	27092050	Consulting Fees for Meridian Project	$	170,880.38
303	27052406	ABM Software with Setup and Instruction	$	165,895.85
303	27039668	Network Servers	$	154,136.95
303	27083783	EDMSAPI Interface to link Passport to Document Mgmt	$	150,000.00
303	27084157	RF Inventory Purchase Software	$	150,000.00
303	27113450	Media Mosaic E-Learning Project	$	147,608.54
303	27172865	Passport ICF BO'S:MR, Catalog, MWFM Wishbone, CIS Banner	$	146,412.50
303	27159533	Remote Access / Monitoring	$	145,841.42
303	27165721	SOX Software Project	$	143,466.42
303	27085627	DB2 Connect for S/W (IVRU)	$	142,048.62
303	27203693	Instant Messageing Gateway	$	126,785.93
303	27039303	Data Warehouse Development	$	126,710.20
303	27161736	Storage Management Software	$	126,013.97
303	27039689	AEGIS	$	123,900.00
303	27136651	Commvault Backup	$	121,200.00
303	27161687	Client Services Manager-Microsoft Project Svr 2002 Implementation	$	115,892.92
303	27148418	GIS Database Development	$	115,289.54
303	27085528	Phoenix Project: AM/FM/OMS	$	113,660.87
303	27031075	PPPS Software Loan	$	112,142.38
303	27138111	OMS Project - DORD, Sentry, Web Call	$	109,015.04

303	27181991	Technical Opperations-Map Board	$	104,132.65
303	27044988	Mosaix Upgrade	$	103,111.05
303	27083797	Power Mart Purchase	$	100,000.00
303	27109689	CISCO Works Upgrade	$	96,035.24
303	27188701	Mobile GIS Project	$	95,772.50
303	27085866	Reliability Performance Software-Update Performance Threshld	$	95,000.00
303	27118405	Facilities Data Cleanup	$	90,972.11
303	27190344	E-Mail Encryption Project-ASLC	$	88,309.21
303	27112797	Portal Management Software	$	87,670.67
303	27109699	Internet Filtering & Monitoring	$	87,061.96
303	27219041	Mike - 11HCC, Phase 1 (Replaces 27137496 Task 01)	$	83,415.93
303	27189317	Upgrade Webmethods	$	82,669.04
303	27199608	Loadstar Contract Renewal	$	81,825.00
303	27210056	Mapframe Site License	$	80,523.62
303	27166453	CC852	$	76,381.40
303	27109621	Aud Logic File Creation	$	75,000.00
303	27196951	N 20 Source Code Management for Natural	$	74,386.05
303	27210909	Webmethods License Agreement	$	73,778.25
303	27088239	Convert Joint Use Records to Electronic Database	$	73,538.50
303	27162869	Water Mgmt: Hydrologic Database	$	73,046.65
303	27189722	Call Manager Upgrade	$	71,128.88
303	27109692	SQL Srvr 2000 Test Prod Servers	$	70,276.06
303	27059718	Snapshot	$	70,000.00
303	27186866	PGP Universal Software Licenses	$	66,710.00
303	27109675	Security Software	$	64,850.56
303	27161695	Business Service Manager-Other Intangibles (Regional W/S Techs)	$	64,844.20
303	27177541	Geodatabase Conversion Tools Development	$	64,520.44
303	27017173	Function Contingency	$	64,404.85
303	27059644	T&D Debelopment (CC342) - Phoenix Project GIS (Y2000)	$	61,929.60
303	27065450	Transmission Inspection and Maintenance Program	$	61,369.58
303	27109700	ADIC Upgrade	$	60,596.27
303	27109705	GIS System Upgrade	$	59,800.00
303	27097113	Map R2 & R3 Upgrades and VIP Subscriptions	$	58,977.63
303	27108520	OSI-PI Licenses and Interfaces	$	53,550.00
303	27109618	AUD/Passport API	$	50,904.54
303	27081436	Dolphin MSDS Intranet Software	$	50,375.81
303	27041105	T&D Development CC342-Phoenix Project GIS Support	$	50,313.55
303	27085653	Mecury Tools (Web Team)	$	48,371.48
303	27118830	DB2 Utilities	$	46,806.90
303	27172856	Imaging Software and Services for Phase III of AP Imaging	$	45,108.42
303	27109670	Scheduling Agents	$	45,000.90
303	27213464	Purchase Annual Copies of PLS CADD and PLS Pole Software	$	44,619.80
303	27070829	Purchase 175 Additional Seagate Info Client Licenses	$	43,930.95
303	27161471	OMS Project - DORS, Sentary, Web Call	$	43,324.38
303	27076248	Purchase and implement 1099 Reporting System	$	42,289.77
303	27153823	New CMFX Software Licenses	$	40,433.48
303	27108658	Hydrologoic Database	$	40,395.14
303	27085913	Phoenix Hardware Purchases and Upgrades	$	39,592.15
303	27222163	Plateau Software License for Performance Management	$	38,711.37
303	27072209	Purchase and Install Faxgate Software and Server	$	38,619.41
303	27033176	Substation Reliability Software	$	38,443.91
303	27039680	Mainframe Upgrade	$	37,587.73
303	27136645	Push SQL Server Enterprise License	$	37,477.95
303	27219193	Software/Server needs for PQ staff, Eng & Techs	$	37,472.98
303	27131703	ESRI to Autocad Interface	$	37,283.86
303	27039683	Asset Management	$	37,159.50
303	27192627	Purchase of Cybermation Peoplesoft Agent	$	36,787.50

303	27030317	RSCAS Software Development	$	35,338.11
303	27028993	Jim Stout-MV90 Software Order	$	35,122.50
303	27186406	NSM Advanced Analystics - SIMS Project	$	33,454.00
303	27109667	Aperture (Documentation)	$	33,349.33
303	27161713	E-Talk License & Install for Support Center	$	30,606.18
303	27191948	Enterpise Storage DASD Upgrade	$	30,163.11
303	27125438	Sharepoint Compliance System Software Costs - Capital	$	29,997.52
303	27210917	Commvault	$	29,818.95
303	27109691	Upgrade Centre-VU	$	29,668.13
303	27165284	Arcview and Misc Software Line Services - Development	$	28,967.15
303	27158339	Mobile Computing Pilot Project	$	28,944.31
303	27199128	OATI Enhancements	$	28,810.97
303	27107445	Cybermation	$	28,556.50
303	27110489	Printers for Customer Service Centers	$	28,549.38
303	27017187	Data CenterADSM Tape	$	28,432.27
303	27169593	Customer Care Dev/Test Servers	$	26,375.33
303	27150637	Incident Response-Laptop, Hardware, Software, Misc Items	$	25,651.40
303	27084264	AM Meridian Software, Maintenance & Telephone Tech Support	$	25,507.92
303	27097536	GIS API for PassPort Purchase	$	25,000.00
303	27109678	Voice Network Contingencies	$	24,897.42
303	27136862	Portal Server Software	$	24,137.86
303	27161733	Install Enterprise SQL Server Ouster-Data DMZ	$	23,158.73
303	27147733	Centre VU Upgrade - Security Driven	$	22,776.26
303	27069724	Purchase Teammate Software for Internal Audit	$	21,000.00
303	27051278	Company Street Light Process Improvements	$	20,767.80
303	27084095	Stations D & C	$	20,734.26
303	27190435	ASLC-Temperature and DO Monitoring Software-Capital-2005	$	20,621.98
303	27122728	Transfer Real Time Trading Function to CHQ	$	20,303.81
303	27085161	Hydrologic Database	$	20,256.63
303	27086416	Consulting Fees for Records Management Project	$	20,120.00
303	27136628	META Data	$	19,950.00
303	27207039	CEMS Software Upgrade Unit #2 and #3 Training	$	18,934.28
303	27098543	Annual Software Support for MV90	$	18,032.49
303	27161737	Anti-Spam Project	$	18,015.16
303	27059524	Marketing Purchases for Y2000	$	17,994.70
303	27110031	ARCSDE Server w/Processor for SQL Server-Frank Mynar	$	16,950.00
303	27053539	ESRI ARC/INFO Licenses	$	16,884.00
303	27017188	New Network Servers	$	16,570.62
303	27142481	Geographic Data Technology - Dynamap/Transportation	$	16,001.25
303	27039306	1999 Sentry Software, Hardware	$	15,937.44
303	27217302	IBM ISPF Software VM Racf	$	15,004.50
303	27161738	Server Management Software	$	14,980.01
303	27189397	Purchase Software: Composer, Autodesk, Support Software	$	14,101.62
303	27189035	CC855 (2005) Ariel Image Archive	$	13,552.06
303	27113908	Consulting Fees for Records Management Project-2002	$	13,480.90
303	27170611	Verint/Loronix Web Review Site License for Security Cameras	$	13,364.01
303	27022816	Dispatch Center Mapping	$	13,278.75
303	27085623	E-Mail Redundancy	$	12,718.81
303	27074463	Building a Redundant Network of Internet Reliability	$	11,966.59
303	27075529	Building a Redundant Network of Internet Reliability	$	11,966.59
303	27146160	Autocad Map and Civil Series Relicensing with Eterra	$	11,510.44
303	27079302	Dell Poweredge 2450 Servers	$	11,362.82
303	27135585	Erwin/Modelmart Licenses	$	11,235.00
303	27074161	Building a Redundant Network of Internet Reliability	$	11,140.00
303	27075528	Building a Redundant Network of Internet Reliability	$	11,140.00
303	27113820	Software Purchase for T&D Design	$	10,494.75
303	27037996	Software Purchase for T & D Design	$	10,450.00

303	27042977	Site License for IPRAX Coursew	$	10,000.00
303	27211635	APOS Report Package Consolidation for CE 10 & XI	$	10,000.00
303	27039658	Encrypted E-mail	$	9,778.24
303	27189435	Intrusion Detection System Update-Labor (CC 820)	$	9,508.30
	27052786	The Upline Group, Inc.	$	9,426.79
303	27085639	Call Center Team SVR	$	9,200.75
303	27049929	Purchase Monitoring Equipment	$	8,912.69
303	27037462	Guardian for Scanning Vault Project (AMWF/CADNET)	$	8,370.00
303	27198125	GIS Software for GIS Applications Group	$	7,718.64
303	27092514	Power Mart Purchase	$	7,499.70
303	27032598	Kevin Wartman Chem Lab Software	$	7,056.85
303	27107072	Purchase of Omicron Software	$	6,850.32
303	27152708	Aces & Oasis Upgrade	$	6,700.51
303	27069825	Purchase SQR-Runner	$	6,520.50
303	27038270	CHQ-8 Unclaimed Property Reporting Software	$	5,772.98
303	27020736	Electronic Vault Protection - Network Space, Hardware & Software	$	5,647.77
303	27037463	Guardian AMWF 5 Alp for Engineering Vault Scanning Project	$	5,339.50
303	27059712	Redundent Servers and Software	$	5,298.78
303	27030320	Load Profile Software Development	$	5,245.00
303	27116102	GIS Software for the GIS Group	$	5,010.46
303	27210172	Maplex for Arcgis Concurrent Use Licenses	$	3,981.44
303	27037466	Spicer for Engineering Vault Project	$	3,465.27
303	27037465	AM View Engineering Vault Scanning Project - Field Reps	$	3,088.00
303	27079855	Imagine Orthobase for Windows	$	3,000.00
303	27030321	Weather System Software Development	$	2,310.00
303	27083611	Aspect Communications	$	1,054.50
303	27079448	WM Hydrologic Forecast Model	$	633.07
303	27085838	Phoenix Project AM/FM and OMS Hardware Upgrades	$	546.43
303	27092530	Crystal Reports V 8.0	$	224.52
			$	30,055,875.69

APPENDIX D

Account 303

2008

Unit	Category	Project	Title	Cost
IPC	30300	27025529	CIS PROJECT TEAM LABOR	$ 7,414,812
IPC	30300	27247456	MOBILE WORKFORCE MANAGEMENT 2007 CAPITAL WORKORDER	$ 4,810,796
IPC	30300	27171873	EMS/ADVANCED APPLICATION PROJECT	$ 2,975,076
IPC	30300	27215851	EMS PHASE I	$ 1,421,469
IPC	30300	27024541	PCS FOR CIS PROJECT-SSO BRENT LULLOFF	$ 1,322,893
IPC	30300	27245330	POPULATION VIABILITY MODEL - WHITE STURGEON	$ 943,616
IPC	30300	27166352	METER DATA SYSTEM SOFTWARE & INTERFACES - PHASE ONE AMR	$ 917,703
IPC	30300	27249543	OP. HYDRO. - PHASE V STREAMFLOW FORECAST MODEL	$ 886,441
IPC	30300	27177530	MOBILE GIS PROJECT	$ 724,215
IPC	30300	27196981	OMS UPGRADE OPSCENTRICITY 1.7.1	$ 710,506
IPC	30300	27176071	WIRE VISION IMPLEMENTATION	$ 680,819
IPC	30300	27220015	PASSPORT NEW USER INTERFACE	$ 675,452
IPC	30300	27165250	ENVIRONMENTAL DATABASE: WQ, FISH AND INVERTEBRATE MODULES	$ 661,569
IPC	30300	27108749	WATER FORECASTING MODEL	$ 608,534
IPC	30300	27123740	HYDRO OPTIMIZATION MODEL	$ 556,733
IPC	30300	27268466	MAINFRAME UPGRADE	$ 511,742
IPC	30300	27190421	TRANSRELAY REPLACEMENT	$ 477,049
IPC	30300	27217992	OP. HYDRO. - PHASE IV STREAMFLOW FORECAST MODEL	$ 475,938
IPC	30300	27180003	NEXUS ENERGY SOFTWARE IMPLEMENTATION	$ 475,047
IPC	30300	27219414	ORACLE RAC	$ 466,452
IPC	30300	27135594	INDUSCONNECT FRAMEWORK	$ 435,260
IPC	30300	27189487	WM STREAMFLOW FORECAST MODEL PHASE 3	$ 432,075
IPC	30300	27136629	CPU UPGRADE	$ 425,217
IPC	30300	27159879	TWACS Software & Interfaces - Phase One AMR	$ 361,079
IPC	30300	27161774	UPGRADE TO TRAINING SERVER	$ 344,205
IPC	30300	27176071	WIRE VISION IMPLEMENTATION	$ 302,607
IPC	30300	27166091	CUSTOMER CARE INTIATIVE 2004	$ 283,335
IPC	30300	27154759	SIMS SOFTWARE AND MAINTENANCE	$ 272,972
IPC	30300	27202746	AUD UPGRADE PROJECT	$ 236,679
IPC	30300	27059705	MAINFRAME UPGRADE	$ 222,558
IPC	30300	27139677	IVRU REPLACEMENT/UPGRADE	$ 220,634
IPC	30300	27190442	SHAREPOINT PORTAL SERVER	$ 207,378
IPC	30300	27074054	CIS + REPORTING / DW	$ 206,970
IPC	30300	27283309	MALANDRO VIDEO LICENSING	$ 206,700
IPC	30300	27188653	ENVIRONMENTAL DATABASE - 2005	$ 195,304
IPC	30300	27203729	OPERATIONAL DATA STORE	$ 194,119
IPC	30300	27136629	CPU UPGRADE	$ 193,737
IPC	30300	27217708	MIKE-11 SWAN FALLS, PHASE I	$ 181,098
IPC	30300	27133629	SECURE ACCESS MANAGEMENT (SSO)	$ 178,451
IPC	30300	27109379	2002 ITRON PROJECT	$ 176,253
IPC	30300	27284056	WNDWS SERVER DATACENTER (MICROSOFT TRUE-UP)	$ 172,579
IPC	30300	27092050	CONSULTING FEES FOR MERIDIAN PROJECT	$ 170,880
IPC	30300	27245912	LOGISTIC LICENSE SERVER (LLS) - INSIGHT	$ 169,853
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$ 153,952
IPC	30300	27113450	MEDIA MOSAIC E-LEARNING PROJECT	$ 147,609
IPC	30300	27172865	PASSPORT ICF BO'S:MR, CATALOG, WR; MWFM WISHBONE; CIS BANNER	$ 146,413
IPC	30300	27159533	REMOTE ACCESS / MONITORING	$ 145,841
IPC	30300	27165721	SOX SOFTWARE PROJECT	$ 143,466
IPC	30300	27248071	RELAY TESTING SOFTWARE	$ 142,158
IPC	30300	27259259	UI VERSION J IMPLEMENTATION	$ 141,969
IPC	30300	27136629	CPU UPGRADE	$ 130,405
IPC	30300	27235020	UPGRADE MV90 TO MV90XI	$ 128,430
IPC	30300	27268805	SIEM - SECURITY INFORMATION EVENT MANAGEMENT	$ 127,768
IPC	30300	27136651	COMMVAULT BACKUP	$ 121,200
IPC	30300	27203740	HR COMPETENCY MANAGEMENT SYSTEM	$ 119,747
IPC	30300	27274840	INTERWOVEN LICENSES	$ 119,075
IPC	30300	27148418	GIS DATABASE DEVELOPMENT	$ 115,290

Account 303

2008

Unit	Category	Project	Title		Cost
IPC	30300	27220559	VULNERABLITY ASSESSMENT (ASLC PROJECT CC820)	$	111,865
IPC	30300	27138111	OMS PROJECT - DORS, SENTRY, WEB CALL	$	109,015
IPC	30300	27059705	MAINFRAME UPGRADE	$	106,855
IPC	30300	27261283	AUD OH LOGIC PROJECT-CAPITAL CHARGES	$	105,111
IPC	30300	27256563	VM WARE 3.0	$	104,617
IPC	30300	27181991	TECHNICAL OPERATIONS- MAP BOARD	$	104,133
IPC	30300	27099181	CES OMS PROJECT	$	103,252
IPC	30300	27276228	OP. HYDRO. - PHASE VI STREAMFLOW FORECAST MODEL	$	99,964
IPC	30300	27109689	CISCO WORKS UPGRADE	$	96,035
IPC	30300	27290866	EXTERNAL FTP REPLACEMENT ASLC PROJECT (CC820)	$	94,032
IPC	30300	27148617	SOFTWARE LICENSES FOR TIM PROJECT	$	91,227
IPC	30300	27118405	FACILITIES DATA CLEANUP	$	90,972
IPC	30300	27203693	INSTANT MESSAGING GATEWAY	$	89,162
IPC	30300	27190344	E-MAIL ENCRYPTION PROJECT-ASLC	$	88,309
IPC	30300	27112797	PORTAL MANAGEMENT SOFTWARE	$	87,671
IPC	30300	27109699	INTERNET FILTERING & MONITOR	$	87,062
IPC	30300	27136629	CPU UPGRADE	$	84,360
IPC	30300	27219041	MIKE-11 HCC, PHASE I (REPLACES 27137496 - TASK 01)	$	83,416
IPC	30300	27198752	SYNERGEE MODEL BUILD PROCESS ENHANCEMENT	$	81,947
IPC	30300	27199608	LODESTAR CONTRACT RENEWAL	$	81,825
IPC	30300	27233598	NETWORK VAULT ASLC PROJECT (CC820)	$	81,753
IPC	30300	27210056	MAPFRAME SITE LICENSE	$	80,524
IPC	30300	27203729	OPERATIONAL DATA STORE	$	79,948
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	77,260
IPC	30300	27166453	CC852 (2004) - AUD CONSULTING SERVICES	$	76,381
IPC	30300	27161687	CLIENT SVRS MGR - MICROSOFT PROJECT SVR 2002 IMPLEMENTATION	$	75,142
IPC	30300	27109621	AUD LOGIC FILE CREATION	$	75,000
IPC	30300	27210909	WEBMETHODS LICENSE AGREEMENT	$	73,778
IPC	30300	27161736	STORAGE MANAGEMENT SOFTWARE	$	73,189
IPC	30300	27246939	MOBILE GIS PHASE III - MAPFRAME CONSULTING SERVICES	$	73,000
IPC	30300	27273530	WO RECONCILIATION SOFTWARE	$	70,696
IPC	30300	27109692	SQL SRVR 2000 TEST & PROD. SERVERS	$	70,276
IPC	30300	27059718	SNAPSHOT	$	70,000
IPC	30300	27186866	PGP UNIVERSAL SOFTWARE LICENSES	$	66,710
IPC	30300	27177541	GEODATABASE CONVERSION TOOLS DEVELOPMENT	$	64,520
IPC	30300	27196971	OMS PREPOCESSOR SOFTWARE UPGRADE	$	63,548
IPC	30300	27226548	SAFETY ASSESSMENT AND REPORITNG	$	63,257
IPC	30300	27059644	T&D DEVELOPMENT (CC 342) - PHOENIX PROJECT GIS (Y2000)	$	61,930
IPC	30300	27059964	PEOPLESOFT TREASURY IMPLEMENTATION	$	59,303
IPC	30300	27085528	PHOENIX PROJECT: AM/FM/OMS	$	58,218
IPC	30300	27161695	BUSINESS SERVICE MGR-OTHER INTANGIBLES (REGIONAL W/S TECHS)	$	55,219
IPC	30300	27148617	SOFTWARE LICENSES FOR TIM PROJECT	$	54,473
IPC	30300	27109700	ADIC UPGRADE	$	52,964
IPC	30300	27161736	STORAGE MANAGEMENT SOFTWARE	$	52,825
IPC	30300	27189317	UPGRADE WEBMETHODS	$	52,648
IPC	30300	27109618	AUD/PASSPORT API	$	50,905
IPC	30300	27292210	HR DATA MART	$	49,930
IPC	30300	27196951	N2O SOURCE CODE MANAGEMENT FOR NATURAL	$	48,071
IPC	30300	27172856	IMAGING SOFTWARE AND SERVICES FOR PHASE III OF AP IMAGING	$	45,108
IPC	30300	27109670	SCHEDULING AGENTS	$	45,001
IPC	30300	27181769	DAMAGE CLAIMS SOFTWARE	$	44,730
IPC	30300	27213464	PURCHASE ADDITIONAL COPIES OF PLS CADD AND PLS POLE SOFTWARE	$	44,620
IPC	30300	27227524	STATION APP. 2006 LAB EQUIP (CHQ)	$	43,618
IPC	30300	27085528	PHOENIX PROJECT: AM/FM/OMS	$	41,188
IPC	30300	27161687	CLIENT SVRS MGR - MICROSOFT PROJECT SVR 2002 IMPLEMENTATION	$	40,751
IPC	30300	27153823	NEW CFMX SOFTWARE LICENSES	$	40,433
IPC	30300	27108658	HYDROLOGIC DATABASE	$	40,395
IPC	30300	27278264	ENVIRO ADMIN: GIS SDE DATABASE DEV (REPLACES 27162302)	$	38,765

Account 303

2008

Unit	Category	Project	Title	Cost
IPC	30300	27222163	PLATEAU SOFTWARE LICENSE FOR PERFORMANCE MANAGEMENT	$ 38,711
IPC	30300	27162871	WATER MGMT: RELICENSING DATABASE	$ 38,468
IPC	30300	27136645	PURH SQL SERVER ENTERPRISE LICENSE	$ 37,478
IPC	30300	27136629	CPU UPGRADE	$ 36,824
IPC	30300	27192627	PURCHASE OF CYBERMATION PEOPLESOFT AGENT	$ 36,788
IPC	30300	27030317	RSCAS SOFTWARE DEVELOPMENT	$ 35,338
IPC	30300	27162869	WATER MGMT: HYDROLOGIC DATABASE	$ 34,579
IPC	30300	27136629	CPU UPGRADE	$ 33,861
IPC	30300	27270794	CUMULUS UPGRADE	$ 33,609
IPC	30300	27186406	NSM ADVANCED ANALYSTICS-SIMS PROJECT	$ 33,454
IPC	30300	27109667	APERTURE (DOCUMENTATION)	$ 33,349
IPC	30300	27085913	PHOENIX HARDWARE PURCHASES AND UPGRADES	$ 32,916
IPC	30300	27188701	MOBILE GIS PROJECT - 2005 COSTS	$ 32,694
IPC	30300	27188701	MOBILE GIS PROJECT - 2005 COSTS	$ 32,694
IPC	30300	27254947	WM CLOUD SEEDING & MET. A&SLC	$ 32,596
IPC	30300	27219193	SOFTWARE/SERVER NEEDS FOR PQ STAFF, ENG & TECHS	$ 31,357
IPC	30300	27191948	ENTERPRISE STORAGE - DASD UPGRADE	$ 30,163
IPC	30300	27125438	SHAREPOINT COMPLIANCE SYSTEM SOFTWARE COSTS - CAPITAL	$ 29,998
IPC	30300	27109691	UPGRADE CENTRE-VU	$ 29,668
IPC	30300	27059964	PEOPLESOFT TREASURY IMPLEMENTATION	$ 29,598
IPC	30300	27188701	MOBILE GIS PROJECT - 2005 COSTS	$ 29,424
IPC	30300	27165284	ARCVIEW & MISC. SOFTWARE FOR LINE SERVICES - DEVELOPMENT	$ 28,967
IPC	30300	27158339	MOBILE COMPUTING PILOT PROJECT	$ 28,944
IPC	30300	27059705	MAINFRAME UPGRADE	$ 28,857
IPC	30300	27199128	OATI ENHANCEMENTS	$ 28,811
IPC	30300	27110489	PRINTERS FOR THE CUSTOMER SERVICE CENTER	$ 28,549
IPC	30300	27189317	UPGRADE WEBMETHODS	$ 28,532
IPC	30300	27148617	SOFTWARE LICENSES FOR TIM PROJECT	$ 27,653
IPC	30300	27169593	CUSTOMER CARE DEV / TEST SERVERS	$ 26,375
IPC	30300	27150637	INCIDENT REPONSE-LAPTOP, HARDWARE, SOFTWARE, MISC ITEMS	$ 25,651
IPC	30300	27249531	RELICENSING DEPARTMENT - COMPLIANCE TRACKER	$ 25,074
IPC	30300	27203693	INSTANT MESSAGING GATEWAY	$ 24,201
IPC	30300	27210917	COMMVAULT	$ 24,145
IPC	30300	27136862	PORTAL SERVER SOFTWARE	$ 24,138
IPC	30300	27161713	E-TALK LICENSE & INSTALL FOR SUPPORT CENTER	$ 24,083
IPC	30300	27263644	3271 EMULATOR REPL/UPGRADE	$ 23,043
IPC	30300	27147733	CENTRE VU UPGRADE-SECURITY DRIVEN	$ 22,776
IPC	30300	27136629	CPU UPGRADE	$ 20,829
IPC	30300	27084095	STATIONS D & C	$ 20,734
IPC	30300	27190435	ASLC-TEMPERATURE AND DO MONITORING SOFTWARE-CAPITAL-2005	$ 20,622
IPC	30300	27122728	TRANSFER REAL TIME TRADING FUNCTIONS TO CHQ	$ 20,304
IPC	30300	27136628	META DATA	$ 19,950
IPC	30300	27252746	SYNERGEE	$ 19,717
IPC	30300	27196951	N2O SOURCE CODE MANAGEMENT FOR NATURAL	$ 19,668
IPC	30300	27131703	ESRI TO AUTOCAD INTERFACE	$ 18,642
IPC	30300	27131703	ESRI TO AUTOCAD INTERFACE	$ 18,642
IPC	30300	27098543	ANNUAL SOFTWARE SUPPORT FOR MV90	$ 18,032
IPC	30300	27161737	ANTI-SPAM PROJECT	$ 17,627
IPC	30300	27142481	GEOGRAPHIC DATA TECHNOLOGY - DYNAMAP/TRANSPORTATION	$ 16,001
IPC	30300	27259385	UPGRADE MV90 TO MV90XI	$ 15,949
IPC	30300	27161733	INSTALL ENTERPRISE SQL SERVER OUSTER - DATA DMZ	$ 15,383
IPC	30300	27217302	IBM ISPF SOFTWARE VM RACF	$ 15,005
IPC	30300	27161738	SERVER MANAGEMENT SOFTWARE.	$ 14,980
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$ 13,900
IPC	30300	27113908	CONSULTING FEES FOR RECORDS MANAGEMENT PROJECT-2002	$ 13,481
IPC	30300	27203693	INSTANT MESSAGING GATEWAY	$ 13,423
IPC	30300	27170611	VERINT/LORONIX WEB REVIEW SITE LICENSE FOR SECURITY CAMERAS	$ 13,364
IPC	30300	27268805	SIEM - SECURITY INFORMATION EVENT MANAGEMENT	$ 13,310

Account 303

2008

Unit	Category	Project	Title		Cost
IPC	30300	27263644	3270 EMULATOR REPL/UPGRADE	$	13,192
IPC	30300	27059964	PEOPLESOFT TREASURY IMPLEMENTATION	$	11,861
IPC	30300	27146160	AUTOCAD MAP AND CIVIL SERIES RELICENSING WITH ETERRA	$	11,510
IPC	30300	27135585	ERWIN/MODELMART LICENSES	$	11,235
IPC	30300	27085528	PHOENIX PROJECT: AM/FM/OMS	$	11,127
IPC	30300	27113820	SOFTWARE PURCHASE FOR T&D DESIGN	$	10,495
IPC	30300	27136629	CPU UPGRADE	$	10,480
IPC	30300	27211635	APOS REPORT PACKAGE CONSOLIDATION FOR CE10 & XI	$	10,000
IPC	30300	27203729	OPERATIONAL DATA STORE	$	9,724
IPC	30300	27273530	WO RECONCILIATION SOFTWARE	$	9,711
IPC	30300	27161695	BUSINESS SERVICE MGR-OTHER INTANGIBLES (REGIONAL W/S TECHS)	$	9,625
IPC	30300	27189435	INTRUSION DETECTION SYSTEM UPDATE-LABOR (CC820)	$	9,508
IPC	30300	27207039	CEMS SOFTWARE UPGRADE UNIT #2 & #3 & TRAINING	$	9,467
IPC	30300	27207039	CEMS SOFTWARE UPGRADE UNIT #2 & #3 & TRAINING	$	9,467
IPC	30300	27189397	PURCHASE SOFTWARE: COMPOSER, AUTODESK, SUPPORT SOFTWARE	$	9,401
IPC	30300	27189035	CC855 (2005) - AERIAL IMAGE ARCHIVE (A&SLC - CAPITAL)	$	8,852
IPC	30300	27161733	INSTALL ENTERPRISE SQL SERVER OUSTER - DATA DMZ	$	7,776
IPC	30300	27109700	ADIC UPGRADE	$	7,632
IPC	30300	27136629	CPU UPGRADE	$	7,548
IPC	30300	27152708	ACES & OASIS UPGRADE	$	6,701
IPC	30300	27085913	PHOENIX HARDWARE PURCHASES AND UPGRADES	$	6,676
IPC	30300	27196951	N2O SOURCE CODE MANAGEMENT FOR NATURAL	$	6,646
IPC	30300	27161713	E-TALK LICENSE & INSTALL FOR SUPPORT CENTER	$	6,523
IPC	30300	27268805	SIEM - SECURITY INFORMATION EVENT MANAGEMENT	$	6,389
IPC	30300	27261283	AUD OH LOGIC PROJECT-CAPITAL CHARGES	$	5,988
IPC	30300	27059964	PEOPLESOFT TREASURY IMPLEMENTATION	$	5,877
IPC	30300	27247955	BENTLEY SOFTWARE MICROSTATION	$	5,677
IPC	30300	27210917	COMMVAULT	$	5,674
IPC	30300	27198125	GIS SOFTWARE FOR GIS APPLICATIONS GROUP	$	5,500
IPC	30300	27059712	REDUNDANT SERVERS AND SOFTWARE	$	5,299
IPC	30300	27203729	OPERATIONAL DATA STORE	$	5,000
IPC	30300	27136629	CPU UPGRADE	$	4,878
IPC	30300	27261283	AUD OH LOGIC PROJECT-CAPITAL CHARGES	$	4,297
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	4,089
IPC	30300	27210172	MAPLEX FOR ARCGIS CONCURRENT USE LICENSES	$	3,981
IPC	30300	27189035	CC855 (2005) - AERIAL IMAGE ARCHIVE (A&SLC - CAPITAL)	$	2,855
IPC	30300	27189397	PURCHASE SOFTWARE: COMPOSER, AUTODESK, SUPPORT SOFTWARE	$	2,350
IPC	30300	27198125	GIS SOFTWARE FOR GIS APPLICATIONS GROUP	$	2,219
IPC	30300	27189397	PURCHASE SOFTWARE: COMPOSER, AUTODESK, SUPPORT SOFTWARE	$	1,880
IPC	30300	27189035	CC855 (2005) - AERIAL IMAGE ARCHIVE (A&SLC - CAPITAL)	$	1,845
IPC	30300	27189317	UPGRADE WEBMETHODS	$	1,488
IPC	30300	27136629	CPU UPGRADE	$	1,214
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	1,015
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	964
IPC	30300	27085528	PHOENIX PROJECT: AM/FM/OMS	$	824
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	809
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	715
IPC	30300	27085838	PHOENIX PROJECT: AM/FM AND OMS HARDWARE UPGRADES	$	546
IPC	30300	27268805	SIEM - SECURITY INFORMATION EVENT MANAGEMENT	$	533
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	509
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	484
IPC	30300	27189397	PURCHASE SOFTWARE: COMPOSER, AUTODESK, SUPPORT SOFTWARE	$	470
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	406
IPC	30300	27161737	ANTI-SPAM PROJECT	$	388
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	359
IPC	30300	27188701	MOBILE GIS PROJECT - 2005 COSTS	$	331
IPC	30300	27188701	MOBILE GIS PROJECT - 2005 COSTS	$	331
IPC	30300	27188701	MOBILE GIS PROJECT - 2005 COSTS	$	298

Account 303

2008

Unit	Category	Project	Title	Cost	
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	92
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	87
IPC	30300	27085528	PHOENIX PROJECT: AM/FM/OMS	$	76
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	73
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	65
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	28
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	27
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	26
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	21
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	19
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	14
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	3
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	1
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	(557)
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	(1,894)
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	(10,527)
IPC	30300	27266722	REMOTE DEVICE SECURITY & MANAGEMENT	$	(20,977)
IPC	30300	27141430	VALMY 26920 CEMS DATA GATHERING SOFTWARE	$	(38,349)
IPC	30300	27099181	CES OMS PROJECT	$	(95,607)
IPC	30300	27059705	MAINFRAME UPGRADE	$	(198,273)
IPC	30300	27123740	HYDRO OPTIMIZATION MODEL	$	(485,985)
IPC	30300	27025529	CIS PROJECT TEAM LABOR	$	(7,414,384)
			Total	$	33,064,583