GIVENS PURSLEY LLP

LAW OFFICES
601 W. Bannock Street
PO Box 2720, Boise, Idaho 83701
TELEPHONE: 208 388-1200
FACSIMILE: 208 388-1300
WEBSITE: www.givenspursley.com

Gary G. Allen
Peter G. Barton
Christopher J. Beeson
Clint R. Bolinder
Erik J. Bolinder
William C. Cole
Michael C. Creamer
Amber N. Dina
Kristin Bjorkman Dunn
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December 6, 2007

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IDAHO PUBLIC
UTILITIES COMMISSION

Via Hand Delivery

Jean Jewell
Idaho Public Utilities Commission
472 W. Washington
P.O. Box 83720
Boise, ID 83720-0074

Re: In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service to Electric Customers in the State of Idaho
Case Number: IPC-E-07-08
Our File: 4489-29

Dear Jean:

Enclosed for filing please find an original and eight (8) copies of Dennis Peseau's Testimony in the above entitled matter. One copy has been designated as the reporter's copy, and a disk containing the testimony in ASCII format is also enclosed.

Thank you for your assistance in this matter.

Sincerely,

Conley Ward

Conley Ward

CEW/tma
cc: Service List (w/enclosures)
S:\CLIENTS\4489\29\CEW to Jean Jewell re Direct Testimony of D Peseau.DOC

Conley E. Ward [ISB No. 1683]
GIVENS PURSLEY LLP
601 W. Bannock Street
P.O. Box 2720
Boise, ID 83701-2720
Telephone No. (208) 388-1200
Fax No. (208) 388-1300
cew@givenspursley.com

Attorneys for Micron Technology, Inc.
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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE TO ELECTRIC CUSTOMERS IN THE STATE OF IDAHO	Case No. IPC-E-07-08

DIRECT TESTIMONY

OF

DENNIS E. PESEAU

ON BEHALF OF

MICRON TECHNOLOGY, INC.

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1 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

2 A. My name is Dennis E. Peseau. My business address is Suite 250, 1500 Liberty
3 Street, S.E., Salem, Oregon 97302.

4 Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

5 A. I am the President of Utility Resources, Inc. ("URI"). URI has consulted on a
6 number of economic, financial and engineering matters for various private and
7 public entities for more than twenty years.

8 Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK
9 EXPERIENCE.

10 A. My resume is attached as Exhibit No. 501.

11 Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE IDAHO PUBLIC
12 UTILITIES COMMISSION?

13 A. Yes, on numerous occasions for more than 20 years.

14 Q. FOR WHOM ARE YOU APPEARING IN THIS CASE?

15 A. I am appearing on behalf of Micron Technology, Inc ("Micron").

16 Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

17 A. Micron has asked me to review Idaho Power Company's application and make
18 appropriate recommendations to the Commission.

19 Q. PLEASE SUMMARIZE THE RECOMMENDATIONS YOU WILL BE
20 MAKING IN THIS TESTIMONY.

21 A. My testimony is divided into three sections. I will first explain why I believe the
22 Commission should reject Idaho Power's use of a forecasted test year. In the
23 second section of my testimony I will identify some specific adjustments to Idaho

Power's test year and revenue requirement. Finally, I will explain why Idaho Power's cost of service studies are badly flawed, and offer more reasonable cost of service alternatives.

Idaho Power's Forecasted Test Year

Q. PLEASE EXPLAIN WHAT A TEST YEAR IS AND THE ROLE IT PLAYS IN PUBLIC UTILITY RATEMAKING?

A. Every public service commission in the country uses the "test year" concept as the foundation for determining a regulated utility's revenue requirement and rates. The traditional form of a test year has been succinctly described by the Iowa Utilities Board as follows:

> A rate proceeding before the Board begins with historical data. This is adjusted for known and measurable changes in costs not associated with a different level of revenue and revenues not associated with a different level of cost that will occur within twelve months of the date of filing by the utility. Typically, an historical test year is the latest calendar year; however, a test year can be any prior 12-month period of audited information. In a rate proceeding, the utility files actual data for the period and proposes adjustments to revenues, expenses, assets, liabilities, and capital issuances. These changes are known as "pro forma adjustments. . ." Once the Board decides which adjustments are allowed and the resulting revenue requirement, the utility files new rates that remain in effect until a new rate case is brought. The goal in setting rates is to take the data from the historical test year and make adjustments to the historical data that more closely reflect the expected costs and revenues going forward.

Iowa Utilities Board, *Review of Utility Ratemaking Procedures, Report to the General Assembly* (January 2004), P. 6 (hereafter "Iowa Report").

1 Q YOU CHARACTERIZED THE ABOVE QUOTE FROM THE IOWA BOARD
2 AS A DESCRIPTION OF A "TRADITIONAL" TEST YEAR. ARE OTHER
3 TYPES OF TEST YEARS USED FOR UTILITY RATEMAKING?
4 A. Yes. According to the Iowa Report, approximately 30 states use the traditional
5 test year described above. Iowa Report, P. 8. Other states allow some form of
6 forecasted results into the test year, although those that do often start the forecast
7 process with historical data, and many impose other restrictions on the use of this
8 data. See Iowa Report, P. 8-9. Another recent study of test year practices by the
9 Nevada Public Utilities Commission provides further details on a state-by-state
10 basis. *See Report to the 74th Session of the Nevada Legislature* (May 10, 2006).
11 Because both the Iowa and Nevada reports contain a detailed discussion of issues
12 present in this case, I have attached the relevant portions of both to my testimony
13 as Exhibit Nos. 502 and 503, respectively.
14 Q. WHERE DOES THE IDAHO COMMISSION FIT IN THIS PICTURE?
15 A. The Idaho Commission normally uses the traditional test year. But in at least one
16 recent case, the Commission authorized the use of a "hybrid" test year, using
17 approximately 6 months of actual test year data and 6 months of forecasted or
18 budgeted data, provided the projections can be tested and verified before the close
19 of the case.
20 Q. HOW DOES IDAHO POWER'S PROPOSAL IN THIS CASE COMPARE TO
21 THE IDAHO COMMISSION'S NORMAL TEST YEAR METHODOLOGIES?
22 A. Idaho Power's proposal is a radical departure from anything remotely resembling
23 this Commission's normal test year practices. First, it has completely discarded

1 the use of historical data in favor of a fully forecasted 2007 test year,
2 supplemented by a further forecast for 2008. Furthermore, it has annualized many
3 of the forecasted 2007 changes and, in addition, it has reached into the 2008
4 forecast for a number of adjustments that are alleged to be known and measurable.
5 Q. WHAT DO YOU MEAN WHEN YOU SAY IDAHO POWER "DISCARDED"
6 THE HISTORICAL DATA?
7 A. I mean that, for most accounts, Idaho Power does not include the historical data
8 even as a starting point for its forecasts.
9 Q. SO HOW WOULD YOU CHARACTERIZE IDAHO POWER'S PROPOSED
10 TEST YEAR?
11 A. Idaho Power characterizes its proposal as a "full forecast test year 2007."
12 Testimony of Greg Said, P. 32, L. 23. But it really isn't a test year at all, as most
13 professionals in this business understand that term.
14 Q. WHY DO YOU SAY THAT?
15 A. To pick just one example, a test year, whether historical or projected, normally
16 contains a 13 month array of most rate base items. However, in this case Idaho
17 Power simply calculated a single average rate base number. *See* Testimony of
18 Lori Smith, P. 6, L. 15-22.
19 In addition, and of far greater importance, Idaho Power's revenues and
20 costs don't match. In Mr. Said's testimony, Idaho Power's claimed jurisdictional
21 revenue for the 2007 test year is $681,765,526. But as Mr. Said acknowledges, if
22 Idaho Power's proposed rates go into effect on January 1, 2008, those rates would

1 produce annual revenues of $695,423,270, roughly $14,000,000 more than its
2 claimed revenue requirement. Testimony of Greg Said, P. 34, L. 7-19.
3 Q. DOES THAT MEAN IDAHO POWER WOULD BE OVEREARNING FROM
4 THE FIRST DAY ITS RATES WENT INTO EFFECT?
5 A. If you assume average costs apply to the entire 2007 year, as Idaho Power did in
6 the case of its rate base, and further assume that no change on January 1, 2008
7 could possibly be great enough to raise annual costs by $14,000,000 in a single
8 day, the answer has to be "Yes."
9 But we need not make any assumptions whatever to determine that Idaho
10 Power's proposed test year violates one of the most important principles of
11 ratemaking, that test year cost and revenues must match. Again I quote the Iowa
12 Board:
13 The fundamental principle in determining rates is the matching
14 principle. Unless there is a matching of costs and revenues, the
15 test year is not a proper one for fixing just and reasonable rates.
16 The inclusion of costs without matching revenues may produce
17 excessive rates. The inclusion of revenues without matching costs
18 may deny the utility reasonable rates. The relationship between
19 costs and revenues for the test period used, whether historical or
20 projected, and the validity of that relationship, constitutes one of
21 the most vital steps in the determination of just and reasonable
22 rates.
23
24 Exhibit No. 502, P. 6 (emphasis added). Idaho Power's testimony contains not a
25 word of justification for this clear mismatch, presumably because it is simply
26 indefensible.
27 Q. HOW DOES THE COMPANY ATTEMPT TO JUSTIFY ITS DEPARTURE
28 FROM PAST TEST YEAR PRACTICES?

A. The Company's basic argument for the use of a forecasted test year is that "regulatory lag" will otherwise produce an inevitable revenue shortfall for Idaho Power. The essence of this argument is summarized by the following quote from the Company's CEO, Mr. Keen:

> It is not fair nor reasonable to determine a utility's revenue requirement based on historical data in a period when prices are increasing or the utility's embedded costs are far below the utility's incremental costs. . . As a result, it is highly unlikely that the Company will earn the return authorized by the Commission.

Testimony of Lamont Keen, P. 10, L. 6-22.

Q. DO YOU FIND THIS ARGUMENT FOR A FORECASTED TEST YEAR PERSUASIVE?

A. No, I don't. In the first place, nothing can justify the violation of the fundamental test year matching principle. If the Commission were to accept Idaho Power's proposal in this regard, it would be an unprecedented departure from fundamental regulatory principles that would very likely produce excessive rates from the outset.

Second, even if Idaho Power's forecasted test year were properly constructed, the implicit assertion that it is necessary because regulatory lag inevitably produces a revenue shortfall is demonstrably untrue.

Finally, concerns about regulatory lag are not new—utilities have been making similar arguments throughout my career in this business. But the Idaho Commission has nevertheless consistently refused to allow the use of a fully projected test year, particularly one based largely on budgeted numbers, primarily because forecasting introduces a host of intractable problems. These problems

1 fall under three general headings: (1) forecasts of this type are inherently
2 inaccurate and unreliable, (2) they are difficult if not impossible to verify, and (3)
3 their use in ratemaking creates a perverse set of incentives and temptations for the
4 utility and a structural bias in the ratemaking process.
5 Q. WHY DO YOU DISAGREE WITH IDAHO POWER'S "IMPLICIT
6 ASSERTION" ABOUT THE EFFECT OF REGULATORY LAG?
7 A. Idaho Power is arguing that a differential between embedded and incremental
8 costs, coupled with system growth and general inflation, will invariably produce a
9 revenue shortfall as a result of regulatory lag. The fundamental flaw in this
10 argument is that it cherry picks the data by focusing only on factors that tend to
11 increase revenue requirements. Idaho Power's argument would be correct if it
12 was preceded by the caveat "all other things being equal." But all other things are
13 never equal or static for a complex economic entity like Idaho Power.
14 While it is true that system load growth and general inflation tend to
15 increase costs, other prevailing trends decrease them. These countervailing
16 factors include such items as labor productivity gains, efficiency improvements,
17 and greater economies of scale. Other major cost inputs, the most notable of
18 which are interest rates and natural gas prices, move in unpredictable ways, and
19 they can either increase or decrease costs significantly. In short, regulatory lag is
20 like financial leverage—it can work both ways. Whether it helps or hurts a utility,
21 or has no effect, depends on the circumstances.
22 To his credit, Mr. Gale is the only Idaho Power witness to acknowledge
23 this fact. As Mr. Gale points out, "The impact of regulatory lag is dependent on

1 the situation—if costs are not going up faster than rates, then the utility is not
2 harmed and may even be helped by lag." But Mr. Gale then goes on to allege that
3 "Idaho Power is not in that situation and will not likely be for the foreseeable
4 future." Testimony of John R. Gale, P. 11, L. 19-24.
5 Q. DO YOU DISAGREE WITH MR. GALE'S VIEWS ABOUT THE
6 "FORSEEABLE FUTURE?"
7 A. I am not in a position to either agree or disagree because the simple fact is that, as
8 I will demonstrate in detail later in my testimony, neither he nor I can possibly
9 make a confident prediction about the effect of regulatory lag in the future. But
10 before I turn to that subject it is important to point out that the historical record
11 shows that there have been long periods of time in recent years when regulatory
12 lag did not produce a revenue shortfall for Idaho Power, notwithstanding the
13 presence of continuing system growth, general inflation, and an
14 embedded/incremental cost differential.
15 Q. PLEASE DESCRIBE THE HISTORICAL EVIDENCE YOU JUST
16 REFERENCED.
17 A. If we look back over the last 15 years, we see that nearly a full decade passed
18 without a rate case prior to Idaho Power's 2003 filing. Avista and Pacificorp
19 experienced a similarly long hiatus between rate cases during roughly the same
20 time frame. In Pacificorp's case, this respite can be partially attributed to agreed
21 upon merger and acquisition related rate freezes. But, to the best of my
22 knowledge, neither Avista nor Idaho Power were under similar constraints.

1 Q. WHAT CONCLUSIONS DO YOU DRAW FROM THIS TEN YEAR
2 SUSPENSION IN RATE CASES?
3 A. Investor owned utilities are for-profit institutions, and neither Idaho Power nor
4 Avista has shown any reluctance to engage in frequent rate cases when they
5 believed they had a revenue shortfall, either before or after the 1994-2003 decade.
6 Therefore, I conclude that these companies generally believed they were earning a
7 fair return during this approximately 10 year time period, notwithstanding the
8 very long lag after the initial rate determination.
9 Q. WAS THAT BECAUSE THERE WAS NO INFLATION DURING THAT TIME
10 FRAME?
11 A. No. My Exhibit No. 504 is a three page Value Line summary of the history of
12 selected economic benchmarks from 1920 through 2005. As you can see, the
13 Consumer Price Index showed general inflation during the 90s holding relatively
14 steady at an annual rate of a little less that 3%, very near the current CPI rate
15 today.
16 Q. MAYBE IDAHO POWER WASN'T EXPERIENCING ANY GROWTH THEN,
17 OR PERHAPS ITS INCREMENTAL COSTS WERE NOT IN EXCESS OF
18 EMBEDDED COSTS.
19 A. The answer to both implicit questions is "No" and "No." My Exhibit No. 505 is
20 the current Value Line report for IDACORP. According to Value Line, Idaho
21 Power's book value per share steadily increased throughout the 1990s, as did
22 capital spending per share in most years. This indicates that Idaho Power was
23 growing at a fairly steady pace during that period.

1 In addition, just based on my experience in this industry and in following
2 Idaho Power over that time frame, I can say with complete confidence that its
3 incremental capital costs also exceeded embedded costs then, just as they do now.
4 Q. SO WHY DIDN'T THE LONG REGULATORY LAG BETWEEN THE
5 SETTING OF RATES IN THE EARLY 90S AND THE GENERAL RATE
6 CASE FILED IN 2003 PRODUCE REVENUE DEFICIENCIES?
7 A. I couldn't say without undertaking a complex and lengthy study. I suspect the
8 persistent decline in capital costs and fuel prices from the highs of the early
9 1980s, together with productivity and efficiency improvements, the adoption of
10 annual power cost adjustments, and other factors, all played a part. But my point
11 is that history shows that for roughly two-thirds of the last 15 years, regulatory lag
12 was benign from the utility's point of view. It also shows that neither system
13 growth, general inflation, nor a differential between embedded and incremental
14 costs means that regulatory lag will inevitably produce a revenue requirement
15 shortfall. Idaho Power's presumed cause and effect relationship between these
16 items simply doesn't exist.
17 Q. WOULD YOU PLEASE EXPLAIN THE DIFFICULTY IN MAKING
18 ACCURATE FINANCIAL FORECASTS?
19 A. First of all, it is important to carefully explain what is really at issue here. There
20 is undeniably a place for forecasts in ratemaking. Idaho Power's annual power
21 cost adjustment (PCA) provides a perfect example. In the PCA proceedings,
22 power supply costs are forecasted using a carefully constructed and agreed upon

1 model, based on projected stream flows provided by an independent third party.
2 At the end of the year, these predictions are, in effect, "trued up" to actual results.
3 Similarly, many pro forma changes that are annualized during the test
4 year, and "known and measurable" changes that occur after the close of the test
5 year, are often a form of forecasting. Even if they don't occur exactly as forecast,
6 there is nevertheless a very high degree of certainty about the probability of the
7 forecasted event and its likely magnitude. The classic example is a nearly
8 finished generating unit that is scheduled to come on line after the close of the test
9 year.
10 These "forecasts" stand on a very different footing than the forecasts
11 Idaho Power is using in this case, where it is attempting to project future costs and
12 revenues in myriad accounts. By definition, these across-the-board forecasts are
13 either "unknown" or "unmeasurable" or both. Viewed in this light, the audacity
14 of Idaho Power's contention should give everyone involved in this case pause.
15 After all, it takes considerable hubris to even contend that one can predict the
16 unknown future.
17 Q. ARE THERE ANY STUDIES ON THE RELIABILITY OF FORECASTED
18 TEST YEARS LIKE THE ONE IDAHO POWER IS PROPOSING?
19 A. To the best of my knowledge, there are no extant studies that attempt to determine
20 the accuracy of utilities' forecasted test years, which is rather strange since
21 someone who purports to divine the future would normally be asked to prove he
22 could do so. But there is a wealth of information about the accuracy of financial
23 forecasts in an analogous situation—the case of Wall Street analysts who produce

1 earnings forecasts for the companies they cover. The endeavor here is very
2 similar to the kind of piece by piece forecasted test year Idaho Power is presenting
3 in this case and we have many, many studies testing the accuracy of their
4 forecasts.
5 Q. BEFORE WE TURN TO THE RESULTS OF THOSE STUDIES, PLEASE
6 EXPLAIN WHY YOU REGARD ANALYSTS' FORECASTS AS
7 ANALAGOUS TO A FORECASTED TEST YEAR.
8 A. The task of a Wall Street analyst is very like that of a utility attempting to
9 forecast its future test year. On the one hand, all interested parties have access to
10 the historical record contained in quarterly and annual reports, plus certain known
11 and measurable changes that must be reported by law, which are roughly
12 analogous to the traditional test year information. The Wall Street analysts
13 attempt to add value to this objective, factual record by forecasting companies'
14 earnings in the future. As in the case of the forecasted test year, the premise of
15 this industry is that the analysts' forecasts will provide a more accurate depiction
16 of the future than could be determined from the factual record alone.
17 Q. HOW MUCH EFFORT GOES INTO THE PREPARATION OF ANALYSTS'
18 FORECASTS?
19 A. An enormous effort, even by the lavish standards of Wall Street. The analysts
20 who produce these earnings forecasts are some of the brightest and most highly
21 compensated individuals in the financial world. If it were possible to produce
22 accurate, reliable financial forecasts in this manner, surely this experienced

1 industry staffed by extravagantly paid professionals with blue chip MBAs and
2 PHDs could do so.[1]
3 Q. ENOUGH BACKGROUND, HOW DO THE ANALYSTS FORECASTS
4 COMPARE TO ACTUAL RESULTS?
5 A. Even to a skeptic like myself, the results are shocking. I first became acquainted
6 with this data via David Dreman's book, *Contrarian Investment Strategies: The*
7 *Next Generation* (Simon & Schuster, 1998) (hereafter "Dreman"). Dreman starts
8 by reviewing the largest, and longest running, data set available at the time of
9 publication, a review of 94,251 consensus analyst forecasts from 1973-1996. The
10 study was limited to companies with at least 4 covering analysts, was for the
11 coming quarter only, and the analysts could revise their projections up to two
12 weeks before the close of the quarter. The results?
13 "The average error for the sample was a whopping 44% annually;" with a
14 median margin of error of 42%. Dreman, P. 91. I should stress that this doesn't
15 mean that 44% of the forecasts erred; it means that the average forecast missed
16 the mark by 44%! Dreman further found there was only a few percentage points
17 difference between the rate of under-estimates and over-estimates, and not much
18 variation of results based on the industry sector of the covered company.
19 Thinking that perhaps this result could not possibly apply if confined to
20 just the largest and most stable companies, Dreman conducted another study
21 eliminating the smaller companies from the 1000 company sample, which would
22 perhaps be more comparable to a utility forecast. This improved the analysts'

[1] Well informed followers of this industry would rightly point out that analysts famously tend to be overly optimistic in their buy/sell recommendations for a variety of reasons. But this is a separate issue from their earnings projections, which they have every incentive to make as accurate as possible.

1 odds, but the average margin of error was still an astonishing 23% for these bluest
2 of blue chips.
3 Q. AS YOU POINTED OUT, THESE RESULTS APPLIED TO QUARTER-
4 AHEAD FORECASTS. IN THIS CASE WE ARE DEALING WITH IDAHO
5 POWER'S LATE 2006 FORECASTS FOR 2007 AND 2008. WHAT DOES
6 DREMAN'S REVIEW HAVE TO SAY ABOUT LONGER FORECASTS?
7 A. Not unexpectedly, the longer forecasts were even less accurate. The odds of
8 forecasts for each of the following 4 quarters falling within 10% (which
9 coincidentally is the amount of Idaho Power's requested increase in this case) of
10 actuals were 21 to 1 against, and for predicting all 4 quarters within a plus or
11 minus variance of 5% they were an astounding 130 to 1! As the time horizon is
12 lengthened or the tolerable variation range is narrowed, the odds of a forecasting
13 error increase exponentially. Dreman, P. 112.
14 Q. MAYBE COMPANY MANAGEMENT OR INSIDERS LIKE THOSE WHO
15 PREPARED IDAHO POWER'S FORECASTS CAN DO BETTER.
16 A. A reasonable question, but there is no help for Idaho Power's case there. In the
17 late 60's and 70's, researchers tested this proposition in 11 studies, and Dreman
18 summarizes their results at page 99. This was a particularly good period for all
19 forecasters, in that the average error was low by historical standards. The mean
20 analysts' error was 16.6% and the mean management error was only a slightly
21 better 14.5%. But in only one study and that was for a single year, did
22 management beat the parameters of this rate increase request, albeit by the
23 smallest of margins, with an average error of 10.1%.

Q. HOW DO YOU EXPLAIN THE MAGNITUDE OF THESE FORECASTING ERRORS?

A. As it turns out, psychologists have studied the forecasting error problem in considerable detail, and concluded that there is a consistent, and vast, difference in forecasting results, depending on whether the forecaster takes what is known as the "inside view' of forecasting, or the "outside view." Inside view forecasters

> treat each problem as unique, paying no attention to history. This method is the one overwhelmingly used to forecast earnings estimates and stock prices. The analyst or the stock forecaster focuses entirely on the stock and related aspects such as growth rates, market share, product development, the general market, the economic outlook, and a host of other variables.
>
> The "outside view," on the other hand, ignores the multitude of factors that go into making the individual forecast, and. . . is essentially statistical and comparative, and does not attempt to read the future in any detail.

Dreman, P. 110.

Studies comparing the relative success rates of the inside view and the outside view repeatedly find the outside view much the superior of the two. Dreman quotes one of the leading researchers in the field (Daniel Kahneman), summarizing the findings as follows:

> It should be obvious that when both methods are applied with judgment and skill the outside view is much more likely to yield a realistic estimate. In general, the future of long and complex undertakings is simply not foreseeable in detail.

Page 110-111. As Dreman elsewhere notes, "These findings apply to many other fields." Page 109.[2]

[2] The Dreman text can't be reproduced in full as an exhibit because of copyright restrictions. But Micron has arranged to have my copy of the book placed in the Idaho Power discovery room.

1 Q. HOW DOES ALL THIS RELATE TO IDAHO POWER'S FORECASTED
2 TEST YEAR?
3 A. Traditional test years take the "outside view" of forecasting. They rest on
4 objective historical data, modified only for pro forma adjustments and future
5 changes that are "known and measurable." While they recognize future changes
6 that are known with virtual certainty, speculations about the future play no role in
7 the process.
8 Idaho Power's forecasted test year, on the other hand, is a classic example
9 of the "inside view." It attempts to create from whole cloth forecasts for all the
10 myriad accounts involved in a complex rate case. These budgets and forecasts
11 were mostly prepared in late 2006 for a test year that is roughly "centered" in
12 early 2008. That being so, if Idaho Power's forecast of rate or return is no more
13 accurate than Wall Street analysts' earnings estimates, the odds are at least 21 to 1
14 against this forecast coming within 10% of actual results for all four quarters of
15 2008.
16 Q. YOUR SECOND GENERAL CRITICISM OF FORECAST TEST YEARS IS
17 THAT THEY ARE NOT ONLY INACCURATE AND UNRELIABLE BUT
18 ALSO UNVERIFIABLE. WHAT DID YOU MEAN BY THAT COMMENT?
19 A. I think the point is rather obvious. Actual recorded results can be audited and
20 verified. Forecasts cannot. I don't mean that forecasts don't have a paper trail. I
21 am relatively certain Idaho Power can produce a document of some sort to
22 support each of its line by line forecasts. But I have already explained why these
23 forecast documents are likely to be unreliable.

1 Actual recorded results stand on a much different footing. They can be
2 audited and verified. At least within the limitations of GAAP and regulatory
3 accounting rules, they are a matter of fact. That is why SEC regulations require
4 companies to issue annual reports based on audited results rather than budgets.
5 Sarbanes-Oxley now requires the top levels of management to verify, under
6 penalty of law, that those reports are basically true and correct. Conversely, when
7 management issues what are called in the trade "forward looking statements,"
8 they typically come with a legal disclaimer to the effect that they are not
9 statements of fact and are not to be relied upon for investment decisions.
10 Q. BUT AS YOU ACKNOWLEDGED EARLIER IN YOUR TESTIMONY,
11 THERE ARE SOME STATES THAT ALLOW FULLY FORECASTED TEST
12 YEARS. HOW DO THEY DEAL WITH THE VERIFICATION ISSUE?
13 A. The roster of states that allow fully forecasted test years is almost exclusively
14 confined to populous states with very large public service commission staffs, e.g.,
15 California, New York, Pennsylvania, Illinois, Michigan, Minnesota, and
16 Wisconsin. Wisconsin, for instance, has 185 staff members, and almost all of its
17 auditors are CPAs. Exhibit No. 502, P. 8-9. In addition, Wisconsin requires each
18 utility to file a rate case every year, thus providing an opportunity for a continual
19 true up and refinement of forecasts. *Id.*
20 With these kind of resources it might be possible to make forecasted test
21 years more or less verifiable, <u>if</u> they include historical data and <u>if</u> there are strict
22 rules and guidelines in place governing the manner in which the forecasts are
23 prepared. But even if the Idaho Commission had the necessary staff to conduct

1 this verification exercise, I am personally very skeptical that it would produce
2 ratemaking benefits that would remotely justify the costs.
3 Q. YOUR FINAL OBJECTION TO THE USE OF A PROJECTED TEST YEAR IS
4 THAT IT WILL BIAS RESULTS IN FAVOR OF THE UTILITY. THIS IS
5 SOMETHING OF AN INFLAMMATORY STATEMENT. WHAT IS YOUR
6 EXPLANATION?
7 A. First of all, let me make it clear what we are talking about. We are not talking
8 about Enron style fraud. What I am talking about here is a systemic bias that has
9 little or nothing to do with fraudulent activities.
10 Q. WHAT DO YOU MEAN BY THE TERM "SYSTEMIC" BIAS?
11 A. This comes in two forms. First, it is obvious that Idaho Power's board and
12 management are primarily responsible to the Company's shareholders. If rates
13 and ultimately rates of return are dependent on forecasts, then there is every
14 incentive for management to overestimate costs and underestimate revenues.
15 Then it becomes a game of "catch me if you can" for the PUC staff. This point
16 seems so obvious to me that it doesn't require further elaboration, but those who
17 wish to see the argument fleshed out in detail can peruse Exhibit Nos. 502 and
18 503.
19 But there is also a second, more subtle type of bias that creeps into the
20 regulatory process if budgets are used for forecasts. As I pointed out earlier in my
21 testimony, forecasting of the sort Idaho Power is proposing is an enormously
22 difficult undertaking that is almost certain to produce errors. Under normal

1 circumstances, if the project is conducted objectively, we would expect those
2 errors to be symmetrical, i.e., as many underestimates as overestimates.
3 Unfortunately, the consequences for the forecaster are not symmetrical.
4 Anyone who has spent any time in or around the corporate world knows that
5 coming in over budget 50% of the time is not conducive to a long and successful
6 career. On the other hand, consistently coming in under budget will at least earn
7 hearty congratulations and maybe a promotion or raise. This means that every
8 department head submitting a budget/forecast has a personal incentive, quite apart
9 from that of his or her employer, to estimate costs on the high side.
10 Q. PLEASE SUMMARIZE YOUR TESTIMONY REGARDING IDAHO
11 POWER'S FORECASTED TEST YEAR.
12 A. First, Idaho Power's proposal isn't really a test year at all because it mismatches
13 revenues and costs. Second, I believe that the use of a forecasted test year like the
14 one proposed here is almost certain to produce results that are less accurate than
15 the current practice, that are inherently biased in favor of the utility, and
16 essentially unverifiable. I fail to see how any of this is in the public interest.
17 Q. HAVE YOU PREPARED A TRADITIONAL HISTORIC TEST YEAR AS A
18 SUBSTITUTE FOR IDAHO POWER'S FORECAST?
19 A. The sad fact is there is simply no evidence in the record that would enable me to
20 do so. Furthermore, even if the record contained the necessary evidence,
21 untangling and reversing all of Idaho Power's intertwined forecasts would be a
22 Herculean effort that is beyond the capabilities of any intervenor unless it is
23 prepared to spend enormous sums.

1 Q. SO WHERE DOES THAT LEAVE US?

2 A. I truly believe that Idaho Power's forecasted test year should not, and as a
3 practical matter cannot, be used to determine rates that are required by law to be
4 "just and reasonable." Therefore, unless Staff can construct a more reasonable
5 and reliable test year based on its audit of the Company, I believe the case should
6 be dismissed.

7 Revenue Requirement Adjustments

8 Q. DO YOU HAVE ANY OTHER COMMENTS ON IDAHO POWER'S
9 PROPOSED REVENUE REQUIREMENT EIN ADDITION TO YOU
10 CRITIQUE OF THE FORECASTED TEST YEAR?

11 A. Yes. There are several significant changes that should be made to Idaho Power's
12 forecasted revenue requirement. In Idaho Power's forecasted test year, all
13 changes from the 2006 year end rate base and all associated expenses such as
14 depreciation and property taxes are forecasted based on projected plant additions
15 and retirements. Idaho Power follows these forecasted increases in plant in
16 service by further identifying major plant additions beyond the test period, then
17 assuming these major plant additions will be in service for the entire forecast, and
18 finally calculating annualizing adjustments to rate base and expense to
19 accommodate the longer assumed period in service.

20 While such annualizing adjustments may be appropriate for an historic test
21 period, in my opinion they are totally inappropriate for a future test period. When
22 applied to an historic test period they may reduce regulatory lag; however, when
23 applied to a future test period they will probably introduce just the opposite,

1 regulatory lead. In any historical test period, additions to rate base will be made
2 throughout the period. Actual earned return on rate base will depend on income
3 and actual in service dates for rate base additions. Setting rates based on the
4 assumption that some assets will be in rate base for the whole period, when in fact
5 they are not, will likely produce actual rates of return in excess of the return rates
6 were designed to recover.

7 Q. DO YOU HAVE ANY OTHER ISSUES WITH RESPECT TO THE
8 ANNUALIZING ADJUSTMENTS FOR MAJOR PLANT ADDITIONS?

9 A. Yes. Even assuming that such annualizing adjustments are appropriate for a
10 future test period, Idaho Power has overstated the magnitude of the adjustments.
11 Idaho Power uses a simple average of year end 2006 and projected year end 2007
12 rate base for the 2007 test period. This implicitly assumes that all plant additions
13 occur at mid year and the assets are in service for ½ the test year. An annualizing
14 adjustment would then accommodate the first six months of the year that the
15 assets were not in service.

16 But Idaho Power's annualizing adjustment for major plant additions then
17 reverts to a 13 month average rate base to make the annualizing adjustments.
18 Since the major plant additions have a weighted average in service date of late
19 September, Idaho Power's annualizing adjustment accommodates an additional
20 9.6 months of service for these additions. In effect, Idaho Power adds more to
21 rate base than the total capital expenditures on these assets, by assuming they are
22 in service for 15 months of a 12 months test period. This is clearly wrong.

1 Q. HOW SHOULD THIS BE CORRECTED?

2 A. I recommend that, at a minimum, the Commission should disallow the total $44.9
3 million in annualizing adjustments and the associated adjustments for
4 accumulated depreciation, depreciation, property taxes and insurance. The net
5 effect would be to reduce Idaho Power's total system rate base by $43.7 million
6 and expenses by approximately $2.5 million. The effect of this disallowance
7 would be to reduce Idaho Power's requested rate increase by approximately $8.0
8 million.

9 Q. WHAT CONCERNS DO YOU HAVE WITH RESPECT TO IDAHO POWER'S
10 FILING CONCERNING SALARY INCREASE ADJUSTMENTS?

11 A. I take issue with the Company's request to raise its revenue requirement by
12 $3,020,719 to account for a 2008 salary structure adjustment (Exhibit 18, page 2).
13 Again, this request is outside even its forecasted test year. The request puts other
14 parties in the impossible position of having to review all other 2008 operating
15 expense increases and decreases to determine whether or not rates even need to be
16 adjusted (given load and revenue growth) to collect such expenses. I recommend
17 that the entire $3 million request be denied.

18 Q. DO YOU AGREE WITH IDAHO POWER'S REQUEST TO INCREASE ITS
19 REVENUE REQUIREMENT TO NORMALIZE IERCO REVENUES?

20 A. No. This request appears on page 18 of the testimony of Ms. Lori Smith. The
21 request is made because IERCO (Idaho Energy Resources) is expecting and
22 forecasting normalized revenues to IERCO will be reduced in 2007 and 2008.
23 While 2007 has substantially elapsed at the time this testimony is being written,

1 parties are obviously still unable to assess this prediction in light of other
2 unspecified changes to 2007 and 2008 revenues and costs. For these reasons, I
3 recommend that the Commission deny the Company's proposed $2.2 million
4 revenue adjustment to account for IERCO.
5 Q. PLEASE STATE YOUR RESPONSE TO THE COMPANY'S REQUEST FOR
6 INCREASED EXPENSES TO COVER ITS INCENTIVE PLAN?
7 A. Company Exhibit No. 18, page 2 indicates that Idaho Power is requesting 4%
8 over its normal payroll, or $6,215,289, for incentives that comprise three
9 components: customer satisfaction, budgetary goals and network reliability. I
10 oppose two-thirds of this proposed adjustment on the basis that the latter two
11 components, budgetary goals and network reliability, produce benefits that fall
12 primarily to shareholders. Once rates are set in this case, all budgetary reductions
13 will increase shareholder profitability. Customer rates will remain the same.
14 Also, after rates are established in this case, all subsequent gains in network
15 reliability will lower power supply expenses and increase shareholder returns,
16 with no corresponding decrease in rates. I therefore recommend that these
17 incentive expenses be borne by shareholders. Two-thirds of the request or
18 $4,145,598 should be disallowed in this case.
19 Rate Structure – Cost of Service Issues
20 Q. PLEASE EXPLAIN WHY YOU REGARD IDAHO POWER'S COST OF
21 SERVICE STUDIES AS "BADLY FLAWED."
22 A. Before I do so I would like to first offer some background information that I hope
23 will help to frame the cost of service issues in this case. Idaho Power's cost of

1 service witness, Mr. Timothy Tatum, correctly describes the cost of service
2 process from a technical point of view, but he doesn't explain what's really at
3 issue, or provide the context of such studies within the regulatory framework.
4 Consequently, I suspect that this technical discussion is virtually unintelligible to
5 members of the general public. So I propose to start with some basic principles of
6 cost of service, and then gradually hone in on the more difficult concepts, as well
7 as the issues in this case.
8 Q. WOULD YOU PLEASE START BY EXPLAINING THE PURPOSE OF A
9 COST OF SERVICE STUDY?
10 A. All rate cases really consist of two distinct undertakings, and in fact the Idaho
11 Commission has occasionally divided rate cases into two separate hearings on
12 these issues. First, the Commission determines a utility's overall revenue
13 requirement, i.e., the size of the pie. The next task is to determine what
14 proportion of that total revenue requirement should be recovered from each rate
15 group or "customer class," i.e., how the pie should be apportioned among the rate
16 groups.
17 These rate groups or customer classes exist because it is a universally
18 accepted principle of ratemaking that, "It is more expensive to serve some
19 customers than others." Charles F. Phillips, Jr., *The Regulation of Public Utilities*
20 (Public Utilities Reports, 1993), P. 435 (hereafter "Phillips"). Therefore,
21 customers are grouped into rate classes with roughly similar cost characteristics,
22 e.g., a residential class, an industrial class, etc. Very large customers—like
23 Micron, Simplot, and DOE on the Idaho Power system—are typically each treated

1 as a unique customer class unto themselves, known in the trade as "contract
2 customers."
3 The purpose of a cost of service study is to allocate an appropriate portion
4 of the utility's total revenue requirement to each of these customer classes based
5 primarily on cost causation principles.
6 Q. WHY IS COST CAUSATION IMPORTANT?
7 A. Economists don't always agree on much, but on this issue there is rare unanimity
8 in the profession. While the Commission can, and sometimes should, consider
9 factors other than costs, there are two primary reasons for focusing on cost
10 causation in creating the rate structure.
11 The first is "fairness," which basically refers to the idea that customers
12 should pay their own costs and not someone else's. Furthermore, those who
13 cause a higher revenue requirement should pay an appropriate share of the costs
14 they cause, and vice versa.
15 The second reason, and probably the most important to economists, is the
16 "efficiency" rationale. This is the idea that prices should promote the most
17 efficient possible use of the utility system. Thus, those who use the system
18 primarily when costs are high should pay a rate that reflects those
19 disproportionately high costs so they will be encouraged to conserve or find
20 alternative means of meeting their needs. And there is an important, but out of
21 favor, counterpoint here as well. Those who consume in low cost periods should
22 receive an appropriate price signal to do so when consumption is an economic
23 plus for all.

Q. IS THERE A SIMILAR AGREEMENT AMONG ECONOMISTS ON THE PROPER METHOD OF DETERMINING COST CAUSATION?

A. Only to a degree. Some cost of service issues are relatively non-controversial, but others are routinely contentious, perhaps none more so than the proper method of allocating peak and off peak costs.

Q. WHY IS THIS ISSUE SO CONTENTIOUS?

A Very few practitioners in this field would argue with the general view expressed in a basic regulatory text:

> Customers who use the service during the peak demand period are more expensive to serve than off-peak users. A basic factor in determining the size of a utility plant is the peak demand. Therefore, it costs less to serve those customers who use the service without burdening the business as a whole by adding to the peak demand period. Further, if off-peak usage is increased, the utility may obtain a better utilization of its plant throughout the day, thereby resulting in a larger total output over which fixed costs may be spread.

Phillips, P. 436.

But while there is little argument about the general principle that on-peak usage should cost more than off-peak, there are repeated disputes about the manner of calculating the cost difference between peak and off-peak usage. This issue is so significant that cost of service methodologies are in fact named for the manner in which they allocate costs between high load factor and low load factor customers.

Q. WHAT DO YOU MEAN BY THE TERM "LOAD FACTOR?"

A. For the utility itself, "load factor" refers to the relationship between the peak load on the system and the average load. When applied to customers, the term "load

factor" refers to a customer's consumption related to a utility's peak sales. A customer with a high load factor is one who consumes in a nearly steady state, both daily and annually. A low load factor customer consumes electricity unevenly, generally in disproportionate amounts either on the daily or monthly peaks, or both. In general, a greater allocation of costs to peak periods tends to benefit high load factor customer classes, while a lesser allocation benefits low load factor customer classes.

It is important to point out a common misconception here. If peak costs are appropriately assigned, high load factor customers don't escape these peak costs. After all, if a customer is consuming a steady load 24/7, then it is on line during the peak, and should get an appropriate share of those costs. The benefit to high load factor customers of a properly designed cost of service study is that they are also online when costs are low, and therefore should get an appropriate "credit" in their average rate.

Q. IS THERE A SINGLE CORRECT METHOD FOR ALLOCATING PEAK COSTS BETWEEN HIGH AND LOW LOAD FACTOR CUSTOMERS?

A. No, because a large component of peak costs consist of what are known in economics as "joint and common" costs. Most of these joint and common costs consist of the capital cost of generating plants and transmission facilities that are used to some degree by all customers throughout the year, both on and off peak. In the lingo of the cost of service profession, these facilities provide either "capacity" or "demand" (peak)" and "energy" (off and on peak) services.

1 Economic theory alone cannot determine the correct method of assigning these
2 costs to customer classes.
3 Having said that, however, it is worth noting that many engineers and
4 economists would argue for assigning the bulk of the capital costs of generation
5 and transmission plant to customer classes in proportion to their use on the
6 highest single peak of the year, on the grounds that these facilities are sized to
7 meet this peak demand. There are, however, some practical problems with this
8 approach, and most commissions don't weight single peak costs as heavily as
9 many members of these professions would.
10 Q. DOES THE IDAHO COMMISSION HAVE AN ESTABLISHED METHOD OF
11 RESOLVING THESE ISSUES IN IDAHO POWER RATE CASES?
12 A. Yes. For roughly 25 years now, the Idaho Commission has used what is known
13 as the "Weighted 12 Coincident Peak" ("W12CP") cost of service method to
14 allocate costs on the Idaho Power Company system. Mr. Tatum's testimony
15 contains a good description of the implementation of this complex process, but a
16 simpler explanation of the purpose of this cost of service choice would probably
17 be more helpful to understanding the issues in this case.
18 With regard to the always controversial issue of allocating generating
19 plant costs, the Idaho methodology first classifies a percentage of generation plant
20 to "energy" based on the system load factor, which in this case is approximately
21 58%. The remaining 42% is classified as a demand cost. Because these demand
22 costs are caused by the peak load months, Idaho Power weights the summer

months by the relatively higher demand costs in these months but then, as I explain below, erroneously disregards those weights in designing rates.

It is important to point out that the language employed by cost of service studies can lead to real confusion here. When we talk about the classification of generating costs to "energy," we are not talking about actual "energy" costs, primarily fuel and related items, that vary with the amount of energy consumed and are directly assigned to the various customer classes based on their actual, recorded usage. Instead, we are talking about the amount, or percentage, of the fixed capital costs of generating plants that don't vary with usage, but are treated as if they did for cost of service purposes.

Q. WHEN DID THE IDAHO COMMISSION FIRST ADOPT THE W12CP METHOD?

A. The Idaho Commission first adopted the weighted W12CP methodology in 1982 in Case No. U-1006-185. In reviewing the cost of service studies before it, the Commission found:

> We find: For the limited purposes for which we use cost of service data in allocation of the revenue requirement among the customer classes, Idaho Power's weighted 12 coincident peak study may be reasonably used to represent costs. Although there could be improvements in both W12CP studies presented in this case, the similarities in the results obtained from both of them, which were the best cost-of-service studies presented in this case, show that we may use the Company's W12CP for the next step of the rate allocation process.

Order No. 17856, P. 13.

In 1987, in Case No. U-1006-265A, the Commission again revisited cost of service issue in what was probably the most intensive litigation of the issue in

the history of Idaho rate cases. The following quote from the Commission's final order provides something of the atmosphere of the proceedings:

> Idaho Power prepared five cost-of-service studies. A Weighted 12 Coincident Peak (IPCo W12CP) study, a 12 Coincident Peak (IPCo 12CP) Study, an Average and Excess Demand (IPCo AED) study, a Positive Excess Demand (IPCo PED) study, and a Modified Positive Excess Demand (IPCo MPED) study. In addition, the City of Boise presented two variations of the Company's W12CP called Boise I and Boise II. FMC presented a modified weighted 12 coincident peak (FMC MW12CP) study and a 7 coincident peak (FMC 7CP) study. The Staff presented an alternative weighted 12CP (Staff W12CP) study and an unweighted 12CP (Staff U12CP). The results of those studies are shown on Table 6 on the following page. For the reasons stated in the following pages of this Order, we will use the Company's W12CP as a starting point in our allocation of revenues among the customer classes.

Order No. 21365. Since the 1982 case, the Idaho Commission has relied solely or primarily on the W12CP method in every Idaho Power rate case.

Q. WHY DID THE COMMISSION CHOOSE THE W12CP METHOD IN 1982?

A. In the spectrum of possible cost of service methodologies, the W12CP method assigns less cost to peak periods than most. This made some sense at the time it was first adopted. In the early 1980s, Idaho Power was still predominantly a hydroelectric utility. It had two base load coal plants, Jim Bridger and Valmy, but no peaking plants analogous to today's gas fired peakers.

Instead it met peak loads with its hydroelectric plants, which could adjust load almost instantly to meet demand, plus power purchases and exchanges. These hydroelectric plants were (1) relatively cheap on a dollar per kilowatt of

capacity basis, (2) more heavily depreciated than more recent plants, and (3) had variable energy costs close to zero.

The result was that actual peak costs did not greatly exceed, and were sometimes below, base costs! In this context, the Commission's choice of a cost of service methodology that gave relatively little weight to peak costs made considerable sense.

Q. HAS THE IDAHO COMMISSION CONTINUED TO USE THE WEIGHTED 12 CP METHOD IN RECENT CASES?

A. Yes. In the 1994 rate case, the Commission again endorsed use of the weighted 12 CP methodology, with very little controversy.

> In this case, the Commission was presented with only one cost-of-service study, a study based on the W12CP method prepared by the Company, and the IPCo study as modified by Staff. The testimony in this case almost universally support the use of a W12CP methodology, and thus we find it appropriate and reasonable to once again utilize the W12CP methodology to establish revenue requirement for the customer classes.

Order No. 25880, P. 25.

Finally, in the 2003 rate case the Commission again adopted the W12CP methodology, although it included without comment a variation on this method in the Order's Appendix:

> As we have in most rate cases, the Commission finds the W12CP cost of service study is the appropriate starting point to allocate costs to customer classes. . .[W]e find that the W12CP cost of service results reflect "a reasonable approximation of class responsibility" and thus provide a measure of relative revenue responsibility among the customer classes.

Order No. 29505, P. 46-47 (citations omitted).

In my testimony in this case, I intend to follow this Commission endorsed method, which is the W12CP, not an unweighted or average set of allocators. However, it is important to point out that, for reasons which will become apparent later in my testimony, I believe that after this case is concluded, the Commission should reexamine the appropriateness of this methodology in the light of changes on the Idaho Power system.

Q. DOES IDAHO POWER ALSO FOLLOW THE COMMISSION APPROVED COST OF SERVICE METHOD IN THIS CASE?

A. Mr. Tatum, Idaho Power's cost of service witness, never quite says so explicitly, but his testimony clearly implies that his "Base Case Study" follows the traditional Commission approved methodology. It does not, as I shall demonstrate later. But he also prepared three other studies that are clearly a radical departure from prior practice.

Q. YOU EARLIER STATED THAT ALL FOUR OF THESE COST OF SERVICE STUDIES ARE "BADLY FLAWED." WOULD YOU PLEASE EXPLAIN WHAT YOU MEANT BY THAT STATEMENT?

A. This is one of those instances where the view from a distance provides a reality check on specific results. When I first read Mr. Tatum's testimony and looked at his summary exhibit, I knew immediately there was something terribly wrong with the results.

Q. HOW COULD YOU REACH THIS CONCLUSION BEFORE EXAMINING THE DETAILS OF THE STUDIES?

1 A. Because Idaho Power's results in this case are wildly divergent from the results
2 the W12CP studies have consistently produced over the last 25 years. During that
3 entire period, the cost of service studies in Idaho Power rate cases produced a
4 repetitive pattern. These studies found that the highest production costs were
5 incurred at times of system peak loads. Generally, such studies concluded that the
6 residential class' rates have been about right; that is, the residential rates have
7 been set to approximately collect the class's cost of service. Small general service
8 rates were generally slightly low. Large general service and industrial rates,
9 including Micron, were typically found to be somewhat, to considerably, too high,
10 while the irrigation class rates have historically been far below the cost of serving
11 this class.
12 Even more telling, however, is the fact that all of Mr. Tatum's four cost of
13 service studies would have us conclude that it is the Company's nonsummer
14 months' that are causing the adverse peak load growth on Idaho Power's system.
15 This is the implied conclusion because the cost allocators actually used in these
16 studies allocate most of the capacity and energy costs to periods other than the
17 summer.
18 Q. HAVE RECENT RATE CASES CONFIRMED THE GENERAL
19 RELATIONSHIPS YOU JUST DESCRIBED?
20 A. Yes. The 2005 Idaho Power rate case was settled without a specific Commission
21 decision on cost of service. But in the last litigated case in 2003, the Commission
22 found the cost of service study results to be entirely consistent with the

longstanding historical results, as is apparent from the ultimate decision on rate design:

> By this Order, we authorize Idaho Power to increase its Idaho revenues by $25,327,533, or approximately 5.2%. As a result, electric base rates for specific classes will be increased on average by the following percentages: Residential 5.98%; Small General Service 5.97%; Large General Service 1.98%; Industrial 2.41%; and Irrigation 13.95%."

Order No. 29505, P. 1. I note that residential and small general service classes received an increase slightly greater than the overall average of 5.2%, industrial customers received a rate increase less than half of the overall average, and irrigation received an increase of almost 2.5 times the overall average. The three contract customers, Micron, Simplot, and DOE, received increases at or below those of the other industrial customers. A properly conducted cost of service study today would reach conclusions consistent with the 2003 results, as I will show below.

Q. HOW DO THE 2003 COST OF SERVICE RESULTS COMPARE TO IDAHO POWER'S COST OF SERVICE RESULTS IN THIS CASE?

A. With no explanation or justification for a striking change in results, Idaho Power's cost of service studies suggest that the longstanding relationship between customer class's respective costs of service has been suddenly and dramatically reversed. For example, instead of industrial classes and contract customers receiving one-half of the average rate increase as before, Idaho Power in this case contends that Schedule 19 and the special contract customers should receive a <u>rate increase</u> equivalent to roughly 200% to 350% of the average increase if they are to be brought to full cost of service. These results, when compared with the

decades old traditional relationship of industrials' rates to cost of service are simply not credible.

Q. IS THERE A WAY TO CLARIFY THIS DRAMATIC SHIFT IN RESULTS IN A CONCISE FASHION?

A. Yes. The following table summarizes the shift in a simple, straightforward manner. Rather than attempt to explain relative percentage increases in rates from the various studies, I instead present each study's "Return Index." Column 2 shows the Return Index for each of the customer classes as determined by the Commission in the 2003 rate case. Column 3 shows the Idaho Power cost of service results in this case.

A Return Index of "1" indicates that a rate class is paying rates that closely approximate its cost of service. A Return Index below (above) "1" indicates that current rates of a respective customer class are below (above) cost of service. The relative distance from the unity value of 1 indicates the percentage variation of rates from cost of service, i.e, a value of 1.1 means that rates are 10% above cost of service.

RETURN INDEXES 2003 COMMISSION vs. 2007 COMPANY PROPOSAL		
Class	Commission 2003 Index	Idaho Power 2007 Base Case
Residential (1)	1.11	1.32
General Services (7)	1.11	.82
General Services (9)	1.25	1.04
Industrial (19)	1.21	.82
Irrigation (24)	0.17	.30
Micron	1.38	.58
DOE	1.18	.64
Simplot	1.48	.66
Sources: Pages 1 and 2, Appendix 2, Order No. 29505 Company Exhibit No. 43, pages 1 and 2 – IPC-E-07-08		

1 Q. WHAT DOES THIS TABLE SHOW?

2 A. Only four years ago, the Commission determined the Return Indexes under the
3 "Commission 2003 Index." As evidenced by the Return Indexes that exceed
4 unity, all major customer rate classes except the irrigation class were paying more
5 than their respective cost of service. The .17 contribution of the irrigation class
6 was remarkably small. The higher load factor rate classes (general service,
7 industrial, and the contract customers) were paying rates much higher than their
8 respective costs of service.

9 The changes Idaho Power made to its costs of service study in this case
10 inexplicably turn these results upside down. Note in the right most column in the
11 table that the proposed study purports to show that now the high load factor
12 classes, particularly the contract customers, have inexplicably fallen well below
13 unity. This, of course, is the reason Idaho Power is arguing for above average rate
14 increases for its high load factor customers in this case.

15 Q. WHAT CONCLUSIONS DO YOU DRAW FROM THIS RETURN INDEX
16 ANALYSIS?

17 A. First, a cost of service shift of this magnitude in a mere four years is
18 unprecedented in my decades of experience with cost of service studies. If the
19 underlying cost of service study is properly conducted, these results could only be
20 justified by a recent and enormous change in either customer usage patterns or the
21 nature of Idaho Power's production and delivery system.

22 Q. IS THERE IN FACT ANY EVIDENCE OF SUCH A CHANGE?

A. Other than the general increase in fuel costs, most of the changes that have occurred in the past four years run the other way, i.e., they would suggest a relative cost shift from high load factor customers (industrials and contract customers) to low load factor customers (primarily residential and irrigation customers), rather than the other way around as Idaho Power's results suggest.

Q. WOULD YOU PLEASE DESCRIBE THE SYSTEM CHANGES YOU JUST REFERRED TO?

A. First, with respect to customer usage, it is quite clear that the high load factor customers are not growing appreciably. There appears to have been some modest growth in industrial load, but the contract customers' consumption is essentially unchanged from four years ago. Consequently, a change in these customers' usage cannot account for huge swing in cost of service results.

Q. CAN IDAHO POWER'S COST OF SERVICE RESULTS BE EXPLAINED BY CHANGES TO IDAHO POWER'S SYSTEM?

A. No. By far the most important change to Idaho Power's system in recent years is the Company's worsening summer peak demands, relative to demand at other times of the year. Mr. Tatum succinctly summarizes the situation in his testimony:

> In recent years, the Company's system peak has grown at a much faster pace than average demand. With a comparison of Figures 4-1 and 4-2 on pages 39 and 40 of the 2006 IRP, which I have included in my workpapers, it is clear that this trend is expected to continue into the future."

Testimony of Timothy Tatum, P. 13, L. 8-12.

In effect, Idaho Power's load factor is deteriorating and is expected to continue doing so for the foreseeable future. Once again, this circumstance suggests that the low load factor customers' Return Index should be deteriorating, rather than radically improving, as Idaho Power suggests.

Q. PERHAPS MR. TATUM IS MISTAKEN IN HIS ANALYSIS OF THE DETERIORATING LOAD FACTOR. WHAT IS THE CHANCE OF THAT?

A. None whatsoever. First of all, since the 1994 rate case, Idaho Power's load factor has steadily dropped from 68% to 58% today, and this decline, as I will explain later, appears to be accelerating.

Second, Idaho Power's engineering department has essentially confirmed his analysis, and mine, with actions that speak louder than words. Over the last few years, Idaho Power has added single cycle natural gas combustion turbines to its resource mix without adding any significant intermediate (combined cycle gas plants) or base load plants (e.g., coal plants).

Single cycle gas plants are, in effect, a utility engineer's response to disproportionate peak load growth. Of all the possible generating plants, they have the lowest capital costs. But they also have, by far, the highest fuel cost because they are relatively inefficient. So, in general, they are only added when the engineers are trying to cope with extraordinary growth in peak loads or something of a "needle peak."

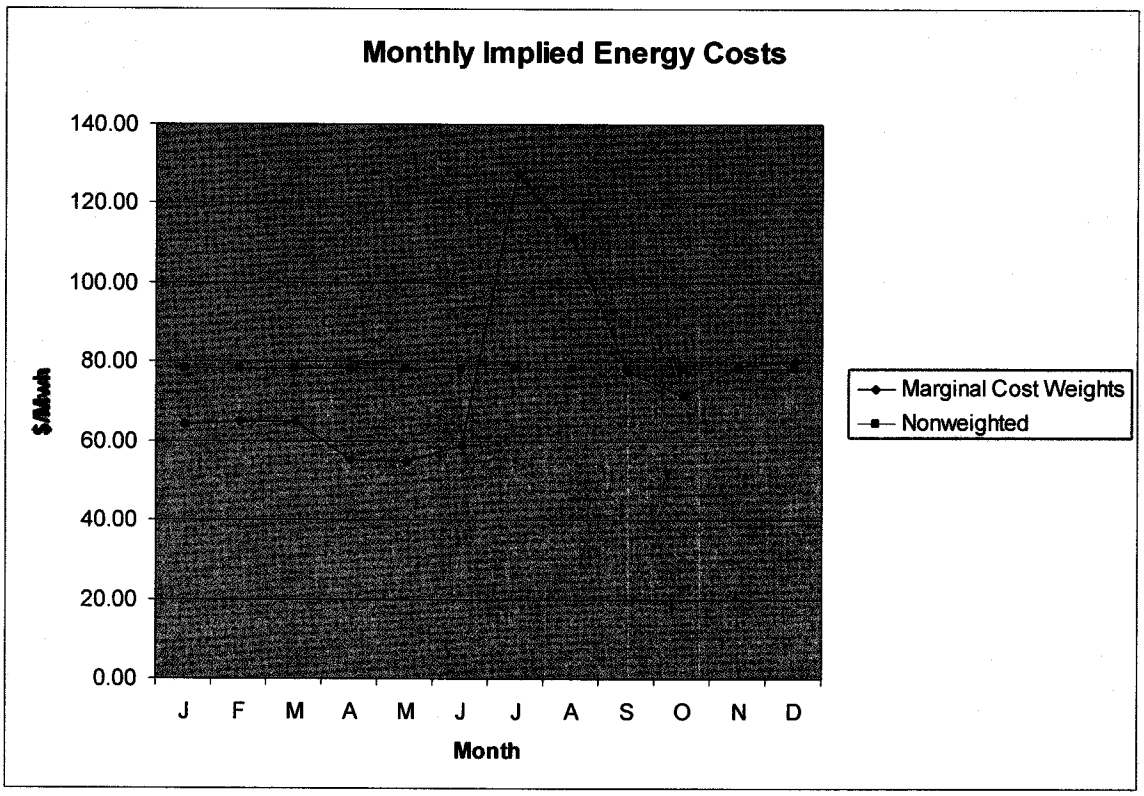
Q. YOU HAVE NOW EXPLAINED WHY YOU KNEW IMMEDIATELY THAT IDAHO POWER'S COST OF SERVICE STUDIES COULDN'T POSSIBLY BE RIGHT. WHERE DID THESE STUDIES GO WRONG?

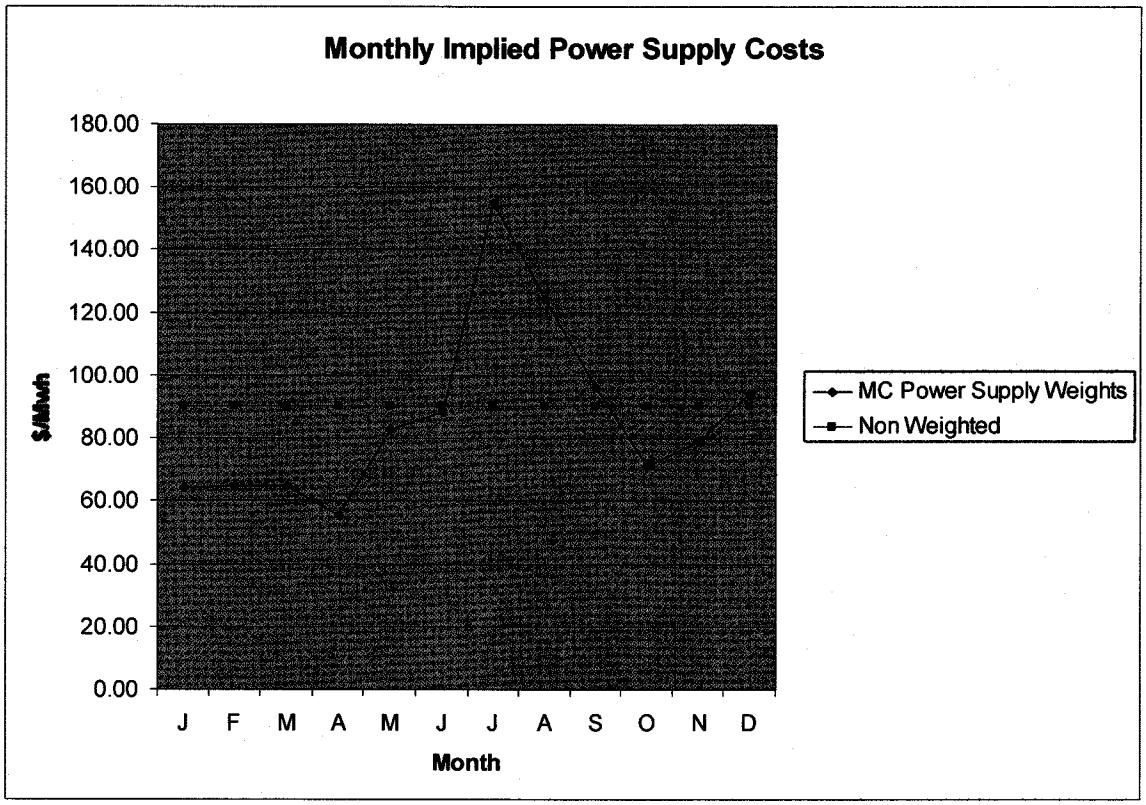
1 A. First, and foremost, Idaho Power's attempt at constructing a future test year, then
2 incorporating its unsubstantiated forecast of future costs into its cost of service
3 model, has been done in a manner that completely inverts its prior rate design
4 results dating back to at least the early 1980s. As I just explained, the huge
5 changes to the cost burden and recommended rates to customer classes are not
6 due to any attributable or identifiable changes to any customer class' usage
7 characteristics, or to generation, transmission and distribution makeup, but largely
8 due to the use, or more correctly, the misuse of a forecasted test year.
9 Q. HOW DOES IDAHO POWER'S FORECASTED TEST YEAR UNDERMINE
10 ITS COST OF SERVICE RESULTS?
11 A. In two ways. The first is relatively simple. In what is presumably an effort to
12 maximize its revenue requirement, Idaho Power forecasts energy prices that are
13 both very high and disproportionate to other cost increases. This has the effect of
14 increasing the relative cost burden on high load factor customers.
15 I have previously critiqued the forecasted test year in general, and I will
16 not repeat that discussion here. Suffice it to say, the use of forecasts in a cost of
17 service study is subject to all the defects of a forecasted test year. Moreover, it is
18 completely unnecessary because, even if the Commission decided to accept Idaho
19 Power's regulatory lag argument and use the forecasts for revenue requirement
20 purposes, it would still be preferable to use verifiable, historic results to apportion
21 the revenue requirement between customer classes. Unfortunately, Idaho Power
22 hasn't provided the data that would make that possible.

1 Q. YOU SAID THERE ARE TWO WAYS THE USE OF A FORCASTED TEST
2 YEAR SKEWS COST OF SERVICE RESULTS. WHAT IS THE SECOND?
3 A. The second problem is a little more complicated and more difficult to explain.
4 The problem arises from the fact that Idaho Power's forecasted cost of service
5 studies tend to ignore the tremendous monthly and seasonal variation in capacity
6 and energy costs that actually occur on Idaho Power's system. Instead, Idaho
7 Power's cost of service studies assume, for the most part, that these costs are
8 constant throughout the year. This results in a severe misallocation of high peak
9 demand costs by "averaging" these costs into low cost seasons. It is also at odds
10 with everything we know about the historical operation of Idaho Power's system,
11 or for that matter, any other utility system I am familiar with.
12 Q. HAS THE COMMISSION EVER SANCTIONED THIS TYPE OF COST
13 AVERAGING IN THE PAST?
14 A. No. All recent cases have used the costs Idaho Power's engineers determined for
15 the Company's power supply planning model for cost allocations. Company
16 witness Greg Said again uses this model to calculate the monthly power costs that
17 form the basis for the Company's requested increase in revenue requirement, but
18 this time the Company ignores these results in three of its four cost of service
19 studies, and minimizes the importance of these system costs in a fourth study.
20 Remarkably, this valuable monthly power cost variation information is
21 largely ignored within the Company's proposed cost of service study without a
22 word of explanation for the departure from prior practices. This is indefensible,

given the magnitude of the cost of service shifts involved, as demonstrated in the following graphs.

Graph No. 1 compares Idaho Power's power supply model's variable or marginal energy costs with the average variable or marginal costs contained in its unweighted allocators. Graph No. 2 compares the combined marginal monthly energy and capacity costs for the model and the annual average marginal monthly energy and capacity costs.





These graphs show that, by Idaho Power's own power supply model estimates, monthly energy costs range from a low of $55/mwh in May to a high of $128 in July, a range of over 232%. Similarly, total monthly power supply costs vary from $55/mwh in April to a high of $155 in the month of July. This seasonal cost information is crucial in a cost of service study in order to ensure that rates in effect reflect costs allocated to these seasons.

But in its proposed cost of service studies, Idaho Power chooses to assume that monthly power supply costs do not vary month-to-month, as is shown in each of the above graphs as a horizontal line, when it averages this with a truly weighted allocator. The Company's study is misleading because it claims to use the historical method of computing the W12CP, when in fact it does not. Instead, the Company uses a modified allocator that averages out seasonal cost

1 differences. Choosing entirely new inputs for the model is not a legitimate "Base
2 Case" scenario.
3 Q. ARE THERE ANY OTHER DEFECTS IN THE IDAHO POWER COST OF
4 SERVICE STUDIES?
5 A. Yes. As Mr. Tatum explains in his testimony at pages 25-27, he weighted annual
6 capacity costs based on monthly peak hour deficits identified in the Company's
7 2006 Integrated Resource Plan ("IRP"). The months with projected deficits
8 include, reasonably enough, the months of June-August and, less reasonably,
9 December. But the other two identified deficit months are May and September.
10 Assigning a disproportionate share of capacity costs to these months is
11 nonsensical on its face.
12 Anyone at all familiarity with Idaho Power's system will immediately
13 recognize that May and September are both off-peak months. In fact, as the
14 graphs I produced above show, April and May are typically the lowest cost
15 months of the year on the Idaho Power system by a substantial margin. Yet Idaho
16 Power's cost of service studies treat May as a high cost, peak month. This
17 misidentification of peak months is a very serious and consequential error.
18 Q. HOW DOES THIS ERROR OCCUR?
19 A. The problem is that IRP identified load deficiencies and off system purchases are
20 not reasonable or appropriate substitutes for actual system peaks. Deficiencies
21 can occur for a variety of reasons, not the least of which is scheduled plant
22 maintenance. For most Northwest utilities, spring is the optimal time to take
23 plants down for maintenance because power demands are low and hydropower

generation is relatively high, making replacement power relatively (and sometimes very) cheap. The fall months are, of course, the next best time to take plants down. Somewhat similar considerations apply to power exchanges and a host of other factors.

Q. HOW DOES THIS WEIGHTING ERROR AFFECT THE COST OF SERVICE RESULTS?

A. It completely corrupts the results, and once again the result is an erroneous transfer of costs from on-peak to off-peak.

Q. PLEASE SUMMARIZE THE CONSEQUENCES OF IDAHO POWER'S COST OF SERVICE ERRORS THAT DILUTE ITS ACTUAL SEASONAL COST DIFFERENCES.

A. There are two chief consequences. First, high load factor customers are allocated a larger share of costs than they actually cause the power system to incur. Conversely, low load factor customers are charged too little. This is not only unfair; it is also terribly inefficient because it creates cross subsidies between rate classes.

A corollary to this consequence is the undesirable effect that the misallocation has on the valuable conservation and load management programs in place and being developed here in Idaho for everyone's benefit. By proposing to set rates that undercharge summer peak costs and overcharge during low cost seasons, the proposed rates act in direct contradiction to responsible efforts to conserve energy when it is most costly. In the longer-term, costs of service will

be higher for all customers because peak loads will grow faster that average energy consumption.

Q. DO THE IDAHO POWER SYSTEM PLANNERS RECOGNIZE THIS RISK?

A. Yes. The perils of promoting on-peak load growth are discussed on page 1 of Mr. Greg Said's workpapers, from which I quote an excerpt:

> *Effect of Load Growth.* Peak load in the Idaho Power Company service territory is growing <u>twice as fast</u> as the annual energy requirement. Going forward, then, this growth will lead to higher ramp rate requirements in the summertime and less available hydro capacity for managing the system. The cost of reserves would then likely increase, which could increase the integration cost for wind.

Page 1 (emphasis added).

Q. DO THESE "COST AVERAGING" ERRORS OCCUR IN ALL FOUR IDAHO POWER STUDIES?

A. Yes, and even without the errors I have previously described, and some others I am about to explain, it renders all four studies completely unusable, in my opinion.

Q. ARE THERE ADDITIONAL ERRORS IN THE STUDIES OTHER THAN THE "BASE CASE" IDAHO POWER STUDY?

A. Yes. As to the unweighted 12CP method, I propose to give that short shrift. It is very much beyond the norms for cost of service studies, and I suspect it is only inserted into Idaho Power's list of studies in an attempt to make the other studies look more reasonable by comparison. My prepared testimony is already too long to deal with a methodology the Commission has consistently rejected since 1987, but I will be more than happy to answer questions about it.

1 Q. PLEASE EXPLAIN WHAT IS WRONG WITH THE OTHER TWO IDAHO
2 POWER METHODOLOGIES.
3 A. Let's begin with Mr. Tatum's "preferred" methodology, which he labels
4 3CP/Energy. Mr. Tatum's reasoning in support of this method goes something
5 like this—Idaho Power's natural gas peakers were built to serve peak load in the
6 three summer months, so I will classify their entire fixed costs to demand. Ergo,
7 the remaining base load and intermediate plants weren't built to serve peak load,
8 and therefore all their remaining fixed costs, in addition to the 58% already
9 classified to energy on the basis of load factor, should also be classified as energy
10 costs.
11 Stated this way, the error here becomes readily apparent. The fact that
12 Idaho Power's gas peakers were built primarily to serve peak capacity demands
13 does not in any way disprove the basic premise of all cost of service studies,
14 which is that <u>all generating plants are built to meet both capacity and energy</u>
15 <u>needs</u>. In other words, you can't leap from the obvious truism that peakers are
16 primarily for peak load, to the supposition that other plants don't serve peaks too.
17 Q. WOULD YOU PLEASE EXPLAIN THIS IN A LITTLE MORE DETAIL?
18 A. Let's deal with the theory first. Earlier in my testimony I explained there is an
19 extensive body of academic literature demonstrating that the discipline of
20 economics cannot determine a single correct theoretical allocation of joint and
21 common costs, such as the fixed capital costs of generating plants. These plants
22 all serve both demand and energy needs, but a proper allocation of costs between

these classifications can only be determined by factors or considerations other than economic theory.

But what economic theory can tell us, is that there are two, and only two, allocations that are certainly wrong. These are to classify 100% of any plant's fixed costs to either demand or energy, which of course is what Mr. Tatum has done in his testimony by classifying the overwhelming majority of Idaho Power's generating resources 100% to energy.

Q. BUT THIS IS JUST THEORY. DOES IT HOLD UP IN THE REAL WORLD?

A. Yes. Let me illustrate with a simple hypothetical. Let us suppose a very hot July afternoon, which is typical for Idaho Power's system peak. Let us further suppose that Idaho Power's system generating resources are exactly sufficient to meet this two or three hour peak. For the purposes of this simple hypothetical, I will ignore a number of real world complications, such as the possibility of cheaper purchased power, the need for spinning reserves, etc.

In this case, with all of Idaho Power's generating resources running at full capacity, which plants are supplying capacity and which are supplying energy? The answer is they are all supplying both. In a plant engineer's terms, Idaho Power is using the entirety of its "resource stack" to meet this peak demand. This is no less true of the base load coal plants than it is of the gas fired peakers. And without all the plants running simultaneously on peak, the system would experience a brown out or black out even though not all the plants would necessarily be required to meet the total energy load for the entirety of that same peak day.

My simple hypothetical peak load scenario was created to demonstrate the fallacy of Idaho Power's approach. But the real world operation of a utility system is so much more complex, and the same point emerges even more clearly. In Idaho Power's case, its dispatchable resource stack generally consists of, in ascending order of variable costs, several units on the hydro system, the four units of the Jim Bridger coal plant, the Valmy coal plant's two units, and the gas fired peakers. Each plant and each unit has unique operating and cost characteristics, leading to an almost infinite number of possible operating scenarios.

By way of illustration, let us assume we are looking over the shoulders of the Idaho Power's dispatchers on a warm but not torrid June morning. The hydro system is running at medium load for the season but with some available additional capacity, Jim Bridger is running full out, one Valmy unit and the peakers are off. But the dispatcher knows these resources will be insufficient to meet the coming afternoon peak load. If the coming peak is apt to be small, and of short duration, maybe the dispatcher sacrifices a little water and meets it with hydro facilities. On the other hand if temperatures are expected to continue soaring through the next day, maybe the dispatcher fires up another Valmy unit, particularly if any excess power over peak needs can be sold to other utilities. On the other hand, if it is a Friday maybe the dispatcher brings on a peaker, knowing that loads will fall on the weekend, and it can then be shut down again and its high fuel costs terminated. I could postulate many other scenarios, but I think the point is made. All plants are used, both in theory and in fact, to provide both capacity and energy.

1 Q. HOW DO THESE ERRORS IN MR. TATUM'S PREFERRED
2 METHODOLOGY AFFECT THE CUSTOMER CLASS RATES?
3 A. They erroneously shift an enormous amount of costs from low load factor peak
4 customers to high load factor customers, over and above those costs shifted by the
5 "average cost" assumption and other errors I described earlier.
6 Q. DOES MR. TATUM'S OTHER OPTION, THE "3 CP/12 CP" METHOD SHIFT
7 COSTS IN THE SAME WAY?
8 A. The effect on high load factor customers in this case is less dramatic, but there is a
9 shift nonetheless. In Micron's case, the effect is relatively small, and if Idaho
10 Power's next peaker is a combined cycle unit with higher fixed costs than the
11 existing turbines, Idaho Power's 3 CP/12 CP method could actually benefit
12 Micron. But even though the 3 CP/12 CP proposal might benefit Micron in the
13 long run, I strongly urge its rejection.
14 Q. WHY WOULD YOU TAKE THIS POSITION?
15 A. Quite apart from the fact that the methodology cannot be squared with sound cost
16 of service logic and theory, the attempt to pick and choose plants that will be
17 assigned to demand and energy in different proportions, as Mr. Tatum does, is apt
18 to lead to complete chaos in future proceedings, as each party tries to claim a
19 disproportionate share of low cost plants for its own individual load profile.
20 The irony is that if these are the new ground rules, which Mr. Tatum's
21 testimony suggests, then Micron could fare very well indeed. Because the flip
22 side of Mr. Tatum's argument, and one that is much more defensible, is we should
23 assign only base load plants to high load factor customers like Micron, and they

1 should not be responsible for any peaking costs. That implies a huge rate
2 decrease for Micron and other high load factor customers.
3 Q. PLEASE SUMMARIZE YOUR FINDINGS REGARDING THE IDAHO
4 POWER COST OF SERVICE STUDIES.
5 A. I have not addressed the unweighted 12 CP method, other that to note it is very
6 extreme and was rejected by the Commission long ago. What Idaho Power calls
7 the "Base Case" is anything but, primarily because of the use of very high
8 forecasted energy costs and the "averaging away" of very real on peak energy
9 costs to off peak periods. The remaining two studies are so fraught with logical
10 and practical problems as to be both useless, and, like Idaho Power's mishandled
11 Base Case, potentially dangerous.
12 Q. HOW COULD A COST OF SERVICE STUDY BE "POTENTIALLY
13 DANGEROUS?"
14 A. Leaving aside the "scientific" merits of various cost of service methodologies, it
15 is very obvious that adopting any of Idaho Power's proposed cost of service
16 methodologies would allocate seasonal costs opposite to their actual seasonal
17 incurrence.
18 As I explained earlier, there was a rational basis for the Commission's
19 original decision 25 years ago to choose a cost of service methodology that
20 minimized the influence of peak costs. But this is no longer Idaho Power's
21 situation, and hasn't been for some time, as we can see in the steady decline in
22 Idaho Power's load factor from 68% in 1994 to 58% a dozen years later. All of us
23 who participate in these cases, including myself, have been too slow to recognize

1 this dramatic change. Peaking costs are now driving costs higher for everyone, to
2 the detriment of all. So we should be looking to adapt our cost of service to
3 recognize these changes, rather than vice versa. To adopt any of Idaho Power's
4 proposed methodologies would further de-emphasize peak usage and further
5 promote the costly growth in summer peak demand.

6 The disproportionate increase in peak demand usage of recent years has
7 arguably been exacerbated by a cost of service methodology that increasingly
8 underestimated summer peak costs. These underestimated summer rates, under
9 any reasonable interpretation of economic principles, partially caused additional
10 summer peak consumption, to the point that the summer peak is now growing
11 twice as fast as average consumption.

12 Under these circumstances, it is not surprising that Idaho Power's system
13 peak is growing faster than its average demand. The cost of service study choice
14 is helping drive this disparity. Now Idaho Power is proposing to shift a huge
15 amount of costs, not on peak as any rational proposal would suggest, but off peak!
16 This will certainly exacerbate the problem. This promotion of peak usage is
17 doubly troubling when customers are, at the same time, paying for conservation
18 and demand side management programs.

19 Q. AT LEAST THAT MAY BE BENEFICIAL TO IDAHO POWER IN THAT IT
20 MAKES REVENUES GROW.

21 A. Not in the least. Underpricing peak growth makes it much more likely that Mr.
22 Gale's revenue requirement shortfall forecast we discussed earlier will come true.
23 That is, regulatory lag will become a self fulfilling prophecy. The shareholders

are hurt, just as the ratepayers are hurt, by the acceleration of peak costs because those costs are less likely to be recovered by average cost based rates. The result is a revenue shortfall for shareholders and more rate cases for ratepayers.

Q. HAVE YOU CONDUCTED A COST OF SERVICE STUDY THAT ATTEMPTS TO REMOVE SOME OF THE EFFECTS OF IDAHO POWER'S FUTURE TEST YEAR ASSUMPTIONS AND SEASONAL UNWEIGHTINGS?

A. I have made an attempt to do so that I believe fairly portrays the present cost of service. But I want to stress that because the Company has not provided data on a normalized and annualized basis in this case, no party can complete a traditional cost of service study.

Q. WHAT THEN DID YOU USE FOR DATA IN PREPARING YOUR COST OF SERVICE STUDY?

A. Due to the manner in which Idaho Power constructed the future test year, historical data were available in its filing and responses to data requests, but not the corresponding normalizing, annualizing and various regulatory adjustments necessary to conduct our cost of service study.

Therefore, I was forced to use as the basis of revenues and expenses the 2007 data used in Idaho Power's study. To capture the true summer and nonsummer large capacity and energy cost differences, I calculated the summer period peak costs using monthly weighted costs. The peak summer months were established as June, July and August by calculating the probabilities that monthly peak loads (over the last recorded 10 years) were within 5% of Idaho Power's

1 annual system peak load. This roughly corresponds to the Company's pre-2003
2 capacity and energy weights that were computed using loss of load probabilities.
3 I made two other adjustments. Within the cost of service model, income
4 taxes were allocated on the basis of taxable income of each rate schedule. Lastly,
5 the cost of service model classified cogeneration and small power production
6 ("CSPP") purchases made by the Company into capacity and energy as reflected
7 by Idaho Power's system load factor.
8 Q. PLEASE EXPLAIN THE REASONS FOR THESE CHANGES.
9 A. The monthly capacity and energy weights allow the cost of service model to
10 correctly reflect the high summer peak load costs and help dampen the severe and
11 costly high rates of growth of the Company's summer peak loads.
12 Income taxes can be apportioned in either of two ways in the cost of
13 service model: on either taxable income of each rate schedule, or on allocated
14 rate base. In my opinion it is more appropriate to allocate income taxes on the
15 basis of taxable income.
16 Finally, CSPP purchases in the aggregate provide the Idaho Power system
17 with both valuable capacity and energy, and in fact their rates are based on this
18 assumed provision of capacity and energy. For cost of service purposes, it is
19 appropriate to estimate these values with the system load factor.
20 Q. PLEASE BRIEFLY SUMMARIZE THE RESULTS OF YOUR COST OF
21 SERVICE STUDY.
22 A. The full cost of service study and its results are contained in my Exhibit No. 506.
23 But, as I explained above, the convenient way to compare my study with others is

with the various customer class's return Indexes. The following table compares the results of my study with those adopted by this Commission in 2003 and the four proposed Idaho Power cost studies:

Return Indexes	Peseau / Micron	2003	Tatum Base Case	Tatum Unwt.	Tatum 3CP/12CP	Tatum 3CP/Ave
Residential (1)	1.4	1.1	1.32	1.2	1.28	1.38
Gen Service (7)	.83	1.1	.82	.81	.82	.84
Gen Service (9)	1.1	1.2	1.04	1.0	1.04	1.01
Industrial (19)	1.1	1.2	.82	.74	.81	.68
Irrigation (24)	.06	.17	.30	.77	.42	.38
Micron (SC)	.97	1.4	.58	.47	.56	.32
DOE	1.29	1.2	.64	.37	.56	.41
Simplot	1.16	1.5	.66	.54	.62	.40

Q. WHAT DOES THIS COMPARISON SHOW?

A. My cost of service study in this case, in contrast to Idaho Power's four cost of service studies, is generally much more consistent with results found to be valid by the Commission in the 2003 general rate case. Although the data in the present case is not as verifiable as it might be, general recommendations can be made with respect to the allocation of any increase in revenue requirement to customer classes.

Q. HOW DO YOU PROPOSE THAT THIS COMMISSION ALLOCATE REVENUE REQUIREMENT TO THE VARIOUS RATE CLASSES IN THE ABSENCE OF MORE PRECISE COST OF SERVICE DATA?

A. I believe that my proposed study generally apportions revenue requirement among customer classes fairly. Referring to both the "Peseau/Micron" and the "Commission 2003" columns in the table, all rate classes with the exception of the Schedule 24 irrigation class, are nearly at or above respective cost of service.

1 These rate classes should be treated consistently with each other in terms of any
2 change in rates in this case. On the other hand, both of these studies, and Idaho
3 Power's as well, conclude that the irrigation class rates are far below cost of
4 service. Given the complexity of these cost of service issues, and the
5 compounded problems caused by introducing the estimates and projections of a
6 future test year, the Commission may wish to defer technical cost of service
7 findings to another venue. In the meantime, a fair and reasonable allocation of the
8 revenue requirement would be to set all rate classes, except for the irrigation
9 class, at an equal percentage increase or decrease, depending on the
10 Commission's ordered revenue change.
11 This equal percentage change to all non-irrigation rates would be
12 determined by that level of change necessary, after increasing the irrigation
13 class's rates by something greater than the average increase. I suggest an increase
14 of twice the system average, but I recognize this is a matter in which the
15 Commission will have to exercise its judgment.
16 Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS TO MAKE IN THIS
17 CASE?
18 A. First, I want to reiterate my previous recommendation that the case be dismissed
19 if the forecasted test year cannot be corrected. Second, Idaho Power's
20 accelerating peak load growth and deteriorating load factor are sufficiently
21 alarming that I think the case for proactive Commission intervention of some sort
22 is overwhelming. Accordingly, I recommend that the Commission direct its Staff
23 to undertake an investigation of the problem and possible solutions. That

1 investigation should include the consideration of new load control and demand
2 side management solutions and a reconsideration of the W12CP cost of service
3 methodology and other rate design possibilities. After the Staff issues its report,
4 other interested parties should be given an opportunity to comment and make
5 further suggestions.
6 I want to stress, however, that any proactive response cannot be expected
7 to succeed if it has to overcome the headwinds posed by the irrational cost of
8 service shift and ratemaking policies Idaho Power is proposing in this case.
9 Furthermore, it would be grossly unfair to ask high load factor customers to both
10 subsidize peak growth via the rate structure, while simultaneously subsidizing
11 programs that attempt to curb that growth.
12 Q. DOES THIS CONCLUDE YOUR TESTIMONY?
13 A. Yes.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 6th day of December, 2007, I caused to be served a true and correct copy of the foregoing by the method indicated below, and addressed to the following:

Jean Jewell Idaho Public Utilities Commission 472 W. Washington Street P.O. Box 83720 Boise, ID 83720-0074	____ U.S. Mail _X_ Hand Delivered ____ Overnight Mail ____ Facsimile ____ E-Mail
Barton L. Kline Monica B. Moen Idaho Power Company P.O. Box 70 Boise, ID 83707 email: bkline@idahopower.com	____ U.S. Mail _X_ Hand Delivered ____ Overnight Mail ____ Facsimile ____ E-Mail
John R. Gale Vice President Regulatory Affairs Idaho Power Company P.O. Box 70 Boise, ID 83707 email: rgale@idahopower.com	____ U.S. Mail _X_ Hand Delivered ____ Overnight Mail ____ Facsimile ____ E-Mail
Peter J. Richardson Richardson & O'Leary 515 N. 27th Street Boise, ID 83702 email: peter@richardsonandoleary.com	_X_ U.S. Mail ____ Hand Delivered ____ Overnight Mail ____ Facsimile ____ E-Mail
Eric L. Olsen Racine, Olson, Nye, Budge & Bailey Chartered P.O. Box 1391 201 E. Center Pocatello, Idaho 83204-1391 email: rcb@racinelaw.net elo@racinelaw.net	_X_ U.S. Mail ____ Hand Delivered ____ Overnight Mail ____ Facsimile ____ E-Mail
Anthony Yankel 29814 Lake Road Bay Village, Ohio 44140 email: yankel@attbi.com	_X_ U.S. Mail ____ Hand Delivered ____ Overnight Mail ____ Facsimile ____ E-Mail

Dr. Don Reading 6070 Hill Road Boise, Idaho 83703 email: dreading@mindspring.com	X U.S. Mail ____ Hand Delivered ____ Overnight Mail ____ Facsimile ____ E-Mail
Lot H. Cooke United States DOE 1000 Independence Ave. SW Washington, DC 20585	X ~~Hand Delivered~~ U.S. MAil ____ Overnight Mail ____ Facsimile ____ E-Mail
Weldon Stutzman Donovan Walker Idaho Public Utilities Commission P.O. Box 83720 Boise, Idaho 83720-0074	X ~~Hand Delivered~~ U.S. MAil ____ Overnight Mail ____ Facsimile ____ E-Mail
Michael Kurtz Boehm, Kurtz & Lowry 36 E. Seventh Street, Suite 1510 Cincinnati, OH 45202	X ~~Hand Delivered~~ U.S. MAil ____ Overnight Mail ____ Facsimile ____ E-Mail
Dale Swan Exeter Associates 5565 Sterrett Place, Suite 310 Columbia, MD 21044	X ~~Hand Delivered~~ U.S. MAil ____ Overnight Mail ____ Facsimile ____ E-Mail
Dennis Peseau Utility Resources, Inc. 1500 Liberty Street, Suite 250 Salem, OR 97302	X ~~Hand Delivered~~ U.S. MAil ____ Overnight Mail ____ Facsimile ____ E-Mail

Conley Ward

Conley E. Ward

STATEMENT OF OCCUPATIONAL AND
EDUCATIONAL HISTORY AND QUALIFICATIONS
DENNIS E. PESEAU

Dr. Peseau has conducted economic and financial studies for regulated industries for the past thirty-five years. In 1972, he was employed by Southern California Edison Company as Associate Economic Analyst, and later as Economic Analyst. His responsibilities included review of financial testimony, incremental cost studies, rate design, econometric estimation of demand elasticities and various areas in the field of energy and economic growth. Also, he was asked by Edison Electrical Institute to study and evaluate several prominent energy models as part of the Ad Hoc Committee on Economic Growth and Energy Pricing.

From 1974 to 1978, Dr. Peseau was employed by the Public Utility Commissioner of Oregon as Senior Economist. There he conducted a number of economic and financial studies and prepared testimony pertaining to public utilities.

In 1978 Dr. Peseau established the Northwest office of Zinder Companies, Inc. He has since submitted testimony on economic and financial matters before state regulatory commissions in Alaska, California, Idaho, Maryland, Minnesota, Montana, Nevada, Washington, Wyoming, the District of Columbia, the Bonneville Power Administration and the Public Utilities Board of Alberta on over one hundred occasions. He has conducted marginal cost and rate design studies and prepared testimony on these matters in Alaska, California, Idaho, Maryland, Minnesota, Nevada, Oregon, Washington and in the District of Columbia. He has

also conducted cost and rate studies regarding PURPA issues in the states of Alaska, California, Idaho, Montana, Nevada, New York, Washington, and Washington, D.C.

Dr. Peseau holds the B.A., M.A. and Ph.D. degrees in economics.

He has co-authored a book in the field of industrial organization entitled, Size, Profits and Executive Compensation in the Large Corporation, which devotes a chapter to regulated industries.

Dr. Peseau has published articles in the following professional journals: Review of Economics and Statistics, Atlantic Economic Journal, Journal of Financial Management, and Journal of Regional Science. His articles have been read before the Econometric Society, the Western Economic Association, the Financial Management Association, the Regional Science Association and universities in the United Kingdom as well as in the United States.

He has guest lectured on marginal costing methods in seminars in New Jersey and California for the Center of Professional Advancement. He has also guest lectured on cost of capital for the public utility industry before the Pacific Coast Gas and Electric Association, and for the Executive Seminar at the Colgate Darden Graduate School of Business, University of Virginia.

Dr. Peseau and his firm have participated with and been members of the American Economic Association, the American Financial Association, the Western Economic Association, the Atlantic Economic Association and the Financial

Management Association. He was formerly a member of the Staff Subcommittee on Economics of the National Association of Regulatory Utility Commissioners.

Dr. Peseau has been President of Utility Resources, Inc. since 1985.

REVIEW OF UTILITY RATEMAKING PROCEDURES

Report to the Iowa General Assembly

January 2004

Iowa Utilities Board

Diane Munns
Mark O. Lambert
Elliott G. Smith

EXHIBIT NO. 502
Case No.: IPC-E-07-08
D. Peseau, Micron

REVIEW OF UTILITY RATEMAKING PROCEDURES

Report to the Iowa General Assembly

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I. EXECUTIVE SUMMARY

Background

Senate File 458, passed during the 2003 Legislative Session, directs the Utilities Board (Board) to review current ratemaking procedures and report its findings to the Legislature by January 5, 2004. The law requires two standards to be applied to the review of the proposed changes: the cost effectiveness of the proposal and the degree of accuracy of matching rates (revenues) with costs. Interested persons were invited to file proposals for legislative change to ratemaking procedures. The Board identified 25 of these proposals for review. Following is a brief summary of the Board's findings.

General Rate Regulation Proposals

Ten proposals were considered that relate to rate of return regulation. The electric and gas investor-owned utilities in Iowa are rate regulated. The three largest telecommunications companies are price regulated, but retain the option of returning to rate regulation.

Most of the ten proposals are already available under Iowa law or are allowed in appropriate situations. For example, one proposal is the option of using a future test year to set rates. A future test year is based on estimates or forecasted data rather than on the relationship between historical costs and revenues. However, Iowa currently uses a hybrid approach that considers both historical and projected data for use in setting rates.

In recent years the Legislature has made several major changes in law that require the Board to consider projected data when setting rates. In the 2001 Session utilities were allowed to seek advanced ratemaking principles for new electric generation. A provision was also included for utilities to present a plan and budget for addressing emissions for generating facilities fueled by coal and allows the reasonable costs of implementing the emissions plan to be included in rates. In 2003 the Legislature directed the Board to consider capital infrastructure costs that would not produce significant additional revenues and would be in service within nine months after the conclusion of the test year. Capital cost changes that would occur within nine months after the conclusion of the test year and are associated with new generating plant for which the Board granted advanced ratemaking treatment are also allowed under the new law. These changes were made to spur new investment and mitigate risk to the utilities.

The two standards set by the legislature in Senate File 458 were applied to the option of a future test year. The Board found that adding this option would significantly increase the costs of ratemaking during the transition and probably in the long-term. The Board also found that use of a future test year over the

current hybrid approach would not necessarily provide rates that more accurately reflect a utility's cost of providing service.

Other proposals relating to general rate regulation that are already available under current law or have been allowed in specific circumstances are deferred accounting, automatic adjustments of rates outside a rate case, single-issue ratemaking, year-end adjustments, and electronic delivery of proposed rate increases.

Implementing temporary rates within ten days and reducing the interest rate on refunds are not found to be in the best interests of ratepayers. Both the current 90-day review period and the existing interest rate on refunds protect the customer from excessive temporary rates while giving the utility rate relief until the final rates are decided.

The Board did not come to a conclusion on the proposal for customer notification within 30 days after the filing of a proposed rate increase. Some potential postage savings could be achieved, because the utility could send a rate case notice as part of the regular billing. However, this would mean some customers would receive the notice before others, which could cause confusion.

The final proposal in this category is to allow for a ratemaking plan that would establish rates for a fixed period of time. The Board has approved multiyear ratemaking plans in the past based on a settlement among the parties to a general rate proceeding. This has provided rate predictability and has protected customers. The Board, however, believes that the current method of negotiating a multiyear plan with the parties is preferable to allowing the utility to propose a plan without the agreement of the other parties.

Telecommunications Proposals

Because the three largest local exchange carriers are price regulated, their prices do not directly reflect costs. Therefore, the legislative standard that a proposal should result in rates that more accurately reflect a utility's cost of providing service does not apply to the telecommunications proposals. The Board applied the second standard, cost effectiveness, to the proposals and found that some of them would increase regulatory costs without offsetting benefits. For example, decreasing the interval for allowed price plan modifications from three years to two years would tend to increase the associated regulatory costs. Likewise, the proposal to shorten the time available to conduct price regulation modification proceedings would result in a more concentrated procedural schedule and an increase in the associated costs for the Board and all parties. It also poses the risk of a flawed decision due to an incomplete record.

Several other proposals would delete provisions required for a company to enter price regulation. These include the requirement for a telecommunications carrier that is changing from traditional rate regulation to price regulation to either reduce its basic communications service rates by three percent or to establish new rates through a rate case. Another proposal would delete the requirement that access service rates be reduced when a company enters price regulation. While all existing rate-regulated carriers have opted for price regulation, new rate-regulated carriers might be created (by exceeding the 15,000 line threshold for regulation) through growth or sale of exchanges. In addition, a price regulated carrier may return to rate regulation and then decide at some future time to re-enter price regulation. Therefore, the requirements proposed to be deleted might serve a purpose in the future and do no harm by remaining in the law.

Energy Efficiency Proposals

Three of the proposals relate to energy efficiency. The first recommendation is that customers with an aggregated electric peak load of greater than two megawatts (MW) be exempt from energy efficiency participation and cost recovery on a voluntary basis. This proposal does not pass the cost effectiveness standard because the reduction of energy efficiency funding from large industrial customers would diminish future energy efficiency savings. It also has the potential to increase future utility rates by reducing cost effective energy efficiency, thus forcing utilities to pass through to ratepayers the costs of acquiring additional energy resources.

The second proposal would establish a single, statewide administrator for energy efficiency programs. The Board found this proposal would require a transformation of energy efficiency programs in Iowa and is outside the purview of Senate File 458's directive to review ratemaking procedures.

Finally, a proposal was suggested that the Board be given the authority for approval and oversight of the energy efficiency plans of municipal and cooperative utilities. Current law only requires that these utilities file plans with the Board. This proposal does not strictly apply to ratemaking methods and, therefore, does not fit into the framework of this review.

II. INTRODUCTION

The Iowa Utilities Board (Board) has prepared the following report in response to the mandate of the General Assembly as set out in Acts of the 80th General Assembly, 2003 Session, Senate File 458, Section 150. The General Assembly directed the Board as follows:

> The utilities board shall initiate and coordinate a review of current ratemaking procedures to determine whether different procedures would be cost-effective and would result in rates that more accurately reflect a utility's cost of providing service to its customers in Iowa. The board shall allow the consumer advocate division of the department of justice, the rate-regulated utilities, and other interested persons to participate in its review. The board shall report the results of its review to the general assembly, with recommendations as appropriate, on or before January 5, 2004.

On July 14, 2003, the Board issued an order initiating an inquiry, identified as Docket No. NOI-03-2. Interested persons were invited to file, by July 25, 2003, proposals for changes to ratemaking procedures, with the primary focus on changes that would require legislative action. After review of the submitted proposals, the Board issued an order on September 2, 2003, which identified ratemaking procedures for consideration and established a procedural schedule. The participants were asked to file comments by September 15, 2003, and reply comments by October 3, 2003. Three workshops were held on November 7, 2003, for further discussion and to give participants an opportunity to respond to questions by Board staff. The three separate workshops addressed: (1) proposals involving all rate-regulated utilities, (2) proposals affecting only telecommunications utilities, and (3) energy efficiency proposals. Additional comments subsequent to the workshop were allowed by November 14, 2003.

Participants filing information in the inquiry included the Consumer Advocate, Division of the Department of Justice (Consumer Advocate), MidAmerican Energy Company (MidAmerican), Qwest Corporation (Qwest), Interstate Power and Light Company (IPL), Iowa Telecommunications Services, Inc., d/b/a Iowa Telecom (Iowa Telecom), Ag Processing, Inc. (Ag Processing), and Aquila, Inc., d/b/a Aquila Networks (Aquila). Atmos Energy Corporation, Deere & Company, and the Iowa Consumers Coalition expressed interest in and followed the proceedings. Agri Industrial Plastics, HON Industries Inc., IPSCO Steel Inc., Alcoa Mill Products, Box USA, Curries and Graham, Elkem Carbon, General Mills, Griffin Pipe Products Co., Griffin Wheel Company, Lehigh Cement Co., Nestle Purina, North Star Steel, Penford Products, PMS Industries, Inc.,

Progressive Foundry, and Quaker Foods & Beverages joined with Ag Processing in addressing the energy efficiency proposals.

The Legislature gave the Board two standards to apply to the proposed changes: the cost effectiveness of the proposal and the degree of accuracy of matching rates (revenues) with costs. These two standards have been applied to each of the proposed changes. This report examines the identified proposals, summarizes the comments of the participants, and reaches conclusions under the standards given.

III. GENERAL RATE REGULATION PROPOSALS

Description of Current Iowa Ratemaking Practices for Electric and Gas

Iowa currently uses a hybrid approach that considers both historical and projected data for use in setting rates. A rate proceeding before the Board begins with historical data. This is adjusted for known and measurable changes in costs not associated with a different level of revenue and revenues not associated with a different level of cost that will occur within twelve months from the date of filing by the utility. Typically, an historical test year is the latest calendar year; however, a test year can be any prior 12-month period of audited information. In a rate proceeding, the utility files actual data for the historical test year and proposes adjustments to revenues, expenses, assets, liabilities, and capital issuances. These changes are known as "pro forma adjustments." The Board may also consider other proposed changes under its authority in Iowa Code § 476.33(4) to "consider other evidence." Once the Board decides which adjustments are allowed and the resulting revenue requirement, the utility files new rates that remain in effect until a new case is brought. The goal in setting rates is to take the data from the historical test year and make adjustments to the historical data that more closely reflect the expected costs and revenues going forward.

The fundamental principle in determining rates is the matching principle. Unless there is a matching of costs and revenues, the test year is not a proper one for fixing just and reasonable rates. The inclusion of costs without matching revenues may produce excessive rates. The inclusion of revenues without matching costs may deny the utility reasonable rates. The relationship between costs and revenues for the test period used, whether historical or projected, and the validity of that relationship, constitutes one of the most vital steps in the determination of just and reasonable rates.

Although the Iowa statute has an historical test year as its base, the Board is not restricted from looking beyond the test year in appropriate situations. The statute expressly grants the Board the authority to consider other evidence, and the Iowa Supreme Court has affirmed the Board's interpretation that this provision allows it to consider adjustments that are outside the test year. Proposed adjustments are considered on a case-by-case basis to ensure they meet the requirements and concerns of the matching principle.

In the past several sessions, the Iowa Legislature has implemented several major changes that look beyond the historical test year in the setting of rates. A 2001 law allows utilities to seek advanced ratemaking principles related to major capital investments in generating facilities. Utilities may seek binding regulatory assurances related to the treatment of these investments in future rates. Utilities may also present a plan and budget for addressing emissions from rate-regulated electric power generating facilities that are fueled by coal. The law

requires the reasonable costs of implementing the plan to be included in rates. Finally, during the 2003 Session, the Legislature required the Board to consider capital infrastructure costs that will be in service within nine months after the conclusion of the test year and will not produce significant additional revenues. Capital cost changes that will occur within nine months after the conclusion of the test year and are associated with new generating plant for which the Board granted advanced ratemaking treatment are also allowed under the new law. These changes were made by the Legislature to spur investment in generation, mitigate risk associated with environmental requirements, and mitigate regulatory lag with respect to major capital additions and cost of capital. In each case, they require the Board to consider projected data when setting rates.

Two other aspects of Iowa's ratemaking approach require discussion in order to understand proposals for change. Utilities are able to implement rate increases that are consistent with previously accepted regulatory principles within three months of a rate filing. These temporary rates give relief to the utility during the pendency of the 10-month ratemaking process. If final rates are lower than those collected during the proceeding, refunds are made with interest set at a statutory level. Iowa's statute also allows for the automatic adjustment of rates in certain circumstances. These adjustments have historically been used to flow through the cost of purchased gas and the cost of power purchases, among other things.

1. Option of a Future Test Year

a. Description of the Proposal

IPL proposes the option of using a future or projected test year to determine rates. This method is based not upon the relationship between historical costs and revenues, but rather on estimates or forecasted data. All the components that would be considered when determining rates, including the revenues, expenses, rate base, working capital, and capital structure, are based on estimates and projections.

IPL's specific proposal would limit the use of projected data to a two-year period and would allow the utility to choose whether it would use an historical period or a projected, forecasted period for setting rates. IPL, Iowa Telecom, Aquila, and MidAmerican support an optional future test year as long as the option to choose either a historical or future test year is allowed. Consumer Advocate, Ag Processing, and Qwest argue against the option of a future test year.

b. Review of Other States

Survey results filed by Consumer Advocate[1] indicate that 30 states use historical test periods, seven states use future test periods, eight allow utility choice, and six use a hybrid form. IPL responded with the results from three different surveys[2] that categorize the test periods in slightly different ways, making strict comparisons difficult.[3] However, approximately 30 states continue to employ the historical test period. Other states use a variety of alternatives ranging from utility choice, hybrids/partially forecasted, to fully forecasted test years.

Of the closest Midwestern states, South Dakota, Missouri, Indiana, and Kansas use historical test periods. Minnesota and Illinois allow utility choice of historical and future test periods. Wisconsin requires a future test year.

Illinois has the option of a future test year, but requires an independent audit of projections to explore the link between actual data, assumptions, and projections. Illinois also has a significant number of rules that apply specifically to a filing based on a future test year. Companies that choose the option of a future test year must also file information to support an historical test year. The appropriateness of either an historical or future test year might be an issue of controversy in any particular case. According to Illinois staff most companies prefer the historical test year because they find these requirements to be burdensome.

Minnesota also allows the option of a forecasted test year. However, its Commission does not allow the forecasted test year to reach out very far. For example, if a case is filed December 31, 2003, the company might use a 2004 test year. By the time the 10-month process ends, the end of the forecasted test year is close. In this example, the Commission would not allow a 2005 test year.

Wisconsin mandates a future test year for large utilities. Wisconsin staff states their regulatory approach is very hands on and requires frequent audits. Major energy utilities in Wisconsin file a rate case every year unless they are under a rate freeze. Wisconsin staff also notes a strong auditing or accounting

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[1] Taken from Consumer Advocate Witness Brosch's Attachment MLB-3 entitled, "Survey of State PUC Test Period Approaches as of September 2003."

[2] The three surveys are:

- Regulatory Research Report, Table entitled "Regulatory Practices Test Period/Rate Base/Statutory Case Lag Summary of All 50 States plus the District of Columbia," 2003.
- Deloitte & Touche, "Questar: State Commissions Test Year Survey," 2000.
- NARUC, Table entitled "Type of Test Year Used in determining Rates: Electric and Gas Utilities," Compilation of Utility Regulatory Policy 1995-1996.

[3] For example, of the three surveys provided by IPL, one identified six states as using future test year periods (similar to Consumer Advocate's finding), but the other two identified twice that many.

background is required to effectively review a forecasted test year and most of its auditors are CPAs. In addition, a larger staff is required to review a future test year; the Wisconsin Commission has 185 staff, double the number for the Board and Consumer Advocate combined.

Both Illinois and Minnesota require that future test year filings also include historical period data so that comparisons can be made between the estimated data proposed for the projected test period and actual data from the historical test period. Wisconsin, which requires future test year filings, also requires annual reports of a utility's costs and revenues to allow the Commission to continually review and assess the reasonableness of a utility's forecasts.

c. Is the Proposal Cost Effective?

IPL states that a projected test year would not significantly increase the cost of utility ratemaking. It suggests that the only additional cost is the hiring of consultants well versed in capital budgeting, a short-lived expense until the Board and Consumer Advocate staff are trained in this area. Furthermore, while new issues would arise from using a projected test year, many issues argued today would disappear. As for IPL's own costs, it already does forecasting and is comfortable with its ability to project items such as customer levels and usage, fuel costs, and capital expenditures.

At the same time, IPL acknowledges that more frequent or annual rate reviews may be necessary because of the lack of annualization adjustments in a projected test year. Based on the company's experience, a future test year regulatory approach is more active and requires frequent audits. IPL also states that weather normalization, a necessary element in a future test-year case, would require additional staff expertise. IPL's sister-company, Wisconsin Power and Light Company, normalizes revenues for weather based on a regression model and analysis. In Iowa, weather normalization is routinely used in natural gas proceedings. However, though utilities advocated the use of weather normalization for electric cases in the 1980s, normalization was never approved and it has not been a component in more recent electric cases. Thus, both the Board and Consumer Advocate would need to acquire expertise in this area. Finally, the company agrees that Consumer Advocate would need new skills to evaluate projected versus historical data in a rate case[4] because it is unlikely these skills could be found in an outside auditing firm.

MidAmerican acknowledges that the cost of preparing a case with a proposed future test period would be greater because data for an historical period must be filed at the same time. However, to the extent the use of the forecast test period

[4] Since the mathematics related to thermodynamics are well known and much natural gas usage is heating related, normalization is a relatively simple procedure for natural gas. Though electricity usage related to heating and cooling can be fairly predictable, usage of electricity for other purposes is far less predictable, making normalization much more complex for electricity.

better reflects the cost of providing service during the period in which the rates are in effect, some future rate case proceedings and costs may be avoided. The company argues that the rates based on the forecasted data already include any increase in costs that may occur when the rates are in effect, and so a utility should not have to file another rate case until it has moved beyond the forecasted period.

Consumer Advocate believes the future test-year option would dramatically increase the cost of utility ratemaking in Iowa. Both the cost of a proceeding and number of proceedings would increase. Consumer Advocate's expert states that future test years are inherently more difficult to prepare, document, investigate, and verify, causing the utility, the consumer representatives, and the regulatory agency to invest more resources in the process of regulation. There also would be new issues related to the use of projections, such as adjustments for inflation and calculations of productivity.

Ag Processing's main concern is that the use of future test years will add litigation costs to the point where industry's involvement in the process is precluded. In addition, use of future test years will cause an increase in rate case-related workloads for Board members, Board staff, and Consumer Advocate.

Thus, it is evident there is no consensus among the participants on the cost effectiveness of this proposal. The information filed shows there would be transition costs as staffing levels and skills are changed to accommodate for an additional ratemaking method. The review of other states indicates a need for additional staff including economists, statisticians, auditors, and CPAs. A number of rulemakings would be necessary. Litigation would probably increase with a new approach to ratemaking. It appears from the record there would be long-term costs associated with the change for a number of reasons:

- Frequency of rate cases may increase, especially if a future test-year approach similar to Wisconsin's is used.
- If the company files a future test-year option, other parties to the case may file the historical test-year option. This would necessitate evaluation of simultaneous historical and future rate cases, increasing the work, the cost, and the time required for the proceeding.
- A more active auditing role seems essential.
- New issues appear likely with a future test-year filing.
- Additional costs are associated with a possible independent audit.[5]

[5] In Illinois Commerce Commission Docket No. 92-0357, MidAmerican used some elements of a future test year and required the services of an independent auditor. The cost of that audit was $132,000.

d. Would the Proposal Result in Rates That More Accurately Reflect a Utility's Cost of Providing Service?

IPL believes that a projected test year provides a better matching of rates with costs and revenues that will occur at the time those rates will be in effect. This would benefit customers because changes in costs are included in rates sooner, allowing customers to receive better pricing signals and lessening differences between current customers and future customers. The company asserts that a projected test year benefits the utility by providing for full regulatory assurance and up-front guidance on planned expenditures. Under a future test year, the Board would provide proactive input into capital investment decisions and other expenditures before those decisions are implemented. Under the current standard, the Board is limited to defining public policy through the denial of costs that have already been incurred.

IPL contends that costs and revenues in an historical test year are as much as two years old before rates are finalized. IPL questions the value of auditable data and the assumption of a constant historical relationship between revenues and costs, especially during times of major capital investment.

The company also asserts that a projected test year benefits the utility by potentially reducing the cost of capital. It states that the financial community prefers a regulatory structure that allows a projected test period because there is less risk that prudent capital expenditures will not be recovered in rates. Less risk to the stockholders may mean improved ratings that may result in reducing the cost of capital.

MidAmerican states there is little difference between a future test period and an historical test period that reflects appropriate post test-year adjustments. At the same time it argues that two fundamental points need to be kept in mind: (1) ratemaking exists to determine the reasonableness of rates that will apply sometime in the future, after the rate filing has been made, and (2) there is no inherent reason why historical data from the company's books and records more accurately reflects what will happen in the future than forecasts will.

However, Consumer Advocate disagrees that a future test year would result in rates that more accurately reflect a utility's cost of providing service. Further, the Consumer Advocate states it is impossible to know if a forecast is accurate until the forecast period has passed. It also argues that what is important in establishing accurate rates is the relationship between revenues and costs. As long as a recent and internally consistent historical test year is used, the revenue/cost relationship will generally be representative of ongoing conditions and the revenue requirement will be accurate for the period when rates are in effect. Consumer Advocate also believes that the mere potential to reduce regulatory lag with a future test-year option is not worth the risk of reducing or eliminating the critical incentive the current system provides Iowa utilities to

operate efficiently. Regulatory lag tends to replace some of the efficiency incentives that are otherwise blunted by cost-of-service regulation. It also rewards or punishes a utility in the short run by attributing cost and revenue changes to shareholders between rate cases. Consumer Advocate adds that notwithstanding IPL's assertion concerning the staleness of historical data, the use of a future test year will increase the probability of inaccuracy, excess profits, and excessive rates. Further, a future test year relies heavily on utility management's expectations, and it is likely that management will err on the high side when estimating future costs and on the low side when estimating future revenues.

Consumer Advocate believes giving the utility the option of a future test year invites abuse of the regulatory process. It would mean that utility companies would submit the type of filing most beneficial to shareholders at any given point in time. Making an option available allows gaming of the system to the advantage of the party that is granted the option to choose.

Ag Processing states that a future test-year filing does not necessarily reflect a more accurate cost of service. It believes there are more appropriate ways to match revenues and costs and send price signals to customers.

The Board has the authority to allow additional evidence into the record after the initial filing. In a situation where only part of a proposed adjustment is known at the time of filing, additional updates have been allowed up through the date of the hearing. The Board also is able to consider other evidence outside the test period. Recently, the Board allowed year-end rate-base adjustments for major plant additions and considered several changes to capital structure that occurred after the test year. It also indicated a willingness to consider alternatives to the thirteen-month average capital structure.

In addition, the Legislature has recently enacted provisions that address the desire for regulatory input into capital investment decisions, regulatory risk related to environmental requirements, and regulatory lag. Iowa Code § 476.53, enacted in 2001, provides for advanced ratemaking principles for new generation and transmission projects. Both IPL and MidAmerican have requested and received advanced ratemaking principles that are binding on future ratemaking. These advanced ratemaking principles have led to the following capital investment in Iowa:

- IPL's 568 MW natural gas-fueled generation plant in Mason City
- MidAmerican Energy's 540 MW natural gas-fueled generation plant in Pleasant Hill
- MidAmerican Energy's 900 MW coal-fueled generation plant in Council Bluffs
- MidAmerican Energy's 310 MW wind energy facility in northwest Iowa

Iowa Code section 476.6(25) allows utilities to look to the future with respect to emission controls on coal-fired generating plants. Utilities are required to develop a plan and budget designed to meet environmental requirements. The Board then must include the reasonable costs of implementing the plan in rates. Amendments to Iowa Code § 476.33 enacted during the 2003 Session allow the Board to consider capital infrastructure investments in service within nine months after the conclusion of the test year and cost-of-capital changes that occur in that time period for new generating plants, thus lessening regulatory lag related to large investments.

Since these statutory provisions allow for future costs of large investments to be considered in a rate case, a future test year would provide little additional benefit.

e. Conclusion

The Board concludes the implementation of the future test-year option would significantly increase costs of ratemaking during the transition and probably in the long-term. It also finds use of a future test year over the current hybrid approach will not necessarily provide rates that more accurately reflect a utility's cost of providing service. Iowa's hybrid approach allows for consideration of evidence outside the historical test year. The implementation of two new laws allowing regulatory assurances for capital investment decisions and for environmental improvements; and the ability to consider capital investments and cost of capital changes after the test period alleviate the major concerns raised by IPL.

2. Deferred Expenses and Revenues Occurring Outside the Test Year

a. Description of the Proposal

IPL proposes that deferred accounting would be a useful procedure to support a future test-year case. Large abnormal expenses and revenues occurring outside a test year could be accounted for in a deferred account and reflected in the utility's next rate case.

Consumer Advocate argues that deferred accounting is just a variation of piecemeal, or single-issue, ratemaking. Single-issue ratemaking occurs when a cost or revenue item is considered without considering other costs and revenues. Not generally accepted, single-issue ratemaking can lead to an improper matching of costs and revenues, and potentially unjust and unreasonable rates. Consumer Advocate states the inclusion of costs without matching revenues will produce excessive rates; the inclusion of revenues without the matching costs will deny the utility reasonable rates. It adds that the relationship between costs and revenues is an important component in the determination of just and reasonable rates. If deferred accounting is used appropriately and is properly matched to other costs of providing service, it need not result in single-

issue ratemaking. However, deferred accounting can distort the revenue requirement if other offsetting cost savings or revenue increases are ignored.

b. Is the Proposal Cost Effective?

Allowing the use of deferred accounting in a rate case would not have a significant financial impact on the cost of the rate proceeding since the Board has current authority to allow deferred accounting.

c. Would the Proposal Result in Rates That More Accurately Reflect a Utility's Cost of Providing Service?

If the costs in a deferred account are properly matched against related cost reductions and revenues, they could result in rates that more closely reflect the cost of providing service. Since a utility controls the information concerning these accounts, there is the potential that this matching may not occur.

d. Conclusion

Deferred accounting is available under current law. Utilities may request accounting rulings from the Board. However, rulings made outside a rate case are only advisory, not binding, when considered in a future rate case. The utility may account for costs and revenues in a deferred account but the Board retains the authority to determine whether the costs and revenues will be allowed in rates, and under what terms and conditions.

3. Government-Mandated Costs Outside a Rate Case

a. Description of the Proposal

MidAmerican proposed that government-mandated expenditures should be recovered through an automatic adjustment rather than through a rate case. These are non-fuel items such as capital projects for the relocation or improvement of any facilities when the expense of these items are verifiable or mandated by a government entity or are outside of the control of the utility's management. Mandated expenses could also include emission control equipment, manufactured gas plant remediation, or expenses related to upgrading facilities to thwart terrorism attacks. MidAmerican says the automatic adjustment mechanism is particularly appropriate in situations where it is desirable to obtain a better matching of costs and revenues in a specified period than could be accomplished by infrequent rate cases.

Aquila believes that government-mandated expenditures should be recovered through an automatic adjustment including expedited recovery for mandated non-fuel expenses and those required by the Office of Homeland Security.

Consumer Advocate argues that government-mandated costs should not be automatic because they are not volatile and may be offset by other cost changes that are not verifiable. Furthermore, automatic recovery provides no incentive to minimize costs. Consumer Advocate believes the Board currently has the authority to provide for automatic adjustment clauses.

b. Is the Proposal Cost Effective?

Although Iowa law allows for automatic rate adjustments, the types of expenses discussed in this proposal have not been allowed. The Board would have to approve any new automatic adjustment. The cost involved would be the additional time necessary to establish the automatic adjustment and to verify that reasonable accounting was used for all of the major elements of the proposed government-mandated expenditure.

c. Would the Proposal Result in Rates That More Accurately Reflect a Utility's Cost of Providing Service?

An automatic adjustment would allow a utility to recover the cost of government-mandated items in a timelier manner and without the necessity for a rate case; however, it may also allow for piecemeal ratemaking if consideration of matching cost and revenue changes do not take place.

d. Conclusion

Iowa law already allows for the automatic adjustment of rates outside a rate case. For example, the Board currently allows automatic adjustment of electric rates for fuel-related costs. These fuel costs are beyond direct control of management, are subject to sudden significant changes in level, are an important factor in determining costs, and are readily, precisely, and continually segregated in accounts. Automatic recovery is also allowed for energy efficiency expenditures. All amounts recovered through automatic adjustments are subject to prudence reviews.

The types of expenses discussed in this proposal have not been historically allowed to be collected through an automatic adjustment mechanism. Any automatic adjustment mechanism for government-mandated costs would need to meet similar criteria as fuel-related costs and meet the requirements of the matching principle to ensure just and reasonable rates.

It should be noted that when a utility has voluntarily agreed to forego rate increases for a period of years, allowance of new automatic recovery for expenses incurred during this period would change the conditions under which the agreement was reached. Any new automatic adjustments should not be implemented during such a period.

4. Use of Single-Issue Ratemaking

a. Description of the Proposal

MidAmerican proposes that rate adjustments producing small amounts of revenue should be allowed outside of a general rate proceeding.

b. Is the Proposal Cost Effective?

If a utility were allowed to file for a rate increase based upon a single cost item, there would likely be an increase in filings and the regulatory costs would increase. Some, if not most, of these single-issue ratemaking filings could become time-consuming contested cases and would place an additional burden on Board, Consumer Advocate, and third-party resources. There may be a decrease in general rate cases since there would be allowances for rate recovery between rate cases.

c. Would the Proposal Result in Rates That More Accurately Reflect a Utility's Cost of Providing Service?

The proposal does not provide for the proper matching of costs and revenues that is essential in setting just and reasonable rates. For the filing to result in rates that more accurately reflect a utility's cost of providing service, any corresponding cost savings or additional revenue would have to be reviewed for possible offset. Allowing the costs to be recovered without the offsetting revenues or reduction in costs would not accurately reflect the cost of providing service. Rates are best established in a general ratemaking proceeding where all the costs and revenues can be reviewed. If a utility is allowed to file for rate relief every time an increase in costs occurs, rates will likely be higher than under existing procedures.

d. Conclusion

This proposal would allow a utility to file for rate increases without having to give consideration to offsetting decreases in costs or increases in revenue in violation of the matching principle. The Board has allowed single-issue ratemaking outside of a general rate case in specific cases. However, single-issue ratemaking should be a rare occurrence and not become an accepted way of setting rates.

5. Adjustments to Year-End Data

a. Description of the Proposal

IPL proposes changes to require the Board to consider data that will become known and measurable within twelve months from the commencement of the proceeding. The proposal would require that any pro forma adjustments be made using a year-end test year, rather than a thirteen-month average test year.

b. Is the Proposal Cost Effective?

The proposed statutory changes would make it mandatory for the Board to consider all post test-year changes, not just changes that exist at the commencement of the proceeding. As previously stated, the Board has the ability (and has used it) to adjust historical test year data beyond known and measurable changes related to data that exists as of the date the proceeding is filed regarding known and measurable changes in costs not associated with a different level of revenue and revenues not associated with a different level of cost, that will occur within twelve months from the date of filing by the utility. The authority to do so exists in Iowa Code § 476.33(4), which states the Board's ability to "consider other evidence". In recent proceedings, the Board has considered these types of issues under its current statutory authority. Therefore, the resources needed to review a rate case in the context of the statutory changes would be similar to the resources needed currently. Given the Board's use of already existing authority, the benefits of changing the statutory language are not obvious.

c. Would the Proposal Result in Rates That More Accurately Reflect a Utility's Cost of Providing Service?

The use of a year-end rate base and capital structure could reduce regulatory lag to some degree by allowing full rate treatment for items that were placed in service late in the test year. Potentially, this could make rates better reflect the costs of the utility.

Consumer Advocate states that an annualized, or year-end, test period is somewhat more conducive to known and measurable changes beyond the test year end and does have the effect of eliminating up to six months of regulatory lag. However, Consumer Advocate believes there is no advantage to the use of either the average or year-end-annualized test period approach that cannot also be achieved with known and measurable changes routinely considered by the Board under existing ratemaking procedures. It points out that the average test year reduces the dependence on only a single data point, which could be distorted by unusual accounting entries or one-time transactions. Also, by using the average approach, the income statement presentation is simplified.

Customer levels, employee levels, depreciation, property taxes, and other costs do not need to be adjusted to reflect year-end annualized numbers.

With respect to the capital structure, a thirteen-month average capital structure for determining rates helps to eliminate distortions caused by issuance of new preferred stock and long-term debt, equity infusions, security retirements, and fluctuations in retained earnings. Further, if a year-end test year were used, any of these one-time events could distort the capital structure, making the capital ratios unrepresentative. The thirteen-month average capital structure averages these potential events over several months to provide a better match between capital structure, rate base, revenues, and expenses.

Any capital issued outside the test year is not normally included in the capital structure because it would violate the matching principle. The thirteen-month average capital structure supports the thirteen-month rate base. By using data for only one point in time, the utility could include an equity infusion in the month of December such that the rates are set using a capital structure with a higher common equity ratio. Common equity is the most expensive source of capital available. Therefore, the customers' rates would support a higher overall cost of capital than rates determined using an average capital structure.

d. Conclusion

The current statute already allows the Board to consider year-end evidence. Any proposal to use a year-end test year, annualize single items, or approve appropriate pro forma adjustments is reviewed and considered on a case-by-case basis by the Board to ensure compliance with the matching principle.

6. Temporary Rate Implementation

a. Description of the Proposal

IPL proposes to modify the way in which temporary rates are implemented. First, it proposes to eliminate language requiring the Board to apply previously established regulatory principles in determining the appropriate level of temporary rate relief. Second, IPL proposes to reduce the time frame for implementation from 90 days to 10 days.

In addition, IPL argues that since its proposal would eliminate three months of review for temporary rates, the ten-month period allowed to reach a final decision should be reduced to seven months.

MidAmerican agrees with IPL's proposal but argues the utility should have the option of implementing temporary rates immediately or using the existing temporary rate procedures.

Consumer Advocate argues that if temporary rates are implemented immediately, without review, the ten-month time frame should be extended to allow for additional review of the final rates.

b. Is the Proposal Cost Effective?

Implementing temporary rates within 10 days, rather than allowing 90 days for review and approval, would probably not add costs to the rate proceeding. However, the ultimate issues to be decided in the case would remain. Most of the costs that would be saved by eliminating analysis and approval of temporary rates would be shifted to the remainder of the case. Therefore, it would not likely be cost effective, or even possible, to shorten the schedule in the manner proposed. The proposal to shorten the schedule appears to proceed from the assumption that temporary rate review requires a significant part of the first 90 days, but experience has shown that review of temporary rates actually requires very little in the way of Board resources.

c. Would the Proposal Result in Rates That More Accurately Reflect a Utility's Cost of Providing Service?

The current statute allows 90 days for implementation of temporary rate increases. Increases based on established regulatory principles are allowed. If the utility seeks recovery for expenditures that have been denied in the past or are new, it must wait until the Board has approved the expense before it can recover these expenses in rates. IPL proposes to eliminate the requirement in the statute that past Board precedent is used in determining an appropriate increase for temporary rates. Instead, the entire increase sought by the utility could be implemented in temporary rates. Consumer Advocate argues there must be some reasonable constraint on temporary rates. If temporary rates are put into effect without any regulatory review, utilities could use ratepayers as a source for instant rate relief when cash flows are below desired levels. Consumer Advocate contends that refunds with interest at the end of a case are not a sufficient remedy for customers who may have difficulty paying their utility bills even before the rate increases.

Eliminating the use of previously established regulatory principles when setting temporary rates would probably make temporary rates less, rather than more, accurate. The use of previously established regulatory principles results in temporary rates that are based on prior Board decisions and are therefore likely to bear a reasonable relationship to the final rates. Removal of this factor would mean potentially unlimited temporary rates that would have no relationship to actual costs.

d. Conclusion

IPL's initial proposal removes the requirement that temporary rate increases be based on previously established past Board precedent. It also would implement temporary rates in 10 days rather than the current 90-day period for review and approval. In the workshop IPL indicated a willingness to use past Board precedent in order to implement temporary rates without Board review. The Board believes that the current requirements, past precedent and a 90-day review period provide a balance that gives the utility expedited rate relief while the case progresses. It also protects the customer from excessive temporary rate increases.

Because IPL's proposal would essentially eliminate three months of the review process, it also proposes to reduce the current ten-month rate case review period to seven months. Even if review of temporary rates is removed, other issues requiring a full ten-month proceeding remain. Verification of company figures and calculations often require the full time period.

Finally, if the statutory method is modified to allow implementation of temporary rates within 10 days, the current interest rate should be retained. (See the next issue.) The relatively high interest rate serves as a constraint on the utility to discourage it from using the ratepayers as a source of funds during the pendency of the proceeding.

7. Interest Rates on Refunds

a. Description of the Proposal

Iowa Telecom proposes to reduce the interest rate on refunds. The current rate is two percentage points above the 24-month consumer loan rate. MidAmerican states the rate should: (1) not be so high that it works to prevent utilities from seeking needed rate relief, (2) be high enough to discourage utility use of excessive temporary rate relief for financing purposes, and (3) adequately reimburse customers for the use of their money. MidAmerican encourages the Board to consider using a public utility bond yield as representative of the utility's credit quality. This long-term rate has a built-in penalty. Short-term financing would be used as a source of funds during the period that temporary rates are in effect. Since short-term rates are cheaper than long-term sources, the utility would pay a "penalty" if the utility were required to make refunds to the customers. The customers would receive a return higher than any other investment option of the same duration and recover their opportunity cost of lending funds to the utility.

Consumer Advocate opposes any change to the interest rate on refunds. It argues that to reduce the current average commercial bank rates to money

market account rates would be unfair. Many customers have outstanding credit card balances, bank loans, and mortgages at higher rates of interest such that their cost of money would likely be higher than money market rates of return. It is Consumer Advocate's position that the current rate is more indicative of the opportunity cost of capital for ratepayers. Also, utilities may be overly aggressive in temporary rate requests if extremely low interest rates are used. This would make customers involuntary investors in the utility. The interest rate should be at or above the average consumer's marginal cost of capital.

IPL proposes to implement temporary rates immediately without Board review and approval and did not propose any change to the current rate. Qwest also agrees that no change is needed.

b. Is the Proposal Cost Effective?

Changing the refund interest rate has no cost implications for implementation. It would simply require looking to a different indicator to set the rate.

c. Would the Proposal Result in Rates That More Accurately Reflect a Utility's Cost of Providing Service?

The interest rate is not intended to reflect a utility's cost of providing service. It is intended to partially or fully compensate the consumer for the use of money during the pendency of a rate case. It may also provide a deterrent to collecting excessive temporary rates. The 24-month consumer loan rate is a borrowing rate, not an investment rate. Based on August 2003 data, this rate was 11.95 percent, slightly lower than the Credit Card Plan (All Accounts) rate of 12.49 percent for the same time period. After adding the additional two percent, as required in Iowa Code, the refund rate exceeds the credit card plan rate. The high refund rate that results from this formula suggests that it is used to protect the customers from the utility charging excessive temporary rates. If excessive temporary rates were in effect, a customer may be forced to either use funds that would have been used to reduce other debt obligations such as credit cards or to borrow funds to pay the bill. This assumption seems consistent with the position held by the Consumer Advocate. If a refund were necessary, the consumers would more likely receive their opportunity cost of money, providing better protection than if a lower rate were used.

MidAmerican suggests that the existing rate is excessively punitive and should be lower. MidAmerican argues that the public utility bond yield is more representative of the utility's credit quality. It also claims that the customer would earn a higher return than for any other investment for that duration. However, the concern may not be with recovering a customer's opportunity cost of investment, but instead with covering customers' potential borrowing rates.

Most Iowa utilities have bond ratings in the range of A to Caa. Using August data from the Merchant Bond Record, the yields for an "A" rating and a "Baa" rating ranged from 6.78 percent to 7.08 percent. The recommended bond utility rate is almost half of the current consumer rate. Refunds would be based on the individual rating of each utility.

d. Conclusion

The proposed change is neutral with respect to cost-effectiveness but would not tend to produce more accurate rates. The existing rate is set at a high level to protect customers from paying excessive temporary rates. If the utility wishes to avoid paying this rate on potential refunds, it should only request reasonable rates when it files for temporary relief. As discussed previously, IPL is proposing a statutory change that would allow it to collect temporary rates immediately without Board review. If this change were allowed, the need for maintaining the current refund rate is even greater.

8. Electronic Delivery of Proposed Rate Increase Notices

a. Description of the Proposal

MidAmerican proposes a statutory change to allow for electronic delivery of proposed rate increase notices.

b. Is the Proposal Cost Effective?

The comments lack sufficient information to conclude that electronic delivery of customer notices meets the cost-effectiveness criterion. Electronic delivery potentially reduces notice costs. However, the utilities that commented on this proposal indicated that their systems currently are not set up for electronic delivery of customer notices. No comments estimated the start-up or program change costs and ongoing expenses. Qwest's comments concerning the use of radio and television indicate that "electronic" may be too broad a term, but no alternative term was offered.

c. Would the Proposal Result in Rates That More Accurately Reflect a Utility's Cost of Providing Service?

The form of notice does not significantly affect costs recovered as part of the rate proceeding.

d. Conclusion

By the conclusion of the inquiry, MidAmerican indicated that Iowa law may already allow for the electronic delivery of rate notices. Qwest and MidAmerican

encouraged the Board to allow for electronic delivery and allow parties to work out details in the future as technologies develop.

9. Notification Within 30 Days of Filing of a Proposed Rate Increase

a. Description of the Proposal

MidAmerican proposes to change the notice period from no more than 62 days prior to filing to within 30 days after the filing. The utility would then be able to work with the Board to include preliminary public comment hearing dates and locations on the notice of proposed rate increase filings. The practical effect of the change may not be very great; however, under current law, most utilities send the notice the day before they file the rate case. Under the proposed change, they would be able to delay the notice by two or three days and then include the notice in the regular bills to customers.

b. Is the Proposal Cost Effective?

The change would not incur additional costs and might allow utilities to avoid the postage expenses associated with mailing separate rate case notices. It could be beneficial, as the Board might have the opportunity to set up preliminary dates and locations for public comment hearings and work with the utility to list the dates and locations in the notice of proposed rate increase to its customers. However, that can be accomplished with the existing process as well.

c. Would the Proposal Result in Rates That More Accurately Reflect a Utility's Cost of Providing Service?

The time frame for rendering the notice does not play a role in the costs that are considered as part of the rate proceeding.

d. Conclusion

The statute currently requires rate-regulated utilities to provide notice of a proposed rate increase within sixty-two days prior to the time the application for the increase is filed with the Board. The proposed change would potentially allow utilities to save postage costs, because they could send a rate case notice as a part of the regular billing cycle. However, this would mean different customers would receive the notice at different times, which could cause customer confusion. Thus, it is difficult to say if the proposed change would be an improvement.

10. Rates for a Fixed Period

a. Description of the Proposal

MidAmerican proposes to establish a mechanism that would allow filing and approval of a ratemaking plan that would establish rates for a fixed period of time. While Consumer Advocate has agreed to such multiyear plans in the past, it opposes the Board having the authority to approve such a plan over its objection.

b. Is the Proposal Cost Effective?

This proposal may be a more cost-effective method of ratemaking since it would set rates for a certain period of time. A review of the rate cases filed since 1981[6] shows that rate cases are often filed at three-or four-year intervals. Allowing a utility the option of filing a multiyear ratemaking plan could fit this pattern.

Both the utility and Consumer Advocate would be precluded from bringing cases during this time. That could result in savings if a rate case would otherwise have been filed. But the savings only exist if a rate case would otherwise have been brought, i.e., rates need to be changed.

A multiyear rate filing would be subject to the same analysis with respect to costs of review as was discussed in the future test year filing. The utility, the Board, Consumer Advocate, and interveners would be required to consider data concerning an historical test year as well as data concerning a future period. This future data would be very similar to data to support a future test year.

MidAmerican has suggested that other alternative ratemaking procedures might be proposed to determine the rates under a multiyear rate plan. Any alternative ratemaking procedures could increase the cost and complexity of a ratemaking proceeding.

c. Would the Proposal Result in Rates That More Accurately Reflect a Utility's Cost of Providing Service?

MidAmerican argues that allowing for multiyear ratemaking would provide rate predictability for businesses, government, and other Iowa consumers. However, the predictability of rates does not necessarily mean that the rates accurately reflect a utility's cost of service. In periods of high inflation and increasing costs, it is likely a utility would make annual filings, and in times of low inflation and declining costs, the utility would file a multiyear plan. Consumer Advocate would then be precluded from filing a rate reduction case. While there may be public policy objectives achieved through multiyear plans that are mutually beneficial to

[6] Attachment A to Consumer Advocate's Reply Comments filed October 3, 2003.

the utility and to its customers, more accurately reflecting a utility's cost of providing service is not a primary goal or a likely result.

d. Conclusion

This proposal would make a statutory change to allow the utility to propose and the Board to approve a multiyear rate plan. There have been several periods when multiyear agreements have been approved by the Board based upon a settlement among the parties to a general rate proceeding. This method of setting rates for a period of time has provided rate predictability and has protected consumers. MidAmerican has recognized that current procedures have worked to its benefit as well as the benefit of customers. The current procedures in which the parties negotiate a multiyear plan and bring it to the Board for its approval is a better method of developing rates that are set for a fixed period.

05-7048

KENNY C. GUINN
Governor

STATE OF NEVADA
PUBLIC UTILITIES COMMISSION OF NEVADA
1150 East William Street
Carson City, Nevada 89701-3109
Policy (775) 684-6107 • Fax (775) 684-6110
Staff (775) 684-6101 • Fax (775) 684-6120
http://puc.state.nv.us

RURAL NEVADA
557 W. Silver Street, No. 205
Elko, Nevada 89801
(775) 738-4914 • Fax (775) 778-6928

SOUTHERN NEVADA OFFICE
101 Convention Center Dr., Suite 250
Las Vegas, Nevada 89109
(702) 486-7210 • Fax (702) 486-7206

May 10, 2006

Loren Malkiewich
Director of the Legislative Counsel Bureau
401 S. Carson Street
Carson City, Nevada 89701-4747

RE: The Public Utilities Commission of Nevada's Report to the 74th Session of the Nevada Legislature on Alternatives to the Historical Test Year Methodology Used by Public Utilities in Nevada

Dear Mr. Malkiewich:

Section 7 of Nevada Senate Bill 238 ("SB 238"), passed at the 73rd Session of the Nevada Legislature, directed the Public Utilities Commission of Nevada (the "PUCN") to explore alternatives to the historical test year methodology currently used in Nevada for general rate applications filed by public utilities. The PUCN conducted an investigation into this matter with the assistance of the Regulatory Operations Staff of the PUCN, the Bureau of Consumer Protection, public utilities operating in Nevada and other interested parties. Additionally, the PUCN held a workshop in this matter to provide all interested parties an opportunity present their comments and suggestions.

SB 238 directed the PUCN to submit a written report of its findings and recommendations to the Director of the Legislative Counsel Bureau for transmittal to the 74th Session of the Nevada Legislature no later than October 1, 2006. Pursuant to this directive, the PUCN has drafted a report containing its findings and recommendations attached hereto.

Should you have any questions or concerns, please contact my Administrative Attorney, Cassandra Cordova, at (702) 486-7233.

Sincerely,

Donald L. Soderberg
Chairman, Public Utilities Commission of Nevada

Enclosure

EXHIBIT NO. 503
Case No.: IPC-E-07-08
D. Peseau, Micron

REPORT TO THE 74TH SESSION OF THE NEVADA LEGISLATURE:

ALTERNATIVES TO THE HISTORICAL TEST YEAR METHODOLOGY FOR SETTING PUBLIC UTILITY RATES IN NEVADA

Public Utilities Commission of Nevada

May 10, 2006

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I. NEVADA SENATE BILL 238

The Nevada Legislature passed Nevada Senate Bill ("SB") 238 at its 73rd Session. SB 238 became effective on June 14, 2005. Section 7 of SB 238 directed the Public Utilities Commission of Nevada ("Commission") to open an investigatory docket to "...study, examine and review the various processes, theories and methodologies that may be used to establish just and reasonable rates in cases involving general rate applications filed by public utilities." Over the past several years there has been mounting concern that in a rapid growth state such as Nevada, the historical test year methodology may not be the most accurate methodology in determining general rates. Therefore, the Legislature specifically requested that the Commission open an investigatory docket to explore alternatives to the historical test year methodology used in Nevada for cases involving general rate applications filed by public utilities.

Pursuant to this legislative directive, on July 27, 2005, the Commission opened Commission Docket No. 05-7048 to explore alternative ratemaking methodologies to the historical test year methodology for general rate cases. This matter was conducted by the Commission pursuant to the Nevada Revised Statutes ("NRS") and the Nevada Administrative Code ("NAC"), Chapters 233B, 703, and 704. SB 238 further directed the Commission to submit a written report of its findings and recommendations to the Director of the Legislative Counsel Bureau for transmittal to the 74th Session of the Nevada Legislature no later than October 1, 2006. This report is made pursuant to the Legislative directive.

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II. HISTORICAL TEST YEAR

Public utilities are considered natural monopolies affected with a public interest. A natural monopoly works within a specific service area, and generally builds and operates large expensive equipment with lower unit costs at increasing levels of output to produce and supply an essential everyday service. Direct competition with a natural monopoly is uneconomical since it would require duplicate investments in similarly large expensive equipment. The lack of competition in the public utility's service area allows the utility to restrict output, raise prices and collect monopoly profits. The public interest view of regulation is to protect customers against these practices for a service that is essential to everyday life. As a result, public utilities are subjected to regulation, and the role of regulation is to provide a substitute for the economic controls of competition in assuring fair prices and adequate service to customers.

In Nevada, the Public Utilities Commission's mechanism for setting fair prices (rates) and protecting the customer is based on a historical test year and is codified in NRS 704.110(3). Pursuant to this statute, if a public utility files a general rate case with the Commission to change the rates, the Commission reviews the recorded results of operations for the most recent twelve (12) months that data was available. Essentially, the procedure for calculating rates is to add up the various costs incurred in providing service during a recent 12-month period, commonly referred to as the historical test-year, and divide that by the sales volumes (e.g., kilowatt hours "kWhs" or therms). Additionally, a limited update for known and measurable events that occur within six months after the end of the historical test year is also permitted. The costs of providing service include operating and maintenance expenses, depreciation and amortization expenses, tax expense, interest expense and profit. Investors receive a return on their investment via that portion of rates covering interest and profit (cost of equity). Other things being equal, if the costs of service increase, rates increase.

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The basic assumption underlying the use of a historical period for setting future rates is that historical conditions are sufficiently predictive of likely future circumstances to serve as a reliable method for predicting future costs. Historical costs have the added benefit of offering ready verification. However, under rapidly changing conditions, like the vast and continuous growth experienced by Nevada utilities, historical costs can fail to accurately predict future costs or allow for the timely recovery of new investments. In addition to their rapid growth, Nevada's public utilities are coping with industry-wide challenges associated with changing use characteristics, changing technologies and changing wholesale market structures. If unit costs are reasonably constant, the use of a historical test year is a viable ratemaking methodology, but to account for the rapid growth and changes currently being experienced by Nevada's public utilities using a test year with historical costs can be challenging and ineffective.

In today's environment, timely rates capturing new investments and operating costs are an important source of growth-related revenue for the utility. The new revenue also allows for an improved capital structure and lower capital costs. Without revenue that matches the cost of providing services, Nevada's utilities will require large amounts of debt and equity financings to build the necessary infrastructure to service its growth. This financing results in customer rates that are much higher due to higher capital costs. A financially strong public utility with investment grade credit is in the best interests of customers and will ultimately lower a customer's rates over the life of the new investments compared to a utility with weaker credit ratings.

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III. METHOD USED BY COMMISSION TO GATHER COMMENTS AND DATA

SB 238 directed the Commission to conduct its investigation with the help of interested parties, including the Regulatory Operations Staff of the Commission ("Staff"), the Consumer's Advocate and the Bureau of Consumer Protection in the Office of the Attorney General ("BCP"), each public utility operating in Nevada, and all other interested persons. On August 26, 2005, the Presiding Officer commenced the investigation by requesting comments from interested parties to be filed by October 31, 2005. The Commission received and reviewed comments from the following: jointly from Sierra Pacific Power Company and Nevada Power Company ("the Companies"); Verizon; Utilities, Inc.; Sprint; Southwest Gas Corporation ("SWG"); Southern Nevada Water Authority ("SNWA"); Newmont Mining Corporation ("Newmont"); AT&T; Nevada Rural ILECs; Staff; and the BCP (collectively referred to herein as "the Commentors"). The Commentors provided the Commission with suggestions for alternative ratemaking methodologies and provided information on methodologies used in other jurisdictions.

Based on these initial comments, the Commission was able to develop several alternative ratemaking methodologies for discussion by the Commentors. On December 15, 2005, the Commission issued a second request for comments and Notice of Workshop, scheduled for February 7, 2006, to discuss these alternatives. The Commission received and reviewed comments from the second request from the following Commentors: the Companies; SWG; SNWA; Newmont; AT&T; Nevada Rural ILECs; Staff; and the BCP. At the workshop, the parties were given an opportunity to make a short presentation of their comments and to provide the Commission with any other proposals not discussed in their written comments.

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IV. ALTERNATIVE RATEMAKING METHODOLOGIES USED IN OTHER JURISDICTIONS

Many of the Commentors referenced a study released by the National Association of Regulatory Utility Commissioners ("NARUC") in 1994-1995.[1] The study showed that approximately 24 percent of jurisdictions indicated that they use fully forecasted test years. In the West, California, Oregon and Utah utilize either a fully forecasted or a 12-month forecast test year. California utilizes a fully forecasted test year for both electric and gas utilities. Historic data is filed and then updated as much as possible. Oregon allows all utilities the option of using either a future or historic test year. Utah allows its gas and electric utilities to choose either a fully forecasted test period, or some combination of historical and future months in the test period utilizing a 12-month forecast. (See Attachment 1).

V. ALTERNATIVE RATEMAKING METHODOLOGIES TO HISTORICAL TEST YEAR

As discussed above, the Commission identified several distinct alternative ratemaking methodologies. The methodologies differ from one another in how they incorporate cost levels from a specified period into rates through the ratemaking process. The Commission chose three of these options and asked the Commentors to address the merits of each. The first option ("Option 1") utilizes a fully forecasted future test year based on estimates and forecasts, which may or may not be based on a historical test year. The second option ("Option 2") is a hybrid approach that begins with the historical conditions and then, after the application has been filed, makes adjustments for all reasonably known and measurable data through the rate effective period, which is data that is not fully recorded on the utility's books and records when the historical test year ends, such as new investments and expense changes. The third option ("Option 3") also begins with historical conditions, but is more restrictive than Option 2 because it does not extend into the rate effective period. For each of these options, the "period rates are in effect" is defined as the first year rates go into effect. For example for rates effective on January 1, 2006, the "period rates are in effect" is defined as January 1, 2006 through December 31, 2006. Each of these options is discussed in detail below.

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[1] This study has not been updated by NARUC since 1994-1995.

a. Option 1 - Future test year with all elements fully forecasted to reflect the "period rates are in effect"

A future test year can be based on the most recent 12-month historical data with adjustments that estimate and fully forecast the costs of service to reflect the period rates are in effect, or the entire future test year can be based solely on estimates and forecasts. Regardless of its basis, using a future test year would be the most effective method to account for the impacts that rapid infrastructure and load growth can impose on a utility and its customers. But it is not without controversy. It is controversial because the use of estimated and forecasted data is not based on actual, verifiable, auditable information. Instead, it is comprised of sometimes subjective estimates and forecasts of future billing determinants, revenues, expenses and rate base. Because these estimates and forecasts may be subjective, they may yield the least accurate results in terms of unreasonable rates, which can be either too high or too low. For instance, parties to a ratemaking proceeding have a vested interest to keep rates as high or low as possible. The closer the costs of service are to actual verifiable costs the less biased rates will be.

There are, however, several advantages to using a fully forecasted future test year versus a historical test year. The first is collecting the expected costs of service in rates improves the financial position of the utility, thus lowering its capital costs. Utilizing a fully forecasted future test year also improves the utility's revenue position, which is an important source of growth related revenue for the utility. Another is economic efficiency:[2] when utility rates reflect the costs of service that are expected to occur during the period rates are in effect, consumers will more efficiently choose how to use the utility's services, i.e., through the purchase of energy-efficient appliances, through the purchase of products and services that promote energy conservation, or by using less energy (e.g., turning down the thermostat).

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[2] Consistent with principles of economic efficiency, prices (i.e. rates), should reflect current costs insofar as possible. Customers should receive a "correct" price signal and those who cause costs to be incurred will be responsible for paying for them. Paying for costs on a current basis helps to keep rates predictable and avoids future rate shocks when "catch up" payments would otherwise need to be made.

b. Option 2 - Hybrid test period that starts with the most recent 12-month historical data, and in which all major rate case elements are adjusted for "reasonably known and measurable"[3] data to reflect the period rates are in effect

This method is referred to as a hybrid test period because it is a combination of historical data and estimated data. This is an extremely effective method to account for the impacts that rapid infrastructure and load growth can impose on a utility and its customers. The hybrid test period may be just as effective as a fully forecasted future test year. The hybrid test period starts with the most recent 12-month historical data and adjusts it for "reasonably known and measurable" data to reflect the period rates are in effect. Again, if unit costs are reasonably constant, the use of a historical test year is a viable ratemaking methodology. However, in periods of rapid growth, modifications to the historical test year can enhance its viability more effectively than using a fully forecasted future test year. The desire to use the most recent 12-month historical data and to allow the utility a reasonable opportunity to collect its current costs of service can be accomplished by adjusting the historical data with reasonably known and measurable new investments and expense changes.

Reasonably known and measurable rate base additions and expense changes are more defendable than forecasts and can be more easily calculated than resorting to the forecasts used in a fully forecasted future test year because they are typically based on actual auditable data. For example, revenue requirement impacts of major rate base additions, which are almost completed when the historical test year ends but are not scheduled for commercial operation until the rate effective period are easy to estimate. Certain expense changes, such as annual union pay increases already approved in a contract but not scheduled to go into effect until the rate effective period, can be calculated with minimal controversy. Both of these examples reduce the chance of regulatory lag and earnings shortfalls.

The hybrid test period accomplishes many of the positive things the fully forecasted future test period does, i.e., matching current revenues with load growth to improve financial position, which lowers capital costs, without reverting to totally subjective estimates.

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[3] "Reasonably known and measurable" data is data that is not fully recorded on the utility's books and records when the historical test year ends. Therefore, "reasonably known and measurable" data, although mostly actual, does include minimal estimates.

c. Option 3 - Hybrid test period that starts with the most recent 12-month historical data, and in which all major rate case elements are adjusted for "reasonably known and measurable" data up to 7-months after the general rate case filing date

This hybrid test period starts with the most recent 12-month historical data and adjusts it for "reasonably known and measurable" data up to 7-months after the general rate case's filing date. This method is the similar to Option 2, but it is more restrictive because the adjustments to the historical test year do not extend into the rate effective period. As in Option 2, reasonably known and measurable events reflect actual recorded costs plus minor estimates. This method reflects the same changes the Legislature made to NRS 704.110(4) by SB 238 for gas utilities. It may not, however, go far enough in reflecting the costs of service into the rate effective period since it is limited to seven months beyond the rate case filing date. Therefore, its drawback is that revenues could be lower than required reducing the source of growth related revenue for the utility and impacting the utility's financial position, thus leading to higher capital costs and higher rates for the utility's customers.

d. Commission's Recommendation: Option 2, Hybrid Test Period

After analyzing all three options and carefully reviewing the comments received from interested parties, the Commission believes that Option 2, the hybrid test period, would most accurately reflect costs of service when determining general rates in times of rapid growth. However, the Commission should not be limited to one methodology when faced with a general rate case. The main concern of the Commission is that costs of service should reflect the costs incurred during the period rates are in effect. While the hybrid method may provide the most accurate reflection of costs in periods of rapid growth, the historical ratemaking methodology is still the preferred choice when unit costs are reasonably constant. Therefore, the Commission believes that the hybrid test period should be added as an alternative to the historical ratemaking methodology, and the Commission should be able to choose which methodology is the most appropriate when considering a general rate application from a public utility.

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VI. DISCUSSION OF THE ALTERNATIVE RATEMAKING METHODOLOGIES

SB 238, section 7(2), directed the Commission to address the following areas with respect to each alternative ratemaking methodology: (1) the rate impact on customers and whether the methodology would result in rates that more accurately reflect the costs of providing service to those customers; (2) the cost effectiveness of using the methodology; (3) the fiscal impact on state and local agencies; (4) the procedures and mechanisms necessary to implement the methodology; and (5) any other related matters that the Commission deems appropriate. The Commission instructed the Commentors to address these issues in their written comments. Each of these areas is discussed in detail below.

a. <u>The rate impact on customers and whether the methodology would result in rates that more accurately reflect the costs of providing service</u>

Most Commentors agree that in general, any ratemaking methodology that allows the utility to update major costs of service (plant, revenues, operating and capital expenses) beyond the historical test year would, by design, result in rates that more accurately reflect the costs of providing service as compared to a strict historical test year with minimal adjustments allowed for changes that occur subsequent to the test period. This is particularly true in times of swiftly changing conditions, i.e. high inflation, rapid customer and infrastructure growth, when historical data generally is not representative of future results. The hybrid test period would provide for reasonably known and measurable adjustments to test year historical costs for changes that would occur throughout the period rates are in effect. This would significantly reduce regulatory lag and produce rates which generally would be more reflective of costs that will be incurred during the effective rate period. Either the fully forecasted test period or the hybrid test period will be the most likely ratemaking alternatives to produce rates that will allow recovery of the costs that would be incurred during the period rates are in effect.

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It is not possible to quantify with precision what, if any, rate impact there will be on customers when comparing and contrasting the three options, since the facts and circumstances are different depending on the test period under consideration when a utility files for a change in general rates. The elements of the costs of service are constantly changing. Commentors noted that in Nevada, at least for the last several years, significant growth has caused costs to steadily increase as utilities install facilities to serve new customers and the increased infrastructure necessary to continue to provide safe and reliable service to existing customers. On the other hand, there may be instances where a utility is about to implement a new system or operating procedure that will have a significant positive impact on the utility's productivity. By using a ratemaking methodology that considers changes beyond the traditional historical test year, these projects and other impacted ratemaking elements, which benefit customers through lower costs, would be considered as well.

In a transition to a ratemaking methodology that more accurately matches rate recovery to costs incurred, the Commentors state that there may initially be an upward impact on rates to customers. This should only occur in the first transition to the alternative methodology. Thereafter, once a regular rate case cycle and methodology are established, rates should not change any more or less from case to case than they would under the existing methodology, but rates and costs would be more accurately matched.

In looking at whether states with hybrid test periods have rate levels appreciably different from states with historical test years, there was no apparent correlation; rates in different states appear to depend far more on internal factors than on test year standards.

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b. The cost effectiveness of the methodology

The Commentors agree that general rate case alternatives that rely more on historical data rather than forecasted information are less expensive and easier for utilities to prepare and for all parties to litigate, at least initially. However, the differences in costs of preparing and processing a general rate case, under any of the four methodologies, would be minimal. There would be transition costs associated with the introduction of a new or alternative ratemaking methodology. For example, the utility must develop a new general rate case model, as well as the related testimony to support it. Intervening parties, including Staff, may also have some costs related to time spent to review and/or revise methods they employ to evaluate the utility's filing, for additional training, or they may undertake to develop and employ new analytical techniques. The initial investment would not be recurring and may not be significant.

The primary difference between the three alternative ratemaking methodologies, and the existing ratemaking methodology, is the time period the utility is allowed to consider beyond the historical test year. Commentors agree that it makes very little difference, in terms of increased costs or time, whether the allowable updated period is five months, seven months, twelve months or encompasses a fully-forecasted test period. Each alternative, regardless of the adjustments allowed to update the historical test year, will be fully litigated by the parties involved. As noted earlier, the use of a ratemaking methodology that more accurately matches revenue recovery with cost incurrence will lead to long-term benefits for all parties to the ratemaking process. Inherent in those benefits is increased efficiency and effectiveness in the use of scarce utility, the BCP, and Commission resources.

c. The fiscal impact on state and local agencies

The Commentors state there would be little, if any, fiscal impact on state and local agencies on an ongoing basis, regardless of which of the three alternative ratemaking methodologies is adopted. Although there could be some minor one-time "learning curve" and administrative proceeding costs in transitioning to any new ratemaking methodology.

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d. The procedures and mechanisms necessary to implement the methodologies

Implementation of any of the above-mentioned alternative ratemaking methodologies will necessarily increase the level of complexity of rate case proceedings. However, it is helpful that many of the changes needed to implement the proposals are not entirely new. Commission Staff, the BCP and the Commentors are familiar with forecasting techniques and underlying data which the Commission has relied upon to make decisions. For example, resource planning is already based upon forecasted resource options, loads and capital costs. Energy supply plans are developed with the use of forecasted information. Certain rates, for example gas and electric utilities' base tariff energy rate ("BTER") are already calculated using forecasted sales, fuel and power prices.

The Commentors state it is highly desirable to set ground rules at the outset regarding acceptable parameters for a new alternative to the historical test year to ensure that rate proceedings are not derailed by disputes over techniques and method. Adjustment mechanisms to realign rates and costs as needed could also serve to ameliorate concerns over the precision of forecasted costs and needed utility revenues. It is essential to establish general agreement on these processes and on acceptable levels of precision before the fact in order to avert contentiousness during the transition rate cases. In addition, clear guidelines should reduce the costs of these proceedings to all concerned. These new procedures should be addressed by the Commission in a future rulemaking, where the Commission can adopt, amend, or repeal regulations.

While there is an expectation that eliminating the lag between cost causation and collection will initially lead to higher rates, the data are inconclusive regarding rate levels in future test year States compared with historical test year States. Over time, it should be expected that there will be an initial bump in rates during the "catch up" phase followed by a decline from what rates would otherwise be as financial markets respond to the more favorable, less risky regulatory environment by reducing costs of capital.

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e. Any other matters the parties deem appropriate

The Commentors addressed several areas of concern throughout this investigatory docket that should be investigated by the Commission if the Legislature adopts an alternative ratemaking methodology. First, several Commentors suggested that a public utility should be permitted to use rate indexing whereby a public utility could make periodic adjustments to rates based on an appropriate cost index. Second, one Commentor proposed that a true-up process should be adopted, which would require a public utility to update reasonably known and measurable adjustments after they become actual. Third, the filing requirements for general rate cases would need to be modified to provide the Commission with guidance in determining what data can be identified as reasonably known and measurable. Finally, Commentors were concerned that rate of return regulation has become antiquated for competitive telecommunications carriers and should be modified so that it encompasses the principle that competition serves consumers better than regulation. These concerns are more fully described below.

i. Rate Indexing

Several Commentors recommended that the Commission should adopt a rate indexing system, which allows a public utility to make periodic adjustments to rates based on an appropriate cost index, such as the effects of inflation and efficiency gains on operating and maintenance expenses. Rate indexing is useful when base rates are set every two-years since it keeps the costs of service current with the rate effective period.[4] This would require a minimum of administrative effort on behalf of the Commission Staff to oversee. An adjustment mechanism, combined with a forecasted test year, which begins the day that rates are expected to become effective, would result in a cost-efficient process of setting rates that should closely reflect the actual cost of serving customers.

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[4] Pursuant to NRS 704.110(3), an electric utility must file a general rate application at least every 24 months. The Commission has drafted a Bill Draft Request that would require a public utility which purchases natural gas for resale to file a general rate application every 36 months. (See Attachment 2).

ii. True-Up Process

Another proposal by one of the Commentors would require a public utility to update reasonably known and measurable adjustments after they become actual. However, by adopting this proposal, the Commission would be faced with a significant increase in the administrative effort required to prepare and process a general rate case. The effort involved in preparing a full set of trued-up schedules, work papers and testimony would be the near equivalent of filing an entirely new general rate case. In addition, Staff and other Commentors would have to dedicate significant resources to analyze this "trued-up" information. The Companies support this process, but SWG does not.

iii. Filing Requirements

One Commentor suggested that prior to the time an alternative ratemaking methodology is available to the utilities, the general rate case filing requirements, as set forth in NRS 704.110 and NAC 703.2201 through 703.2452, should be reviewed and modified. The current requirements do not address the issue of what documents would need to be filed in order for the Commission to make a determination of what can be defined as reasonably known and measurable data, nor do they address the procedures and mechanisms the Commission would be required to utilize to make this determination. This review and modification should also include the master data request. The current filing requirements may not be entirely suitable or appropriate for an alternative or new ratemaking methodology.

iv. Telecommunications Carriers: Non-Rural Incumbent Local Exchange Companies

A new approach is needed to Commission regulation of ratemaking that balances the interest of consumers and the regulated carriers, but at the same time is more efficient and reflective of a competitive marketplace. Traditional rate cases for large telecommunications carriers have become relics of the past. Only five states still rate regulate all incumbent local exchange carriers using traditional rate-of-return regulation. Most of the states - including Nevada - have adopted some form of price cap regulation. Rate cases are not practical for large integrated telecommunications companies providing services and products in a competitive marketplace.

Today, in Nevada there are two telecommunications companies that were recently formed as the result of mergers. The merger between AT&T and SBC Nevada formed AT&T Nevada. The merger between Sprint and Nextel formed Embarq. Nevada telecommunications companies, along with their affiliates, market and provide traditional voice service, as well as, high speed data service, voice mail, custom calling features, dial-up Internet access, DSL service, inside wiring, satellite TV programming, Centrex, customer premises equipment, PBXs, key systems, 911 and Enhanced 911 services, public phones, intrastate and interstate long distance services, Caller-ID, call center management, voice over internet protocol ("VoIP"), wireless telephone service, WIFI internet access, two-way paging, instant wireless messaging services, alarm and line monitoring, and private networks. While a few of these services are still subject to traditional rate regulation, the products and most of the services have been deemed "competitive" or "deregulated" and therefore are no longer subject to rate regulation. Attempting to allocate the costs of telephone company equipment and personnel that provide this wide variety of products and services between regulated versus unregulated is increasingly more complex, arbitrary and unnecessary.

Probably the main disadvantage with rate of return regulation, in the increasingly complex telecommunications industry which provides multiple regulated and unregulated services over one joint network, is that setting cost-based prices is increasingly time-consuming and arbitrary.

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The presence of competition further undermines the effectiveness of traditional rate-of-return regulation. Local telephone service is no longer a "natural monopoly" - there are competitors. Under the Telecommunications Act of 1996 ("Telecom Act"), competitive local exchange carriers ("CLECs") can offer services that directly compete with the incumbent local exchange carriers ("ILECs"). As of the end of 2004, the FCC estimated that CLECs provide 18.5% of the switched access lines. Even with the recent changes regarding the availability of Unbundled Network Elements ("UNEs") adopted by the FCC in the Triennial Review proceedings; CLECs still have access to the ILECs local loop plant to provide a competitive alternative to its services. In addition to being entitled to cost-based UNEs, CLECs are also entitled to resell the telecommunications services of the ILEC at a substantial discount. CLECs in Nevada are not subject to rate regulation. In fact, Nevada (along with three other states) provides the CLECs with the greatest flexibility, even when compared to states that do not review CLECs' rates. Competitive carriers in these four states are not required to file tariffs or provide notification of changes and the rate changes are not normally reviewed by their respective state commissions.

The Commission encourages the Legislature to adopt a new framework for telecommunications based on the principle that competition serves consumers better than regulation. This framework can incorporate a "safety net" to ensure that basic telephone service remains affordable and available to residents throughout Nevada by requiring the continued availability of both Lifeline service and a basic service offering which can be supported by universal service funding. This approach strikes an appropriate balance between the need for a safety net and the existence of competition. In addition, it acknowledges that one size does not fit all when it comes to local exchange carriers. By the time the 2007 Legislature addresses this proposal, it will be very appropriate to replace PAR regulation with a framework that acknowledges the new competitive marketplace while continuing to assure the availability of Lifeline service.

The telecommunications market continues to be reviewed very closely at the federal level and as a result deregulation may occur at the federal level before states have time to effectively put deregulation in place.

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The Commission recognizes that telecommunications will continue to change in ways that are driven more by consumer demand than regulation. The Commission also recognizes that State regulation of the telecom industry may need to be further liberalized in light of technology, markets and consumer demand. The Commission stands ready to assist the 2007 Legislature in any effort to review and update Nevada telecommunications law.

VII. COMMISSION RECOMMENDATIONS

The Commission recommends the hybrid test period for its energy utilities that starts with the most recent 12-month historical data and adjusts all major costs of service elements for reasonably known and measurable data through the rate effective period. The Commission believes this hybrid test period has more advantages than either the fully forecasted methodology or the more restrictive hybrid methodology, which adjusts for 7-months of data, to successfully deal with unprecedented infrastructure and load growth, changing use characteristics, changing technologies and changing wholesale market structures, which are being imposed on Nevada's energy utilities and their customers. At the same time, this hybrid approach leverages the existing ratemaking methodology, providing consumers, regulated utilities and the regulatory community with more consistency than the fully forecasted test year methodology.

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The hybrid approach has an advantage over the fully forecasted methodology because it starts with the 12-month historical test year and adjusts it with reasonably known and measurable data, which is based on specific events whose costs are verifiable and easily estimated into the rate effective period, rather than relying on adjustments that are unverifiable and based purely on forecasts. It has the advantage over the more restrictive hybrid approach since it adjusts the 12-month historical test year through the rate effective period rather than to a point in time before rates become effective. As a result, this hybrid methodology would produce rates that would better reflect the actual costs of service that are expected to be incurred during the period rates are in effect thus improving accuracy and reducing regulatory lag. Reflecting the actual costs of service in rates would also send an economically correct pricing signal thus helping customers to efficiently choose how to use the utility's services, i.e. through the purchase of energy-efficient appliances, through the purchase of products and services that promote energy conservation, or by using less energy (turning down the thermostat). Finally, reflecting current costs of service in rates would improve the financial position of the utility thus lowering its cost of capital and improving its source of growth related revenues to build its infrastructure and load.

The Commission agrees with the Commentors that it is highly desirable to set ground rules at the outset regarding acceptable parameters for a new alternative to the historical test year to ensure that rate proceedings are not derailed by disputes over techniques and method. It is essential to establish general agreement on these processes and on acceptable levels of precision before the fact in order to avert contentiousness during the transition rate cases. In addition, clear guidelines should reduce the costs of these proceedings to all concerned. Therefore, the Commission believes that if the hybrid approach is authorized by the Legislature, the new procedures would be addressed by the Commission in a future rulemaking.

The comments regarding rate indexing and true-up processes are very helpful to the Commission. The Commission, however; believes that if the hybrid approach is adopted, coupled with the development of the appropriate procedures during a rulemaking plus a fully litigated rate case filed by the utility will be sufficient. The Commission also recommends that the Legislature review and update Nevada telecommunications law.

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VIII. PROPOSED LEGISLATION TO AUTHORIZE AN ALTERNATIVE RATEMAKING METHODOLOGY: THE HYBRID TEST PERIOD

The Commission has drafted a Bill Draft Request ("BDR") encompassing the elements necessary to implement the hybrid test period as an alternative ratemaking methodology. (See Attachment 3). As discussed above, the main concern of the Commission is that costs of service should reflect the costs incurred during the period rates are in effect. The hybrid test period provides the most accurate reflection of costs in periods of rapid growth, but the historical ratemaking methodology is preferred when unit costs are reasonably constant. Thus, the Commission recommends that the Legislature adopt the hybrid test period as an alternative to the historical ratemaking methodology, but leave the Commission with the option to choose which methodology is the most appropriate when considering a general rate application from a public utility.

The language used in the BDR permits a public utility to elect to use the hybrid methodology, but, if the public utility so elects, it will need to provide the Commission with the 12-month historical data, as well as with data reflecting all expected changes in circumstances which are reasonably known and measurable and which are reasonably forecasted to become effective during the rate effective period. The Commission can then determine which methodology, either the historical methodology or the hybrid methodology, most accurately reflects the costs of service that are expected to be incurred during the period rates are in effect.

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ATTACHMENT 1

TYPE OF TEST YEAR USED IN DETERMINING RATES ELECTRIC AND GAS UTILITIES

AGENCY		TEST YEAR USED IN DETERMINING RATES			
		ELECTRIC		GAS	
FERC		Forecast/Historic	11/	Historic	6/
ALABAMA PSC	21/	Historic	1/ 14/	Historic	1/ 14/
ALASKA PUC		Historic		Historic	
ARIZONA CC		Historic		Historic	
ARKANSAS PSC		Historic/Part Forecast		Historic/Part Forecast	
CALIFORNIA PUC		Full Forecast		Full Forecast	
COLORADO PUC		Historic	12/	Historic	12/
CONNECTICUT DPUC		Forecast		Historic/Forecast	1/
DELAWARE PSC		Historic/Forecast	3/	Historic/Forecast	3/
DC PSC		Historic/Part Forecast		Historic/Part Forecast	
FLORIDA PSC		Historic/Projected		Historic/Projected	
GEORGIA PSC		Full Forecast		Historic/Part Forecast	4/
HAUAII PUC		Full Forecast		Full Forecast	
IDAHO PUC		Historic/Part Forecast	5/	Historic/Part Forecast	5/
ILLINOIS CC		Historic/current/future		Historic/current/future	
INDIANA URC		Historic		Historic	
IOWA UB		Historic		Historic	
KANSAS SCC		Historic	7/	Historic	
KENTUCKY PSC		Historic/Forecast	17/ 19/	Historic/Forecast	17/ 19/
LOUISIANA PSC		Historic		Historic	
MAINE PUC		Historic	12/	Historic	12/
MARYLAND PSC		Historic/Part Forecast	17/	Historic/Part Forecast	17/
MASSACHUSETTS DPU		Historic	1/	Historic	1/
MICHIGAN PSC		Full Forecast (large)/Historic (small)	8/	same	8/
MINNESOTA PUC		Full Forecast (large)/Historic (small)	8/	same	8/
MISSISSIPPI PSC		Full Forecast/Historic		Full Forecast/Historic	
MISSOURI PSC		Historic		Historic	
MONTANA PSC		Historic		Historic	
NEBRASKA PSC		PSC has no jurisdiction over energy utilities			
NEVADA PUC		Historic	13/	Historic	13/
NEW HAMPSHIRE PUC		Historic		Historic	
NEW JERSEY BPU	21/	Partial Forecast	4/	Partial Forecast	4/
NEW MEXICO PUC		Historic		Historic or Forecast	
NEW YORK PSC		Full Forecast (large)/Historic (small)	8/	same	8/
NORTH CAROLINA UC		Historic	17/	Historic	17/
NORTH DAKOTA PSC		Part or Full Forecast	9/	Part or Full Forecast	9/
OHIO PUC		Part Forecast/Historic	10/	Part Forecast/Historic	10/
OKLAHOMA CC		Historic	20/	Historic	20/
OREGON PUC		Full Forecast/Historic		Full Forecast/Historic	
PENNSYLVANIA PUC		Full Forecast (large)/Historic (small)	8/	same	8/
RHODE ISLAND PUC		Historic & Forecast		Historic & Forecast	1/
SOUTH CAROLINA PSC		Historic	17/	Historic	17/
SOUTH DAKOTA PUC		Historic		Historic	
TENNESSEE PSC		Historic & Forecast		Historic & Forecast	
TEXAS PUC TEXAS RC		Historic		Does not regulate	
UTAH PSC		Historic/12-mo forecast		Historic/12-mo forecast	
VERMONT PSB	21/	Historic		Historic	
VIRGINIA SCC		Historic w/ pro forma adjs		Historic w/ pro forma adjs	

WASHINGTON UTC		Historic			Historic	
WEST VIRGINIA PSC		Historic	12/		Historic	12/
WISCONSIN PSC		Full Forecast (large)/Historic (small)		8/	same	8/
WYOMING PSC		Historic			Historic	
VIRGIN ISLANDS PSC		Historic			none in jurisdiction	
ALBERTA EUB		Full Forecast	15/		Full Forecast	
NOVA SCOTIA UARB		Full Forecast			none in jurisdiction	
ONTARIO EB	21/	Full Forecast	2/		Full Forecast	
QUEBEC NGB		Does not regulate			Full Forecast	

FOOTNOTES - TYPE OF TEST YEAR USED IN DETERMINING RATES

1/ Historic test year is required to be normalized, thus removing or averaging any unusual occurrences and updating information for known and measurable changes. Commission is investigating use of forecasted test period; companies may file future test period although formal guidelines or regulations have not yet been adopted.
2/ For Ontario Hydro's bulk power rates, Power Corporation Act presupposes full forecast year.
3/ Test year must be historic. Test period used in determining rates can be historic or projected, but no more than nine months projected.
4/ Often when partial forecast is filed, it is updated to actual by the time case is taken under advisement, thereby becoming historic test year.
5/ Commission normally used historic test year with 12-month average rate base, but has departed from this in several rate cases by approving use of partial or full forecast test year in appropriate circumstances.
6/ Generally, rate increases are based on 12-month historic data ending not more than four months prior to filing date and adjusted for known changes within nine months after the last month of actual experience.
7/ Generally use Historic Test Year, although full forecast test year used in a recent case. Generally inadequate utility budgeting procedures prevent Commission from accurately testing projected data.
8/ Major companies use full forecast; smaller utilities permitted to use historic test year.
9/ Historic test year data must be submitted as supplemental information. Telephone not subject to rate of return regulation.
10/ Use of historic or partial forecast test year is permitted provided that the test year ends no more than nine months subsequent to the date of the filing of the application for an increase in rates and no less than three months of actual data is used.
11/ Major electric rate increases are based on forecast 12-month test period data. Other increases may be based on recent historic data.
12/ Commission normally uses historic test year, but has allowed partially or fully forecasted test year on a limited basis.
13/ Historic test year with six-month update subsequent-expense and capital items must be experienced and certified. Revenue, salary expense, depreciation expense, and Federal Income Taxes are annualized.
14/ New rate concept prescribed for Alabama Power Co. (electric) and Alabama Gas Corp. See Alabama Gas Corp. Settlement, Docket Nos. 18046 and 18328, Alabama Power Co. Settlement, Nos. 18117 and 18416.
Under the Electric Energy Marketing Act, the price at which electric energy is sold by the three utilities to the Alberta Electric Energy Marketing Agency is set on a Full Forecast basis. This price is subject to retroactive adjustment on a Historic test year basis. Purpose of the Agency is to average wholesale electric rates and roll back to the utilities at a uniform rate.
Test year may be historic or use up to 6 months projected. Test year data may be further adjusted for known and measurable changes occurring within succeeding 12 months.
Historic Test year is required to be normalized, thus removing or averaging any unusual occurrences and updating information for known and measurable changes.
18/ Regulates gas pipeline carriers and common carrier oil pipelines.
19/ Forecasted test year permitted by 1992 legislature, new regulations effective 3/12/93 establish rules for filing forecasted test year applications.
1994 legislation requires the CC to "give effect to known and measurable changes occurring or reasonably certain to occur within six months of the end of the test period upon which the rate review is based."
21/ Commission did not respond to request for update information; this data may not be current

ATTACHMENT 2

BILL DRAFT REQUEST FOR 3-YEAR GAS RATE CYCLE

EXPLANATION – Matter in *italics* is new; matter in strikethrough ~~omitted material~~ is material to be omitted.

704.110

3. If a public utility files with the Commission a general rate application, the public utility shall submit with its application a statement showing the recorded results of revenues, expenses, investments and costs of capital for its most recent 12 months for which data were available when the application was prepared. Except as otherwise provided in subsection 4, in determining whether to approve or disapprove any increased rates, the Commission shall consider evidence in support of the increased rates based upon actual recorded results of operations for the same 12 months, adjusted for increased revenues, any increased investment in facilities, increased expenses for depreciation, certain other operating expenses as approved by the Commission and changes in the costs of securities which are known and are measurable with reasonable accuracy at the time of filing and which will become effective within 6 months after the last month of those 12 months, but the public utility shall not place into effect any increased rates until the changes have been experienced and certified by the public utility to the Commission and the Commission has approved the increased rates. The Commission shall also consider evidence supporting expenses for depreciation, calculated on an annual basis, applicable to major components of the public utility's plant placed into service during the recorded test period or the period for certification as set forth in the application. Adjustments to revenues, operating expenses and costs of securities must be calculated on an annual basis. Within 90 days after the date on which the certification required by this subsection is filed with the Commission, or within the period set forth in subsection 2, whichever time is longer, the Commission shall make such order in reference to the increased rates as is required by this chapter.

(a) An electric utility shall file a general rate application pursuant to this subsection at least once every 24 months based on the following schedule:

(1) An electric utility that primarily serves less densely populated counties shall file a general rate application on or before October 3, 2005, and at least once every 24 months thereafter.

(2) An electric utility that primarily serves densely populated counties shall file a general rate application on or before November 15, 2006, and at least once every 24 months thereafter.

(b) A public utility which purchases natural gas for resale shall file a general rate application pursuant to this subsection at least once every 36 months based on the following schedule:

(1) A public utility which purchases natural gas for resale that primarily serves less densely populated counties shall file a general rate application on or before November 7, 2008, and at least once every 36 months thereafter.

(2) A public utility which purchases natural gas for resale that primarily serves densely populated counties shall file a general rate application on or before October 5, 2009, and at least once every 36 months thereafter.

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(e) "A public utility which purchases natural gas for resale that primarily serves less densely populated counties" has the meaning ascribed to it in NRS 704.185.
(f) "A public utility which purchases natural gas for resale that primarily serves densely populated counties" has the meaning ascribed to it in NRS 704.185.

704.185
4. As used in this section:
(a) "A public utility which purchases natural gas for resale that primarily serves densely populated counties" means a utility that, with regard to the provision of purchasing natural gas for resale, derives more of its annual gross operating revenue in this State from customers located in counties whose population is 400,000 or more than it does from customers located in counties whose population is less than 400,000.
(b) "A public utility which purchases natural gas for resale that primarily serves less densely populated counties" means a utility that, with regard to the provision of purchasing natural gas for resale, derives more of its annual gross operating revenue in this State from customers located in counties whose population is less than 400,000 than it does from customers located in counties whose population is 400,000 or more.

ATTACHMENT 3

BILL DRAFT REQUEST FOR PROPOSED RATEMAKING METHODOLOGY

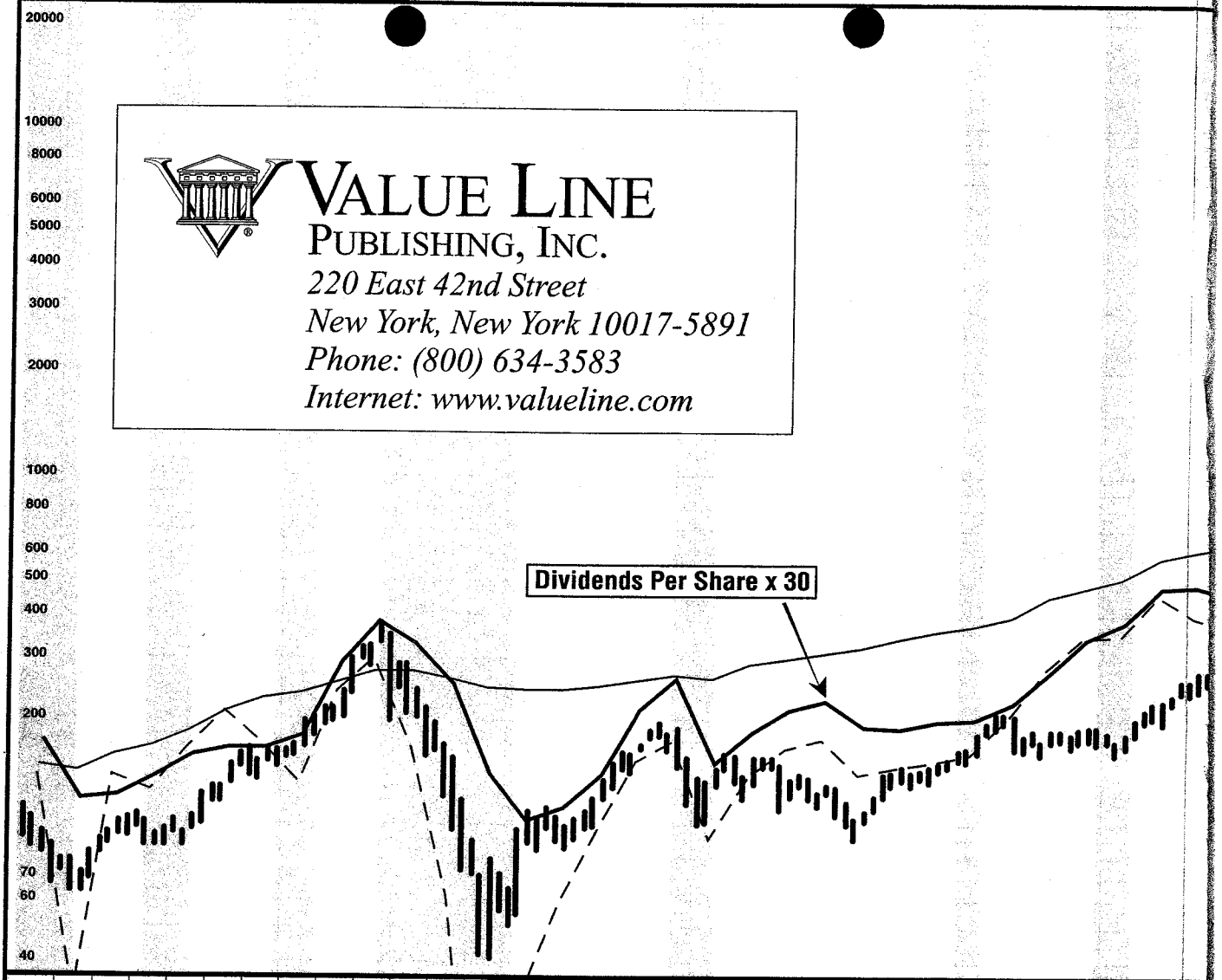
EXPLANATION – Matter in *italics* is new; matter in strikethrough ~~omitted material~~ is material to be omitted.

704.110

4. In addition to submitting the statement required pursuant to subsection 3, a public utility ~~which purchases natural gas for resale~~ may submit with its general rate application a statement showing the effects, on an annualized basis, of all expected changes in circumstances. If such a statement is filed, it must include all increases and decreases in revenue and expenses which may occur within *575* ~~210~~ days after the date on which its general rate application is filed with the Commission if such expected changes in circumstances are reasonably known and are measurable with reasonable accuracy. If a public utility submits such a statement, the public utility has the burden of proving that the expected changes in circumstances set forth in the statement are reasonably known and are measurable with reasonable accuracy. If the Commission determines that the public utility has met its burden of proof:

(a) The Commission shall consider the statement submitted pursuant to this subsection and evidence relevant to the statement in addition to the statement required pursuant to subsection 3 as evidence in establishing just and reasonable rates for the public utility; and

(b) The public utility is not required to file with the Commission the certification that would otherwise be required pursuant to subsection 3.



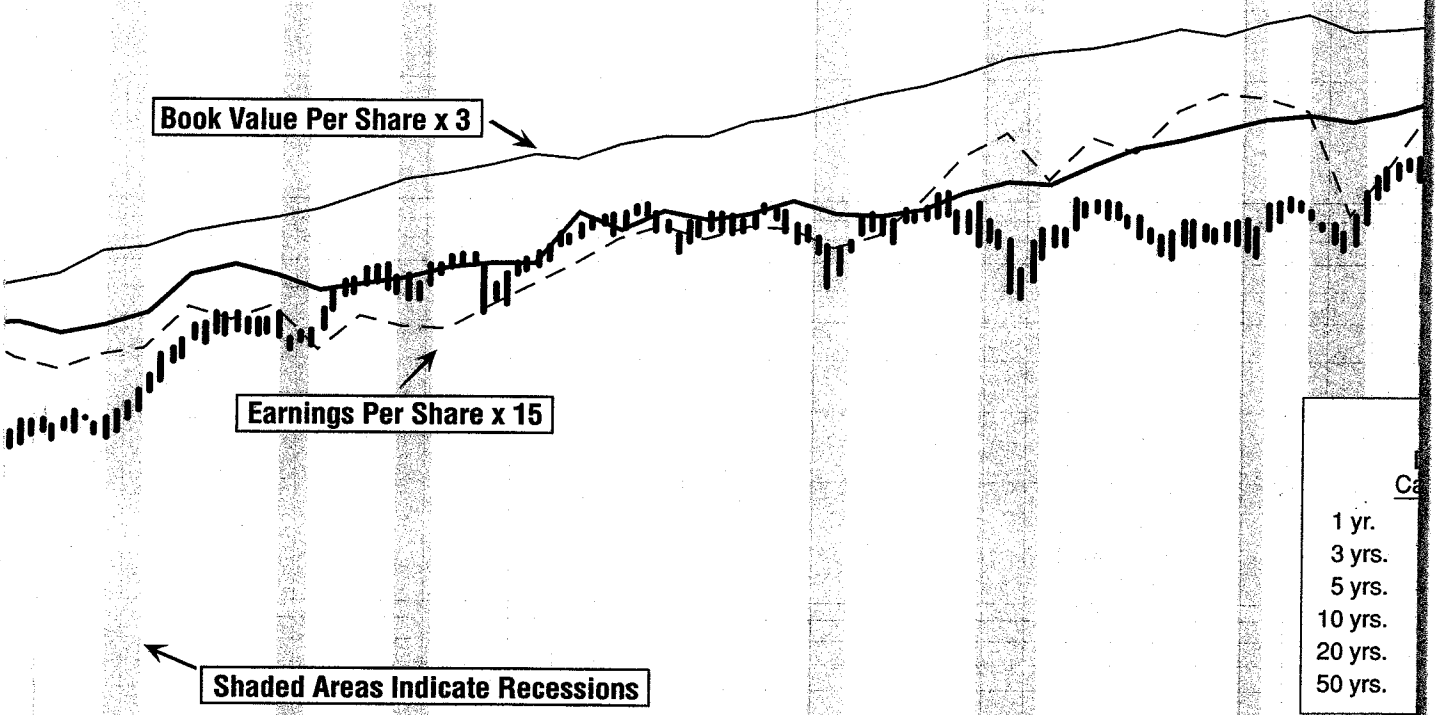
1920	'21	'22	'23	'24	'25	'26	'27	'28	'29	1930	'31	'32	'33	'34	'35	'36	'37	'38	'39	1940	'41	'42	'43	'44	'45	'46	'47	'48	'49	1950	'51
9.1	2.1	9.1	8.3	10.9	13.9	11.4	8.7	16.0	19.9	11.0	4.1	-0.5	2.1	3.9	6.3	10.1	11.5	6.0	9.1	10.9	11.6	9.2	9.7	10.1	10.6	13.6	18.8	23.1	23.5	30.7	26.6
5.8	3.9	4.0	4.5	5.2	5.5	5.5	6.0	9.8	12.8	11.1	8.4	4.6	3.4	3.7	4.6	7.1	8.8	5.0	6.1	7.1	7.6	6.4	6.3	6.6	6.7	7.5	9.2	11.5	12.8	16.1	16.3
48.2	46.4	51.6	55.3	61.0	69.4	75.2	77.9	84.1	91.3	91.2	86.9	81.8	80.5	80.7	82.5	85.5	88.3	87.1	95.6	98.7	103.0	107.0	113.0	118.3	122.7	131.4	149.1	159.7	170.1	194.2	202.6
9.9	34.8	10.2	11.4	9.2	9.6	13.3	20.1	14.2	15.6	21.4	NMF	NMF	NMF	25.1	18.9	16.1	14.5	22.0	15.7	12.3	10.5	11.6	13.8	14.2	16.1	14.1	9.4	7.8	7.6	7.0	9.7
15.5	18.8	23.5	20.8	19.4	24.2	27.4	29.0	23.3	24.4	21.2	16.5	14.0	24.6	26.9	26.4	23.0	19.0	26.6	23.4	19.1	16.0	16.8	21.4	21.8	25.4	25.5	19.3	15.6	14.0	13.4	15.8
18.9	4.5	17.7	14.9	17.8	20.0	15.1	11.2	19.0	21.8	12.1	4.7	-0.6	2.6	4.8	7.7	11.8	13.0	6.9	9.5	11.1	11.3	8.6	8.6	8.5	8.6	10.4	12.6	14.4	13.8	15.8	13.1
10.1	2.9	9.8	8.8	10.9	10.4	7.5	5.0	7.0	6.4	4.7	3.0	-0.8	2.5	4.0	5.3	6.2	6.9	4.5	6.4	8.1	9.6	8.6	7.2	7.0	6.2	7.1	10.6	12.8	13.1	14.2	10.3
6.4	5.3	4.2	4.8	5.2	4.1	3.6	3.5	4.3	4.1	4.7	6.1	7.2	4.1	3.7	3.8	4.3	5.3	3.8	4.3	5.2	6.2	6.0	4.7	4.6	3.9	3.9	5.2	6.4	7.1	7.5	6.3
–	-77.0	NMF	-9.4	31.9	27.7	-18.0	-23.4	83.1	24.9	-44.7	-62.9	NMF	NMF	85.3	62.1	58.8	14.1	-47.7	51.6	19.9	6.6	-20.8	5.6	3.4	4.9	29.1	37.9	22.7	2.0	30.4	-13.4
–	-32.8	1.5	14.2	14.4	7.2	0.2	9.0	61.6	30.6	-12.7	-24.5	-45.0	-26.4	7.6	24.3	54.9	24.5	-43.3	22.7	15.5	7.5	-15.7	-1.6	4.3	1.8	12.1	22.8	24.9	11.2	26.1	1.3
–	-3.7	11.2	7.2	10.3	13.8	8.4	3.6	8.0	8.6	-0.1	-4.7	-5.9	-1.6	0.2	2.2	3.6	3.3	-1.4	9.8	3.2	4.4	3.9	5.6	4.7	3.7	7.1	13.5	7.1	6.5	14.2	4.3
–	-74.1	NMF	-0.7	42.8	38.0	-10.5	-18.5	90.2	31.3	-40.1	-59.9	NMF	NMF	89.3	67.4	65.0	21.0	-43.2	58.0	28.0	16.2	-12.2	12.9	10.4	11.1	36.2	48.5	35.5	15.2	44.6	-3.1
–	-27.5	5.8	19.0	19.6	11.3	3.8	12.5	65.9	34.7	-8.0	-18.5	-37.8	-22.3	11.4	28.1	59.3	29.8	-39.5	27.0	20.8	13.7	-9.7	3.1	8.9	5.8	16.0	28.0	31.3	18.3	33.6	7.6
6.1	6.0	5.1	5.1	5.0	4.9	4.7	4.6	4.5	4.8	4.5	4.6	5.0	4.5	4.0	3.6	3.2	3.3	3.2	3.0	2.8	2.8	2.8	2.7	2.7	2.6	2.5	2.6	2.8	2.7	2.6	2.9
15.6	-10.9	-6.2	1.8	0.4	2.4	0.9	-1.9	-1.2	0.0	-2.7	-8.9	-10.3	-5.2	3.5	2.6	1.0	3.7	-2.0	-1.3	0.7	5.1	10.9	6.0	1.6	2.3	8.5	14.4	7.7	-1.0	1.1	7.9
-9.5	16.9	11.3	3.3	4.6	2.5	3.8	6.5	5.7	4.8	7.2	13.5	15.3	9.7	0.5	1.0	2.2	-0.4	5.2	4.3	2.1	-2.3	-8.1	-3.3	1.1	0.3	-6.0	-11.8	-4.9	3.7	1.5	-5.0
109.9	81.5	103.4	105.4	120.5	159.4	166.6	202.4	300.0	381.1	294.1	194.4	88.8	108.7	110.7	148.4	184.9	194.4	158.4	155.9	152.8	133.6	119.7	145.8	152.5	195.8	212.5	186.9	193.2	200.5	235.5	276.4
66.8	63.9	78.6	85.8	88.3	115.0	135.2	152.7	191.3	198.7	157.5	73.8	41.2	50.2	85.5	96.7	143.1	113.6	99.0	121.4	111.8	106.3	92.9	119.3	134.2	151.4	163.1	163.2	165.4	161.6	196.8	239.0
90.0	73.4	93.2	94.9	99.6	134.5	153.0	175.8	226.0	311.2	236.3	138.6	64.6	83.7	98.3	120.0	162.2	166.4	132.4	142.7	134.7	121.8	107.2	134.8	143.3	169.8	191.6	177.6	179.9	179.5	216.3	257.6
–	–	–	–	–	–	–	–	19.94	26.12	21.04	13.64	6.91	9.06	9.83	10.59	15.44	15.38	11.46	12.05	11.01	9.83	8.66	11.52	12.47	15.13	17.09	15.16	15.54	15.22	18.40	22.32
–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
91.5	69.6	74.2	85.3	84.9	93.3	97.2	95.1	97.1	103.8	91.1	76.4	58.6	56.2	65.9	73.1	83.6	91.8	85.4	91.9	101.2	126.7	161.6	198.3	219.7	223.2	222.6	244.6	269.7	267.8	294.6	339.7

* Average 1920 - 2005 inclusive. (A) Excludes net nonrecurring per share loss: 1983, $12.48; 1984, $7.46; 1985, $16.39; 1986, $3.67; 1987, $24.68; 1988, $0.36; 1989, $7.29; 1990, $8.63; 1991, $27.24 ; 1992, $132.36; 1993, $32.99 1994 $1.34; 1995, $15

EXHIBIT NO. 504, P. 1 of 3
Case No.: IPC-E-07-08
D. Peseau, Micron

A Long-Term Perspective

Dow Jones Industrial Average, 1920-2005
(Quarterly Price Range)



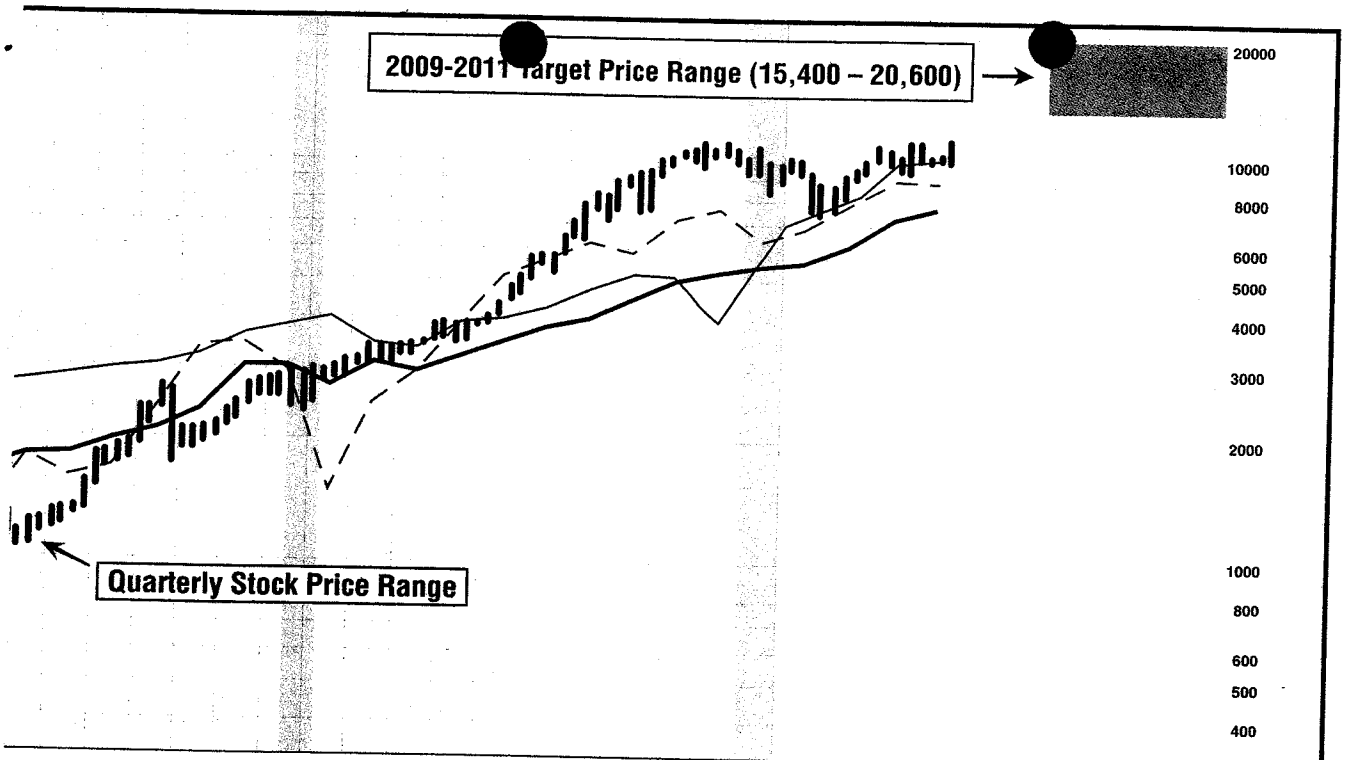
Ca

1 yr.
3 yrs.
5 yrs.
10 yrs.
20 yrs.
50 yrs.

'51	'52	'53	'54	'55	'56	'57	'58	'59	1960	'61	'62	'63	'64	'65	'66	'67	'68	'69	1970	'71	'72	'73	'74	'75	'76	'77	'78	'79	1980	'81	'82	'83
26.6	24.8	27.2	28.2	35.8	33.3	36.1	28.0	34.3	32.2	31.9	36.4	41.2	46.4	53.7	57.7	53.9	57.9	57.0	51.0	55.1	67.1	86.2	99.0	75.7	96.7	89.1	112.8	124.5	121.9	113.7	62.0	84.9
16.3	15.4	16.1	17.5	21.6	23.0	21.6	20.0	20.7	21.4	22.7	23.3	23.4	31.2	28.6	31.9	30.2	31.3	33.9	31.5	30.9	32.3	35.3	37.7	37.5	41.4	45.8	48.5	51.0	54.4	56.2	54.1	56.3
212.6	213.4	244.3	249.0	271.8	284.8	298.7	311.0	339.0	369.9	385.8	401.0	425.9	417.4	453.3	475.9	476.5	521.1	542.3	573.2	607.6	642.9	690.2	747.0	783.6	798.2	841.8	890.7	859.4	928.5	975.6	881.5	888.2
9.7	10.9	10.1	11.8	12.4	14.8	13.2	17.6	18.4	19.2	21.7	17.6	17.3	18.0	17.0	15.1	16.3	15.7	15.4	14.8	16.1	14.1	10.7	7.7	10.6	10.1	10.0	7.3	6.8	7.3	8.2	14.3	14.0
15.8	17.6	17.1	19.1	20.5	21.4	22.0	24.6	30.5	28.9	30.4	27.5	30.5	26.7	31.8	27.4	29.1	28.9	25.9	23.9	28.7	29.4	26.2	20.1	21.4	23.5	19.5	16.9	16.6	16.4	16.6	16.3	21.1
13.1	11.6	11.1	11.3	13.2	11.7	12.1	9.0	10.1	8.7	8.3	9.1	9.7	11.1	11.8	12.1	11.3	11.1	10.5	8.9	9.1	10.4	12.5	13.3	9.7	12.1	10.6	12.7	14.5	13.1	11.7	7.0	9.6
10.3	9.2	9.9	8.4	8.1	6.8	7.6	5.7	5.4	5.2	4.6	5.7	5.8	5.6	5.9	6.6	6.1	6.4	6.5	6.8	6.2	7.1	9.3	13.0	9.4	9.9	10.0	13.8	14.7	13.7	12.2	7.0	7.1
16.3	5.7	5.8	5.2	4.9	4.7	4.5	4.1	3.3	3.5	3.3	3.6	3.3	3.7	3.1	3.7	3.4	3.5	3.9	4.2	3.5	3.4	3.8	5.0	4.7	4.2	5.1	5.9	6.0	6.1	6.0	6.1	4.7
13.4	-6.8	9.9	3.5	27.0	-6.8	8.2	-22.5	22.8	-6.1	-0.9	14.2	13.1	12.7	15.6	7.5	-6.6	7.5	-1.5	-10.5	8.0	21.8	28.4	14.9	-23.6	27.8	-7.9	26.6	10.4	-2.1	-6.7	-45.5	37.0
11.3	-5.6	4.4	8.4	23.5	6.5	-6.0	-7.5	3.7	3.0	6.3	2.6	0.5	33.4	-8.4	11.5	-5.3	3.8	8.2	-7.0	-2.1	4.6	9.5	6.8	-0.7	10.5	10.7	5.8	5.1	6.6	3.4	-3.7	4.0
14.3	5.3	14.5	1.9	9.2	4.8	4.9	4.1	9.0	9.1	4.3	3.9	6.2	-2.0	8.6	5.0	0.1	9.4	4.1	5.7	6.0	5.8	7.4	8.2	4.9	1.9	5.5	5.8	-3.5	8.0	5.1	-9.6	0.8
13.1	2.3	19.8	11.9	35.1	-0.1	15.8	-16.8	28.2	-0.9	3.7	19.9	18.9	18.2	21.5	14.1	-0.5	13.9	5.0	-3.7	14.2	28.9	37.7	28.0	-14.2	37.8	2.1	40.4	25.1	11.6	5.5	-38.5	44.1
17.6	0.1	10.2	13.7	28.4	11.2	-1.5	-3.4	7.0	6.4	9.6	6.2	3.7	37.2	-5.3	15.1	-1.9	7.3	12.0	-2.8	1.4	8.0	13.3	11.7	4.0	14.8	15.8	11.8	11.1	12.7	9.4	2.4	8.8
12.9	3.0	3.2	2.9	3.1	3.4	3.9	3.8	4.4	4.4	4.3	4.3	4.3	4.4	4.5	5.1	5.5	6.2	7.0	8.0	7.4	7.2	7.4	8.6	8.8	8.4	8.0	8.7	9.6	11.9	14.2	13.8	12.0
17.9	2.3	0.8	0.3	-0.3	1.5	3.3	2.7	1.0	1.5	1.1	1.2	1.2	1.3	1.6	3.0	2.8	4.3	5.5	5.8	4.3	3.3	6.2	11.1	9.1	5.7	6.5	7.6	11.3	13.5	10.3	6.1	3.2
15.0	0.7	2.4	2.6	3.4	1.9	0.6	1.1	3.4	2.9	3.2	3.1	3.1	3.1	2.9	2.1	2.7	1.9	1.5	2.2	3.1	3.9	1.2	-2.5	-0.3	2.7	1.5	1.1	-1.7	-1.6	3.9	7.7	8.8
16.4	292.0	293.8	404.4	488.4	521.1	520.8	583.7	679.4	685.5	734.9	726.0	767.2	891.7	969.3	995.2	943.1	985.2	968.9	842.0	950.8	1036	1052	891.7	879.0	1015	999.8	907.7	897.6	1000	1024	1071	1287
19.0	256.4	255.5	279.9	388.2	462.4	419.8	436.9	574.5	566.1	610.3	535.8	646.8	766.1	840.6	744.3	786.4	825.1	769.9	631.2	798.0	889.2	788.3	577.6	632.0	858.7	801.5	742.1	796.7	759.1	824.0	776.9	1027
17.6	270.8	276.0	333.9	442.7	493.0	475.7	491.7	632.1	618.0	691.5	639.8	714.8	834.0	910.9	873.6	879.1	906.0	876.7	753.2	884.8	949.1	923.9	759.4	802.5	974.9	894.6	820.2	844.4	891.4	932.9	884.4	1190
1.32	24.50	24.72	29.72	40.49	46.65	44.42	46.20	57.41	55.85	66.27	62.32	69.86	81.37	88.15	85.18	91.96	98.37	97.77	83.18	98.31	109.1	107.4	82.78	86.18	102.0	98.18	96.12	103.0	118.7	128.0	119.7	160.5
–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	137.2
9.7	358.6	379.7	381.3	415.1	438.0	461.0	467.3	507.2	526.6	544.8	585.2	617.4	663.0	719.1	787.8	833.6	910.6	982.2	1036	1125	1237	1383	1497	1631	1819	2031	2296	2566	2796	3131	3259	3535

$15.81; 1996, $15.44; 1997, $26.24; 1998, $12.48; 1999, $8.01; 2000, $5.71; 2001, $35.50; 2002, $33.23; 2003, $0.26; 2004, $4.43; 2005, $15.23; as determined by Value Line, Inc. (B) Estimated 1920 - 1935. (C) Annual average excludes years with NMF: 1931

EXHIBIT NO. 504, P. 2 of 3
Case No.: IPC-E-07-08
D. Peseau, Micron



Average Annualized Rates, 50-Year Summary

DJIA, Dividend + Capital Appreciation	P/E Ratio	Earnings Growth	Earnings as % of Price	Inflation Rate	AAA-Corp. Bond Yield
1.7%	17.9	-4.3%	6%	3.4%	5.7%
11.2%	17.3	8.4%	6%	2.8%	5.6%
2.0%	18.9	3.3%	5%	2.6%	6.1%
9.8%	19.1	5.5%	5%	2.5%	6.6%
13.1%	16.3	8.9%	6%	3.0%	7.6%
10.3%	13.7	5.8%	7%	4.1%	7.5%

'84	'85	'86	'87	'88	'89	1990	'91	'92	'93	'94	'95	'96	'97	'98	'99	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Legend
20.4	106.2	113.6	160.8	228.0	233.9	197.9	100.8	165.8	199.1	262.9	343.2	378.5	420.1	396.3	480.3	500.1	413.9	461.1	523.2	614.3	587.6	Average*						
60.6	62.0	67.0	71.2	79.5	103.0	103.7	95.18	100.7	99.66	105.7	116.6	131.1	136.1	151.1	168.5	172.1	181.1	189.7	210.7	239.7	257.8	–						Earnings per share (A)
16.7	945.0	986.5	1009	1075	1276	1332	1301	1146	1118	1305	1337	1414	1594	1692	1638	1315	2464	2287	2810	3519	3584	–						Dividends per share
9.8	12.5	15.8	14.1	9.0	10.7	13.4	31.8	19.7	17.7	14.2	13.1	15.2	17.7	21.8	21.8	21.5	24.7	20.0	17.2	16.8	17.9	–						Book Value per share (B)
9.4	21.4	26.8	31.8	25.9	24.4	26.0	30.4	30.9	34.9	35.3	38.6	43.8	54.7	57.1	62.2	62.4	56.4	48.6	42.8	43.0	40.9	14.5						Price-Earnings Ratio (C)
																						26.6						Price-Dividend Ratio
3.1	11.2	11.5	15.9	21.2	19.4	15.0	7.6	14.5	17.8	21.7	26.0	27.5	27.9	24.1	28.8	33.9	21.9	19.4	20.5	19.4	16.5	13.4%						Earned as a % of Book Value
0.2	8.0	6.3	7.1	11.1	9.3	7.5	3.2	5.1	5.7	7.0	7.6	6.6	5.6	4.6	4.6	4.7	4.1	5.0	5.8	6.0	5.6	7.4%						Earned as a % of Avg. Price
5.1	4.7	3.7	3.1	3.9	4.1	4.0	2.8	3.2	2.9	2.8	2.6	2.3	1.8	1.8	1.6	1.6	1.8	2.1	2.3	2.3	2.4	4.2%						Dividend Yield
1.8	-11.8	7.0	41.5	41.8	2.6	-18.0	-47.4	64.5	20.0	25.3	30.6	10.3	11.0	-5.7	21.2	4.1	-17.2	11.4	13.5	17.4	-4.3	5.3%						Earnings Growth Rate
7.6	2.3	8.1	6.2	11.7	29.5	0.1	-10.0	14.3	-4.9	5.4	10.3	12.5	3.8	11.0	11.5	2.1	5.2	4.8	11.1	13.8	7.6	4.9%						Dividend Growth Rate
3.2	3.1	4.4	2.3	6.5	12.2	5.8	4.3	-14.0	-2.5	16.8	2.5	5.7	12.7	6.1	-3.2	-19.7	87.3	-7.2	22.9	25.2	1.8	5.2%						Book Value Growth Rate
2.0	-3.8	13.3	48.7	52.8	11.9	-10.6	-44.3	69.6	25.7	32.3	38.2	16.9	16.6	-1.1	25.8	8.8	-13.2	16.4	19.3	23.4	1.2	12.7%						Earn's as % of Price + Earn's Growth
2.8	7.0	11.8	9.4	15.6	33.6	4.1	-7.2	17.5	-2.0	8.2	12.9	14.8	5.6	12.8	13.1	3.7	7.0	6.8	13.4	16.1	10.0	9.2%						Dividend Yield + Dividend Growth
2.7	11.4	9.0	9.4	9.7	9.3	9.3	8.8	8.1	7.2	8.0	7.6	7.4	7.3	6.5	7.0	7.6	7.1	6.5	5.7	5.6	5.2	5.9%						Moody's Aaa Corp. Bond Yield
4.3	3.5	1.9	3.7	4.1	4.8	5.4	4.2	3.0	3.0	2.6	2.8	3.0	2.3	1.6	2.7	3.4	1.6	2.4	1.9	3.3	3.4	3.0%						CPI Growth Rate:Inflation
3.4	7.9	7.1	5.7	5.6	4.5	3.9	4.6	5.1	4.2	5.4	4.8	4.4	5.0	4.9	4.3	4.2	5.5	4.1	3.8	2.3	1.8	3.0%						Real L.T. Aaa Corp. Bond Yield
87	1553	1956	2722	2184	2791	3000	3169	3413	3794	3978	5216	6561	8259	9374	11497	11723	11338	10634	10454	10855	10941	–						DJIA High for Year
87	1185	1502	1739	1879	2145	2365	2470	3137	3242	3593	3832	5033	6392	7539	9121	9796	8236	7285	7524	9750	10012	–						DJIA Low for Year
78	1330	1797	2264	2062	2510	2670	2933	3282	3565	3735	4494	5740	7448	8631	10482	10731	10209	9214	9007	10316	10547	–						DJIA Average for Year
1.5	186.8	236.4	287.0	265.9	323.0	334.6	376.2	415.7	451.6	460.4	541.7	670.5	873.4	1086	1327	1427	1194	994	965	1131	1207	–						S&P 500 Avg. for Year
.1	159.8	200.4	235.9	233.6	281.1	262.0	302.2	353.7	420.2	455.1	518.0	621.0	787.6	896.9	971.5	1072	1174	1126	1224	1598	1803	–						Value Line Avg. for Year
33	4213	4453	4743	5108	5489	5803	5996	6338	6657	7072	7398	7817	8304	8747	9268	9817	10128	10470	10971	11734	12487	–						Gross Domestic Product (D)

33. (D) Gross National Product from: 1920 - 1928. Factual material is obtained from sources believed to be reliable, but the publisher is not responsible for errors or omissions contained herein. Copyright 2006 by Value Line Publishing, Inc.

IDACORP, INC. NYSE-IDA

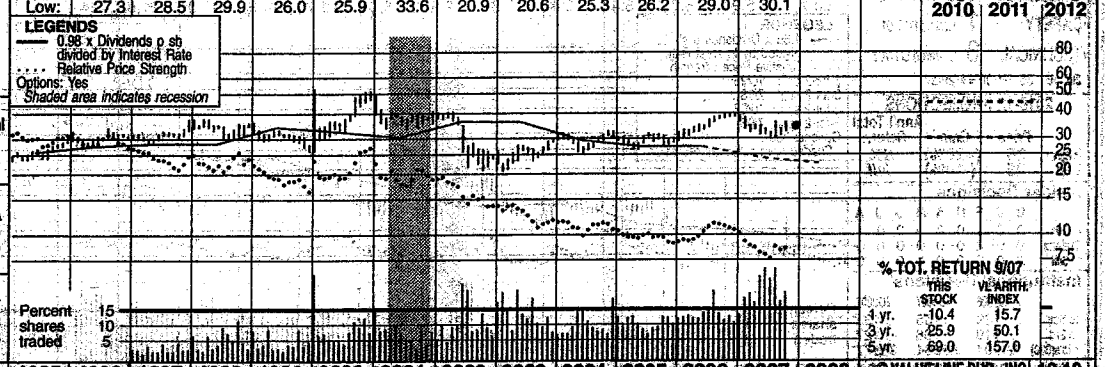
RECENT PRICE 34.58 | P/E RATIO 17.0 (Trailing: 16.0; Median: 15.0) | RELATIVE P/E RATIO 0.92 | DIV'D YLD 3.5% | VALUE LINE 1777

TIMELINESS 3 Raised 8/17/07
SAFETY 3 Lowered 2/14/03
TECHNICAL 3 Lowered 10/26/07
BETA 1.00 (1.00 = Market)

High:	34.3	37.8	38.1	36.5	53.0	49.4	41.0	30.2	32.9	32.1	40.2	39.2
Low:	27.3	28.5	29.9	26.0	25.9	33.6	20.9	20.6	25.3	26.2	29.0	30.1

Target Price Range 2010 | 2011 | 2012

LEGENDS
— 0.98 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+30%)	7%
Low	30	(-15%)	-4%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	0	0	0	0	0	0	0
to Sell	1	0	0	2	2	2	0	0	1

Institutional Decisions

	4Q2006	1Q2007	2Q2007
to Buy	89	84	93
to Sell	78	84	78
Hld's(000)	28485	27777	34771

Percent shares traded 15 10 5

% TOT. RETURN 9/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	-10.4	15.7
3 yr.	25.9	50.1
5 yr.	69.0	157.0

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
14.22	13.76	14.57	14.45	14.51	15.38	19.90	29.83	17.50	27.10	150.10	24.43	20.41	20.00	20.15	21.23	20.10	21.80	Revenues per sh	27.80
3.26	3.16	3.53	3.39	3.89	4.05	4.22	4.69	4.50	5.63	5.63	4.08	3.50	4.12	3.87	4.64	4.35	4.55	"Cash Flow" per sh	5.25
1.56	1.55	1.97	1.80	2.10	2.21	2.32	2.37	2.43	3.50	3.35	1.63	.96	1.90	1.75	2.35	2.00	2.15	Earnings per sh A	2.25
1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.70	1.20	1.20	1.20	1.20	Div'd Decl'd per sh B† ■	1.20
3.94	3.26	3.32	2.94	2.23	2.49	2.51	2.37	2.95	3.73	4.78	3.53	3.89	4.73	4.53	5.16	6.95	6.15	Cap'l Spending per sh	5.25
17.06	17.28	17.86	17.91	18.15	18.47	18.93	19.42	20.02	21.82	23.15	23.01	22.54	23.88	24.04	25.76	26.50	27.75	Book Value per sh C	30.95
33.98	36.19	37.09	37.61	37.61	37.61	37.61	37.61	37.61	37.61	37.63	38.02	38.34	42.22	42.66	43.63	44.30	46.30	Common Shs Outst'g D	47.50
16.8	17.0	15.4	13.9	12.4	13.7	13.6	14.4	12.7	10.9	11.4	18.9	26.5	15.5	16.7	15.1	Bold figures are		Avg Ann'l P/E Ratio	16.5
1.07	1.03	.91	.91	.83	.86	.78	.75	.72	.71	.58	1.03	1.51	.82	.89	.82	Value Line		Relative P/E Ratio	1.10
7.1%	7.1%	6.1%	7.4%	7.2%	6.1%	5.9%	5.4%	6.0%	4.9%	4.9%	6.0%	6.7%	4.1%	4.1%	3.4%	estimates.		Avg Ann'l Div'd Yield	3.2%
						748.5	1122.0	658.3	1019.4	5648.0	928.8	782.7	844.5	859.5	926.3	890	1010	Revenues ($mill)	1320
						92.3	94.8	96.9	137.6	130.0	66.3	40.1	77.8	63.7	100.1	88.0	97.0	Net Profit ($mill)	105
						33.5%	32.0%	32.0%	32.1%	33.3%	--	--	--	16.9%	13.3%	32.0%	32.0%	Income Tax Rate	32.0%
						.6%	1.3%	3.2%	3.6%	3.1%	3.0%	7.5%	3.9%	4.7%	4.0%	5.0%	5.0%	AFUDC % to Net Profit	5.0%
						46.2%	49.4%	48.9%	48.3%	46.4%	49.2%	50.8%	49.3%	50.0%	45.2%	47.5%	47.5%	Long-Term Debt Ratio	50.0%
						46.8%	44.2%	44.8%	45.9%	47.9%	47.9%	46.4%	50.7%	50.0%	54.8%	52.5%	52.5%	Common Equity Ratio	50.0%
						1522.2	1652.3	1680.3	1790.0	1818.0	1826.9	1882.5	1987.8	2048.8	2052.8	2245	2455	Total Capital ($mill)	2940
						1716.9	1711.5	1745.7	1805.0	1886.0	1906.5	2088.3	2209.5	2314.3	2419.1	2620	2795	Net Plant ($mill)	3175
						7.8%	7.3%	7.4%	9.2%	8.7%	5.1%	3.7%	5.3%	4.5%	6.2%	5.5%	5.5%	Return on Total Cap'l	5.0%
						11.3%	11.3%	11.3%	14.9%	13.3%	7.1%	4.4%	7.7%	6.2%	8.9%	7.5%	7.5%	Return on Shr. Equity	7.0%
						12.2%	12.2%	12.1%	16.0%	14.4%	7.0%	4.2%	7.2%	6.2%	8.9%	7.5%	7.5%	Return on Com Equity E	7.0%
						2.4%	2.6%	2.9%	7.5%	6.3%	NMF	NMF	2.7%	1.3%	4.3%	3.0%	3.5%	Retained to Com Eq	3.5%
						82%	80%	78%	55%	58%	113%	NMF	65%	80%	51%	60%	56%	All Div'ds to Net Prof	53%

CAPITAL STRUCTURE as of 6/30/07
Total Debt $1241.8 mill. Due in 5 Yrs $401.7 mill.
LT Debt $1064.6 mill. LT Interest $55.5 mill.
(LT interest earned: 2.8x)

Pension Assets-12/06 $400.9 mill. Oblig. $425.6 mill.

Pfd Stock None

Common Stock 44,303,372 shs.

MARKET CAP: $1.5 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+2.0	--	+1.0
Avg. Indust. Use (MWH)	26548	26535	26731
Avg. Indust. Revs. per KWH (¢)	3.35	3.45	2.96
Capacity at Peak (Mw)	2912	3084	3085
Peak Load, Summer (Mw)	2843	2963	3084
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+3.2	+3.8	+3.6
Fixed Charge Cov. (%)	148	207	274

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	3.5%	20.5%	5.0%
"Cash Flow"	1.0%	-4.5%	4.0%
Earnings		-8.5%	2.0%
Dividends	-4.5%	-8.5%	Nil
Book Value	3.0%	2.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	188.2	211.9	246.7	197.7	844.5
2005	195.6	204.9	248.4	210.6	859.5
2006	268.4	242.6	230.5	184.8	926.3
2007	205.9	213.8	261.5	208.8	890
2008	235	260	270	245	1010

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.51	.34	.68	.37	1.90
2005	.55	.22	.56	.42	1.75
2006	.64	.53	.76	.42	2.35
2007	.56	.40	.69	.35	2.00
2008	.60	.43	.75	.37	2.15

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.465	.465	.465	.465	1.86
2004	.465	.465	.465	.30	1.70
2005	.30	.30	.30	.30	1.20
2006	.30	.30	.30	.30	1.20
2007	.30	.30	.30		

BUSINESS: IDACORP, Inc. is the holding company for Idaho Power, a utility that owns 17 hydroelectric generation developments and partly owns three coal plants. Sold a patented fuel cell system in 2006. Sells electricity in Idaho (96% of revenues.) and Oregon (4%). Revenue breakdown: residential, 33%; commercial, 18%; industrial, 11%; other, 38%. Fuel and purchased power cost: 43% of '06 revenues; estimated labor costs: 9.0%. 2006 depreciation rate: 2.8%. Fuel sources: hydro, 43%; thermal, 33%; purchases, 24%. Has 1,976 employees. Chairman: Jon H. Miller. Chief Executive Officer & President: J. LaMont Keen. Incorporated: Idaho. Address: 1221 W. Idaho St., Boise, Idaho 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

IDACORP awaits an order on its request for higher rates. The company's energy sales are rising at a 2% annual rate, and they're expected to continue doing so for several years. To meet its obligations, IDA invested $300 million in its electric system since the last rate case. About two-thirds of this amount was spent on 650 miles of new transmission and distribution lines. The balance was allocated to maintenance, improvements on the infrastructure, and environmental work. To achieve a reasonable return on these outlays, the company applied for an increase of $63.9 million, based on an 11.5% return on equity, up from the current 10.25%. A regulatory decision on the request is due by yearend. Whatever amount is granted will take effect February 1st.

Planned resource additions are geared to cover customer requirements for the next 10 years. For starters, IDA has contracted to purchase 45 megawatts (mw) of geothermal energy and 400 mw of wind-driven power. Too, it has begun construction of a 170-mw gas-fired unit and will increase the capacity of the Shoshone Falls hydro unit from 12.5 mw to 62.5 mw, provided that water is available. Meanwhile, supply-side efforts are under way to reduce demand. For the longer term, management may build new facilities at existing coal-fired stations. The program is flexible and is subject to change. At this juncture, the company expects to add 1,250 mw of generation and 285 mw of transmission capacity by 2016. Too, demand-side management should reduce loads by 1,100 mw over the same timeframe.

Subpar hydro conditions point to an earnings downturn in 2007. What's more, last year's favorable tax settlement with the IRS and profits on the sale of sulfur dioxide emission allowances will be absent this year. For now, we estimate 2007 earnings will fall 15%, to $2.00 a share. An order on the pending rate case suggests improved results next year.

The yield is about average by utility standards. But no hike in the payout is likely over the next 3 to 5 years because of the need to conserve funds for the building program. Investors seeking income growth will likely fare better elsewhere.

Arthur H. Medalie *November 9, 2007*

(A) EPS diluted. Excl. nonrecurring gains (loss): '93, 16¢; '00, 22¢; '03, 26¢; '05, (24¢); '06, 17¢. Next earnings report due early Feb. (B) Div'ds historically paid in late Feb., late May, late Aug., and late Nov. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred debits. In '06: $9.65/sh. (D) In mill. (E) Rate Base: Net original cost. Rate allowed on com. eq. in Idaho in '04: 10.25%; earned on avg. system com. eq., '06: 9.3%. Regulatory Climate: Above Average.

Company's Financial Strength	B+
Stock's Price Stability	85
Price Growth Persistence	45
Earnings Predictability	045

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EXHIBIT NO. 505
Case No.: IPC-E-07-08
D. Peseau, Micron

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007

****** REVENUE REQUIREMENT SUMMARY ******

	SOURCES & NOTES	(A) TOTAL	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV PRIMARY (9-P)	(E) GEN SRV SECONDARY (9-S)	(F) AREA LIGHTING (15)	(G) LG POWER PRIMARY (19-P)	(H) IRRIGATION SECONDARY (24-S)
TOTAL RATE BASE		1,882,670,774	783,366,025	44,495,597	40,636,810	380,861,863	835,025	203,578,870	342,575,963
REVENUES FROM RATES									
RETAIL		617,820,268	294,087,610	15,381,328	12,772,697	126,221,210	931,147	65,869,474	70,750,659
TOTAL SALES REVENUES		617,820,268	294,087,610	15,381,328	12,772,697	126,221,210	931,147	65,869,474	70,750,659
TOTAL OTHER OPERATING REVENUES		178,391,078	66,704,398	2,877,448	5,422,220	37,903,523	173,305	28,553,979	23,308,188
TOTAL REVENUES		796,211,346	360,792,008	18,258,776	18,194,917	164,124,733	1,104,452	94,423,453	94,058,847
OPERATING EXPENSES									
WITHOUT INC TAX		629,346,490	261,979,623	14,960,091	14,232,957	127,438,811	862,669	75,810,858	96,893,466
OPERATING INCOME									
BEFORE INCOME TAXES		166,864,856	98,812,384	3,298,685	3,961,959	36,685,922	241,783	18,612,594	(2,834,619)
TOTAL FEDERAL INCOME TAX		46,753,611	27,686,092	924,254	1,110,095	10,278,973	67,745	5,215,035	(794,228)
TOTAL STATE INCOME TAX		2,849,268	1,687,252	56,326	67,652	626,423	4,129	317,816	(48,402)
TOTAL OPERATING EXPENSES		678,949,369	291,352,967	15,940,670	15,410,704	138,344,207	934,542	81,343,709	96,050,836
TOTAL OPERATING INCOME		117,261,976	69,439,041	2,318,105	2,784,212	25,780,526	169,910	13,079,744	(1,991,989)
ADD: IERCO OPERATING INCOME	E10	4,969,962	1,818,331	76,460	127,730	1,134,233	2,131	757,963	659,325
CONSOLIDATED OPER INCOME		122,231,938	71,257,372	2,394,565	2,911,942	26,914,759	172,040	13,837,707	(1,332,665)
RATES OF RETURN		6.49	9.096	5.382	7.166	7.067	20.603	6.797	-0.389
RATES OF RETURN - INDEX		1.000	1.401	0.829	1.104	1.088	3.173	1.047	-0.060
AVERAGE MILLS/KWH		50.20	59.24	73.93	35.41	40.86	157.75	30.70	45.96
REVENUE REQUIREMENT CALCULATION									
RATE OF RETURN REQUIRED		8.561	8.561	8.561	8.561	8.561	8.561	8.561	8.561
REQUIRED REVENUE		681,765,506	287,202,037	17,704,270	13,703,671	135,565,545	766,038	71,765,371	121,095,352
REVENUE DEFICIENCY		63,945,238	(6,885,573)	2,322,942	930,974	9,344,335	(165,109)	5,895,897	50,344,693
PERCENT CHANGE REQUIRED		10.35%	-2.34%	15.10%	7.29%	7.40%	-17.73%	8.95%	71.16%
RETURN AT CLAIMED ROR		161,175,445	67,063,965	3,809,268	3,478,917	32,605,584	71,486	17,428,387	29,327,928
EARNINGS DEFICIENCY		38,943,507	(4,193,406)	1,414,703	566,976	5,690,825	(100,554)	3,590,681	30,660,593
REVENUE REQUIREMENT FOR RATE DESIGN									
TOTAL IDAHO SALES REVENUES		617,820,268	294,087,610	15,381,328	12,772,697	126,221,210	931,147	65,869,474	70,750,659
REQUESTED CHANGE IN REVENUE (%)		10.35%	-2.34%	15.10%	7.29%	7.40%	-17.73%	8.95%	71.16%
SALES REVENUE REQUIRED		681,765,506	287,202,037	17,704,270	13,703,671	135,565,545	766,038	71,765,371	121,095,352
RATE OF RETURN AT REQUIRED REVENUE		8.561	8.561	8.561	8.561	8.561	8.561	8.561	8.561
REQUESTED AVERAGE MILLS/KWH		55.40	57.86	85.10	37.99	43.88	129.78	33.45	78.67
ACTUAL RATE OF RETURN (SALES REVENUE ONLY)		-3.25	0.35	-1.26	-6.49	-3.18	-0.41	-7.60	-7.39
REQUESTED RATE OF RETURN (SALES REVENUE ONLY)		0.15	-0.53	3.96	-4.20	-0.73	-20.18	-4.70	7.31

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007

****** REVENUE REQUIREMENT SUMMARY ******

	SOURCES & NOTES	TOTAL	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
TOTAL RATE BASE		1,882,670,774	2,379,787	2,658,191	537,935	13,907,056	15,284,812	51,552,839
REVENUES FROM RATES		0						
RETAIL		617,820,268	880,610	2,056,146	188,543	5,384,849	4,657,881	18,638,114
TOTAL SALES REVENUES		617,820,268	880,610	2,056,146	188,543	5,384,849	4,657,881	18,638,114
TOTAL OTHER OPERATING REVENUES		178,391,078	198,656	424,365	66,514	2,320,225	2,616,624	7,821,634
TOTAL REVENUES		796,211,346	1,079,266	2,480,511	255,057	7,705,074	7,274,505	26,459,748
OPERATING EXPENSES		0						
WITHOUT INC TAX		629,346,490	793,677	2,112,917	200,450	6,140,109	5,735,756	22,185,105
		0						
OPERATING INCOME		0						
BEFORE INCOME TAXES		166,864,856	285,590	367,594	54,607	1,564,964	1,538,749	4,274,643
TOTAL FEDERAL INCOME TAX		46,753,611	80,019	102,996	15,300	438,485	431,140	1,197,706
TOTAL STATE INCOME TAX		2,849,268	4,877	6,277	932	26,722	26,275	72,991
TOTAL OPERATING EXPENSES		678,949,369	878,572	2,222,190	216,683	6,605,317	6,193,170	23,455,802
TOTAL OPERATING INCOME		117,261,976	200,694	258,322	38,374	1,099,757	1,081,334	3,003,946
		0						
ADD: IERCO OPERATING INCOME	E10	4,969,962	5,897	7,474	1,976	72,014	64,967	241,463
CONSOLIDATED OPER INCOME		122,231,938	206,591	265,795	40,350	1,171,771	1,146,302	3,245,409
RATES OF RETURN		6.492	8.681	9.999	7.501	8.426	7.500	6.295
RATES OF RETURN - INDEX		1.000	1.337	1.540	1.155	1.298	1.155	0.970
AVERAGE MILLS/KWH		50.201	53.90	109.93	34.44	24.99	24.73	26.54
REVENUE REQUIREMENT CALCULATION								
RATE OF RETURN REQUIRED		8.561	8.561	8.561	8.561	8.561	8.561	8.561
REQUIRED REVENUE		681,765,506	875,918	1,993,376	197,906	5,415,739	4,924,264	20,556,018
REVENUE DEFICIENCY		63,945,238	(4,692)	(62,770)	9,363	30,890	266,383	1,917,904
PERCENT CHANGE REQUIRED		10.35	-0.53%	-3.05%	4.97%	0.57%	5.72%	10.29%
RETURN AT CLAIMED ROR		161,175,445	203,734	227,568	46,053	1,190,583	1,308,533	4,413,439
EARNINGS DEFICIENCY		38,943,507	(2,857)	(38,228)	5,702	18,812	162,231	1,168,029
REVENUE REQUIREMENT FOR RATE DESIGN								
TOTAL IDAHO SALES REVENUES		617,820,268	880,610	2,056,146	188,543	5,384,849	4,657,881	18,638,114
REQUESTED CHANGE IN REVENUE (%)		10.35%	-0.53%	-3.05%	4.97%	0.57%	5.72%	10.29%
SALES REVENUE REQUIRED		681,765,506	875,918	1,993,376	197,906	5,415,739	4,924,264	20,556,018
RATE OF RETURN AT REQUIRED REVENUE		8.561	8.561	8.561	8.561	8.561	8.561	8.561
REQUESTED AVERAGE MILLS/KWH		55.40	53.61	106.57	36.15	25.13	26.15	29.28
ACTUAL RATE OF RETURN (SALES REVENUE ONLY)		(3.25)	0.09	-6.25	-5.23	-8.78	-10.04	-9.35
REQUESTED RATE OF RETURN (SALES REVENUE ONLY)		0.15	-0.11	-8.61	-3.49	-8.55	-8.30	-5.62

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
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SUMMARY OF FUNCTIONALIZED COSTS

****** RATE BASE ******

	(A) PLANT IN SERVICE	(B) DEPRECIATION RESERVE	(C) AMORTIZATION RESERVE	(D) SUBSTATION CIAC	(E) NET PLANT	(F) CUSTOMER ADV CONST	(G) ACCUM DEF INC TAXES	(H) ACQUISITION ADJUSTMENT	(I) WORKING CAPITAL	(J) DEFERRED PROGRAMS	(K) SUBSIDIARY RATE BASE	(L) PLNT HLD FOR FUTURE USE	(M) TOTAL RATE BASE
FUNCTION													
PRODUCTION													
DEMAND - POWER SUPPLY	760,409,097	340,483,913	8,020,176	0	411,905,008	0	42,195,020	0	6,660,146	3,361,782	0	0	379,731,915
DEMAND - Summer	0	0	0	0	0	0	0	0	0	0	0	0	0
DEMAND - Non-Summer	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY - POWER SUPPLY	916,959,624	471,866,681	9,671,343	0	435,421,599	0	50,881,992	0	21,901,760	5,761,624	64,384,654	0	476,587,645
ENERGY - Summer	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY - Non-Summer	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0
TRANSMISSION	0	0	0	0	0	0	0	0	0	0	0	0	0
DEMAND - POWER SUPPLY	0	0	0	0	0	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	623,355,694	203,387,772	6,574,648	0	413,393,273	0	34,589,941	0	7,392,060	257,663	0	218,994	386,672,049
DEMAND - SUBTRANSMISSION	0	0	0	0	0	0	0	0	0	0	0	0	0
DEMAND - DIRECT	3,681	1,417	39	0	2,226	0	204	0	44	2	0	0	2,066
	0	0	0	0	0	0	0	0	0	0	0	0	0
DISTRIBUTION	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBSTATIONS - GENERAL	186,855,295	46,218,356	1,970,797	0	138,666,141	0	9,649,659	(16,597)	2,537,886	0	0	570,224	132,107,995
SUBSTATIONS - DIRECT	19,068,034	422,883	201,114	0	18,444,038	0	194,955	(1,694)	258,984	0	0	6	18,506,379
LINES - PRIMARY DEMAND	268,736,374	104,050,594	2,834,412	0	161,851,368	10,209,767	14,912,153	(23,870)	3,650,002	0	0	0	140,355,581
LINES - PRIMARY CUSTOMER	152,612,597	59,089,252	1,609,633	0	91,913,711	5,798,021	8,468,457	(13,555)	2,072,798	0	0	0	79,706,477
LINES - SECONDARY DIRECT	16,134,181	5,310,188	170,170	0	10,653,823	0	895,284	(1,433)	219,136	0	0	0	9,976,242
LINE TRANS - PRIMARY DEMAND	40,778,019	16,560,288	430,093	0	23,787,638	281	2,262,768	(3,622)	553,851	0	0	0	22,074,818
LINE TRANS - PRIMARY CUST	23,157,414	9,404,416	244,246	0	13,508,753	159	1,285,002	(2,057)	314,526	0	0	0	12,536,061
LINE TRANS - SECOND DIRECT	14,924,661	6,061,027	157,413	0	8,706,221	0	828,168	(1,326)	202,708	0	0	0	8,079,435
LINE TRANS - SECOND DEMAND	157,921,840	64,133,355	1,665,631	0	92,122,855	1,149	8,763,066	(14,027)	2,144,909	0	0	0	85,489,521
LINE TRANS - SECOND CUSTOMER	89,682,174	36,420,666	945,895	0	52,315,613	653	4,976,454	(7,966)	1,218,072	0	0	0	48,548,611
LINES - SECONDARY DEMAND	54,943,795	17,715,293	579,502	0	36,648,999	3,804,071	3,048,825	(4,880)	746,252	0	0	0	30,537,474
LINES - SECONDARY CUSTOMER	31,202,011	10,060,331	329,093	0	20,812,586	2,160,292	1,731,396	(2,771)	423,789	0	0	0	17,341,915
SERVICES	53,766,390	31,515,050	567,084	0	21,684,255	7,772,371	2,983,491	(4,776)	730,260	0	0	0	11,653,877
METERS	55,910,396	9,149,146	589,697	0	46,171,553	918	3,102,462	(4,966)	759,380	0	0	0	43,822,587
STREET LIGHTS	4,209,103	2,795,397	44,394	0	1,369,311	95,982	233,563	(374)	57,168	0	0	0	1,096,561
INSTALL ON CUST PREMISES	2,628,194	2,444,495	27,720	0	155,979	(34,436)	145,838	(233)	35,696	0	0	0	80,040
	0	0	0	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTING	0	0	0	0	0	0	0	0	0	0	0	0	0
METER READING	0	0	0	0	0	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	0	0	0	0	0	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	0	0	0	0	0	0	0	0	0	0	0	0	0
MISC	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSUMER INFORMATION	0	0	0	0	0	0	0	0	0	0	0	0	0
CUSTOMER ASSIST	0	0	0	0	0	0	0	0	0	0	0	0	0
SALES EXPENSE	0	0	0	0	0	0	0	0	0	0	0	0	0
ADVERTISING	0	0	0	0	0	0	0	0	0	0	0	0	0
MISC	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0
MISCELLANEOUS	0	0	0	0	0	0	0	0	0	0	0	0	0
DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0
CUSTOMER	0	0	0	0	0	0	0	0	0	0	0	0	0
REVENUE	0	0	0	0	0	0	0	0	0	0	0	0	0
OTHER	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBSTATION CIAC	0	0	0	(22,236,331)	(22,236,331)	0	0	0	0	0	0	0	(22,236,331)
TOTALS	3,473,258,574	1,437,090,522	36,633,103	(22,236,331)	1,977,298,618	29,809,228	191,148,701	(104,146)	51,879,427	9,381,070	64,384,654	789,224	1,882,670,920

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
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SUMMARY OF FUNCTIONALIZED COSTS

****** OPERATING EXPENSES ******

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
FUNCTION	OPERATION & MAINTENANCE	DEPRECIATION EXPENSE	AMORTIZATION EXPENSE	OTHER TAXES	REGULATORY DEB/CRED	PROV FOR DEF FIT	DEFERRED ITC						TOTAL EXPENSES
PRODUCTION													
DEMAND - POWER SUPPLY	95,811,785	20,340,432	1,738,027	3,151,169	0	(2,417,565)	338,177						118,962,025
DEMAND - Summer	0	0	0	0	0	0	0						0
DEMAND - Non-Summer	0	0	0	0	0	0	0						0
ENERGY - POWER SUPPLY	289,552,474	24,106,255	2,095,847	3,672,311	0	(2,915,285)	407,800						316,919,401
ENERGY - Summer	0	0	0	0	0	0	0						0
ENERGY - Non-Summer	0	0	0	0	0	0	0						0
	0	0	0	0	0	0	0						0
TRANSMISSION	0	0	0	0	0	0	0						0
DEMAND - POWER SUPPLY	0	0	0	0	0	0	0						0
DEMAND - TRANSMISSION	26,113,429	14,599,095	1,424,772	3,241,513	0	(1,981,831)	277,225						43,674,202
DEMAND - SUBTRANSMISSION	0	0	0	0	0	0	0						0
DEMAND - DIRECT	129	94	8	19	0	(12)	2						241
	0	0	0	0	0	0	0						0
DISTRIBUTION	0	0	0	0	0	0	0						0
SUBSTATIONS - GENERAL	9,904,028	3,425,314	427,085	960,337	0	(552,877)	77,338						14,241,226
SUBSTATIONS - DIRECT	978,884	101,924	43,583	28,106	0	(11,170)	1,562						1,142,889
LINES - PRIMARY DEMAND	20,208,661	8,989,314	614,237	1,475,989	0	(854,392)	119,515						30,553,323
LINES - PRIMARY CUSTOMER	11,476,289	5,104,938	348,819	838,199	0	(485,200)	67,871						17,350,915
LINES - SECONDARY DIRECT	827,842	463,358	36,877	88,195	0	(51,295)	7,175						1,372,152
LINE TRANS - PRIMARY DEMAND	845,159	803,457	93,204	221,317	0	(129,645)	18,135						1,851,627
LINE TRANS - PRIMARY CUST	479,957	456,275	52,930	125,684	0	(73,624)	10,299						1,051,520
LINE TRANS - SECOND DIRECT	309,326	294,063	34,113	81,002	0	(47,450)	6,637						677,691
LINE TRANS - SECOND DEMAND	3,273,065	3,111,563	360,954	857,100	0	(502,080)	70,233						7,170,834
LINE TRANS - SECOND CUSTOMER	1,858,740	1,767,024	204,982	486,738	0	(285,126)	39,884						4,072,242
LINES - SECONDARY DEMAND	3,343,227	1,600,257	125,582	300,912	0	(174,683)	24,435						5,219,732
LINES - SECONDARY CUSTOMER	1,898,584	908,770	71,317	170,885	0	(99,200)	13,876						2,964,231
SERVICES	1,014,152	2,034,749	122,891	291,783	0	(170,939)	23,912						3,316,547
METERS	11,976,075	2,321,337	127,791	321,258	0	(177,756)	24,865						14,593,571
STREET LIGHTS	1,248,662	237,445	9,621	24,377	0	(13,382)	1,872						1,508,594
INSTALL ON CUST PREMISES	2,724,797	264,725	6,007	18,126	0	(8,356)	1,169						3,006,468
	0	0	0	0	0	0	0						0
CUSTOMER ACCOUNTING	0	0	0	0	0	0	0						0
METER READING	9,629,578	0	0	14,650	0	0	0						9,644,228
CUSTOMER ACCOUNTS	17,058,632	0	0	21,986	0	0	0						17,080,618
UNCOLLECTIBLES	2,926,405	0	0	0	0	0	0						2,926,405
MISC	0	0	0	0	0	0	0						0
	0	0	0	0	0	0	0						0
CONSUMER INFORMATION	0	0	0	0	0	0	0						0
CUSTOMER ASSIST	8,040,987	0	0	9,337	0	0	0						8,050,324
SALES EXPENSE	0	0	0	0	0	0	0						0
ADVERTISING	0	0	0	0	0	0	0						0
MISC	0	0	0	0	0	0	0						0
	0	0	0	0	0	0	0						0
MISCELLANEOUS	0	0	0	0	0	0	0						0
DEMAND	0	0	0	0	0	0	0						0
ENERGY	0	0	0	1,944,834	0	0	0						1,944,834
CUSTOMER	0	0	0	0	0	0	0						0
REVENUE	0	0	0	0	0	0	0						0
OTHER	50,649	0	0	0	0	0	0						50,649
RETAIL SALES REVENUE	0	0	0	0	0	0	0						0
TOTALS	521,551,516	90,930,388	7,938,646	18,345,826	0	(10,951,869)	1,531,983	0	0	0	0	0	629,346,490

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007
SUMMARY OF FUNCTIONALIZED COSTS

****** OTHER REVENUES ******

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
FUNCTION	REVENUES												TOTAL REVENUES
PRODUCTION													
DEMAND - POWER SUPPLY	532,931												532,931
DEMAND - Summer	0												0
DEMAND - Non-Summer	0												0
ENERGY - POWER SUPPLY	154,118,883												154,118,883
ENERGY - Summer	0												0
ENERGY - Non-Summer	0												0
	0												
TRANSMISSION	0												
DEMAND - POWER SUPPLY	0												0
DEMAND - TRANSMISSION	9,324,159												9,324,159
DEMAND - SUBTRANSMISSION	0												0
DEMAND - DIRECT	25												25
	0												
DISTRIBUTION	0												
SUBSTATIONS - GENERAL	86,202												86,202
SUBSTATIONS - DIRECT	8,797												8,797
LINES - PRIMARY DEMAND	1,537,124												1,537,124
LINES - PRIMARY CUSTOMER	872,917												872,917
LINES - SECONDARY DIRECT	48,467												48,467
LINE TRANS - PRIMARY DEMAND	97,833												97,833
LINE TRANS - PRIMARY CUST	55,559												55,559
LINE TRANS - SECOND DIRECT	35,807												35,807
LINE TRANS - SECOND DEMAND	378,881												378,881
LINE TRANS - SECOND CUSTOMER	215,163												215,163
LINES - SECONDARY DEMAND	207,139												207,139
LINES - SECONDARY CUSTOMER	117,632												117,632
SERVICES	128,995												128,995
METERS	25,793												25,793
STREET LIGHTS	10,098												10,098
INSTALL ON CUST PREMISES	6,305												6,305
	0												
CUSTOMER ACCOUNTING	0												
METER READING	0												0
CUSTOMER ACCOUNTS	0												0
UNCOLLECTIBLES	0												0
MISC	0												0
	0												
CONSUMER INFORMATION	0												
CUSTOMER ASSIST	0												0
SALES EXPENSE	0												0
ADVERTISING	0												0
MISC	0												0
	0												
MISCELLANEOUS	0												
DEMAND	0												0
ENERGY	0												0
CUSTOMER	0												0
MISC. REVENUE	4,933,621												4,933,621
FACILITIES CHARGE REVENUE	5,648,745												5,648,745
RETAIL SALES REVENUE													0
TOTALS	178,391,078	0	0	0	0	0	0	0	0	0		0	178,391,078

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007
UNIT COSTS

****** RESIDENTIAL SERVICE - SCHEDULE 1 ******

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	
FUNCTION	RETURN @ 0.349%	OPERATING EXPENSES	SALES REVS PER BOOKS	REVENUE @ -0.530%	BILLING UNITS	UNIT COSTS ($/EACH)	SUMMER ($/KWH)	NON-SUMMER ($/KWH)	SERVICE ($/CUST/MO)	
PRODUCTION										
DEMAND - POWER SUPPLY	0	0	0	0	4,964,097,044	0.00000				
DEMAND - Summer	312,046	31,355,355	31,667,401	30,881,699	1,228,355,483	0.02514	0.02514			
DEMAND - Non-Summer	134,321	13,496,995	13,631,316	13,293,108	3,735,741,561	0.00356		0.00356		
ENERGY - POWER SUPPLY	0	0	0	0	4,964,097,044	0.00000				
ENERGY - Summer	195,508	39,342,142	39,537,650	39,045,379	1,228,355,483	0.03179	0.03179			
ENERGY - Non-Summer	413,185	83,145,429	83,558,614	82,518,252	3,735,741,561	0.02209		0.02209		
ENERGY - ANNUAL						0.0334				
TRANSMISSION										
DEMAND - POWER SUPPLY	0	0	0	0	0	0.00000				
DEMAND - TRANSMISSION	481,708	20,759,942	21,241,649	20,028,755	4,964,097,044	0.00403	0.00403	0.00403		
DEMAND - SUBTRANSMISSION	0	0	0	0	0	0.00000				
DEMAND - DIRECT	0	0	0	0	0	0.00000				
DISTRIBUTION										
SUBSTATIONS - GENERAL	185,513	7,721,344	7,906,857	7,439,752	4,964,097,044	0.00150	0.00150	0.00150		
SUBSTATIONS - DIRECT	0	0	0	0	0	0.00000				
LINES - PRIMARY DEMAND	197,095	14,407,490	14,604,585	14,108,319	4,964,097,044	0.00284	0.00284	0.00284		
LINES - PRIMARY CUSTOMER	233,760	17,087,676	17,321,436	16,732,851	4,623,896	3.61878			3.61878	
LINES - SECONDARY DIRECT	0	0	0	0	0	0.00000				
LINE TRANS - PRIMARY DEMAND	30,999	1,077,803	1,108,801	1,030,750	4,964,097,044	0.00021	0.00021	0.00021		
LINE TRANS - PRIMARY CUST	36,765	1,278,303	1,315,069	1,222,497	4,623,896	0.26439			0.26439	
LINE TRANS - SECOND DIRECT	0	0	0	0	0	0.00000				
LINE TRANS - SECOND DEMAND	137,952	4,796,519	4,934,471	4,587,120	4,964,097,044	0.00092	0.00092	0.00092		
LINE TRANS - SECOND CUSTOMER	142,459	4,953,203	5,095,662	4,736,964	4,623,896	1.02445			1.02445	
LINES - SECONDARY DEMAND	68,465	4,087,712	4,156,177	3,983,789	4,964,097,044	0.00080	0.00080	0.00080		
LINES - SECONDARY CUSTOMER	52,649	3,143,420	3,196,069	3,063,504	4,623,896	0.66254			0.66254	
SERVICES	33,206	3,063,703	3,096,909	3,013,300	4,623,896	0.65168			0.65168	
METERS	79,304	8,417,015	8,496,319	8,296,640	4,623,896	1.79430			1.79430	
STREET LIGHTS	0	0	0	0	0	0.00000				
INSTALL ON CUST PREMISES	0	1,982,914	1,982,914	1,982,914	4,623,896	0.42884			0.42884	
CUSTOMER ACCOUNTING										
METER READING	0	7,008,071	7,008,071	7,008,071	4,623,896	1.51562			1.51562	
CUSTOMER ACCOUNTS	0	14,269,027	14,269,027	14,269,027	4,623,896	3.08593			3.08593	
UNCOLLECTIBLES	0	2,466,737	2,466,737	2,466,737	4,623,896	0.53348			0.53348	
MISC	0	0	0	0	4,623,896	0.00000				
CONSUMER INFORMATION										
CUSTOMER ASSIST	0	6,763,178	6,763,178	6,763,178	4,623,896	1.46266			1.46266	
SALES EXPENSE	0	0	0	0	4,623,896	0.00000				
ADVERTISING	0	0	0	0	4,623,896	0.00000				
MISC	0	0	0	0	4,623,896	0.00000				9.47250
MISCELLANEOUS										
DEMAND	0	0	0	0	0	0.00000				
ENERGY	0	717,304	717,304	717,304	4,964,097,044	0.00014	0.000144	0.000144		
CUSTOMER	0	0	0	0	4,623,896	0.00000				
REVENUE	0	0	0	0	4,623,896	0.00000				
OTHER	0	14,805	14,805	14,805	4,623,896	0.00320			0.0032	
SUBSTATION CIAC	(290)	(3,119)	(3,409)	(2,678)	4,623,896	(0.00058)			(0.0006)	
TOTALS	2,734,643	291,352,967	294,087,610	287,202,037			0.067382	0.036101	15.04528	

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007
UNIT COSTS

****** SMALL GENERAL SERVICE - SCHEDULE 7 ******

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
FUNCTION	RETURN @ -1.257%	OPERATING EXPENSES	SALES REVS PER BOOKS	REVENUE @ 3.964%	BILLING UNITS	UNIT COSTS ($/EACH)	SUMMER ($/KWH)	NON-SUMMER ($/KWH)	SERVICE ($/CUST/MO)
PRODUCTION									
DEMAND - POWER SUPPLY	0	0	0	0	208,043,392	0.00000			
DEMAND - Summer	(58,493)	1,560,276	1,501,782	1,744,705	58,681,959	0.02973	0.029732		
DEMAND - Non-Summer	(22,352)	596,223	573,871	666,698	149,361,433	0.00446		0.004464	
ENERGY - POWER SUPPLY	0	0	0	0	208,043,392	0.00000			
ENERGY - Summer	(31,865)	1,741,476	1,709,611	1,841,946	58,681,959	0.03139	0.031389		
ENERGY - Non-Summer	(60,304)	3,295,706	3,235,402	3,485,842	149,361,433	0.02334		0.023338	
ENERGY - ANNUAL						0.03720			
TRANSMISSION									
DEMAND - POWER SUPPLY	0	0	0	0	0	0.00000			
DEMAND - TRANSMISSION	(85,565)	918,811	833,246	1,188,596	208,043,392	0.00571	0.005713	0.005713	
DEMAND - SUBTRANSMISSION	0	0	0	0	0	0.00000			
DEMAND - DIRECT	0	0	0	0	0	0.00000			
DISTRIBUTION									
SUBSTATIONS - GENERAL	(29,023)	299,766	270,743	391,275	208,043,392	0.00188	0.00188	0.0019	
SUBSTATIONS - DIRECT	0	0	0	0	0	0.00000			
LINES - PRIMARY DEMAND	(30,835)	588,019	557,184	685,241	208,043,392	0.00329	0.00329	0.0033	
LINES - PRIMARY CUSTOMER	(67,845)	1,293,795	1,225,950	1,507,709	374,514	4.02577			4.025771
LINES - SECONDARY DIRECT	0	0	0	0	0	0.00000			
LINE TRANS - PRIMARY DEMAND	(4,850)	40,862	36,012	56,153	208,043,392	0.00027	0.00027	0.0003	
LINE TRANS - PRIMARY CUST	(10,670)	89,906	79,236	123,550	374,514	0.32989			0.329895
LINE TRANS - SECOND DIRECT	0	0	0	0	0	0.00000			
LINE TRANS - SECOND DEMAND	(21,582)	181,846	160,263	249,894	208,043,392	0.00120	0.00120	0.0012	
LINE TRANS - SECOND CUSTOMER	(41,346)	348,371	307,025	478,736	374,514	1.27828			1.278284
LINES - SECONDARY DEMAND	(10,711)	164,420	153,709	198,192	208,043,392	0.00095	0.00095	0.0010	
LINES - SECONDARY CUSTOMER	(15,280)	234,561	219,281	282,740	374,514	0.75495			0.754952
SERVICES	(10,545)	257,207	246,663	290,455	374,514	0.77555			0.77555
METERS	(62,947)	1,777,900	1,714,953	1,976,372	374,514	5.27716			5.27716
STREET LIGHTS	0	0	0	0	0	0.00000			
INSTALL ON CUST PREMISES	0	159,817	159,817	159,817	374,514	0.42673			0.42673
CUSTOMER ACCOUNTING									
METER READING	0	616,260	616,260	616,260	374,514	1.64549			1.64549
CUSTOMER ACCOUNTS	0	1,150,050	1,150,050	1,150,050	374,514	3.07078			3.07078
UNCOLLECTIBLES	0	57,586	57,586	57,586	374,514	0.15376			0.15376
MISC	0	0	0	0	374,514	0.00000			
CONSUMER INFORMATION									
CUSTOMER ASSIST	0	545,096	545,096	545,096	374,514	1.45547			1.45547
SALES EXPENSE	0	0	0	0	374,514	0.00000			
ADVERTISING	0	0	0	0	374,514	0.00000			
MISC	0	0	0	0	374,514	0.00000			
MISCELLANEOUS									
DEMAND	0	0	0	0	0	0.00000			
ENERGY	0	30,062	30,062	30,062	208,043,392	0.00014	0.000144	0.000144	
CUSTOMER	0	0	0	0	374,514	0.00000			
REVENUE	0	0	0	0	374,514	0.00000			
OTHER	0	1,193	1,193	1,193	374,514	0.00319			0.0032
SUBSTATION CIAC	4,871	(8,540)	(3,668)	(23,898)	374,514	(0.06381)			(0.06381)
TOTALS	(559,342)	15,940,670	15,381,328	17,704,270			0.074576	0.041258	19.133224

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007
UNIT COSTS

****** LARGE GENERAL SERVICE - SCHEDULE 9 SECONDARY ******

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
FUNCTION	RETURN @ -3.18%	OPERATING EXPENSES	SALES REVS PER BOOKS	REVENUE @ -0.73%	BILLING UNITS	UNIT COSTS ($/EACH)	SUMMER ($/KW)	NON-SUMMER ($/KW)	SUMMER ($/KWH)	NON-SUMMER ($/KWH)	SERVICE ($/CUST/MO)	BASIC ($/KW)
PRODUCTION												
DEMAND - POWER SUPPLY					9,628,751	2.88334						
DEMAND - Summer	(1,788,694)	19,213,596	17,424,902	18,803,617	2,643,288	7.11372	7.11372					
DEMAND - Non-Summer	(852,262)	9,154,738	8,302,475	8,959,394	6,985,463	1.28258		1.28258				
ENERGY - POWER SUPPLY	0	0	0	0	3,089,296,204	0.00000						
ENERGY - Summer	(1,225,307)	26,700,391	25,475,084	26,419,544	827,392,135	0.03193			0.031931			
ENERGY - Non-Summer	(2,236,751)	48,740,537	46,503,786	48,227,861	2,261,904,069	0.02132				0.021322		
ENERGY - ANNUAL						0.02416						
TRANSMISSION												
DEMAND - POWER SUPPLY	0	0	0	0	0	0.00000						
DEMAND - TRANSMISSION	(2,599,987)	11,564,797	8,964,810	10,968,865	9,628,751	1.13918	1.13918	1.13918				
DEMAND - SUBTRANSMISSION	0	0	0	0	0	0.00000						
DEMAND - DIRECT	0	0	0	0	0	0.00000						
DISTRIBUTION												
SUBSTATIONS - GENERAL	(849,908)	3,642,922	2,793,014	3,448,118	12,215,389	0.28228						0.28228
SUBSTATIONS - DIRECT	0	0	0	0	0	0.00000						
LINES - PRIMARY DEMAND	(902,968)	6,987,586	6,084,618	6,780,620	12,215,389	0.55509						0.55509
LINES - PRIMARY CUSTOMER	(136,757)	1,058,287	921,531	1,026,942	296,325	3.46559					3.46559	
LINES - SECONDARY DIRECT	0	0	0	0	0	0.00000						
LINE TRANS - PRIMARY DEMAND	(142,017)	501,996	359,979	469,445	12,215,389	0.03843						0.03843
LINE TRANS - PRIMARY CUST	(21,509)	76,029	54,520	71,099	296,325	0.23993					0.23993	
LINE TRANS - SECOND DIRECT	0	0	0	0	0	0.00000						
LINE TRANS - SECOND DEMAND	(632,014)	2,234,021	1,602,008	2,089,160	12,215,389	0.17103						0.17103
LINE TRANS - SECOND CUSTOMER	(83,343)	294,598	211,255	275,495	296,325	0.92971					0.92971	
LINES - SECONDARY DEMAND	(313,663)	1,966,525	1,652,861	1,894,631	12,215,389	0.15510						0.15510
LINES - SECONDARY CUSTOMER	(30,801)	193,109	162,308	186,050	296,325	0.62786					0.62786	
SERVICES	(24,028)	236,439	212,411	230,931	296,325	0.77932					0.77932	
METERS	(287,387)	3,265,204	2,977,817	3,199,333	296,325	10.79670					10.79670	
STREET LIGHTS	0	0	0	0	0	0.00000					0.00000	
INSTALL ON CUST PREMISES	0	127,226	127,226	127,226	296,325	0.42935					0.42935	
CUSTOMER ACCOUNTING												
METER READING	0	513,636	513,636	513,636	296,325	1.73335					1.73335	
CUSTOMER ACCOUNTS	0	915,518	915,518	915,518	296,325	3.08957					3.08957	
UNCOLLECTIBLES	0	80,678	80,678	80,678	296,325	0.27226					0.27226	
MISC	0	0	0	0	296,325	0.00000						
CONSUMER INFORMATION												
CUSTOMER ASSIST	0	433,934	433,934	433,934	296,325	1.46438					1.46438	
SALES EXPENSE	0	0	0	0	296,325	0.00000						
ADVERTISING	0	0	0	0	296,325	0.00000						
MISC	0	0	0	0	296,325	0.00000						
MISCELLANEOUS												
DEMAND	0	0	0	0	0	0.00000						
ENERGY	0	446,398	446,398	446,398	3,089,296,204	0.00014			0.000144	0.000144		
CUSTOMER	0	0	0	0	296,325	0.00000						
REVENUE	0	0	0	0	296,325	0.00000						
OTHER	0	0	0	0	3,089,296,204	0.00000					0.00000	
SUBSTATION CIAC	4,400	(3,958)	442	(2,949)	12,215,389	(0.00024)						(0.00024)
TOTALS	(12,122,997)	138,344,207	126,221,210	135,565,545			8.25290	2.42176	0.032076	0.021466	23.8280	1.20168

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007
UNIT COSTS

****** LARGE GENERAL SERVICE - SCHEDULE 9 PRIMARY ******

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
FUNCTION	RETURN @ -6.49%	OPERATING EXPENSES	SALES REVS PER BOOKS	REVENUE @ -4.20%	BILLING UNITS	UNIT COSTS ($/EACH)	SUMMER ($/KW)	NON-SUMMER ($/KW)	SUMMER ($/KWH)	NON-SUMMER ($/KWH)	SERVICE ($/CUST/MO)	BASIC ($/KW)	DIRECT ASSIGN
PRODUCTION													
DEMAND - POWER SUPPLY	0	0	0	0	861,123	0.00000							
DEMAND - Summer	(369,806)	1,949,732	1,579,927	1,710,434	234,758	7.28595	7.28595						
DEMAND - Non-Summer	(188,547)	994,082	805,534	872,074	626,365	1.39228		1.39228					
ENERGY - POWER SUPPLY	0	0	0	0	360,734,755	0.00000							
ENERGY - Summer	(274,180)	2,930,984	2,656,804	2,753,564	95,218,949	0.02892			0.028918				
ENERGY - Non-Summer	(520,948)	5,568,928	5,047,980	5,231,826	265,515,806	0.01970				0.019704			
ENERGY - ANNUAL						0.02214							
TRANSMISSION													
DEMAND - POWER SUPPLY	0	0	0	0	0	0.00000							
DEMAND - TRANSMISSION	(548,199)	1,198,560	650,361	843,825	861,123	0.97991	0.97991	0.97991					
DEMAND - SUBTRANSMISSION	0	0	0	0	0	0.00000							
DEMAND - DIRECT	(47)	105	58	75	861,123	0.00009	0.00009	0.00009					0.00009
DISTRIBUTION													
SUBSTATIONS - GENERAL	(198,738)	418,748	220,011	290,147	1,043,325	0.27810						0.27810	
SUBSTATIONS - DIRECT	0	0	0	0	0	0.00000							
LINES - PRIMARY DEMAND	(211,145)	802,299	591,154	665,669	1,043,325	0.63803						0.63803	
LINES - PRIMARY CUSTOMER	(1,519)	5,773	4,253	4,790	1,591	3.01065					3.01065		
LINES - SECONDARY DIRECT	(124,197)	318,591	194,393	238,224	1,043,325	0.22833							0.22833
LINE TRANS - PRIMARY DEMAND	(33,208)	57,735	24,527	36,246	1,043,325	0.03474						0.03474	
LINE TRANS - PRIMARY CUST	(239)	415	176	261	1,591	0.16393					0.16393		
LINE TRANS - SECOND DIRECT	(131,036)	227,812	96,776	143,020	1,043,325	0.13708							0.13708
LINE TRANS - SECOND DEMAND	0	0	0	0	1,043,325	0.00000							
LINE TRANS - SECOND CUSTOMER	0	0	0	0	1,591	0.00000							
LINES - SECONDARY DEMAND	0	0	0	0	1,043,325	0.00000							
LINES - SECONDARY CUSTOMER	0	0	0	0	1,591	0.00000							
SERVICES	(1,138)	5,497	4,359	4,760	1,591	2.99223							2.99223
METERS	(40,696)	226,933	186,237	200,599	1,591	126.09158					126.09158		
STREET LIGHTS	(240)	5,183	4,943	5,028	1,591	3.16039							3.16039
INSTALL ON CUST PREMISES	(6)	695	689	691	1,591	0.43446							0.43446
CUSTOMER ACCOUNTING													
METER READING	0	590,782	590,782	590,782	1,591	371.35098					371.35098		
CUSTOMER ACCOUNTS	0	55,987	55,987	55,987	1,591	35.19195					35.19195		
UNCOLLECTIBLES	0	0	0	0	1,591	0.00000							
MISC	0	0	0	0	1,591	0.00000							
CONSUMER INFORMATION													
CUSTOMER ASSIST	0	2,364	2,364	2,364	1,591	1.48574					1.48574		
SALES EXPENSE	0	0	0	0	1,591	0.00000							
ADVERTISING	0	0	0	0	1,591	0.00000							
MISC	0	0	0	0	1,591	0.00000							
MISCELLANEOUS													
DEMAND	0	0	0	0	0	0.00000							
ENERGY	0	52,126	52,126	52,126	360,734,755	0.00014			0.000144	0.000144			
CUSTOMER	0	0	0	0	1,591	0.00000							
REVENUE	0	0	0	0	1,591	0.00000							
OTHER	0	0	0	0	360,734,755	0.00000					0.00000		
SUBSTATION CIAC	5,881	(2,626)	3,256	1,180	1,043,325	0.00113						0.00113	
TOTALS	(2,638,007)	15,410,704	12,772,697	13,703,671			8.26594	2.37228	0.029063	0.019849	537.29482	0.95200	6.95258

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007
UNIT COSTS

****** LARGE POWER - SCHEDULE 19 PRIMARY ******

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
FUNCTION	RETURN @ -7.60%	OPERATING EXPENSES	SALES REVS PER BOOKS	REVENUE @ -4.70%	BILLING UNITS	UNIT COSTS ($/EACH)	SUMMER ($/KW)	NON-SUMMER ($/KW)	SUMMER ($/KWH)	NON-SUMMER ($/KWH)	SERVICE ($/CUST/MO)	BASIC ($/KW)	DIRECT ASSIGN
PRODUCTION													
DEMAND - POWER SUPPLY	0	0	0	0	4,174,327	0.00000							
DEMAND - Summer	(2,356,803)	10,556,236	8,199,433	9,097,408	1,140,408	7.97733	7.97733						
DEMAND - Non-Summer	(1,229,593)	5,507,406	4,277,813	4,746,305	3,033,919	1.56441		1.56441					
ENERGY - POWER SUPPLY	0	0	0	0	2,145,340,040	0.00000							
ENERGY - Summer	(1,877,685)	17,098,147	15,220,462	15,935,886	558,708,042	0.02852			0.028523				
ENERGY - Non-Summer	(3,647,081)	33,210,219	29,563,138	30,952,726	1,586,631,998	0.01951				0.019508			
ENERGY - ANNUAL						0.02186							
TRANSMISSION													
DEMAND - POWER SUPPLY	0	0	0	0	0	0.00000							
DEMAND - TRANSMISSION	(3,484,006)	6,422,791	2,938,786	4,266,240	4,174,327	1.02202	1.02202	1.02202					
DEMAND - SUBTRANSMISSION	0	0	0	0	0	0.00000							
DEMAND - DIRECT	0	0	0	0	0	0.00000							
DISTRIBUTION													
SUBSTATIONS - GENERAL	(1,075,586)	1,909,989	834,403	1,244,216	4,842,029	0.25696						0.25696	
SUBSTATIONS - DIRECT	(5,187)	6,069	882	2,858	4,842,029	0.00059							0.00059
LINES - PRIMARY DEMAND	(1,142,735)	3,681,225	2,538,490	2,973,888	4,842,029	0.61418						0.61418	
LINES - PRIMARY CUSTOMER	(1,529)	4,924	3,395	3,978	1,395	2.85089					2.85089		
LINES - SECONDARY DIRECT	(507,853)	1,100,545	592,692	786,191	4,842,029	0.16237							0.16237
LINE TRANS - PRIMARY DEMAND	(179,727)	262,594	82,867	151,345	4,842,029	0.03126						0.03126	
LINE TRANS - PRIMARY CUST	(240)	351	111	202	1,395	0.14509					0.14509		
LINE TRANS - SECOND DIRECT	(410,869)	600,304	189,434	345,981	4,842,029	0.07145							0.07145
LINE TRANS - SECOND DEMAND	(3,779)	5,522	1,742	3,182	4,842,029	0.00066							0.00066
LINE TRANS - SECOND CUSTOMER	(8)	12	4	7	1,395	0.00485							
LINES - SECONDARY DEMAND	(1,876)	4,888	3,013	3,727	4,842,029	0.00077							0.00077
LINES - SECONDARY CUSTOMER	(3)	8	5	6	1,395	0.00423							
SERVICES	(3,077)	12,619	9,542	10,714	1,395	7.67881							7.67881
METERS	(57,740)	273,611	215,871	237,871	1,395	170.47984					170.47984		
STREET LIGHTS	(36)	656	620	634	1,395	0.45423							0.45423
INSTALL ON CUST PREMISES	(1)	594	593	593	1,395	0.42504							0.42504
CUSTOMER ACCOUNTING													
METER READING	0	507,635	507,635	507,635	1,395	363.81792					363.81792		
CUSTOMER ACCOUNTS	0	48,107	48,107	48,107	1,395	34.47806					34.47806		
UNCOLLECTIBLES	0	0	0	0	1,395	0.00000							
MISC	0	0	0	0	1,395	0.00000							
CONSUMER INFORMATION													
CUSTOMER ASSIST	0	2,031	2,031	2,031	1,395	1.45560					1.45560		
SALES EXPENSE	0	0	0	0	1,395	0.00000							
ADVERTISING	0	0	0	0	1,395	0.00000							
MISC	0	0	0	0	1,395	0.00000							
MISCELLANEOUS													
DEMAND	0	0	0	0	0	0.00000							
ENERGY	0	309,998	309,998	309,998	2,145,340,040	0.00014			0.00014	0.00014			
CUSTOMER	0	0	0	0	1,395	0.00000							
REVENUE	0	0	0	0	1,395	0.00000							
OTHER	0	0	0	0	2,145,340,040	0.00000					0.00		
SUBSTATION CIAC	511,179	(182,773)	328,406	133,639	4,842,029	0.02760						0.02760	
TOTALS	(15,474,235)	81,343,709	65,869,474	71,765,371			8.99935	2.58643	0.02867	0.01965	573.22740	0.93000	8.79391

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007
UNIT COSTS

****** IRRIGATION - SCHEDULE 24 SECONDARY ******

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
FUNCTION	RETURN @ -7.39%	OPERATING EXPENSES	SALES REVS PER BOOKS	REVENUE @ 7.31%	BILLING UNITS	UNIT COSTS ($/EACH)	DEMAND ($/KW)	ENERGY ($/KWH)	SERVICE ($/CUST/MO)
PRODUCTION									
DEMAND - POWER SUPPLY	0	0	0	33,156,776	5,190,205	6.38834	6.38834		
DEMAND - Summer	(4,762,132)	20,042,086	15,279,953	24,756,096	3,025,809	8.18165			
DEMAND - Non-Summer	(1,615,972)	6,801,038	5,185,066	8,400,680	2,164,396	3.88130			
ENERGY - POWER SUPPLY	0	0	0	0	1,539,304,092	0.00000			
ENERGY - Summer	(3,614,561)	32,425,417	28,810,856	36,003,453	1,109,400,571	0.03245			
ENERGY - Non-Summer	(1,054,781)	9,462,203	8,407,422	10,506,326	429,903,521	0.02444			
ENERGY - ANNUAL				46,509,778	1,539,304,092	0.03021		0.030215	
TRANSMISSION									
DEMAND - POWER SUPPLY	0	0	0	0	0	0.00000			
DEMAND - TRANSMISSION	(6,385,006)	9,552,448	3,167,442	15,872,932	5,190,205	3.05825	3.05825		
DEMAND - SUBTRANSMISSION	0	0	0	0	0	0.00000			
DEMAND - DIRECT	0	0	0	0	0	0.00000			
DISTRIBUTION									
SUBSTATIONS - GENERAL	(2,379,396)	3,393,862	1,014,466	5,749,213	5,190,205	1.10770	1.10770		
SUBSTATIONS - DIRECT	0	0	0	0	0	0.00000			
LINES - PRIMARY DEMAND	(2,527,943)	7,367,060	4,839,117	9,869,458	5,190,205	1.90155	1.90155		
LINES - PRIMARY CUSTOMER	(196,842)	573,646	376,804	768,498	195,076	3.93948			3.93948
LINES - SECONDARY DIRECT	0	0	0	0	0	0.00000			
LINE TRANS - PRIMARY DEMAND	(397,589)	438,328	40,738	831,899	5,190,205	0.16028	0.16028		
LINE TRANS - PRIMARY CUST	(30,959)	34,131	3,172	64,777	195,076	0.33206			0.33206
LINE TRANS - SECOND DIRECT	0	0	0	0	0	0.00000			
LINE TRANS - SECOND DEMAND	(1,769,381)	1,950,679	181,298	3,702,180	5,190,205	0.71330	0.71330		
LINE TRANS - SECOND CUSTOMER	(119,960)	132,252	12,292	250,999	195,076	1.28667			1.28667
LINES - SECONDARY DEMAND	0	0	0	0	5,190,205	0.00000			
LINES - SECONDARY CUSTOMER	0	0	0	0	195,076	0.00000			
SERVICES	(36,094)	137,885	101,791	173,615	195,076	0.88999			0.88999
METERS	(414,012)	1,853,062	1,439,050	2,262,890	195,076	11.60005			11.60005
STREET LIGHTS	0	0	0	0	5,190,205	0.00000			
INSTALL ON CUST PREMISES	0	78,926	78,926	78,926	195,076	0.40459			0.40459
CUSTOMER ACCOUNTING									
METER READING	0	394,716	394,716	394,716	195,076	2.02340			2.02340
CUSTOMER ACCOUNTS	0	567,951	567,951	567,951	195,076	2.91144			2.91144
UNCOLLECTIBLES	0	318,726	318,726	318,726	195,076	1.63386			1.63386
MISC	0	0	0	0	195,076	0.00000			
CONSUMER INFORMATION									
CUSTOMER ASSIST	0	269,195	269,195	269,195	195,076	1.37995			1.37995
SALES EXPENSE	0	0	0	0	195,076	0.00000			
ADVERTISING	0	0	0	0	195,076	0.00000			
MISC	0	0	0	0	195,076	0.00000			
MISCELLANEOUS									
DEMAND	0	0	0	0	0	0.00000			
ENERGY	0	222,427	222,427	222,427	1,539,304,092	0.00014		0.000144	
CUSTOMER	0	0	0	0	195,076	0.00000			
REVENUE	0	0	0	0	195,076	0.00000			
OTHER	0	34,651	34,651	34,651	195,076	0.17763			0.17763
SUBSTATION CIAC	4,450	148	4,598	(4,257)	5,190,205	(0.00082)	(0.00082)		
TOTALS	(25,300,177)	96,050,836	70,750,659	121,095,352			13.32861	0.030359	26.5791

601 IDAHO POWER COMPANY
602 CLASS COST OF SERVICE STUDY
603 *** *INEL - SCHEDULE 30* ** TWELVE MONTHS ENDING DECEMBER 31, 2007
604 UNIT COSTS

605		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
606	FUNCTION	RETURN @	OPERATING	SALES REVS	REVENUE @	BILLING	UNIT COSTS	DEMAND	ENERGY	SERVICE
607		-8.78%	EXPENSES	PER BOOKS	-8.55%	UNITS	($/EACH)	($/KW)	($/KWH)	($/CUST/MO)
608	PRODUCTION									
609	DEMAND - POWER SUPPLY	0	0	0	937,829	366,600	2.55818	2.55818		
610	DEMAND - Summer	(214,159)	846,129	631,970	637,390	366,600	1.73865			
611	DEMAND - Non-Summer	(100,945)	398,829	297,883	300,438	366,600	0.81953			
612	ENERGY - POWER SUPPLY	0	0	0	4,232,399	215,500,001	0.01964		0.019640	
613	ENERGY - Summer	(181,674)	1,445,847	1,264,173	1,268,772	215,500,001	0.00589			
614	ENERGY - Non-Summer	(424,358)	3,377,245	2,952,887	2,963,628	215,500,001	0.01375			
615										
616	TRANSMISSION									
617	DEMAND - POWER SUPPLY	0	0	0	0	0	0.00000			
618	DEMAND - TRANSMISSION	(298,546)	498,037	199,491	207,047	366,600	0.56478	0.56478		
619	DEMAND - SUBTRANSMISSION	0	0	0	0	0	0.00000			
620	DEMAND - DIRECT	0	0	0	0	0	0.00000			
621										
622	DISTRIBUTION									
[illegible]	SUBSTATIONS - GENERAL	0	0	0	0	366,600	0.00000			
[illegible]	SUBSTATIONS - DIRECT	0	0	0	0	366,600	0.00000			
625	LINES - PRIMARY DEMAND	0	0	0	0	366,600	0.00000			
626	LINES - PRIMARY CUSTOMER	0	0	0	0	12	0.00000			
627	LINES - SECONDARY DIRECT	0	0	0	0	366,600	0.00000			
628	LINE TRANS - PRIMARY DEMAND	0	0	0	0	0	0.00000			
629	LINE TRANS - PRIMARY CUST	0	0	0	0	12	0.00000			
630	LINE TRANS - SECOND DIRECT	0	0	0	0	366,600	0.00000			
631	LINE TRANS - SECOND DEMAND	0	0	0	0	0	0.00000			
632	LINE TRANS - SECOND CUSTOMER	0	0	0	0	12	0.00000			
633	LINES - SECONDARY DEMAND	0	0	0	0	0	0.00000			
634	LINES - SECONDARY CUSTOMER	0	0	0	0	12	0.00000			
635	SERVICES	0	0	0	0	12	0.00000			
636	METERS	(786)	3,282	2,496	2,516	12	209.69			209.69
637	STREET LIGHTS	0	0	0	0	366,600	0.00000			
638	INSTALL ON CUST PREMISES	0	0	0	0	12	0.00			
639										
640	CUSTOMER ACCOUNTING									
641	METER READING	0	4,376	4,376	4,376	12	364.68042			364.68
642	CUSTOMER ACCOUNTS	0	415	415	415	12	34.55980			34.56
643	UNCOLLECTIBLES	0	0	0	0	12	0.00000			
644	MISC	0	0	0	0	12	0.00000			
645										
646	CONSUMER INFORMATION									
[illegible]	CUSTOMER ASSIST	0	18	18	18	12	1.45905			1.46
[illegible]	SALES EXPENSE	0	0	0	0	12	0.00000			
649	ADVERTISING	0	0	0	0	12	0.00000			
650	MISC	0	0	0	0	12	0.00000			
651										
652	MISCELLANEOUS									
653	DEMAND	0	0	0	0	366,600	0.00000			
654	ENERGY	0	31,139	31,139	31,139	215,500,001	0.00014		0.000144	
655	CUSTOMER	0	0	0	0	12	0.00000			
656	REVENUE	0	0	0	0	10,585,967	0.00000			
657	OTHER	0	0	0	0	215,500,001	0.00000			0.00
658	SUBSTATION CIAC	0	0	0	0					
659										
660	TOTALS	(1,220,468)	6,605,317	5,384,849	10,585,967			3.12296	0.01978	610.39

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
****** SIMPLOT - SCHEDULE 29 ******
TWELVE MONTHS ENDING DECEMBER 31, 2007
UNIT COSTS

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
FUNCTION	RETURN @ -10.04%	OPERATING EXPENSES	SALES REVS PER BOOKS	REVENUE @ -8.30%	BILLING UNITS	UNIT COSTS ($/EACH)	DEMAND ($/KW)	ENERGY $/KWH)	SERVICE ($/CUST/MO)	DIRECT ASSIGN
PRODUCTION										
DEMAND - POWER SUPPLY	0	0	0	0	285,559	0.00000				
DEMAND - Summer	(177,882)	607,795	429,912	460,776	285,559	1.61359	1.61359			
DEMAND - Non-Summer	(121,155)	413,966	292,811	313,832	285,559	1.09901	1.09901			
ENERGY - POWER SUPPLY	0	0	0	0	188,325,624	0.00000				
ENERGY - Summer	(196,645)	1,360,431	1,163,786	1,197,905	188,325,624	0.00636		0.006361		
ENERGY - Non-Summer	(429,127)	2,968,787	2,539,661	2,614,117	188,325,624	0.01388		0.013881		
TRANSMISSION										
DEMAND - POWER SUPPLY	0	0	0	0	0	0.00000				
DEMAND - TRANSMISSION	(295,075)	419,719	124,644	175,841	285,559	0.61578	0.61578			
DEMAND - SUBTRANSMISSION	0	0	0	0	0	0.00000				
DEMAND - DIRECT	(135)	196	62	85	285,559	0.00030	0.00030			
DISTRIBUTION										
SUBSTATIONS - GENERAL	0	0	0	0	285,559	0.00000				
SUBSTATIONS - DIRECT	(148,985)	135,987	(12,997)	12,852	285,559	0.04501				0.04501
LINES - PRIMARY DEMAND	0	0	0	0	285,559	0.00000				
LINES - PRIMARY CUSTOMER	0	0	0	0	12	0.00000				
LINES - SECONDARY DIRECT	(106,154)	176,986	70,832	89,250	285,559	0.31255				0.31255
LINE TRANS - PRIMARY DEMAND	0	0	0	0	0	0.00000				
LINE TRANS - PRIMARY CUST	0	0	0	0	12	0.00000				
LINE TRANS - SECOND DIRECT	(65,844)	74,601	8,757	20,182	285,559	0.07067				0.07067
LINE TRANS - SECOND DEMAND	0	0	0	0	0	0.00000				
LINE TRANS - SECOND CUSTOMER	0	0	0	0	12	0.00000				
LINES - SECONDARY DEMAND	0	0	0	0	0	0.00000				
LINES - SECONDARY CUSTOMER	0	0	0	0	12	0.00000				
SERVICES	(132)	413	281	304	12	25.35				25.35254
METERS	(1,209)	4,369	3,160	3,370	12	280.81			280.81	
STREET LIGHTS	0	0	0	0	12	0.00000				
INSTALL ON CUST PREMISES	(7)	2	(5)	(4)	12	(0.32)				(0.31918)
CUSTOMER ACCOUNTING										
METER READING	0	4,376	4,376	4,376	12	364.68042			364.68	
CUSTOMER ACCOUNTS	0	415	415	415	12	34.55980			34.56	
UNCOLLECTIBLES	0	0	0	0	12	0.00000				
MISC	0	0	0	0	12	0.00000				
CONSUMER INFORMATION										
CUSTOMER ASSIST	0	18	18	18	12	1.45905			1.46	
SALES EXPENSE	0	0	0	0	12	0.00000				
ADVERTISING	0	0	0	0	12	0.00000				
MISC	0	0	0	0	12	0.00000				
MISCELLANEOUS										
DEMAND	0	0	0	0	285,559	0.00000	0.00000			
ENERGY	0	27,213	27,213	27,213	188,325,624	0.00014		0.000144		
CUSTOMER	0	0	0	0	12	0.00000				
REVENUE	0	0	0	0	4,924,264	0.00000				0.00000
OTHER	0	0	0	0	188,325,624	0.00000				0.00000
SUBSTATION CIAC	7,061	(2,104)	4,957	3,732	285,559	0.01307				0.01307
TOTALS	(1,535,289)	6,193,170	4,657,881	4,924,264			3.32868	0.02039	681.51	25.47465

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
****** MICRON - SCHEDULE 26 ******
TWELVE MONTHS ENDING DECEMBER 31, 2007
UNIT COSTS

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
FUNCTION	RETURN @ -9.35%	OPERATING EXPENSES	SALES REVS PER BOOKS	REVENUE @ -5.62%	BILLING UNITS	UNIT COSTS ($/EACH)	DEMAND ($/KW)	ENERGY ($/KWH)	SERVICE ($/CUST/MO)
PRODUCTION									
DEMAND - POWER SUPPLY	0	0	0	0	1,015,525	0.00000			
DEMAND - Summer	(815,796)	2,949,980	2,134,184	2,458,950	1,015,525	2.42136	2.42136		
DEMAND - Non-Summer	(430,846)	1,557,973	1,127,127	1,298,645	1,015,525	1.27879	1.27879		
ENERGY - POWER SUPPLY	0	0	0	0	702,140,245	0.00000			
ENERGY - Summer	(730,443)	5,390,298	4,659,855	4,950,641	702,140,245	0.00705		0.007051	
ENERGY - Non-Summer	(1,433,406)	10,577,812	9,144,406	9,715,039	702,140,245	0.01384		0.013836	
TRANSMISSION									
DEMAND - POWER SUPPLY	0	0	0	0	0	0.00000			
DEMAND - TRANSMISSION	(1,189,867)	1,751,954	562,086	1,035,768	1,015,525	1.01993	1.01993		
DEMAND - SUBTRANSMISSION	0	0	0	0	0	0.00000			
DEMAND - DIRECT	0	0	0	0	0	0.00000			
DISTRIBUTION									
SUBSTATIONS - GENERAL	0	0	0	0	1,015,525	0.00000			
SUBSTATIONS - DIRECT	(1,584,460)	1,464,986	(119,473)	511,294	1,015,525	0.50348	0.50348		
LINES - PRIMARY DEMAND	0	0	0	0	1,015,525	0.00000			
LINES - PRIMARY CUSTOMER	0	0	0	0	12	0.00000			
LINES - SECONDARY DIRECT	0	0	0	0	1,015,525	0.00000			
LINE TRANS - PRIMARY DEMAND	0	0	0	0	0	0.00000			
LINE TRANS - PRIMARY CUST	0	0	0	0	12	0.00000			
LINE TRANS - SECOND DIRECT	0	0	0	0	1,015,525	0.00000			
LINE TRANS - SECOND DEMAND	0	0	0	0	0	0.00000			
LINE TRANS - SECOND CUSTOMER	0	0	0	0	12	0.00000			
LINES - SECONDARY DEMAND	0	0	0	0	0	0.00000			
LINES - SECONDARY CUSTOMER	0	0	0	0	12	0.00000			
SERVICES	0	0	0	0	12	0.00			
METERS	(4,805)	18,389	13,585	15,497	12	1,291.45			1,291.45
STREET LIGHTS	0	0	0	0	1,015,525	0.00000			
INSTALL ON CUST PREMISES	0	0	0	0	12	0.00			
CUSTOMER ACCOUNTING									
METER READING	0	4,376	4,376	4,376	12	364.68042			364.68
CUSTOMER ACCOUNTS	0	415	415	415	12	34.55980			34.56
UNCOLLECTIBLES	0	0	0	0	12	0.00000			
MISC	0	0	0	0	12	0.00000			
CONSUMER INFORMATION									
CUSTOMER ASSIST	0	18	18	18	12	1.45905			1.46
SALES EXPENSE	0	0	0	0	12	0.00000			
ADVERTISING	0	0	0	0	12	0.00000			
MISC	0	0	0	0	12	0.00000			
MISCELLANEOUS									
DEMAND	0	0	0	0	1,015,525	0.00000	0.00000		
ENERGY	0	101,458	101,458	101,458	702,140,245	0.00014		0.000144	
CUSTOMER	0	0	0	0	12	0.00000			0.00
REVENUE	0	0	0	0	20,556,018	0.00000			
OTHER	0	0	0	0	702,140,245	0.00000			0.00
SUBSTATION CIAC	1,371,935	(361,857)	1,010,078	463,916	1,015,525	0.45682	0.45682		
TOTALS	(4,817,688)	23,455,802	18,638,114	20,556,018			5.68038	0.02103	1,692.15

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007
ALLOCATION TO CLASSES

	SOURCES & NOTES	(A) TOTALS	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV PRIMARY (9-P)	(E) GEN SRV SECONDARY (9-S)	(F) AREA LIGHTING (15)	(G) LG POWER PRIMARY (19-P)	(H) IRRIGATION SECONDARY (24-S)
****** SUMMARY OF RESULTS ******									
RATE BASE									
ELECTRIC PLANT IN SERVICE	PAGE 2C	3,473,258,281	1,445,002,232	81,760,930	73,679,402	692,879,400	3,932,796	383,585,847	617,556,979
LESS: ACCUM PROVISION FOR DEPRECIATION	PAGE 2D	1,437,090,391	595,376,473	32,428,279	30,890,604	289,521,794	2,951,910	164,200,154	250,170,418
: AMORT OF OTHER UTILITY PLANT	PAGE 2E	36,633,099	15,240,707	862,348	777,110	7,307,928	41,480	4,045,751	6,513,488
SUBSTATION CIAC	PAGE 2F	(22,236,331)	(83,182)	(387,497)	(90,598)	(138,218)	(64)	(6,725,065)	(60,259)
NET ELECTRIC PLANT IN SERVICE		1,977,298,460	834,301,871	48,082,806	41,921,090	395,911,460	939,341	208,614,876	360,812,814
CUSTOMER ADVANCES FOR CONSTRUCTION	PAGE 2H	29,809,228	19,645,669	1,388,222	250,297	4,228,171	(26,033)	1,125,207	3,010,297
ACCUMULATED DEFERRED INCOME TAXES	PAGE 2I	191,148,684	79,893,826	4,524,341	4,071,802	38,302,499	217,863	21,204,950	34,092,843
ELECTRIC PLANT ACQUISITION ADJUSTMENT	PAGE 2J	(104,146)	(56,048)	(3,891)	(1,712)	(16,502)	(314)	(6,694)	(16,307)
WORKING CAPITAL	PAGE 2K	51,879,424	21,464,195	1,174,797	1,136,981	10,538,484	57,466	6,067,637	8,566,647
DEFERRED PROGRAMS	PAGE 2L	9,381,069	3,331,929	150,111	229,849	2,103,867	2,470	1,326,950	1,586,529
SUBSIDIARY RATE BASE	PAGE 2M	64,384,654	23,556,042	990,517	1,654,705	14,693,712	27,600	9,819,221	8,541,391
PLANT HELD FOR FUTURE USE	PAGE 2N	789,224	307,531	13,820	17,997	161,513	292	87,037	188,029
TOTAL RATE BASE		1,882,670,774	783,366,025	44,495,597	40,636,810	380,861,863	835,025	203,578,870	342,575,963
RETURN UNDER PRESENT RATES									
SALES REVENUES	PAGE 1	617,820,268	294,087,610	15,381,328	12,772,697	126,221,210	931,147	65,869,474	70,750,659
OTHER OPERATING REVENUES	PAGE 4C	178,391,078	66,704,398	2,877,448	5,422,220	37,903,523	173,305	28,553,979	23,308,188
TOTAL OPERATING REVENUES		796,211,346	360,792,008	18,258,776	18,194,917	164,124,733	1,104,452	94,423,453	94,058,847
OPERATING EXPENSES									
OPERATION & MAINTENANCE EXPENSES	PAGE 3C	521,551,479	216,208,084	12,259,015	11,964,894	106,068,169	759,958	64,017,270	78,200,603
DEPRECIATION EXPENSE	PAGE 3D	90,930,380	38,648,431	2,296,236	1,906,523	18,007,433	92,229	9,909,541	15,818,126
AMORTIZATION OF LIMITED TERM PLANT	PAGE 3E	7,938,645	3,306,728	187,196	168,400	1,583,932	4,286	876,742	1,411,675
TAXES OTHER THAN INCOME	PAGE 3F	18,345,825	7,758,306	440,986	393,793	3,667,133	11,306	2,052,289	3,143,349
REGULATORY DEBITS/CREDITS	PAGE 3G	0	0	0	0	0	0	0	0
PROVISION FOR DEFERRED INCOME TAXES	PAGE 3H	(10,951,868)	(4,583,030)	(259,666)	(233,287)	(2,194,896)	(5,941)	(1,214,938)	(1,953,570)
INVESTMENT TAX CREDIT ADJUSTMENT	PAGE 3I	1,531,983	641,089	36,323	32,633	307,029	831	169,950	273,272
FEDERAL INCOME TAXES	PAGE 3J	46,753,611	27,686,092	924,254	1,110,095	10,278,973	67,745	5,215,035	(794,228)
STATE INCOME TAXES	PAGE 3K	2,849,268	1,687,252	56,326	67,652	626,423	4,129	317,816	(48,402)
TOTAL OPERATING EXPENSES		678,949,323	291,352,952	15,940,670	15,410,703	138,344,197	934,542	81,343,703	96,050,826
OPERATING INCOME		117,262,022	69,439,056	2,318,106	2,784,213	25,780,536	169,910	13,079,750	(1,991,979)
ADD: IERCO OPERATING INCOME	PAGE 1	4,969,962	1,818,331	76,460	127,730	1,134,233	2,131	757,963	659,325
CONSOLIDATED OPERATING INCOME		122,231,984	71,257,387	2,394,566	2,911,943	26,914,769	172,040	13,837,712	(1,332,654)
RATE OF RETURN UNDER PRESENT RATES		6.492%	9.096%	5.382%	7.166%	7.067%	20.603%	6.797%	-0.389%
RATE OF RETURN INDEX		1.000	1.401	0.829	1.104	1.088	3.173	1.047	(0.060)

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007
ALLOCATION TO CLASSES

	SOURCES & NOTES	TOTALS	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
****** SUMMARY OF RESULTS ******								
RATE BASE								
ELECTRIC PLANT IN SERVICE	PAGE 2C	3,473,258,281	4,364,684	7,051,010	989,897	25,972,230	27,158,494	109,324,382
LESS: ACCUM PROVISION FOR DEPRECIATION	PAGE 2D	1,437,090,391	1,798,155	4,016,695	425,710	11,847,943	11,480,235	41,982,021
: AMORT OF OTHER UTILITY PLANT	PAGE 2E	36,633,099	46,035	74,368	10,441	273,934	286,446	1,153,065
SUBSTATION CIAC	PAGE 2F	(22,236,331)	(178)	(226)	(28)	0	(70,292)	(14,680,723)
NET ELECTRIC PLANT IN SERVICE		1,977,298,460	2,520,316	2,959,720	553,718	13,850,353	15,321,521	51,508,574
CUSTOMER ADVANCES FOR CONSTRUCTION	PAGE 2H	29,809,228	53,007	127,562	5,981	0	846	1
ACCUMULATED DEFERRED INCOME TAXES	PAGE 2I	191,148,684	241,168	389,955	54,766	1,441,196	1,437,844	5,275,630
ELECTRIC PLANT ACQUISITION ADJUSTMENT	PAGE 2J	(104,146)	(195)	(504)	(23)	(1)	(397)	(1,557)
WORKING CAPITAL	PAGE 2K	51,879,424	66,721	109,974	15,933	445,516	455,445	1,779,629
DEFERRED PROGRAMS	PAGE 2L	9,381,069	9,751	8,664	3,270	117,539	103,631	406,510
SUBSIDIARY RATE BASE	PAGE 2M	64,384,654	76,392	96,819	25,599	932,919	841,638	3,128,098
PLANT HELD FOR FUTURE USE	PAGE 2N	789,224	978	1,035	184	1,927	1,664	7,217
TOTAL RATE BASE		1,882,670,774	2,379,787	2,658,191	537,935	13,907,056	15,284,812	51,552,839
RETURN UNDER PRESENT RATES								
SALES REVENUES	PAGE 1	617,820,268	880,610	2,056,146	188,543	5,384,849	4,657,881	18,638,114
OTHER OPERATING REVENUES	PAGE 4C	178,391,078	198,656	424,365	66,514	2,320,225	2,616,624	7,821,634
TOTAL OPERATING REVENUES		796,211,346	1,079,266	2,480,511	255,057	7,705,074	7,274,505	26,459,748
OPERATING EXPENSES								
OPERATION & MAINTENANCE EXPENSES	PAGE 3C	521,551,479	656,820	1,765,048	169,802	5,338,492	4,934,137	19,209,187
DEPRECIATION EXPENSE	PAGE 3D	90,930,380	114,998	310,474	25,731	670,539	667,543	2,462,578
AMORTIZATION OF LIMITED TERM PLANT	PAGE 3E	7,938,645	9,994	16,118	2,264	59,363	62,069	249,877
TAXES OTHER THAN INCOME	PAGE 3F	18,345,825	23,771	40,496	5,354	142,738	142,858	523,447
REGULATORY DEBITS/CREDITS	PAGE 3G	0	0	0	0	0	0	0
PROVISION FOR DEFERRED INCOME TAXES	PAGE 3H	(10,951,868)	(13,842)	(22,344)	(3,140)	(82,573)	(82,374)	(302,267)
INVESTMENT TAX CREDIT ADJUSTMENT	PAGE 3I	1,531,983	1,936	3,126	439	11,551	11,523	42,282
FEDERAL INCOME TAXES	PAGE 3J	46,753,611	80,019	102,996	15,300	438,485	431,140	1,197,706
STATE INCOME TAXES	PAGE 3K	2,849,268	4,877	6,277	932	26,722	26,275	72,991
TOTAL OPERATING EXPENSES		678,949,323	878,572	2,222,190	216,683	6,605,316	6,193,170	23,455,800
OPERATING INCOME		117,262,022	200,694	258,322	38,374	1,099,758	1,081,335	3,003,948
ADD: IERCO OPERATING INCOME	PAGE 1	4,969,962	5,897	7,474	1,976	72,014	64,967	241,463
CONSOLIDATED OPERATING INCOME		122,231,984	206,591	265,795	40,350	1,171,771	1,146,302	3,245,411
RATE OF RETURN UNDER PRESENT RATES		649.248%	8.681%	9.999%	7.501%	8.426%	7.500%	6.295%
RATE OF RETURN INDEX		1.000	1.337	1.540	1.155	1.298	1.155	0.970

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007
ALLOCATION TO CLASSES

****** TABLE 1 - PLANT IN SERVICE ******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
FUNCTION	ALLOCATION FACTOR	TOTALS	RESIDENTIAL	GEN SRV	GEN SRV PRIMARY	GEN SRV SECONDARY	AREA LIGHTING	LG POWER PRIMARY	IRRIGATION SECONDARY
PRODUCTION			(1)	(7)	(9-P)	(9-S)	(15)	(19-P)	(24-S)
DEMAND - POWER SUPPLY	D10	760,409,097	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0	178,999,896	9,317,862	11,407,417	112,528,827	0	62,089,337	129,123,410
DEMAND - Non-Summer	D10NS	0	77,050,976	3,560,605	5,816,135	53,616,821	0	32,393,287	43,816,460
ENERGY - POWER SUPPLY	E10	916,959,624	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	107,754,682	4,877,077	8,126,199	74,064,479	128,311	47,528,459	94,166,483
ENERGY - Non-Summer	E10NS	0	227,728,047	9,229,760	15,439,940	135,201,857	264,771	92,315,881	27,479,135
		0							
TRANSMISSION		0							
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	623,355,694	222,454,268	10,973,079	13,613,659	131,680,616	0	73,891,681	139,375,921
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	3,681	0	0	1,290	0	0	0	0
		0							
DISTRIBUTION		0							
SUBSTATIONS - GENERAL	D20	186,855,295	75,164,874	3,265,560	4,330,122	37,766,408	95,559	20,014,506	45,569,717
SUBSTATIONS - DIRECT	DA3602	19,068,034	0	0	0	0	0	70,313	0
LINES - PRIMARY DEMAND	D20	268,736,374	108,102,560	4,696,547	6,227,607	54,315,868	137,433	28,784,978	65,538,632
LINES - PRIMARY CUSTOMER	C20	152,612,597	128,212,585	10,333,627	44,809	8,226,275	0	38,503	5,103,251
LINES - SECONDARY DIRECT	DA3647	16,134,181	0	0	3,094,108	0	525,474	10,805,424	0
LINE TRANS - PRIMARY DEMAND	D50	40,778,019	16,403,467	712,653	944,976	8,241,882	20,854	4,367,829	9,944,823
LINE TRANS - PRIMARY CUST	C50	23,157,414	19,454,959	1,568,023	6,799	1,248,254	0	5,842	774,367
LINE TRANS - SECOND DIRECT	DA368	14,924,661	0	0	3,728,700	0	0	9,985,060	0
LINE TRANS - SECOND DEMAND	D60	157,921,840	72,999,958	3,171,504	0	36,678,651	92,806	91,843	44,257,207
LINE TRANS - SECOND CUSTOMER	C60	89,682,174	75,384,594	6,075,818	0	4,836,767	0	195	3,000,536
LINES - SECONDARY DEMAND	D30	54,943,795	35,287,095	1,533,058	0	17,729,915	44,861	44,396	0
LINES - SECONDARY CUSTOMER	C30	31,202,011	27,135,515	2,187,057	0	1,741,048	0	70	0
SERVICES	CW369	53,766,390	43,885,217	3,870,045	80,874	3,482,637	0	186,733	2,254,821
METERS	CW370	55,910,396	28,983,537	6,388,655	799,810	11,519,097	258	969,153	7,152,216
STREET LIGHTS	DA373	4,209,103	0	0	14,162	0	0	1,794	0
INSTALL ON CUST PREMISES	DA371	2,628,194	0	0	2,795	0	2,622,468	562	0
		0							
CUSTOMER ACCOUNTING		0							
METER READING	CW902	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
CONSUMER INFORMATION		0							
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
MISCELLANEOUS		0							
DEMAND	D99U	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0
TOTALS	PAGE 2C	SCREWED UP	1,445,002,232	81,760,930	73,679,402	692,879,400	3,932,796	383,585,847	617,556,979

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
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ALLOCATION TO CLASSES

****** TABLE 1 - PLANT IN SERVICE ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
PRODUCTION								
DEMAND - POWER SUPPLY	D10	760,409,097	0	0	0	0	0	0
DEMAND - Summer	D10S	0	403,899	0	134,495	4,886,692	3,546,281	17,480,978
DEMAND - Non-Summer	D10NS	0	212,047	0	72,421	2,303,375	2,415,354	9,232,230
ENERGY - POWER SUPPLY	E10	916,959,624	0	0	0	0	0	0
ENERGY - Summer	E10S	0	355,716	451,318	119,202	3,982,985	3,766,693	15,038,602
ENERGY - Non-Summer	E10NS	0	732,249	927,565	245,381	9,303,553	8,219,830	29,511,450
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	623,355,694	463,814	0	156,580	5,484,197	4,735,818	20,526,060
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	3,681	0	0	0	0	2,391	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	186,855,295	267,132	339,064	42,354	0	0	0
SUBSTATIONS - DIRECT	DA3602	19,068,034	0	0	0	0	1,528,258	17,469,464
LINES - PRIMARY DEMAND	D20	268,736,374	384,191	487,644	60,913	0	0	0
LINES - PRIMARY CUSTOMER	C20	152,612,597	564,594	45,473	43,481	0	0	0
LINES - SECONDARY DIRECT	DA3647	16,134,181	0	0	0	0	1,709,175	0
LINE TRANS - PRIMARY DEMAND	D50	40,778,019	58,297	73,995	9,243	0	0	0
LINE TRANS - PRIMARY CUST	C50	23,157,414	85,671	6,900	6,598	0	0	0
LINE TRANS - SECOND DIRECT	DA368	14,924,661	0	0	0	0	1,210,902	0
LINE TRANS - SECOND DEMAND	D60	157,921,840	259,438	329,298	41,134	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	89,682,174	331,962	26,736	25,566	0	0	0
LINES - SECONDARY DEMAND	D30	54,943,795	125,409	159,178	19,884	0	0	0
LINES - SECONDARY CUSTOMER	C30	31,202,011	119,493	9,624	9,203	0	0	0
SERVICES	CW369	53,766,390	0	0	0	0	6,063	0
METERS	CW370	55,910,396	772	1,070	3,444	11,427	15,358	65,598
STREET LIGHTS	DA373	4,209,103	0	4,193,146	0	0	0	0
INSTALL ON CUST PREMISES	DA371	2,628,194	0	0	0	0	2,369	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS		SCREWED UP	4,364,684	7,051,010	989,897	25,972,230	27,158,494	109,324,382

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
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ALLOCATION TO CLASSES

****** TABLE 2 - ACCUMULATED RESERVE FOR DEPRECIATION ******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
FUNCTION	ALLOCATION FACTOR	TOTALS	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV PRIMARY (9-P)	GEN SRV SECONDARY (9-S)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	IRRIGATION SECONDARY (24-S)
PRODUCTION									
DEMAND - POWER SUPPLY	D10	340,483,913	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0	80,149,732	4,172,204	5,107,832	50,386,372	0	27,801,378	57,816,831
DEMAND - Non-Summer	D10NS	0	34,500,663	1,594,311	2,604,257	24,007,689	0	14,504,552	19,619,439
ENERGY - POWER SUPPLY	E10	471,866,681	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	55,450,472	2,509,740	4,181,735	38,113,521	66,029	24,458,107	48,457,996
ENERGY - Non-Summer	E10NS	0	117,188,669	4,749,627	7,945,381	69,574,766	136,251	47,505,678	14,140,741
		0							
TRANSMISSION		0							
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	203,387,772	72,582,120	3,580,283	4,441,849	42,964,598	0	24,109,292	45,475,414
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	1,417	0	0	497	0	0	0	0
		0							
DISTRIBUTION		0							
SUBSTATIONS - GENERAL	D20	46,218,356	18,591,911	807,731	1,071,049	9,341,460	23,636	4,950,556	11,271,596
SUBSTATIONS - DIRECT	DA3602	422,883	0	0	0	0	0	1,559	0
LINES - PRIMARY DEMAND	D20	104,050,594	41,855,650	1,818,431	2,411,234	21,030,269	53,212	11,145,101	25,375,551
LINES - PRIMARY CUSTOMER	C20	59,089,252	49,641,943	4,001,022	17,349	3,185,087	0	14,908	1,975,900
LINES - SECONDARY DIRECT	DA3647	5,310,188	0	0	1,018,353	0	172,948	3,556,352	0
LINE TRANS - PRIMARY DEMAND	D50	16,560,288	6,661,583	289,414	383,763	3,347,096	8,469	1,773,811	4,038,674
LINE TRANS - PRIMARY CUST	C50	9,404,416	7,900,819	636,787	2,761	506,926	0	2,373	314,477
LINE TRANS - SECOND DIRECT	DA368	6,061,027	0	0	1,514,256	0	0	4,055,015	0
LINE TRANS - SECOND DEMAND	D60	64,133,355	29,645,882	1,287,974	0	14,895,501	37,689	37,298	17,973,215
LINE TRANS - SECOND CUSTOMER	C60	36,420,666	30,614,302	2,467,439	0	1,964,251	0	79	1,218,542
LINES - SECONDARY DEMAND	D30	17,715,293	11,377,468	494,297	0	5,716,581	14,464	14,314	0
LINES - SECONDARY CUSTOMER	C30	10,060,331	8,749,188	705,164	0	561,359	0	23	0
SERVICES	CW369	31,515,050	25,723,223	2,268,418	47,404	2,041,340	0	109,453	1,321,658
METERS	CW370	9,149,146	4,742,850	1,045,436	130,881	1,884,979	42	158,592	1,170,385
STREET LIGHTS	DA373	2,795,397	0	0	9,406	0	0	1,192	0
INSTALL ON CUST PREMISES	DA371	2,444,495	0	0	2,599	0	2,439,170	523	0
		0							
CUSTOMER ACCOUNTING		0							
METER READING	CW902	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
CONSUMER INFORMATION		0							
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
MISCELLANEOUS		0							
DEMAND	D99U	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0
TOTALS	PAGE 2D	SCREWED UP	595,376,473	32,428,279	30,890,604	289,521,794	2,951,910	164,200,154	250,170,418

IDAHO POWER COMPANY
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ALLOCATION TO CLASSES

****** TABLE 2 - ACCUMULATED RESERVE FOR DEPRECIATION ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
PRODUCTION								
DEMAND - POWER SUPPLY	D10	340,483,913	0	0	0	0	0	0
DEMAND - Summer	D10S	0	180,851	0	60,222	2,188,085	1,587,898	7,827,355
DEMAND - Non-Summer	D10NS	0	94,947	0	32,427	1,031,369	1,081,509	4,133,861
ENERGY - POWER SUPPLY	E10	471,866,681	0	0	0	0	0	0
ENERGY - Summer	E10S	0	183,051	232,248	61,341	2,049,641	1,938,337	7,738,852
ENERGY - Non-Summer	E10NS	0	376,815	477,324	126,273	4,787,601	4,229,918	15,186,568
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	203,387,772	151,333	0	51,089	1,789,377	1,545,197	6,697,219
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	1,417	0	0	0	0	920	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	46,218,356	66,075	83,867	10,476	0	0	0
SUBSTATIONS - DIRECT	DA3602	422,883	0	0	0	0	33,893	387,430
LINES - PRIMARY DEMAND	D20	104,050,594	148,753	188,808	23,585	0	0	0
LINES - PRIMARY CUSTOMER	C20	59,089,252	218,602	17,606	16,835	0	0	0
LINES - SECONDARY DIRECT	DA3647	5,310,188	0	0	0	0	562,535	0
LINE TRANS - PRIMARY DEMAND	D50	16,560,288	23,675	30,050	3,754	0	0	0
LINE TRANS - PRIMARY CUST	C50	9,404,416	34,792	2,802	2,679	0	0	0
LINE TRANS - SECOND DIRECT	DA368	6,061,027	0	0	0	0	491,757	0
LINE TRANS - SECOND DEMAND	D60	64,133,355	105,360	133,731	16,705	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	36,420,666	134,812	10,858	10,382	0	0	0
LINES - SECONDARY DEMAND	D30	17,715,293	40,435	51,323	6,411	0	0	0
LINES - SECONDARY CUSTOMER	C30	10,060,331	38,528	3,103	2,967	0	0	0
SERVICES	CW369	31,515,050	0	0	0	0	3,554	0
METERS	CW370	9,149,146	126	175	564	1,870	2,513	10,734
STREET LIGHTS	DA373	2,795,397	0	2,784,800	0	0	0	0
INSTALL ON CUST PREMISES	DA371	2,444,495	0	0	0	0	2,203	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 2D	SCREWED UP	1,798,155	4,016,695	425,710	11,847,943	11,480,235	41,982,021

IDAHO POWER COMPANY
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ALLOCATION TO CLASSES

****** TABLE 3 - AMORTIZATION RESERVE******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
FUNCTION	ALLOCATION FACTOR	TOTALS	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV PRIMARY (9-P)	GEN SRV SECONDARY (9-S)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	IRRIGATION SECONDARY (24-S)
PRODUCTION									
DEMAND - POWER SUPPLY	D10	8,020,176	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0	1,887,945	98,277	120,316	1,186,862	0	654,868	1,361,889
DEMAND - Non-Summer	D10NS	0	812,671	37,554	61,344	565,507	0	341,658	462,140
ENERGY - POWER SUPPLY	E10	9,671,343	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	1,136,509	51,439	85,709	781,172	1,353	501,291	993,191
ENERGY - Non-Summer	E10NS	0	2,401,890	97,348	162,848	1,425,999	2,793	973,673	289,828
		0							
TRANSMISSION		0							
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	6,574,648	2,346,266	115,735	143,586	1,388,860	0	779,349	1,470,024
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	39	0	0	14	0	0	0	0
		0							
DISTRIBUTION		0							
SUBSTATIONS - GENERAL	D20	1,970,797	792,778	34,442	45,671	398,329	1,008	211,097	480,632
SUBSTATIONS - DIRECT	DA3602	201,114	0	0	0	0	0	742	0
LINES - PRIMARY DEMAND	D20	2,834,412	1,140,178	49,535	65,684	572,880	1,450	303,601	691,248
LINES - PRIMARY CUSTOMER	C20	1,609,633	1,352,282	108,991	473	86,764	0	406	53,825
LINES - SECONDARY DIRECT	DA3647	170,170	0	0	32,634	0	5,542	113,967	0
LINE TRANS - PRIMARY DEMAND	D50	430,093	173,010	7,516	9,967	86,929	220	46,068	104,890
LINE TRANS - PRIMARY CUST	C50	244,246	205,195	16,538	72	13,166	0	62	8,167
LINE TRANS - SECOND DIRECT	DA368	157,413	0	0	39,327	0	0	105,314	0
LINE TRANS - SECOND DEMAND	D60	1,665,631	769,944	33,450	0	386,857	979	969	466,789
LINE TRANS - SECOND CUSTOMER	C60	945,895	795,095	64,083	0	51,014	0	2	31,647
LINES - SECONDARY DEMAND	D30	579,502	372,180	16,169	0	187,001	473	468	0
LINES - SECONDARY CUSTOMER	C30	329,093	286,203	23,067	0	18,363	0	1	0
SERVICES	CW369	567,084	462,866	40,818	853	36,732	0	1,970	23,782
METERS	CW370	589,697	305,695	67,382	8,436	121,494	3	10,222	75,436
STREET LIGHTS	DA373	44,394	0	0	149	0	0	19	0
INSTALL ON CUST PREMISES	DA371	27,720	0	0	29	0	27,660	6	0
		0							
CUSTOMER ACCOUNTING		0							
METER READING	CW902	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
CONSUMER INFORMATION		0							
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
MISCELLANEOUS		0							
DEMAND	D99U	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0
TOTALS	PAGE 2E	SCREWED UP	15,240,707	862,348	777,110	7,307,928	41,480	4,045,751	6,513,488

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
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ALLOCATION TO CLASSES

****** TABLE 3 - AMORTIZATION RESERVE******

				(I)	(J)	(K)	(L)	(M)	(N)
FUNCTION	ALLOCATION FACTOR	TOTALS		UNMETERED GEN SERVICE	MUNICIPAL ST LIGHT	TRAFFIC CONTROL	SC DOE/INL	SC JR SIMPLOT	SC MICRON
PRODUCTION				(40)	(41)	(42)			
DEMAND - POWER SUPPLY	D10	8,020,176		0	0	0	0	0	0
DEMAND - Summer	D10S	0		4,260	0	1,419	51,541	37,403	184,375
DEMAND - Non-Summer	D10NS	0		2,236	0	764	24,294	25,475	97,374
ENERGY - POWER SUPPLY	E10	9,671,343		0	0	0	0	0	0
ENERGY - Summer	E10S	0		3,752	4,760	1,257	42,009	39,728	158,615
ENERGY - Non-Summer	E10NS	0		7,723	9,783	2,588	98,126	86,696	311,263
TRANSMISSION		0							
DEMAND - POWER SUPPLY	D11	0		0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	6,574,648		4,892	0	1,651	57,843	49,950	216,492
DEMAND - SUBTRANSMISSION	D15	0		0	0	0	0	0	0
DEMAND - DIRECT	DA3509	39		0	0	0	0	25	0
DISTRIBUTION									
SUBSTATIONS - GENERAL	D20	1,970,797		2,817	3,576	447	0	0	0
SUBSTATIONS - DIRECT	DA3602	201,114		0	0	0	0	16,119	184,254
LINES - PRIMARY DEMAND	D20	2,834,412		4,052	5,143	642	0	0	0
LINES - PRIMARY CUSTOMER	C20	1,609,633		5,955	480	459	0	0	0
LINES - SECONDARY DIRECT	DA3647	170,170		0	0	0	0	18,027	0
LINE TRANS - PRIMARY DEMAND	D50	430,093		615	780	97	0	0	0
LINE TRANS - PRIMARY CUST	C50	244,246		904	73	70	0	0	0
LINE TRANS - SECOND DIRECT	DA368	157,413		0	0	0	0	12,772	0
LINE TRANS - SECOND DEMAND	D60	1,665,631		2,736	3,473	434	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	945,895		3,501	282	270	0	0	0
LINES - SECONDARY DEMAND	D30	579,502		1,323	1,679	210	0	0	0
LINES - SECONDARY CUSTOMER	C30	329,093		1,260	102	97	0	0	0
SERVICES	CW369	567,084		0	0	0	0	64	0
METERS	CW370	589,697		8	11	36	121	162	692
STREET LIGHTS	DA373	44,394		0	44,226	0	0	0	0
INSTALL ON CUST PREMISES	DA371	27,720		0	0	0	0	25	0
CUSTOMER ACCOUNTING									
METER READING	CW902	0		0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0		0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0		0	0	0	0	0	0
MISC	C10	0		0	0	0	0	0	0
CONSUMER INFORMATION									
CUSTOMER ASSIST	C10	0		0	0	0	0	0	0
SALES EXPENSE	C10	0		0	0	0	0	0	0
ADVERTISING	C10	0		0	0	0	0	0	0
MISC	C10	0		0	0	0	0	0	0
MISCELLANEOUS									
DEMAND	D99U	0		0	0	0	0	0	0
ENERGY	E99U	0		0	0	0	0	0	0
CUSTOMER	C10	0		0	0	0	0	0	0
REVENUE	R02	0		0	0	0	0	0	0
OTHER	R01	0		0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0		0	0	0	0	0	0
TOTALS	PAGE 2E	SCREWED UP		46,035	74,368	10,441	273,934	286,446	1,153,065

IDAHO POWER COMPANY
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ALLOCATION TO CLASSES

****** TABLE 4 - SUBSTATION CIAC ******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
FUNCTION	ALLOCATION FACTOR	TOTALS	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV PRIMARY (9-P)	GEN SRV SECONDARY (9-S)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	IRRIGATION SECONDARY (24-S)
PRODUCTION									
DEMAND - POWER SUPPLY	D10	0	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0	0	0	0	0	0	0	0
DEMAND - Non-Summer	D10NS	0	0	0	0	0	0	0	0
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0	0
		0							
TRANSMISSION		0							
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	0	0	0	0	0	0	0	0
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0	0
		0							
DISTRIBUTION		0							
SUBSTATIONS - GENERAL	D20	0	0	0	0	0	0	0	0
SUBSTATIONS - DIRECT	DA3602	0	0	0	0	0	0	0	0
LINES - PRIMARY DEMAND	D20	0	0	0	0	0	0	0	0
LINES - PRIMARY CUSTOMER	C20	0	0	0	0	0	0	0	0
LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0	0
LINE TRANS - PRIMARY DEMAND	D50	0	0	0	0	0	0	0	0
LINE TRANS - PRIMARY CUST	C50	0	0	0	0	0	0	0	0
LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0	0
LINE TRANS - SECOND DEMAND	D60	0	0	0	0	0	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	0	0	0	0	0	0	0	0
LINES - SECONDARY DEMAND	D30	0	0	0	0	0	0	0	0
LINES - SECONDARY CUSTOMER	C30	0	0	0	0	0	0	0	0
SERVICES	CW369	0	0	0	0	0	0	0	0
METERS	CW370	0	0	0	0	0	0	0	0
STREET LIGHTS	DA373	0	0	0	0	0	0	0	0
INSTALL ON CUST PREMISES	DA371	0	0	0	0	0	0	0	0
		0							
CUSTOMER ACCOUNTING		0							
METER READING	CW902	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
CONSUMER INFORMATION		0							
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
MISCELLANEOUS		0							
DEMAND	D99U	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	(22,236,331)	(83,182)	(387,497)	(90,598)	(138,218)	(64)	(6,725,065)	(60,259)
TOTALS	PAGE 2F	(22,236,331)	(83,182)	(387,497)	(90,598)	(138,218)	(64)	(6,725,065)	(60,259)

IDAHO POWER COMPANY
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ALLOCATION TO CLASSES

****** TABLE 4 - SUBSTATION CIAC ******

			(I)	(J)	(K)	(L)	(M)	(N)
FUNCTION	ALLOCATION FACTOR	TOTALS	UNMETERED GEN SERVICE (40)	MUNICIPAL ST LIGHT (41)	TRAFFIC CONTROL (42)	SC DOE/INL	SC JR SIMPLOT	SC MICRON
PRODUCTION								
DEMAND - POWER SUPPLY	D10	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0	0	0	0	0	0	0
DEMAND - Non-Summer	D10NS	0	0	0	0	0	0	0
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0
TRANSMISSION		0	0	0	0	0	0	0
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	0	0	0	0	0	0	0
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	0	0	0	0	0	0	0
SUBSTATIONS - DIRECT	DA3602	0	0	0	0	0	0	0
LINES - PRIMARY DEMAND	D20	0	0	0	0	0	0	0
LINES - PRIMARY CUSTOMER	C20	0	0	0	0	0	0	0
LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0
LINE TRANS - PRIMARY DEMAND	D50	0	0	0	0	0	0	0
LINE TRANS - PRIMARY CUST	C50	0	0	0	0	0	0	0
LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0
LINE TRANS - SECOND DEMAND	D60	0	0	0	0	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	0	0	0	0	0	0	0
LINES - SECONDARY DEMAND	D30	0	0	0	0	0	0	0
LINES - SECONDARY CUSTOMER	C30	0	0	0	0	0	0	0
SERVICES	CW369	0	0	0	0	0	0	0
METERS	CW370	0	0	0	0	0	0	0
STREET LIGHTS	DA373	0	0	0	0	0	0	0
INSTALL ON CUST PREMISES	DA371	0	0	0	0	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	(22,236,331)	(178)	(226)	(28)	0	(70,292)	(14,680,723)
TOTALS		(22,236,331)	(178)	(226)	(28)	0	(70,292)	(14,680,723)

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007
ALLOCATION TO CLASSES

****** TABLE 5 - CUSTOMER ADVANCES FOR CONSTRUCTION ******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
FUNCTION	ALLOCATION FACTOR	TOTALS	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV PRIMARY (9-P)	GEN SRV SECONDARY (9-S)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	IRRIGATION SECONDARY (24-S)
DEMAND - POWER SUPPLY	D10	0	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0	0	0	0	0	0	0	0
DEMAND - Non-Summer	D10NS	0	0	0	0	0	0	0	0
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0	0
		0							
TRANSMISSION		0							
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	0	0	0	0	0	0	0	0
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0	0
		0							
DISTRIBUTION		0							
SUBSTATIONS - GENERAL	D20	0	0	0	0	0	0	0	0
SUBSTATIONS - DIRECT	DA3602	0	0	0	0	0	0	0	0
LINES - PRIMARY DEMAND	D20	10,209,767	4,107,006	178,430	236,598	2,063,555	5,221	1,093,592	2,489,928
LINES - PRIMARY CUSTOMER	C20	5,798,021	4,871,022	392,593	1,702	312,531	0	1,463	193,881
LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0	0
LINE TRANS - PRIMARY DEMAND	D50	281	113	5	7	57	0	30	68
LINE TRANS - PRIMARY CUST	C50	159	133	11	0	9	0	0	5
LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0	0
LINE TRANS - SECOND DEMAND	D60	1,149	531	23	0	267	1	1	322
LINE TRANS - SECOND CUSTOMER	C60	653	549	44	0	35	0	0	22
LINES - SECONDARY DEMAND	D30	3,804,071	2,443,126	106,142	0	1,227,543	3,106	3,074	0
LINES - SECONDARY CUSTOMER	C30	2,160,292	1,878,745	151,422	0	120,543	0	5	0
SERVICES	CW369	7,772,371	6,343,967	559,447	11,691	503,444	0	26,994	325,953
METERS	CW370	918	476	105	13	189	0	16	117
STREET LIGHTS	DA373	95,982	0	0	323	0	0	41	0
INSTALL ON CUST PREMISES	DA371	(34,436)	0	0	(37)	0	(34,361)	(7)	0
		0							
CUSTOMER ACCOUNTING		0							
METER READING	CW902	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
CONSUMER INFORMATION		0							
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
MISCELLANEOUS		0							
DEMAND	D99U	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0
TOTALS	PAGE 2H	29,809,228	19,645,669	1,388,222	250,297	4,228,171	(26,033)	1,125,207	3,010,297

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
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ALLOCATION TO CLASSES

****** TABLE 5 - CUSTOMER ADVANCES FOR CONSTRUCTION ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
DEMAND - POWER SUPPLY	D10	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0	0	0	0	0	0	0
DEMAND - Non-Summer	D10NS	0	0	0	0	0	0	0
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	0	0	0	0	0	0	0
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	0	0	0	0	0	0	0
SUBSTATIONS - DIRECT	DA3602	0	0	0	0	0	0	0
LINES - PRIMARY DEMAND	D20	10,209,767	14,596	18,526	2,314	0	0	0
LINES - PRIMARY CUSTOMER	C20	5,798,021	21,450	1,728	1,652	0	0	0
LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0
LINE TRANS - PRIMARY DEMAND	D50	281	0	1	0	0	0	0
LINE TRANS - PRIMARY CUST	C50	159	1	0	0	0	0	0
LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0
LINE TRANS - SECOND DEMAND	D60	1,149	2	2	0	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	653	2	0	0	0	0	0
LINES - SECONDARY DEMAND	D30	3,804,071	8,683	11,021	1,377	0	0	0
LINES - SECONDARY CUSTOMER	C30	2,160,292	8,273	666	637	0	0	0
SERVICES	CW369	7,772,371	0	0	0	0	876	0
METERS	CW370	918	0	0	0	0	0	1
STREET LIGHTS	DA373	95,982	0	95,618	0	0	0	0
INSTALL ON CUST PREMISES	DA371	(34,436)	0	0	0	0	(31)	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 2H	29,809,228	53,007	127,562	5,981	0	846	1

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****** TABLE 6 - ACCUMULATED DEFERRED INCOME TAXES ******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
FUNCTION	ALLOCATION FACTOR	TOTALS	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV PRIMARY (9-P)	GEN SRV SECONDARY (9-S)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	IRRIGATION SECONDARY (24-S)
DEMAND - POWER SUPPLY	D10	42,195,020	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0	9,932,685	517,047	632,996	6,244,213	0	3,445,331	7,165,044
DEMAND - Non-Summer	D10NS	0	4,275,550	197,578	322,737	2,975,192	0	1,797,500	2,431,371
ENERGY - POWER SUPPLY	E10	50,881,992	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	5,979,296	270,628	450,922	4,109,830	7,120	2,637,349	5,225,288
ENERGY - Non-Summer	E10NS	0	12,636,605	512,158	856,761	7,502,337	14,692	5,122,598	1,524,814
		0							
TRANSMISSION		0							
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	34,589,941	12,343,964	608,895	755,421	7,306,943	0	4,100,242	7,733,955
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	204	0	0	72	0	0	0	0
		0							
DISTRIBUTION		0							
SUBSTATIONS - GENERAL	D20	9,649,659	3,881,696	168,641	223,618	1,950,349	4,935	1,033,597	2,353,330
SUBSTATIONS - DIRECT	DA3602	194,955	0	0	0	0	0	719	0
LINES - PRIMARY DEMAND	D20	14,912,153	5,998,600	260,611	345,569	3,013,982	7,626	1,597,275	3,636,732
LINES - PRIMARY CUSTOMER	C20	8,468,457	7,114,503	573,412	2,486	456,475	0	2,137	283,179
LINES - SECONDARY DIRECT	DA3647	895,284	0	0	171,692	0	29,159	599,592	0
LINE TRANS - PRIMARY DEMAND	D50	2,262,768	910,227	39,545	52,437	457,341	1,157	242,370	551,837
LINE TRANS - PRIMARY CUST	C50	1,285,002	1,079,554	87,009	377	69,265	0	324	42,970
LINE TRANS - SECOND DIRECT	DA368	828,168	0	0	206,905	0	0	554,070	0
LINE TRANS - SECOND DEMAND	D60	8,763,066	4,050,760	175,986	0	2,035,294	5,150	5,096	2,455,828
LINE TRANS - SECOND CUSTOMER	C60	4,976,454	4,183,083	337,146	0	268,392	0	11	166,499
LINES - SECONDARY DEMAND	D30	3,048,825	1,958,077	85,069	0	983,831	2,489	2,464	0
LINES - SECONDARY CUSTOMER	C30	1,731,396	1,505,747	121,360	0	96,611	0	4	0
SERVICES	CW369	2,983,491	2,435,186	214,748	4,488	193,251	0	10,362	125,120
METERS	CW370	3,102,462	1,608,293	354,506	44,381	639,193	14	53,778	396,876
STREET LIGHTS	DA373	233,563	0	0	786	0	0	100	0
INSTALL ON CUST PREMISES	DA371	145,838	0	0	155	0	145,520	31	0
		0							
CUSTOMER ACCOUNTING		0							
METER READING	CW902	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
CONSUMER INFORMATION		0							
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
MISCELLANEOUS		0							
DEMAND	D99U	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0
TOTALS	PAGE 2I	SCREWED UP	79,893,826	4,524,341	4,071,802	38,302,499	217,863	21,204,950	34,092,843

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****** TABLE 6 - ACCUMULATED DEFERRED INCOME TAXES ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
DEMAND - POWER SUPPLY	D10	42,195,020	0	0	0	0	0	0
DEMAND - Summer	D10S	0	22,412	0	7,463	271,162	196,783	970,018
DEMAND - Non-Summer	D10NS	0	11,766	0	4,019	127,814	134,028	512,295
ENERGY - POWER SUPPLY	E10	50,881,992	0	0	0	0	0	0
ENERGY - Summer	E10S	0	19,739	25,044	6,614	221,015	209,013	834,490
ENERGY - Non-Summer	E10NS	0	40,632	51,470	13,616	516,253	456,118	1,637,587
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	34,589,941	25,737	0	8,689	304,318	262,790	1,138,989
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	204	0	0	0	0	133	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	9,649,659	13,795	17,510	2,187	0	0	0
SUBSTATIONS - DIRECT	DA3602	194,955	0	0	0	0	15,625	178,611
LINES - PRIMARY DEMAND	D20	14,912,153	21,319	27,059	3,380	0	0	0
LINES - PRIMARY CUSTOMER	C20	8,468,457	31,329	2,523	2,413	0	0	0
LINES - SECONDARY DIRECT	DA3647	895,284	0	0	0	0	94,842	0
LINE TRANS - PRIMARY DEMAND	D50	2,262,768	3,235	4,106	513	0	0	0
LINE TRANS - PRIMARY CUST	C50	1,285,002	4,754	383	366	0	0	0
LINE TRANS - SECOND DIRECT	DA368	828,168	0	0	0	0	67,193	0
LINE TRANS - SECOND DEMAND	D60	8,763,066	14,396	18,273	2,283	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	4,976,454	18,421	1,484	1,419	0	0	0
LINES - SECONDARY DEMAND	D30	3,048,825	6,959	8,833	1,103	0	0	0
LINES - SECONDARY CUSTOMER	C30	1,731,396	6,631	534	511	0	0	0
SERVICES	CW369	2,983,491	0	0	0	0	336	0
METERS	CW370	3,102,462	43	59	191	634	852	3,640
STREET LIGHTS	DA373	233,563	0	232,677	0	0	0	0
INSTALL ON CUST PREMISES	DA371	145,838	0	0	0	0	131	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 2I	SCREWED UP	241,168	389,955	54,766	1,441,196	1,437,844	5,275,630

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****** TABLE 7 - ACQUISITION ADJUSTMENT ******

FUNCTION	ALLOCATION FACTOR	(A) TOTALS	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV PRIMARY (9-P)	(E) GEN SRV SECONDARY (9-S)	(F) AREA LIGHTING (15)	(G) LG POWER PRIMARY (19-P)	(H) IRRIGATION SECONDARY (24-S)
DEMAND - POWER SUPPLY	D10	0	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0	0	0	0	0	0	0	0
DEMAND - Non-Summer	D10NS	0	0	0	0	0	0	0	0
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0	0
		0							
TRANSMISSION		0							
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	0	0	0	0	0	0	0	0
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0	0
		0							
DISTRIBUTION		0							
SUBSTATIONS - GENERAL	D20	(16,597)	(6,676)	(290)	(385)	(3,354)	(8)	(1,778)	(4,048)
SUBSTATIONS - DIRECT	DA3602	(1,694)	0	0	0	0	0	(6)	0
LINES - PRIMARY DEMAND	D20	(23,870)	(9,602)	(417)	(553)	(4,824)	(12)	(2,557)	(5,821)
LINES - PRIMARY CUSTOMER	C20	(13,555)	(11,388)	(918)	(4)	(731)	0	(3)	(453)
LINES - SECONDARY DIRECT	DA3647	(1,433)	0	0	(275)	0	(47)	(960)	0
LINE TRANS - PRIMARY DEMAND	D50	(3,622)	(1,457)	(63)	(84)	(732)	(2)	(388)	(883)
LINE TRANS - PRIMARY CUST	C50	(2,057)	(1,728)	(139)	(1)	(111)	0	(1)	(69)
LINE TRANS - SECOND DIRECT	DA368	(1,326)	0	0	(331)	0	0	(887)	0
LINE TRANS - SECOND DEMAND	D60	(14,027)	(6,484)	(282)	0	(3,258)	(8)	(8)	(3,931)
LINE TRANS - SECOND CUSTOMER	C60	(7,966)	(6,696)	(540)	0	(430)	0	(0)	(267)
LINES - SECONDARY DEMAND	D30	(4,880)	(3,134)	(136)	0	(1,575)	(4)	(4)	0
LINES - SECONDARY CUSTOMER	C30	(2,771)	(2,410)	(194)	0	(155)	0	(0)	0
SERVICES	CW369	(4,776)	(3,898)	(344)	(7)	(309)	0	(17)	(200)
METERS	CW370	(4,966)	(2,574)	(567)	(71)	(1,023)	(0)	(86)	(635)
STREET LIGHTS	DA373	(374)	0	0	(1)	0	0	(0)	0
INSTALL ON CUST PREMISES	DA371	(233)	0	0	(0)	0	(233)	(0)	0
		0							
CUSTOMER ACCOUNTING		0							
METER READING	CW902	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
CONSUMER INFORMATION		0							
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
MISCELLANEOUS		0							
DEMAND	D99U	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0
TOTALS	PAGE 2J	(104,146)	(56,048)	(3,891)	(1,712)	(16,502)	(314)	(6,694)	(16,307)

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****** TABLE 7 - ACQUISITION ADJUSTMENT ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
DEMAND - POWER SUPPLY	D10	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0	0	0	0	0	0	0
DEMAND - Non-Summer	D10NS	0	0	0	0	0	0	0
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	0	0	0	0	0	0	0
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	(16,597)	(24)	(30)	(4)	0	0	0
SUBSTATIONS - DIRECT	DA3602	(1,694)	0	0	0	0	(136)	(1,552)
LINES - PRIMARY DEMAND	D20	(23,870)	(34)	(43)	(5)	0	0	0
LINES - PRIMARY CUSTOMER	C20	(13,555)	(50)	(4)	(4)	0	0	0
LINES - SECONDARY DIRECT	DA3647	(1,433)	0	0	0	0	(152)	0
LINE TRANS - PRIMARY DEMAND	D50	(3,622)	(5)	(7)	(1)	0	0	0
LINE TRANS - PRIMARY CUST	C50	(2,057)	(8)	(1)	(1)	0	0	0
LINE TRANS - SECOND DIRECT	DA368	(1,326)	0	0	0	0	(108)	0
LINE TRANS - SECOND DEMAND	D60	(14,027)	(23)	(29)	(4)	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	(7,966)	(29)	(2)	(2)	0	0	0
LINES - SECONDARY DEMAND	D30	(4,880)	(11)	(14)	(2)	0	0	0
LINES - SECONDARY CUSTOMER	C30	(2,771)	(11)	(1)	(1)	0	0	0
SERVICES	CW369	(4,776)	0	0	0	0	(1)	0
METERS	CW370	(4,966)	(0)	(0)	(0)	(1)	(1)	(6)
STREET LIGHTS	DA373	(374)	0	(372)	0	0	0	0
INSTALL ON CUST PREMISES	DA371	(233)	0	0	0	0	(0)	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 2J	(104,146)	(195)	(504)	(23)	(1)	(397)	(1,557)

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****** TABLE 8 - WORKING CAPITAL ******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
FUNCTION	ALLOCATION FACTOR	TOTALS	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV PRIMARY (9-P)	GEN SRV SECONDARY (9-S)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	IRRIGATION SECONDARY (24-S)
DEMAND - POWER SUPPLY	D10	6,660,146	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0	1,567,795	81,612	99,913	985,599	0	543,818	1,130,945
DEMAND - Non-Summer	D10NS	0	674,861	31,186	50,941	469,610	0	283,721	383,772
ENERGY - POWER SUPPLY	E10	21,901,760	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	2,573,742	116,490	194,096	1,769,045	3,065	1,135,227	2,249,185
ENERGY - Non-Summer	E10NS	0	5,439,329	220,455	368,786	3,229,323	6,324	2,204,983	656,345
		0							
TRANSMISSION		0							
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	7,392,060	2,637,973	130,124	161,438	1,561,534	0	876,244	1,652,789
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	44	0	0	15	0	0	0	0
		0							
DISTRIBUTION		0							
SUBSTATIONS - GENERAL	D20	2,537,886	1,020,896	44,353	58,812	512,947	1,298	271,839	618,932
SUBSTATIONS - DIRECT	DA3602	258,984	0	0	0	0	955	0	0
LINES - PRIMARY DEMAND	D20	3,650,002	1,468,259	63,789	84,584	737,723	1,867	390,960	890,152
LINES - PRIMARY CUSTOMER	C20	2,072,798	1,741,395	140,352	609	111,730	0	523	69,313
LINES - SECONDARY DIRECT	DA3647	219,136	0	0	42,024	0	7,137	146,760	0
LINE TRANS - PRIMARY DEMAND	D50	553,851	222,793	9,679	12,835	111,942	283	59,324	135,072
LINE TRANS - PRIMARY CUST	C50	314,526	264,239	21,297	92	16,954	0	79	10,518
LINE TRANS - SECOND DIRECT	DA368	202,708	0	0	50,644	0	0	135,618	0
LINE TRANS - SECOND DEMAND	D60	2,144,909	991,492	43,076	0	498,173	1,261	1,247	601,105
LINE TRANS - SECOND CUSTOMER	C60	1,218,072	1,023,881	82,522	0	65,693	0	3	40,754
LINES - SECONDARY DEMAND	D30	746,252	479,273	20,822	0	240,809	609	603	0
LINES - SECONDARY CUSTOMER	C30	423,789	368,557	29,705	0	23,647	0	1	0
SERVICES	CW369	730,260	596,053	52,563	1,098	47,301	0	2,536	30,625
METERS	CW370	759,380	393,657	86,771	10,863	156,453	4	13,163	97,142
STREET LIGHTS	DA373	57,168	0	0	192	0	0	24	0
INSTALL ON CUST PREMISES	DA371	35,696	0	0	38	0	35,619	8	0
		0							
CUSTOMER ACCOUNTING		0							
METER READING	CW902	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
CONSUMER INFORMATION		0							
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
MISCELLANEOUS		0							
DEMAND	D99U	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0
TOTALS	PAGE 2K	SCREWED UP	21,464,195	1,174,797	1,136,981	10,538,484	57,466	6,067,637	8,566,647

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****** TABLE 8 - WORKING CAPITAL ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
DEMAND - POWER SUPPLY	D10	6,660,146	0	0	0	0	0	0
DEMAND - Summer	D10S	0	3,538	0	1,178	42,801	31,061	153,110
DEMAND - Non-Summer	D10NS	0	1,857	0	634	20,174	21,155	80,862
ENERGY - POWER SUPPLY	E10	21,901,760	0	0	0	0	0	0
ENERGY - Summer	E10S	0	8,496	10,780	2,847	95,134	89,968	359,200
ENERGY - Non-Summer	E10NS	0	17,490	22,155	5,861	222,217	196,332	704,887
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	7,392,060	5,500	0	1,857	65,034	56,160	243,408
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	44	0	0	0	0	28	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	2,537,886	3,628	4,605	575	0	0	0
SUBSTATIONS - DIRECT	DA3602	258,984	0	0	0	0	20,757	237,272
LINES - PRIMARY DEMAND	D20	3,650,002	5,218	6,623	827	0	0	0
LINES - PRIMARY CUSTOMER	C20	2,072,798	7,668	618	591	0	0	0
LINES - SECONDARY DIRECT	DA3647	219,136	0	0	0	0	23,214	0
LINE TRANS - PRIMARY DEMAND	D50	553,851	792	1,005	126	0	0	0
LINE TRANS - PRIMARY CUST	C50	314,526	1,164	94	90	0	0	0
LINE TRANS - SECOND DIRECT	DA368	202,708	0	0	0	0	16,447	0
LINE TRANS - SECOND DEMAND	D60	2,144,909	3,524	4,473	559	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	1,218,072	4,509	363	347	0	0	0
LINES - SECONDARY DEMAND	D30	746,252	1,703	2,162	270	0	0	0
LINES - SECONDARY CUSTOMER	C30	423,789	1,623	131	125	0	0	0
SERVICES	CW369	730,260	0	0	0	0	82	0
METERS	CW370	759,380	10	15	47	155	209	891
STREET LIGHTS	DA373	57,168	0	56,952	0	0	0	0
INSTALL ON CUST PREMISES	DA371	35,696	0	0	0	0	32	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 2K	SCREWED UP	66,721	109,974	15,933	445,516	455,445	1,779,629

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****** TABLE 9 - DEFERRED PROGRAMS ******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
FUNCTION	ALLOCATION FACTOR	TOTALS	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV PRIMARY (9-P)	GEN SRV SECONDARY (9-S)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	IRRIGATION SECONDARY (24-S)
DEMAND - POWER SUPPLY	D10	3,361,782	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0	791,362	41,194	50,432	497,492	0	274,498	570,857
DEMAND - Non-Summer	D10NS	0	340,644	15,741	25,713	237,041	0	143,211	193,713
ENERGY - POWER SUPPLY	E10	5,761,624	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	677,066	30,645	51,060	465,377	806	298,640	591,686
ENERGY - Non-Summer	E10NS	0	1,430,906	57,994	97,015	849,527	1,664	580,058	172,662
		0							
TRANSMISSION		0							
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	257,663	91,951	4,536	5,627	54,430	0	30,543	57,611
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	2	0	0	1	0	0	0	0
		0							
DISTRIBUTION		0							
SUBSTATIONS - GENERAL	D20	0	0	0	0	0	0	0	0
SUBSTATIONS - DIRECT	DA3602	0	0	0	0	0	0	0	0
LINES - PRIMARY DEMAND	D20	0	0	0	0	0	0	0	0
LINES - PRIMARY CUSTOMER	C20	0	0	0	0	0	0	0	0
LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0	0
LINE TRANS - PRIMARY DEMAND	D50	0	0	0	0	0	0	0	0
LINE TRANS - PRIMARY CUST	C50	0	0	0	0	0	0	0	0
LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0	0
LINE TRANS - SECOND DEMAND	D60	0	0	0	0	0	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	0	0	0	0	0	0	0	0
LINES - SECONDARY DEMAND	D30	0	0	0	0	0	0	0	0
LINES - SECONDARY CUSTOMER	C30	0	0	0	0	0	0	0	0
SERVICES	CW369	0	0	0	0	0	0	0	0
METERS	CW370	0	0	0	0	0	0	0	0
STREET LIGHTS	DA373	0	0	0	0	0	0	0	0
INSTALL ON CUST PREMISES	DA371	0	0	0	0	0	0	0	0
		0							
CUSTOMER ACCOUNTING		0							
METER READING	CW902	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
CONSUMER INFORMATION		0							
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
MISCELLANEOUS		0							
DEMAND	D99U	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0
TOTALS	PAGE 2L	SCREWED UP	3,331,929	150,111	229,849	2,103,867	2,470	1,326,950	1,586,529

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****** TABLE 9 - DEFERRED PROGRAMS ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
DEMAND - POWER SUPPLY	D10	3,361,782	0	0	0	0	0	0
DEMAND - Summer	D10S	0	1,786	0	595	21,604	15,678	77,284
DEMAND - Non-Summer	D10NS	0	937	0	320	10,183	10,678	40,816
ENERGY - POWER SUPPLY	E10	5,761,624	0	0	0	0	0	0
ENERGY - Summer	E10S	0	2,235	2,836	749	25,027	23,668	94,494
ENERGY - Non-Summer	E10NS	0	4,601	5,828	1,542	58,458	51,648	185,432
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	257,663	192	0	65	2,267	1,958	8,484
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	2	0	0	0	0	1	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	0	0	0	0	0	0	0
SUBSTATIONS - DIRECT	DA3602	0	0	0	0	0	0	0
LINES - PRIMARY DEMAND	D20	0	0	0	0	0	0	0
LINES - PRIMARY CUSTOMER	C20	0	0	0	0	0	0	0
LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0
LINE TRANS - PRIMARY DEMAND	D50	0	0	0	0	0	0	0
LINE TRANS - PRIMARY CUST	C50	0	0	0	0	0	0	0
LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0
LINE TRANS - SECOND DEMAND	D60	0	0	0	0	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	0	0	0	0	0	0	0
LINES - SECONDARY DEMAND	D30	0	0	0	0	0	0	0
LINES - SECONDARY CUSTOMER	C30	0	0	0	0	0	0	0
SERVICES	CW369	0	0	0	0	0	0	0
METERS	CW370	0	0	0	0	0	0	0
STREET LIGHTS	DA373	0	0	0	0	0	0	0
INSTALL ON CUST PREMISES	DA371	0	0	0	0	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 2L	SCREWED UP	9,751	8,664	3,270	117,539	103,631	406,510

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****** TABLE 10 - SUBSIDIARY RATE BASE ******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
FUNCTION	ALLOCATION FACTOR	TOTALS	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV PRIMARY (9-P)	GEN SRV SECONDARY (9-S)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	IRRIGATION SECONDARY (24-S)
DEMAND - POWER SUPPLY	D10	0	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0	0	0	0	0	0	0	0
DEMAND - Non-Summer	D10NS	0	0	0	0	0	0	0	0
ENERGY - POWER SUPPLY	E10	64,384,654	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	7,566,034	342,446	570,584	5,200,464	9,009	3,337,228	6,611,934
ENERGY - Non-Summer	E10NS	0	15,990,008	648,071	1,084,121	9,493,248	18,591	6,481,993	1,929,458
		0							
TRANSMISSION		0							
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	0	0	0	0	0	0	0	0
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0	0
		0							
DISTRIBUTION		0							
SUBSTATIONS - GENERAL	D20	0	0	0	0	0	0	0	0
SUBSTATIONS - DIRECT	DA3602	0	0	0	0	0	0	0	0
LINES - PRIMARY DEMAND	D20	0	0	0	0	0	0	0	0
LINES - PRIMARY CUSTOMER	C20	0	0	0	0	0	0	0	0
LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0	0
LINE TRANS - PRIMARY DEMAND	D50	0	0	0	0	0	0	0	0
LINE TRANS - PRIMARY CUST	C50	0	0	0	0	0	0	0	0
LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0	0
LINE TRANS - SECOND DEMAND	D60	0	0	0	0	0	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	0	0	0	0	0	0	0	0
LINES - SECONDARY DEMAND	D30	0	0	0	0	0	0	0	0
LINES - SECONDARY CUSTOMER	C30	0	0	0	0	0	0	0	0
SERVICES	CW369	0	0	0	0	0	0	0	0
METERS	CW370	0	0	0	0	0	0	0	0
STREET LIGHTS	DA373	0	0	0	0	0	0	0	0
INSTALL ON CUST PREMISES	DA371	0	0	0	0	0	0	0	0
		0							
CUSTOMER ACCOUNTING		0							
METER READING	CW902	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
CONSUMER INFORMATION		0							
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
MISCELLANEOUS		0							
DEMAND	D99U	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0
TOTALS	PAGE 2M	64,384,654	23,556,042	990,517	1,654,705	14,693,712	27,600	9,819,221	8,541,391

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****** TABLE 10 - SUBSIDIARY RATE BASE ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
DEMAND - POWER SUPPLY	D10	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0	0	0	0	0	0	0
DEMAND - Non-Summer	D10NS	0	0	0	0	0	0	0
ENERGY - POWER SUPPLY	E10	64,384,654	0	0	0	0	0	0
ENERGY - Summer	E10S	0	24,977	31,689	8,370	279,667	264,480	1,055,941
ENERGY - Non-Summer	E10NS	0	51,415	65,129	17,229	653,252	577,158	2,072,157
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	0	0	0	0	0	0	0
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	0	0	0	0	0	0	0
SUBSTATIONS - DIRECT	DA3602	0	0	0	0	0	0	0
LINES - PRIMARY DEMAND	D20	0	0	0	0	0	0	0
LINES - PRIMARY CUSTOMER	C20	0	0	0	0	0	0	0
LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0
LINE TRANS - PRIMARY DEMAND	D50	0	0	0	0	0	0	0
LINE TRANS - PRIMARY CUST	C50	0	0	0	0	0	0	0
LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0
LINE TRANS - SECOND DEMAND	D60	0	0	0	0	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	0	0	0	0	0	0	0
LINES - SECONDARY DEMAND	D30	0	0	0	0	0	0	0
LINES - SECONDARY CUSTOMER	C30	0	0	0	0	0	0	0
SERVICES	CW369	0	0	0	0	0	0	0
METERS	CW370	0	0	0	0	0	0	0
STREET LIGHTS	DA373	0	0	0	0	0	0	0
INSTALL ON CUST PREMISES	DA371	0	0	0	0	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 2M	64,384,654	76,392	96,819	25,599	932,919	841,638	3,128,098

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****** TABLE 11 - PLANT HELD FOR FUTUE USE ******

FUNCTION	ALLOCATION FACTOR	(A) TOTALS	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV PRIMARY (9-P)	(E) GEN SRV SECONDARY (9-S)	(F) AREA LIGHTING (15)	(G) LG POWER PRIMARY (19-P)	(H) IRRIGATION SECONDARY (24-S)
DEMAND - POWER SUPPLY	D10	0	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0	0	0	0	0	0	0	0
DEMAND - Non-Summer	D10NS	0	0	0	0	0	0	0	0
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0	0
		0							
TRANSMISSION		0							
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	218,994	78,152	3,855	4,783	46,261	0	25,959	48,965
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0	0
		0							
DISTRIBUTION		0							
SUBSTATIONS - GENERAL	D20	570,224	229,380	9,965	13,214	115,251	292	61,078	139,064
SUBSTATIONS - DIRECT	DA3602	6	0	0	0	0	0	0	0
LINES - PRIMARY DEMAND	D20	0	0	0	0	0	0	0	0
LINES - PRIMARY CUSTOMER	C20	0	0	0	0	0	0	0	0
LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0	0
LINE TRANS - PRIMARY DEMAND	D50	0	0	0	0	0	0	0	0
LINE TRANS - PRIMARY CUST	C50	0	0	0	0	0	0	0	0
LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0	0
LINE TRANS - SECOND DEMAND	D60	0	0	0	0	0	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	0	0	0	0	0	0	0	0
LINES - SECONDARY DEMAND	D30	0	0	0	0	0	0	0	0
LINES - SECONDARY CUSTOMER	C30	0	0	0	0	0	0	0	0
SERVICES	CW369	0	0	0	0	0	0	0	0
METERS	CW370	0	0	0	0	0	0	0	0
STREET LIGHTS	DA373	0	0	0	0	0	0	0	0
INSTALL ON CUST PREMISES	DA371	0	0	0	0	0	0	0	0
		0							
CUSTOMER ACCOUNTING		0							
METER READING	CW902	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
CONSUMER INFORMATION		0							
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
MISCELLANEOUS		0							
DEMAND	D99U	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0
TOTALS	PAGE 2N	789,224	307,531	13,820	17,997	161,513	292	87,037	188,029

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*** TABLE 11 - PLANT HELD FOR FUTUE USE ***

FUNCTION	ALLOCATION FACTOR	TOTALS	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
DEMAND - POWER SUPPLY	D10	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0	0	0	0	0	0	0
DEMAND - Non-Summer	D10NS	0	0	0	0	0	0	0
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	218,994	163	0	55	1,927	1,664	7,211
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	570,224	815	1,035	129	0	0	0
SUBSTATIONS - DIRECT	DA3602	6	0	0	0	0	1	6
LINES - PRIMARY DEMAND	D20	0	0	0	0	0	0	0
LINES - PRIMARY CUSTOMER	C20	0	0	0	0	0	0	0
LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0
LINE TRANS - PRIMARY DEMAND	D50	0	0	0	0	0	0	0
LINE TRANS - PRIMARY CUST	C50	0	0	0	0	0	0	0
LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0
LINE TRANS - SECOND DEMAND	D60	0	0	0	0	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	0	0	0	0	0	0	0
LINES - SECONDARY DEMAND	D30	0	0	0	0	0	0	0
LINES - SECONDARY CUSTOMER	C30	0	0	0	0	0	0	0
SERVICES	CW369	0	0	0	0	0	0	0
METERS	CW370	0	0	0	0	0	0	0
STREET LIGHTS	DA373	0	0	0	0	0	0	0
INSTALL ON CUST PREMISES	DA371	0	0	0	0	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 2N	789,224	978	1,035	184	1,927	1,664	7,217

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****** TABLE 12 - OTHER REVENUES ******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
FUNCTION	ALLOCATION FACTOR	TOTALS	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV PRIMARY (9-P)	GEN SRV SECONDARY (9-S)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	IRRIGATION SECONDARY (24-S)
DEMAND - POWER SUPPLY	D10	532,931	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0	125,452	6,530	7,995	78,866	0	43,515	90,496
DEMAND - Non-Summer	D10NS	0	54,001	2,495	4,076	37,577	0	22,703	30,709
ENERGY - POWER SUPPLY	E10	154,118,883	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	18,110,973	819,719	1,365,819	12,448,459	21,566	7,988,392	15,827,123
ENERGY - Non-Summer	E10NS	0	38,275,614	1,551,301	2,595,083	22,724,184	44,502	15,516,082	4,618,582
		0							
TRANSMISSION		0							
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	9,324,159	3,327,473	164,135	203,633	1,969,680	0	1,105,272	2,084,786
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	25	0	0	9	0	0	0	0
		0							
DISTRIBUTION		0							
SUBSTATIONS - GENERAL	D20	86,202	34,676	1,507	1,998	17,423	44	9,233	21,023
SUBSTATIONS - DIRECT	DA3602	8,797	0	0	0	0	0	32	0
LINES - PRIMARY DEMAND	D20	1,537,124	618,328	26,863	35,621	310,677	786	164,645	374,869
LINES - PRIMARY CUSTOMER	C20	872,917	733,353	59,107	256	47,053	0	220	29,190
LINES - SECONDARY DIRECT	DA3647	48,467	0	0	9,295	0	1,579	32,459	0
LINE TRANS - PRIMARY DEMAND	D50	97,833	39,355	1,710	2,267	19,774	50	10,479	23,859
LINE TRANS - PRIMARY CUST	C50	55,559	46,676	3,762	16	2,995	0	14	1,858
LINE TRANS - SECOND DIRECT	DA368	35,807	0	0	8,946	0	0	23,956	0
LINE TRANS - SECOND DEMAND	D60	378,881	175,139	7,609	0	87,998	223	220	106,181
LINE TRANS - SECOND CUSTOMER	C60	215,163	180,860	14,577	0	11,604	0	0	7,199
LINES - SECONDARY DEMAND	D30	207,139	133,033	5,780	0	66,842	169	167	0
LINES - SECONDARY CUSTOMER	C30	117,632	102,302	8,245	0	6,564	0	0	0
SERVICES	CW369	128,995	105,288	9,285	194	8,355	0	448	5,410
METERS	CW370	25,793	13,371	2,947	369	5,314	0	447	3,300
STREET LIGHTS	DA373	10,098	0	0	34	0	0	4	0
INSTALL ON CUST PREMISES	DA371	6,305	0	0	7	0	6,292	1	0
		0							
CUSTOMER ACCOUNTING		0							
METER READING	CW902	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
CONSUMER INFORMATION		0							
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
MISCELLANEOUS		0							
DEMAND	D99U	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0
MISC. REVENUE	R02	4,933,621	4,593,857	191,440	649	60,157	1,630	188	83,604
FACILITIES CHARGE REVENUE	DA454	5,648,745	34,648	435	1,185,953	0	96,465	3,635,498	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0
TOTALS	PAGE 4C	178,391,078	66,704,398	2,877,448	5,422,220	37,903,523	173,305	28,553,979	23,308,188

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****** TABLE 12 - OTHER REVENUES ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
DEMAND - POWER SUPPLY	D10	532,931	0	0	0	0	0	0
DEMAND - Summer	D10S	0	283	0	94	3,425	2,485	12,252
DEMAND - Non-Summer	D10NS	0	149	0	51	1,614	1,693	6,470
ENERGY - POWER SUPPLY	E10	154,118,883	0	0	0	0	0	0
ENERGY - Summer	E10S	0	59,787	75,856	20,035	669,444	633,091	2,527,628
ENERGY - Non-Summer	E10NS	0	123,073	155,901	41,243	1,563,704	1,381,556	4,960,166
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	9,324,159	6,938	0	2,342	82,033	70,838	307,029
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	25	0	0	0	0	17	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	86,202	123	156	20	0	0	0
SUBSTATIONS - DIRECT	DA3602	8,797	0	0	0	0	705	8,059
LINES - PRIMARY DEMAND	D20	1,537,124	2,198	2,789	348	0	0	0
LINES - PRIMARY CUSTOMER	C20	872,917	3,229	260	249	0	0	0
LINES - SECONDARY DIRECT	DA3647	48,467	0	0	0	0	5,134	0
LINE TRANS - PRIMARY DEMAND	D50	97,833	140	178	22	0	0	0
LINE TRANS - PRIMARY CUST	C50	55,559	206	17	16	0	0	0
LINE TRANS - SECOND DIRECT	DA368	35,807	0	0	0	0	2,905	0
LINE TRANS - SECOND DEMAND	D60	378,881	622	790	99	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	215,163	796	64	61	0	0	0
LINES - SECONDARY DEMAND	D30	207,139	473	600	75	0	0	0
LINES - SECONDARY CUSTOMER	C30	117,632	450	36	35	0	0	0
SERVICES	CW369	128,995	0	0	0	0	15	0
METERS	CW370	25,793	0	0	2	5	7	30
STREET LIGHTS	DA373	10,098	0	10,060	0	0	0	0
INSTALL ON CUST PREMISES	DA371	6,305	0	0	0	0	6	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
MISC. REVENUE	R02	4,933,621	188	83	1,823	0	0	0
FACILITIES CHARGE REVENUE	DA454	5,648,745	0	177,574	0	0	518,172	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 4C	178,391,078	198,656	424,365	66,514	2,320,225	2,616,624	7,821,634

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****** TABLE 13 - OPERATION & MAINTENANCE EXPENSES ******

FUNCTION	ALLOCATION FACTOR	(A) TOTALS	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV PRIMARY (9-P)	(E) GEN SRV SECONDARY (9-S)	(F) AREA LIGHTING (15)	(G) LG POWER PRIMARY (19-P)	(H) IRRIGATION SECONDARY (24-S)
DEMAND - POWER SUPPLY	D10	95,811,785	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0	22,554,043	1,174,054	1,437,338	14,178,668	0	7,823,276	16,269,590
DEMAND - Non-Summer	D10NS	0	9,708,447	448,637	732,835	6,755,736	0	4,081,564	5,520,888
ENERGY - POWER SUPPLY	E10	289,552,474	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	34,026,182	1,540,056	2,566,046	23,387,674	40,517	15,008,276	29,735,375
ENERGY - Non-Summer	E10NS	0	71,910,712	2,914,523	4,875,539	42,693,300	83,608	29,151,002	8,677,210
		0							
TRANSMISSION		0							
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	26,113,429	9,318,987	459,681	570,299	5,516,325	0	3,095,448	5,838,694
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	129	0	0	45	0	0	0	0
		0							
DISTRIBUTION		0							
SUBSTATIONS - GENERAL	D20	9,904,028	3,984,019	173,087	229,513	2,001,761	5,065	1,060,844	2,415,365
SUBSTATIONS - DIRECT	DA3602	978,884	0	0	0	0	0	3,610	0
LINES - PRIMARY DEMAND	D20	20,208,661	8,129,186	353,175	468,309	4,084,490	10,335	2,164,597	4,928,428
LINES - PRIMARY CUSTOMER	C20	11,476,289	9,641,436	777,077	3,370	618,606	0	2,895	383,759
LINES - SECONDARY DIRECT	DA3647	827,842	0	0	158,758	0	26,962	554,424	0
LINE TRANS - PRIMARY DEMAND	D50	845,159	339,976	14,770	19,585	170,820	432	90,527	206,115
LINE TRANS - PRIMARY CUST	C50	479,957	403,221	32,499	141	25,871	0	121	16,049
LINE TRANS - SECOND DIRECT	DA368	309,326	0	0	77,280	0	0	206,949	0
LINE TRANS - SECOND DEMAND	D60	3,273,065	1,512,986	65,732	0	760,196	1,923	1,904	917,268
LINE TRANS - SECOND CUSTOMER	C60	1,858,740	1,562,410	125,926	0	100,246	0	4	62,189
LINES - SECONDARY DEMAND	D30	3,343,227	2,147,154	93,284	0	1,078,832	2,730	2,701	0
LINES - SECONDARY CUSTOMER	C30	1,898,584	1,651,145	133,078	0	105,939	0	4	0
SERVICES	CW369	1,014,152	827,772	72,998	1,525	65,690	0	3,522	42,531
METERS	CW370	11,976,075	6,208,309	1,368,458	171,320	2,467,405	55	207,594	1,532,013
STREET LIGHTS	DA373	1,248,662	0	0	4,201	0	0	532	0
INSTALL ON CUST PREMISES	CWINSTAL	2,724,797	1,797,138	144,844	627	115,306	585,652	538	71,531
		0							
CUSTOMER ACCOUNTING		0							
METER READING	CW902	9,629,578	6,997,425	615,324	589,885	512,856	0	506,864	394,116
CUSTOMER ACCOUNTS	CW903	17,058,632	14,250,660	1,148,570	55,915	914,339	0	48,045	567,220
UNCOLLECTIBLES	CW904	2,926,405	2,466,737	57,586	0	80,678	2,678	0	318,726
MISC	C10	0	0	0	0	0	0	0	0
		0							
CONSUMER INFORMATION		0							
CUSTOMER ASSIST	C10	8,040,987	6,755,333	544,464	2,361	433,430	0	2,029	268,883
SALES EXPENSE	C10	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
MISCELLANEOUS		0							
DEMAND	D99U	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0
OTHER	INTFUND	50,649	14,805	1,193	0	0	0	0	34,651
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0
TOTALS	PAGE 3C	SCREWED UP	216,208,084	12,259,015	11,964,894	106,068,169	759,958	64,017,270	78,200,603

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****** TABLE 13 - OPERATION & MAINTENANCE EXPENSES ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
DEMAND - POWER SUPPLY	D10	95,811,785	0	0	0	0	0	0
DEMAND - Summer	D10S	0	50,891	0	16,946	615,725	446,833	2,202,609
DEMAND - Non-Summer	D10NS	0	26,718	0	9,125	290,226	304,335	1,163,264
ENERGY - POWER SUPPLY	E10	289,552,474	0	0	0	0	0	0
ENERGY - Summer	E10S	0	112,326	142,515	37,641	1,257,725	1,189,426	4,748,807
ENERGY - Non-Summer	E10NS	0	231,225	292,901	77,485	2,937,825	2,595,613	9,318,964
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	26,113,429	19,430	0	6,559	229,742	198,391	859,872
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	129	0	0	0	0	84	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	9,904,028	14,159	17,972	2,245	0	0	0
SUBSTATIONS - DIRECT	DA3602	978,884	0	0	0	0	78,455	896,819
LINES - PRIMARY DEMAND	D20	20,208,661	28,891	36,670	4,581	0	0	0
LINES - PRIMARY CUSTOMER	C20	11,476,289	42,457	3,420	3,270	0	0	0
LINES - SECONDARY DIRECT	DA3647	827,842	0	0	0	0	87,697	0
LINE TRANS - PRIMARY DEMAND	D50	845,159	1,208	1,534	192	0	0	0
LINE TRANS - PRIMARY CUST	C50	479,957	1,776	143	137	0	0	0
LINE TRANS - SECOND DIRECT	DA368	309,326	0	0	0	0	25,097	0
LINE TRANS - SECOND DEMAND	D60	3,273,065	5,377	6,825	853	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	1,858,740	6,880	554	530	0	0	0
LINES - SECONDARY DEMAND	D30	3,343,227	7,631	9,686	1,210	0	0	0
LINES - SECONDARY CUSTOMER	C30	1,898,584	7,271	586	560	0	0	0
SERVICES	CW369	1,014,152	0	0	0	0	114	0
METERS	CW370	11,976,075	165	229	738	2,448	3,290	14,051
STREET LIGHTS	DA373	1,248,662	0	1,243,928	0	0	0	0
INSTALL ON CUST PREMISES	CWINSTAL	2,724,797	7,914	637	609	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	9,629,578	0	0	0	4,370	4,370	4,370
CUSTOMER ACCOUNTS	CW903	17,058,632	62,753	5,054	4,832	414	414	414
UNCOLLECTIBLES	CW904	2,926,405	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	8,040,987	29,748	2,396	2,291	17	17	17
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	INTFUND	50,649	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 3C	SCREWED UP	656,820	1,765,048	169,802	5,338,492	4,934,137	19,209,187

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****** TABLE 14 - DEPRECIATTION EXPENSE ******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
FUNCTION	ALLOCATION FACTOR	TOTALS	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV PRIMARY (9-P)	GEN SRV SECONDARY (9-S)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	IRRIGATION SECONDARY (24-S)
DEMAND - POWER SUPPLY	D10	20,340,432	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0	4,788,127	249,247	305,141	3,010,070	0	1,660,848	3,453,964
DEMAND - Non-Summer	D10NS	0	2,061,062	95,244	155,578	1,434,214	0	866,499	1,172,061
ENERGY - POWER SUPPLY	E10	24,106,255	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	2,832,798	128,215	213,632	1,947,106	3,373	1,249,491	2,475,574
ENERGY - Non-Summer	E10NS	0	5,986,818	242,644	405,906	3,554,366	6,961	2,426,923	722,408
		0							
TRANSMISSION		0							
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	14,599,095	5,209,916	256,991	318,834	3,083,982	0	1,730,556	3,264,207
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	94	0	0	33	0	0	0	0
		0							
DISTRIBUTION		0							
SUBSTATIONS - GENERAL	D20	3,425,314	1,377,875	59,862	79,377	692,310	1,752	366,893	835,355
SUBSTATIONS - DIRECT	DA3602	101,924	0	0	0	0	0	376	0
LINES - PRIMARY DEMAND	D20	8,989,314	3,616,064	157,101	208,315	1,816,882	4,597	962,866	2,192,287
LINES - PRIMARY CUSTOMER	C20	5,104,938	4,288,750	345,663	1,499	275,171	0	1,288	170,705
LINES - SECONDARY DIRECT	DA3647	463,358	0	0	88,860	0	15,091	310,321	0
LINE TRANS - PRIMARY DEMAND	D50	803,457	323,201	14,042	18,619	162,391	411	86,060	195,945
LINE TRANS - PRIMARY CUST	C50	456,275	383,325	30,895	134	24,595	0	115	15,257
LINE TRANS - SECOND DIRECT	DA368	294,063	0	0	73,467	0	0	196,737	0
LINE TRANS - SECOND DEMAND	D60	3,111,563	1,438,332	62,489	0	722,686	1,829	1,810	872,008
LINE TRANS - SECOND CUSTOMER	C60	1,767,024	1,485,316	119,713	0	95,300	0	4	59,120
LINES - SECONDARY DEMAND	D30	1,600,257	1,027,749	44,651	0	516,390	1,307	1,293	0
LINES - SECONDARY CUSTOMER	C30	908,770	790,331	63,699	0	50,709	0	2	0
SERVICES	CW369	2,034,749	1,660,803	146,459	3,061	131,798	0	7,067	85,332
METERS	CW370	2,321,337	1,203,364	265,250	33,207	478,260	11	40,238	296,952
STREET LIGHTS	DA373	237,445	0	0	799	0	0	101	0
INSTALL ON CUST PREMISES	CWINSTAL	264,725	174,599	14,072	61	11,202	56,898	52	6,950
		0							
CUSTOMER ACCOUNTING		0							
METER READING	CW902	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
CONSUMER INFORMATION		0							
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
MISCELLANEOUS		0							
DEMAND	D99U	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0
TOTALS	PAGE 3D	SCREWED UP	38,648,431	2,296,236	1,906,523	18,007,433	92,229	9,909,541	15,818,126

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****** TABLE 14 - DEPRECIATTION EXPENSE ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
DEMAND - POWER SUPPLY	D10	20,340,432	0	0	0	0	0	0
DEMAND - Summer	D10S	0	10,804	0	3,598	130,716	94,861	467,604
DEMAND - Non-Summer	D10NS	0	5,672	0	1,937	61,614	64,609	246,956
ENERGY - POWER SUPPLY	E10	24,106,255	0	0	0	0	0	0
ENERGY - Summer	E10S	0	9,352	11,865	3,134	104,710	99,024	395,355
ENERGY - Non-Summer	E10NS	0	19,250	24,385	6,451	244,584	216,094	775,836
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	14,599,095	10,863	0	3,667	128,441	110,914	480,724
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	94	0	0	0	0	61	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	3,425,314	4,897	6,216	776	0	0	0
SUBSTATIONS - DIRECT	DA3602	101,924	0	0	0	0	8,169	93,379
LINES - PRIMARY DEMAND	D20	8,989,314	12,851	16,312	2,038	0	0	0
LINES - PRIMARY CUSTOMER	C20	5,104,938	18,886	1,521	1,454	0	0	0
LINES - SECONDARY DIRECT	DA3647	463,358	0	0	0	0	49,086	0
LINE TRANS - PRIMARY DEMAND	D50	803,457	1,149	1,458	182	0	0	0
LINE TRANS - PRIMARY CUST	C50	456,275	1,688	136	130	0	0	0
LINE TRANS - SECOND DIRECT	DA368	294,063	0	0	0	0	23,859	0
LINE TRANS - SECOND DEMAND	D60	3,111,563	5,112	6,488	810	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	1,767,024	6,541	527	504	0	0	0
LINES - SECONDARY DEMAND	D30	1,600,257	3,653	4,636	579	0	0	0
LINES - SECONDARY CUSTOMER	C30	908,770	3,480	280	268	0	0	0
SERVICES	CW369	2,034,749	0	0	0	0	229	0
METERS	CW370	2,321,337	32	44	143	474	638	2,724
STREET LIGHTS	DA373	237,445	0	236,545	0	0	0	0
INSTALL ON CUST PREMISES	CWINSTAL	264,725	769	62	59	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 3D	SCREWED UP	114,998	310,474	25,731	670,539	667,543	2,462,578

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****** TABLE 15 - AMORTIZATION OF LIMITED TERM PLANT ******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
FUNCTION	ALLOCATION FACTOR	TOTALS	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV PRIMARY (9-P)	GEN SRV SECONDARY (9-S)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	IRRIGATION SECONDARY (24-S)
DEMAND - POWER SUPPLY	D10	1,738,027	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0	409,131	21,297	26,073	257,201	0	141,914	295,131
DEMAND - Non-Summer	D10NS	0	176,111	8,138	13,294	122,549	0	74,040	100,149
ENERGY - POWER SUPPLY	E10	2,095,847	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	246,289	11,147	18,574	169,285	293	108,633	215,231
ENERGY - Non-Summer	E10NS	0	520,506	21,096	35,290	309,024	605	211,002	62,808
		0							
TRANSMISSION		0							
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	1,424,772	508,452	25,081	31,116	300,975	0	168,890	318,564
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	8	0	0	3	0	0	0	0
		0							
DISTRIBUTION		0							
SUBSTATIONS - GENERAL	D20	427,085	171,800	7,464	9,897	86,321	218	45,746	104,156
SUBSTATIONS - DIRECT	DA3602	43,583	0	0	0	0	0	161	0
LINES - PRIMARY DEMAND	D20	614,237	247,084	10,735	14,234	124,147	314	65,792	149,798
LINES - PRIMARY CUSTOMER	C20	348,819	293,049	23,619	102	18,802	0	88	11,664
LINES - SECONDARY DIRECT	DA3647	36,877	0	0	7,072	0	1,201	24,697	0
LINE TRANS - PRIMARY DEMAND	D50	93,204	37,493	1,629	2,160	18,838	48	9,983	22,730
LINE TRANS - PRIMARY CUST	C50	52,930	44,467	3,584	16	2,853	0	13	1,770
LINE TRANS - SECOND DIRECT	DA368	34,113	0	0	8,522	0	0	22,822	0
LINE TRANS - SECOND DEMAND	D60	360,954	166,852	7,249	0	83,834	212	210	101,156
LINE TRANS - SECOND CUSTOMER	C60	204,982	172,303	13,887	0	11,055	0	0	6,858
LINES - SECONDARY DEMAND	D30	125,582	80,654	3,504	0	40,524	103	101	0
LINES - SECONDARY CUSTOMER	C30	71,317	62,022	4,999	0	3,979	0	0	0
SERVICES	CW369	122,891	100,306	8,846	185	7,960	0	427	5,154
METERS	CW370	127,791	66,246	14,602	1,828	26,329	1	2,215	16,347
STREET LIGHTS	DA373	9,621	0	0	32	0	0	4	0
INSTALL ON CUST PREMISES	CWINSTAL	6,007	3,962	319	1	254	1,291	1	158
		0							
CUSTOMER ACCOUNTING		0							
METER READING	CW902	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
CONSUMER INFORMATION		0							
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
MISCELLANEOUS		0							
DEMAND	D99U	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0
TOTALS	PAGE 3E	SCREWED UP	3,306,728	187,196	168,400	1,583,932	4,286	876,742	1,411,675

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****** TABLE 15 - AMORTIZATION OF LIMITED TERM PLANT ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
DEMAND - POWER SUPPLY	D10	1,738,027	0	0	0	0	0	0
DEMAND - Summer	D10S	0	923	0	307	11,169	8,106	39,955
DEMAND - Non-Summer	D10NS	0	485	0	166	5,265	5,521	21,102
ENERGY - POWER SUPPLY	E10	2,095,847	0	0	0	0	0	0
ENERGY - Summer	E10S	0	813	1,032	272	9,104	8,609	34,373
ENERGY - Non-Summer	E10NS	0	1,674	2,120	561	21,265	18,788	67,453
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	1,424,772	1,060	0	358	12,535	10,824	46,915
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	8	0	0	0	0	5	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	427,085	611	775	97	0	0	0
SUBSTATIONS - DIRECT	DA3602	43,583	0	0	0	0	3,493	39,929
LINES - PRIMARY DEMAND	D20	614,237	878	1,115	139	0	0	0
LINES - PRIMARY CUSTOMER	C20	348,819	1,290	104	99	0	0	0
LINES - SECONDARY DIRECT	DA3647	36,877	0	0	0	0	3,907	0
LINE TRANS - PRIMARY DEMAND	D50	93,204	133	169	21	0	0	0
LINE TRANS - PRIMARY CUST	C50	52,930	196	16	15	0	0	0
LINE TRANS - SECOND DIRECT	DA368	34,113	0	0	0	0	2,768	0
LINE TRANS - SECOND DEMAND	D60	360,954	593	753	94	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	204,982	759	61	58	0	0	0
LINES - SECONDARY DEMAND	D30	125,582	287	364	45	0	0	0
LINES - SECONDARY CUSTOMER	C30	71,317	273	22	21	0	0	0
SERVICES	CW369	122,891	0	0	0	0	14	0
METERS	CW370	127,791	2	2	8	26	35	150
STREET LIGHTS	DA373	9,621	0	9,584	0	0	0	0
INSTALL ON CUST PREMISES	CWINSTAL	6,007	17	1	1	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 3E	SCREWED UP	9,994	16,118	2,264	59,363	62,069	249,877

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****** TABLE 16 - TAXES OTHER THAN INCOME ******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
FUNCTION	ALLOCATION FACTOR	TOTALS	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV PRIMARY (9-P)	GEN SRV SECONDARY (9-S)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	IRRIGATION SECONDARY (24-S)
DEMAND - POWER SUPPLY	D10	3,151,169	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0	741,783	38,614	47,273	466,324	0	257,301	535,093
DEMAND - Non-Summer	D10NS	0	319,303	14,755	24,102	222,190	0	134,239	181,577
ENERGY - POWER SUPPLY	E10	3,672,311	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	431,544	19,532	32,544	296,619	514	190,346	377,125
ENERGY - Non-Summer	E10NS	0	912,023	36,964	61,835	541,467	1,060	369,714	110,051
		0							
TRANSMISSION		0							
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	3,241,513	1,156,785	57,061	70,792	684,753	0	384,244	724,769
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	19	0	0	7	0	0	0	0
		0							
DISTRIBUTION		0							
SUBSTATIONS - GENERAL	D20	960,337	386,308	16,783	22,255	194,099	491	102,864	234,204
SUBSTATIONS - DIRECT	DA3602	28,106	0	0	0	0	0	104	0
LINES - PRIMARY DEMAND	D20	1,475,989	593,735	25,795	34,204	298,321	755	158,097	359,960
LINES - PRIMARY CUSTOMER	C20	838,199	704,186	56,756	246	45,181	0	211	28,029
LINES - SECONDARY DIRECT	DA3647	88,195	0	0	16,913	0	2,872	59,066	0
LINE TRANS - PRIMARY DEMAND	D50	221,317	89,028	3,868	5,129	44,732	113	23,706	53,974
LINE TRANS - PRIMARY CUST	C50	125,684	105,589	8,510	37	6,775	0	32	4,203
LINE TRANS - SECOND DIRECT	DA368	81,002	0	0	20,237	0	0	54,193	0
LINE TRANS - SECOND DEMAND	D60	857,100	396,198	17,213	0	199,068	504	498	240,200
LINE TRANS - SECOND CUSTOMER	C60	486,738	409,140	32,976	0	26,251	0	1	16,285
LINES - SECONDARY DEMAND	D30	300,912	193,258	8,396	0	97,102	246	243	0
LINES - SECONDARY CUSTOMER	C30	170,885	148,614	11,978	0	9,535	0	0	0
SERVICES	CW369	291,783	238,159	21,002	439	18,900	0	1,013	12,237
METERS	CW370	321,258	166,538	36,709	4,596	66,188	1	5,569	41,096
STREET LIGHTS	DA373	24,377	0	0	82	0	0	10	0
INSTALL ON CUST PREMISES	CWINSTAL	18,126	11,955	964	4	767	3,896	4	476
		0							
CUSTOMER ACCOUNTING		0							
METER READING	CW902	14,650	10,646	936	897	780	0	771	600
CUSTOMER ACCOUNTS	CW903	21,986	18,367	1,480	72	1,178	0	62	731
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
CONSUMER INFORMATION		0							
CUSTOMER ASSIST	C10	9,337	7,844	632	3	503	0	2	312
SALES EXPENSE	C10	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
MISCELLANEOUS		0							
DEMAND	D99U	0	0	0	0	0	0	0	0
ENERGY	E99U	1,944,834	717,304	30,062	52,126	446,398	853	309,998	222,427
CUSTOMER	C10	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0
TOTALS	PAGE 3F	SCREWED UP	7,758,306	440,986	393,793	3,667,133	11,306	2,052,289	3,143,349

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****** TABLE 16 - TAXES OTHER THAN INCOME ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
DEMAND - POWER SUPPLY	D10	3,151,169	0	0	0	0	0	0
DEMAND - Summer	D10S	0	1,674	0	557	20,251	14,696	72,442
DEMAND - Non-Summer	D10NS	0	879	0	300	9,545	10,009	38,259
ENERGY - POWER SUPPLY	E10	3,672,311	0	0	0	0	0	0
ENERGY - Summer	E10S	0	1,425	1,807	477	15,951	15,085	60,228
ENERGY - Non-Summer	E10NS	0	2,933	3,715	983	37,260	32,919	118,190
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	3,241,513	2,412	0	814	28,518	24,627	106,738
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	19	0	0	0	0	12	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	960,337	1,373	1,743	218	0	0	0
SUBSTATIONS - DIRECT	DA3602	28,106	0	0	0	0	2,253	25,749
LINES - PRIMARY DEMAND	D20	1,475,989	2,110	2,678	335	0	0	0
LINES - PRIMARY CUSTOMER	C20	838,199	3,101	250	239	0	0	0
LINES - SECONDARY DIRECT	DA3647	88,195	0	0	0	0	9,343	0
LINE TRANS - PRIMARY DEMAND	D50	221,317	316	402	50	0	0	0
LINE TRANS - PRIMARY CUST	C50	125,684	465	37	36	0	0	0
LINE TRANS - SECOND DIRECT	DA368	81,002	0	0	0	0	6,572	0
LINE TRANS - SECOND DEMAND	D60	857,100	1,408	1,787	223	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	486,738	1,802	145	139	0	0	0
LINES - SECONDARY DEMAND	D30	300,912	687	872	109	0	0	0
LINES - SECONDARY CUSTOMER	C30	170,885	654	53	50	0	0	0
SERVICES	CW369	291,783	0	0	0	0	33	0
METERS	CW370	321,258	4	6	20	66	88	377
STREET LIGHTS	DA373	24,377	0	24,285	0	0	0	0
INSTALL ON CUST PREMISES	CWINSTAL	18,126	53	4	4	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	14,650	0	0	0	7	7	7
CUSTOMER ACCOUNTS	CW903	21,986	81	7	6	1	1	1
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	9,337	35	3	3	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	1,944,834	2,361	2,703	791	31,139	27,213	101,458
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 3F	SCREWED UP	23,771	40,496	5,354	142,738	142,858	523,447

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****** TABLE 17 - REGULATORY DEBITS/CREDITS ******

	FUNCTION	ALLOCATION FACTOR	(A) TOTALS	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV PRIMARY (9-P)	(E) GEN SRV SECONDARY (9-S)	(F) AREA LIGHTING (15)	(G) LG POWER PRIMARY (19-P)	(H) IRRIGATION SECONDARY (24-S)
1020	DEMAND - POWER SUPPLY	D10	0	0	0	0	0	0	0	0
1021	DEMAND - Summer	D10S	0	0	0	0	0	0	0	0
1022	DEMAND - Non-Summer	D10NS	0	0	0	0	0	0	0	0
1023	ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0
1024	ENERGY - Summer	E10S	0	0	0	0	0	0	0	0
1025	ENERGY - Non-Summer	E10NS	0	0	0	0	0	0	0	0
1026			0							
1027	TRANSMISSION		0							
1028	DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
1029	DEMAND - TRANSMISSION	D13	0	0	0	0	0	0	0	0
[illegible]	DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
[illegible]	DEMAND - DIRECT	DA3509	0	0	0	0	0	0	0	0
1032			0							
1033	DISTRIBUTION		0							
1034	SUBSTATIONS - GENERAL	D20	0	0	0	0	0	0	0	0
1035	SUBSTATIONS - DIRECT	DA3602	0	0	0	0	0	0	0	0
1036	LINES - PRIMARY DEMAND	D20	0	0	0	0	0	0	0	0
1037	LINES - PRIMARY CUSTOMER	C20	0	0	0	0	0	0	0	0
1038	LINES - SECONDARY DIRECT	DA3647	0	0	0	0	0	0	0	0
1039	LINE TRANS - PRIMARY DEMAND	D50	0	0	0	0	0	0	0	0
1040	LINE TRANS - PRIMARY CUST	C50	0	0	0	0	0	0	0	0
1041	LINE TRANS - SECOND DIRECT	DA368	0	0	0	0	0	0	0	0
1042	LINE TRANS - SECOND DEMAND	D60	0	0	0	0	0	0	0	0
1043	LINE TRANS - SECOND CUSTOMER	C60	0	0	0	0	0	0	0	0
1044	LINES - SECONDARY DEMAND	D30	0	0	0	0	0	0	0	0
1045	LINES - SECONDARY CUSTOMER	C30	0	0	0	0	0	0	0	0
1046	SERVICES	CW369	0	0	0	0	0	0	0	0
1047	METERS	CW370	0	0	0	0	0	0	0	0
1048	STREET LIGHTS	DA373	0	0	0	0	0	0	0	0
1049	INSTALL ON CUST PREMISES	CWINSTAL	0	0	0	0	0	0	0	0
1050			0							
1051	CUSTOMER ACCOUNTING		0							
[illegible]	METER READING	CW902	0	0	0	0	0	0	0	0
[illegible]	CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0
1054	UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0
1055	MISC	C10	0	0	0	0	0	0	0	0
1056			0							
1057	CONSUMER INFORMATION		0							
1058	CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0
1059	SALES EXPENSE	C10	0	0	0	0	0	0	0	0
1060	ADVERTISING	C10	0	0	0	0	0	0	0	0
1061	MISC	C10	0	0	0	0	0	0	0	0
1062			0							
1063	MISCELLANEOUS		0							
1064	DEMAND	D99U	0	0	0	0	0	0	0	0
1065	ENERGY	E99U	0	0	0	0	0	0	0	0
1066	CUSTOMER	C10	0	0	0	0	0	0	0	0
1067	REVENUE	R02	0	0	0	0	0	0	0	0
1068	OTHER	R01	0	0	0	0	0	0	0	0
1069	SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0
1070										
1071	TOTALS	PAGE 3G	0	0	0	0	0	0	0	0

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****** TABLE 17 - REGULATORY DEBITS/CREDITS ******

				(I)	(J)	(K)	(L)	(M)	(N)
FUNCTION	ALLOCATION FACTOR	TOTALS		UNMETERED GEN SERVICE (40)	MUNICIPAL ST LIGHT (41)	TRAFFIC CONTROL (42)	SC DOE/INL	SC JR SIMPLOT	SC MICRON
DEMAND - POWER SUPPLY	D10		0	0	0	0	0	0	0
DEMAND - Summer	D10S		0	0	0	0	0	0	0
DEMAND - Non-Summer	D10NS		0	0	0	0	0	0	0
ENERGY - POWER SUPPLY	E10		0	0	0	0	0	0	0
ENERGY - Summer	E10S		0	0	0	0	0	0	0
ENERGY - Non-Summer	E10NS		0	0	0	0	0	0	0
TRANSMISSION			0						
DEMAND - POWER SUPPLY	D11		0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13		0	0	0	0	0	0	0
DEMAND - SUBTRANSMISSION	D15		0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509		0	0	0	0	0	0	0
DISTRIBUTION									
SUBSTATIONS - GENERAL	D20		0	0	0	0	0	0	0
SUBSTATIONS - DIRECT	DA3602		0	0	0	0	0	0	0
LINES - PRIMARY DEMAND	D20		0	0	0	0	0	0	0
LINES - PRIMARY CUSTOMER	C20		0	0	0	0	0	0	0
LINES - SECONDARY DIRECT	DA3647		0	0	0	0	0	0	0
LINE TRANS - PRIMARY DEMAND	D50		0	0	0	0	0	0	0
LINE TRANS - PRIMARY CUST	C50		0	0	0	0	0	0	0
LINE TRANS - SECOND DIRECT	DA368		0	0	0	0	0	0	0
LINE TRANS - SECOND DEMAND	D60		0	0	0	0	0	0	0
LINE TRANS - SECOND CUSTOMER	C60		0	0	0	0	0	0	0
LINES - SECONDARY DEMAND	D30		0	0	0	0	0	0	0
LINES - SECONDARY CUSTOMER	C30		0	0	0	0	0	0	0
SERVICES	CW369		0	0	0	0	0	0	0
METERS	CW370		0	0	0	0	0	0	0
STREET LIGHTS	DA373		0	0	0	0	0	0	0
INSTALL ON CUST PREMISES	CWINSTAL		0	0	0	0	0	0	0
CUSTOMER ACCOUNTING									
METER READING	CW902		0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903		0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904		0	0	0	0	0	0	0
MISC	C10		0	0	0	0	0	0	0
CONSUMER INFORMATION									
CUSTOMER ASSIST	C10		0	0	0	0	0	0	0
SALES EXPENSE	C10		0	0	0	0	0	0	0
ADVERTISING	C10		0	0	0	0	0	0	0
MISC	C10		0	0	0	0	0	0	0
MISCELLANEOUS									
DEMAND	D99U		0	0	0	0	0	0	0
ENERGY	E99U		0	0	0	0	0	0	0
CUSTOMER	C10		0	0	0	0	0	0	0
REVENUE	R02		0	0	0	0	0	0	0
OTHER	R01		0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC		0	0	0	0	0	0	0
TOTALS	PAGE 3G		0	0	0	0	0	0	0

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****** TABLE 18 - PROVISIONS FOR DEFERRED INCOME TAXES ******

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	FUNCTION	ALLOCATION FACTOR	TOTALS	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV PRIMARY (9-P)	GEN SRV SECONDARY (9-S)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	IRRIGATION SECONDARY (24-S)
	DEMAND - POWER SUPPLY	D10	(2,417,565)	0	0	0	0	0	0	0
	DEMAND - Summer	D10S	0	(569,093)	(29,624)	(36,268)	(357,762)	0	(197,400)	(410,521)
	DEMAND - Non-Summer	D10NS	0	(244,968)	(11,320)	(18,491)	(170,464)	0	(102,988)	(139,305)
	ENERGY - POWER SUPPLY	E10	(2,915,285)	0	0	0	0	0	0	0
	ENERGY - Summer	E10S	0	(342,584)	(15,506)	(25,836)	(235,473)	(408)	(151,107)	(299,383)
	ENERGY - Non-Summer	E10NS	0	(724,015)	(29,344)	(49,088)	(429,847)	(842)	(293,499)	(87,364)
			0							
	TRANSMISSION		0							
	DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
	DEMAND - TRANSMISSION	D13	(1,981,831)	(707,248)	(34,887)	(43,282)	(418,651)	0	(234,923)	(443,117)
	DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
	DEMAND - DIRECT	DA3509	(12)	0	0	(4)	0	0	0	0
			0							
	DISTRIBUTION		0							
	SUBSTATIONS - GENERAL	D20	(552,877)	(222,402)	(9,662)	(12,812)	(111,745)	(283)	(59,220)	(134,834)
	SUBSTATIONS - DIRECT	DA3602	(11,170)	0	0	0	0	0	(41)	0
	LINES - PRIMARY DEMAND	D20	(854,392)	(343,690)	(14,932)	(19,799)	(172,686)	(437)	(91,516)	(208,367)
	LINES - PRIMARY CUSTOMER	C20	(485,200)	(407,626)	(32,854)	(142)	(26,154)	0	(122)	(16,225)
	LINES - SECONDARY DIRECT	DA3647	(51,295)	0	0	(9,837)	0	(1,671)	(34,354)	0
	LINE TRANS - PRIMARY DEMAND	D50	(129,645)	(52,151)	(2,266)	(3,004)	(26,203)	(66)	(13,887)	(31,618)
	LINE TRANS - PRIMARY CUST	C50	(73,624)	(61,853)	(4,985)	(22)	(3,969)	0	(19)	(2,462)
	LINE TRANS - SECOND DIRECT	DA368	(47,450)	0	0	(11,855)	0	0	(31,745)	0
	LINE TRANS - SECOND DEMAND	D60	(502,080)	(232,088)	(10,083)	0	(116,612)	(295)	(292)	(140,707)
	LINE TRANS - SECOND CUSTOMER	C60	(285,126)	(239,670)	(19,317)	0	(15,378)	0	(1)	(9,540)
	LINES - SECONDARY DEMAND	D30	(174,683)	(112,188)	(4,874)	0	(56,369)	(143)	(141)	0
	LINES - SECONDARY CUSTOMER	C30	(99,200)	(86,272)	(6,953)	0	(5,535)	0	(0)	0
	SERVICES	CW369	(170,939)	(139,524)	(12,304)	(257)	(11,072)	0	(594)	(7,169)
	METERS	CW370	(177,756)	(92,147)	(20,311)	(2,543)	(36,623)	(1)	(3,081)	(22,739)
	STREET LIGHTS	DA373	(13,382)	0	0	(45)	0	0	(6)	0
	INSTALL ON CUST PREMISES	CWINSTAL	(8,356)	(5,511)	(444)	(2)	(354)	(1,796)	(2)	(219)
			0							
	CUSTOMER ACCOUNTING		0							
	METER READING	CW902	0	0	0	0	0	0	0	0
	CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0
	UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0
	MISC	C10	0	0	0	0	0	0	0	0
			0							
	CONSUMER INFORMATION		0							
	CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0
	SALES EXPENSE	C10	0	0	0	0	0	0	0	0
	ADVERTISING	C10	0	0	0	0	0	0	0	0
	MISC	C10	0	0	0	0	0	0	0	0
			0							
	MISCELLANEOUS		0							
	DEMAND	D99U	0	0	0	0	0	0	0	0
	ENERGY	E99U	0	0	0	0	0	0	0	0
	CUSTOMER	C10	0	0	0	0	0	0	0	0
	REVENUE	R02	0	0	0	0	0	0	0	0
	OTHER	R01	0	0	0	0	0	0	0	0
	SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0
	TOTALS	PAGE 3H	SCREWED UP	(4,583,030)	(259,666)	(233,287)	(2,194,896)	(5,941)	(1,214,938)	(1,953,570)

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****** TABLE 18 - PROVISIONS FOR DEFERRED INCOME TAXES ******

				(I)	(J)	(K)	(L)	(M)	(N)
FUNCTION	ALLOCATION FACTOR	TOTALS		UNMETERED GEN SERVICE (40)	MUNICIPAL ST LIGHT (41)	TRAFFIC CONTROL (42)	SC DOE/INL	SC JR SIMPLOT	SC MICRON
DEMAND - POWER SUPPLY	D10	(2,417,565)		0	0	0	0	0	0
DEMAND - Summer	D10S	0		(1,284)	0	(428)	(15,536)	(11,275)	(55,577)
DEMAND - Non-Summer	D10NS	0		(674)	0	(230)	(7,323)	(7,679)	(29,352)
ENERGY - POWER SUPPLY	E10	(2,915,285)		0	0	0	0	0	0
ENERGY - Summer	E10S	0		(1,131)	(1,435)	(379)	(12,663)	(11,975)	(47,812)
ENERGY - Non-Summer	E10NS	0		(2,328)	(2,949)	(780)	(29,579)	(26,133)	(93,826)
TRANSMISSION		0							
DEMAND - POWER SUPPLY	D11	0		0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	(1,981,831)		(1,475)	0	(498)	(17,436)	(15,057)	(65,258)
DEMAND - SUBTRANSMISSION	D15	0		0	0	0	0	0	0
DEMAND - DIRECT	DA3509	(12)		0	0	0	0	(8)	0
DISTRIBUTION									
SUBSTATIONS - GENERAL	D20	(552,877)		(790)	(1,003)	(125)	0	0	0
SUBSTATIONS - DIRECT	DA3602	(11,170)		0	0	0	0	(895)	(10,234)
LINES - PRIMARY DEMAND	D20	(854,392)		(1,221)	(1,550)	(194)	0	0	0
LINES - PRIMARY CUSTOMER	C20	(485,200)		(1,795)	(145)	(138)	0	0	0
LINES - SECONDARY DIRECT	DA3647	(51,295)		0	0	0	0	(5,434)	0
LINE TRANS - PRIMARY DEMAND	D50	(129,645)		(185)	(235)	(29)	0	0	0
LINE TRANS - PRIMARY CUST	C50	(73,624)		(272)	(22)	(21)	0	0	0
LINE TRANS - SECOND DIRECT	DA368	(47,450)		0	0	0	0	(3,850)	0
LINE TRANS - SECOND DEMAND	D60	(502,080)		(825)	(1,047)	(131)	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	(285,126)		(1,055)	(85)	(81)	0	0	0
LINES - SECONDARY DEMAND	D30	(174,683)		(399)	(506)	(63)	0	0	0
LINES - SECONDARY CUSTOMER	C30	(99,200)		(380)	(31)	(29)	0	0	0
SERVICES	CW369	(170,939)		0	0	0	0	(19)	0
METERS	CW370	(177,756)		(2)	(3)	(11)	(36)	(49)	(209)
STREET LIGHTS	DA373	(13,382)		0	(13,331)	0	0	0	0
INSTALL ON CUST PREMISES	CWINSTAL	(8,356)		(24)	(2)	(2)	0	0	0
CUSTOMER ACCOUNTING									
METER READING	CW902	0		0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0		0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0		0	0	0	0	0	0
MISC	C10	0		0	0	0	0	0	0
CONSUMER INFORMATION									
CUSTOMER ASSIST	C10	0		0	0	0	0	0	0
SALES EXPENSE	C10	0		0	0	0	0	0	0
ADVERTISING	C10	0		0	0	0	0	0	0
MISC	C10	0		0	0	0	0	0	0
MISCELLANEOUS									
DEMAND	D99U	0		0	0	0	0	0	0
ENERGY	E99U	0		0	0	0	0	0	0
CUSTOMER	C10	0		0	0	0	0	0	0
REVENUE	R02	0		0	0	0	0	0	0
OTHER	R01	0		0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0		0	0	0	0	0	0
TOTALS	PAGE 3H	SCREWED UP		(13,842)	(22,344)	(3,140)	(82,573)	(82,374)	(302,267)

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****** TABLE 19 - INVESTMENT TAX CREDIT ADJUSTMENT ******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
FUNCTION	ALLOCATION FACTOR	TOTALS	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV PRIMARY (9-P)	GEN SRV SECONDARY (9-S)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	IRRIGATION SECONDARY (24-S)
DEMAND - POWER SUPPLY	D10	338,177	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0	79,607	4,144	5,073	50,045	0	27,613	57,425
DEMAND - Non-Summer	D10NS	0	34,267	1,584	2,587	23,845	0	14,406	19,487
ENERGY - POWER SUPPLY	E10	407,800	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0	47,922	2,169	3,614	32,939	57	21,137	41,879
ENERGY - Non-Summer	E10NS	0	101,278	4,105	6,867	60,128	118	41,056	12,221
		0							
TRANSMISSION		0							
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	277,225	98,932	4,880	6,054	58,562	0	32,862	61,985
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	2	0	0	1	0	0	0	0
		0							
DISTRIBUTION		0							
SUBSTATIONS - GENERAL	D20	77,338	31,110	1,352	1,792	15,631	40	8,284	18,861
SUBSTATIONS - DIRECT	DA3602	1,562	0	0	0	0	0	6	0
LINES - PRIMARY DEMAND	D20	119,515	48,076	2,089	2,770	24,156	61	12,802	29,147
LINES - PRIMARY CUSTOMER	C20	67,871	57,020	4,596	20	3,658	0	17	2,270
LINES - SECONDARY DIRECT	DA3647	7,175	0	0	1,376	0	234	4,805	0
LINE TRANS - PRIMARY DEMAND	D50	18,135	7,295	317	420	3,665	9	1,943	4,423
LINE TRANS - PRIMARY CUST	C50	10,299	8,652	697	3	555	0	3	344
LINE TRANS - SECOND DIRECT	DA368	6,637	0	0	1,658	0	0	4,441	0
LINE TRANS - SECOND DEMAND	D60	70,233	32,465	1,410	0	16,312	41	41	19,683
LINE TRANS - SECOND CUSTOMER	C60	39,884	33,526	2,702	0	2,151	0	0	1,334
LINES - SECONDARY DEMAND	D30	24,435	15,693	682	0	7,885	20	20	0
LINES - SECONDARY CUSTOMER	C30	13,876	12,068	973	0	774	0	0	0
SERVICES	CW369	23,912	19,517	1,721	36	1,549	0	83	1,003
METERS	CW370	24,865	12,890	2,841	356	5,123	0	431	3,181
STREET LIGHTS	DA373	1,872	0	0	6	0	0	1	0
INSTALL ON CUST PREMISES	CWINSTAL	1,169	771	62	0	49	251	0	31
		0							
CUSTOMER ACCOUNTING		0							
METER READING	CW902	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
CONSUMER INFORMATION		0							
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
MISCELLANEOUS		0							
DEMAND	D99U	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0	0
TOTALS	PAGE 3I	1,531,983	641,089	36,323	32,633	307,029	831	169,950	273,272

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****** TABLE 19 - INVESTMENT TAX CREDIT ADJUSTMENT ******

FUNCTION	ALLOCATION FACTOR	TOTALS	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
DEMAND - POWER SUPPLY	D10	338,177	0	0	0	0	0	0
DEMAND - Summer	D10S	0	180	0	60	2,173	1,577	7,774
DEMAND - Non-Summer	D10NS	0	94	0	32	1,024	1,074	4,106
ENERGY - POWER SUPPLY	E10	407,800	0	0	0	0	0	0
ENERGY - Summer	E10S	0	158	201	53	1,771	1,675	6,688
ENERGY - Non-Summer	E10NS	0	326	413	109	4,138	3,656	13,125
TRANSMISSION		0						
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	277,225	206	0	70	2,439	2,106	9,129
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	2	0	0	0	0	1	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	77,338	111	140	18	0	0	0
SUBSTATIONS - DIRECT	DA3602	1,562	0	0	0	0	125	1,431
LINES - PRIMARY DEMAND	D20	119,515	171	217	27	0	0	0
LINES - PRIMARY CUSTOMER	C20	67,871	251	20	19	0	0	0
LINES - SECONDARY DIRECT	DA3647	7,175	0	0	0	0	760	0
LINE TRANS - PRIMARY DEMAND	D50	18,135	26	33	4	0	0	0
LINE TRANS - PRIMARY CUST	C50	10,299	38	3	3	0	0	0
LINE TRANS - SECOND DIRECT	DA368	6,637	0	0	0	0	539	0
LINE TRANS - SECOND DEMAND	D60	70,233	115	146	18	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	39,884	148	12	11	0	0	0
LINES - SECONDARY DEMAND	D30	24,435	56	71	9	0	0	0
LINES - SECONDARY CUSTOMER	C30	13,876	53	4	4	0	0	0
SERVICES	CW369	23,912	0	0	0	0	3	0
METERS	CW370	24,865	0	0	2	5	7	29
STREET LIGHTS	DA373	1,872	0	1,865	0	0	0	0
INSTALL ON CUST PREMISES	CWINSTAL	1,169	3	0	0	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	0	0	0	0	0	0	0
TOTALS	PAGE 3I	1,531,983	1,936	3,126	439	11,551	11,523	42,282

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*** TABLE 20 - STATE INCOME TAXES ***

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
FUNCTION	ALLOCATION FACTOR	TOTALS	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV PRIMARY (9-P)	GEN SRV SECONDARY (9-S)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	IRRIGATION SECONDARY (24-S)
PRODUCTION									
DEMAND - POWER SUPPLY	D10	0	0	0	0	0	0	0	0
DEMAND - Summer	D10S	360,247	192,530	5,890	9,484	92,426	0	48,405	(9,110)
DEMAND - Non-Summer	D10NS	167,253	82,875	2,251	4,835	44,038	0	25,254	(3,092)
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	245,611	120,627	3,209	7,031	63,314	330	38,565	(6,915)
ENERGY - Non-Summer	E10NS	504,002	254,932	6,073	13,360	115,578	680	74,905	(2,018)
		0							
TRANSMISSION		0							
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	543,944	297,210	8,616	14,059	134,347	0	71,556	(12,215)
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	4	0	0	1	0	0	0	0
		0							
DISTRIBUTION		0							
SUBSTATIONS - GENERAL	D20	185,274	114,460	2,923	5,097	43,917	334	22,091	(4,552)
SUBSTATIONS - DIRECT	DA3602	26,662	0	0	0	0	0	107	0
LINES - PRIMARY DEMAND	D20	196,840	121,606	3,105	5,415	46,658	355	23,470	(4,836)
LINES - PRIMARY CUSTOMER	C20	158,520	144,228	6,832	39	7,067	0	31	(377)
LINES - SECONDARY DIRECT	DA3647	17,039	0	0	3,185	0	1,606	10,430	0
LINE TRANS - PRIMARY DEMAND	D50	30,959	19,126	488	852	7,338	56	3,691	(761)
LINE TRANS - PRIMARY CUST	C50	24,932	22,684	1,075	6	1,111	0	5	(59)
LINE TRANS - SECOND DIRECT	DA368	12,926	0	0	3,360	0	0	8,439	0
LINE TRANS - SECOND DEMAND	D60	117,635	85,115	2,173	0	32,658	248	78	(3,385)
LINE TRANS - SECOND CUSTOMER	C60	96,563	87,896	4,164	0	4,307	0	0	(229)
LINES - SECONDARY DEMAND	D30	60,061	42,242	1,079	0	16,208	123	39	0
LINES - SECONDARY CUSTOMER	C30	35,772	32,484	1,539	0	1,592	0	0	0
SERVICES	CW369	22,817	20,488	1,062	29	1,242	0	63	(69)
METERS	CW370	71,675	48,930	6,339	1,044	14,850	1	1,186	(792)
STREET LIGHTS	DA373	2,586	0	0	6	0	0	1	0
INSTALL ON CUST PREMISES	DA371	395	0	0	0	0	395	0	0
		0							
CUSTOMER ACCOUNTING		0							
METER READING	CW902	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
CONSUMER INFORMATION		0							
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
MISCELLANEOUS		0							
DEMAND	D99U	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0
OTHER	INTFUND	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	(11,538)	(179)	(491)	(151)	(227)	(0)	(10,499)	9
TOTALS		2,870,176	1,687,252	56,326	67,652	626,423	4,129	317,816	(48,402)

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****** TABLE 20 - STATE INCOME TAXES ******

		(A)	(I)	(J)	(K)	(L)	(M)	(N)
FUNCTION	ALLOCATION FACTOR	TOTALS	UNMETERED GEN SERVICE	MUNICIPAL ST LIGHT	TRAFFIC CONTROL	SC DOE/INL	SC JR SIMPLOT	SC MICRON
			(40)	(41)	(42)			
PRODUCTION								
DEMAND - POWER SUPPLY	D10	0	0	0	0	0	0	0
DEMAND - Summer	D10S	360,247	413	0	116	4,689	3,044	12,360
DEMAND - Non-Summer	D10NS	167,253	217	0	63	2,210	2,073	6,528
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	245,611	379	554	107	3,978	3,365	11,067
ENERGY - Non-Summer	E10NS	504,002	780	1,138	221	9,291	7,344	21,717
TRANSMISSION								
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	543,944	590	0	168	6,537	5,050	18,027
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	4	0	0	0	0	2	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	185,274	387	566	52	0	0	0
SUBSTATIONS - DIRECT	DA3602	26,662	0	0	0	0	2,550	24,006
LINES - PRIMARY DEMAND	D20	196,840	411	601	55	0	0	0
LINES - PRIMARY CUSTOMER	C20	158,520	604	56	39	0	0	0
LINES - SECONDARY DIRECT	DA3647	17,039	0	0	0	0	1,817	0
LINE TRANS - PRIMARY DEMAND	D50	30,959	65	95	9	0	0	0
LINE TRANS - PRIMARY CUST	C50	24,932	95	9	6	0	0	0
LINE TRANS - SECOND DIRECT	DA368	12,926	0	0	0	0	1,127	0
LINE TRANS - SECOND DEMAND	D60	117,635	288	421	39	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	96,563	368	34	24	0	0	0
LINES - SECONDARY DEMAND	D30	60,061	143	209	19	0	0	0
LINES - SECONDARY CUSTOMER	C30	35,772	136	13	9	0	0	0
SERVICES	CW369	22,817	0	0	0	0	2	0
METERS	CW370	71,675	1	2	5	17	21	73
STREET LIGHTS	DA373	2,586	0	2,579	0	0	0	0
INSTALL ON CUST PREMISES	CWINSTAL	395	0	0	0	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	INTFUND	0	0	0	0	0	0	0
SUBSTATION CIAC	0	(11,538)						
TOTALS		2,870,176	4,877	6,277	932	26,722	26,395	93,776

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****** TABLE 21 - FEDERAL INCOME TAXES ******

FUNCTION	ALLOCATION FACTOR	(A) TOTALS	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV PRIMARY (9-P)	(E) GEN SRV SECONDARY (9-S)	(F) AREA LIGHTING (15)	(G) LG POWER PRIMARY (19-P)	(H) IRRIGATION SECONDARY (24-S)
PRODUCTION									
DEMAND - POWER SUPPLY	D10	0	0	0	0	0	0	0	0
DEMAND - Summer	D10S	5,911,286	3,159,217	96,654	155,617	1,516,617	0	794,276	(149,494)
DEMAND - Non-Summer	D10NS	2,744,446	1,359,893	36,934	79,342	722,625	0	414,390	(50,729)
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	4,030,222	1,979,364	52,653	115,377	1,038,926	5,410	632,806	(113,469)
ENERGY - Non-Summer	E10NS	8,270,156	4,183,175	99,645	219,219	1,896,520	11,164	1,229,118	(33,112)
		0							
TRANSMISSION		0							
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	8,925,573	4,876,908	141,387	230,687	2,204,504	0	1,174,159	(200,439)
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	58	0	0	20	0	0	0	0
		0							
DISTRIBUTION		0							
SUBSTATIONS - GENERAL	D20	3,040,154	1,878,173	47,957	83,630	720,629	5,481	362,488	(74,694)
SUBSTATIONS - DIRECT	DA3602	437,492	0	0	0	0	0	1,748	0
LINES - PRIMARY DEMAND	D20	3,229,953	1,995,428	50,951	88,852	765,618	5,823	385,118	(79,358)
LINES - PRIMARY CUSTOMER	C20	2,601,150	2,366,632	112,106	639	115,955	0	515	(6,179)
LINES - SECONDARY DIRECT	DA3647	279,587	0	0	52,263	0	26,360	171,154	0
LINE TRANS - PRIMARY DEMAND	D50	508,000	313,837	8,014	13,974	120,415	916	60,570	(12,481)
LINE TRANS - PRIMARY CUST	C50	409,103	372,219	17,632	101	18,237	0	81	(972)
LINE TRANS - SECOND DIRECT	DA368	212,100	0	0	55,141	0	0	138,469	0
LINE TRANS - SECOND DEMAND	D60	1,930,267	1,396,658	35,662	0	535,878	4,076	1,274	(55,545)
LINE TRANS - SECOND CUSTOMER	C60	1,584,502	1,442,282	68,320	0	70,666	0	3	(3,766)
LINES - SECONDARY DEMAND	D30	985,542	693,150	17,699	0	265,952	2,023	632	0
LINES - SECONDARY CUSTOMER	C30	586,979	533,027	25,249	0	26,116	0	1	0
SERVICES	CW369	374,399	336,182	17,424	479	20,373	0	1,037	(1,133)
METERS	CW370	1,176,121	802,886	104,013	17,125	243,672	16	19,459	(12,997)
STREET LIGHTS	DA373	42,440	0	0	101	0	0	12	0
INSTALL ON CUST PREMISES		6,484	0	0	2	0	6,479	0	0
		0							
CUSTOMER ACCOUNTING		0							
METER READING	CW902	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
CONSUMER INFORMATION		0							
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
		0							
MISCELLANEOUS		0							
DEMAND	D99U	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0
OTHER	DA454	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	(189,334)	(2,940)	(8,049)	(2,475)	(3,730)	(5)	(172,275)	140
TOTALS		47,096,680	27,686,092	924,254	1,110,095	10,278,973	67,745	5,215,035	(794,228)

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****** TABLE 21 - FEDERAL INCOME TAXES ******

		(A)	(I)	(J)	(K)	(L)	(M)	(N)
FUNCTION	ALLOCATION FACTOR	TOTALS	UNMETERED GEN SERVICE	MUNICIPAL ST LIGHT	TRAFFIC CONTROL	SC DOE/INL	SC JR SIMPLOT	SC MICRON
PRODUCTION			(40)	(41)	(42)			
DEMAND - POWER SUPPLY	D10	0	0	0	0	0	0	0
DEMAND - Summer	D10S	5,911,286	6,782	0	1,910	76,942	49,953	202,812
DEMAND - Non-Summer	D10NS	2,744,446	3,561	0	1,029	36,267	34,023	107,111
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	4,030,222	6,217	9,089	1,762	65,271	55,222	181,592
ENERGY - Non-Summer	E10NS	8,270,156	12,797	18,680	3,627	152,462	120,507	356,353
TRANSMISSION								
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	8,925,573	9,674	0	2,763	107,260	82,863	295,808
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	58	0	0	0	0	38	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	3,040,154	6,350	9,288	852	0	0	0
SUBSTATIONS - DIRECT	DA3602	437,492	0	0	0	0	41,838	393,906
LINES - PRIMARY DEMAND	D20	3,229,953	6,747	9,868	905	0	0	0
LINES - PRIMARY CUSTOMER	C20	2,601,150	9,915	920	646	0	0	0
LINES - SECONDARY DIRECT	DA3647	279,587	0	0	0	0	29,810	0
LINE TRANS - PRIMARY DEMAND	D50	508,000	1,061	1,552	142	0	0	0
LINE TRANS - PRIMARY CUST	C50	409,103	1,559	145	102	0	0	0
LINE TRANS - SECOND DIRECT	DA368	212,100	0	0	0	0	18,490	0
LINE TRANS - SECOND DEMAND	D60	1,930,267	4,722	6,907	633	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	1,584,502	6,042	561	394	0	0	0
LINES - SECONDARY DEMAND	D30	985,542	2,344	3,428	314	0	0	0
LINES - SECONDARY CUSTOMER	C30	586,979	2,233	207	145	0	0	0
SERVICES	CW369	374,399	0	0	0	0	37	0
METERS	CW370	1,176,121	20	32	77	282	340	1,195
STREET LIGHTS	DA373	42,440	0	42,327	0	0	0	0
INSTALL ON CUST PREMISES	CWINSTAL	6,484	0	0	0	0	2	0
CUSTOMER ACCOUNTING								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
		0						
MISCELLANEOUS		0						
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0
OTHER	INTFUND	0	0	0	0	0	0	0
SUBSTATION CIAC	0	(189,334)						
TOTALS		47,096,680	80,025	103,004	15,301	438,485	433,122	1,538,777

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007
ALLOCATION TO CLASSES

******* SUMMARY OF RATE BASE ******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
FUNCTION	ALLOCATION FACTOR	TOTAL RATE BASE	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV PRIMARY (9-P)	GEN SRV SECONDARY (9-S)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	IRRIGATION SECONDARY (24-S)
PRODUCTION									
DEMAND - POWER SUPPLY	D10	379,731,915	0	0	0	0	0	0	0
DEMAND - Summer	D10S	264,630,175	89,388,690	4,653,139	5,696,618	56,194,471	0	31,006,077	64,481,448
DEMAND - Non-Summer	D10NS	115,101,594	38,477,597	1,778,089	2,904,452	26,775,085	0	16,176,509	21,880,996
ENERGY - POWER SUPPLY	E10	476,587,645	0	0	0	0	0	0	0
ENERGY - Summer	E10S	187,296,384	56,005,247	2,534,849	4,223,573	38,494,842	66,690	24,702,807	48,942,812
ENERGY - Non-Summer	E10NS	289,291,261	118,361,126	4,797,146	8,024,873	70,270,853	137,614	47,980,966	14,282,217
			0	0	0	0	0	0	0
TRANSMISSION									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	386,672,049	137,989,993	6,806,680	8,444,651	81,682,439	0	45,835,545	86,455,893
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	2,066	0	0	724	0	0	0	0
DISTRIBUTION									
SUBSTATIONS - GENERAL	D20	132,107,995	53,142,090	2,308,774	3,061,427	26,701,113	67,561	14,150,395	32,218,107
SUBSTATIONS - DIRECT	DA3602	18,506,379	0	0	0	0	0	68,241	0
LINES - PRIMARY DEMAND	D20	140,355,581	56,459,784	2,452,912	3,252,553	28,368,081	71,778	15,033,813	34,229,504
LINES - PRIMARY CUSTOMER	C20	79,706,477	66,962,843	5,397,045	23,403	4,296,417	0	20,109	2,665,325
LINES - SECONDARY DIRECT	DA3647	9,976,242	0	0	1,913,178	0	324,916	6,681,314	0
LINE TRANS - PRIMARY DEMAND	D50	22,074,818	8,879,871	385,789	511,554	4,461,670	11,289	2,364,485	5,383,541
LINE TRANS - PRIMARY CUST	C50	12,536,061	10,531,770	848,835	3,681	675,731	0	3,163	419,196
LINE TRANS - SECOND DIRECT	DA368	8,079,435	0	0	2,018,524	0	0	5,405,392	0
LINE TRANS - SECOND DEMAND	D60	85,489,521	39,517,849	1,716,864	0	19,855,647	50,240	49,718	23,958,228
LINE TRANS - SECOND CUSTOMER	C60	48,548,611	40,808,749	3,289,087	0	2,618,339	0	106	1,624,312
LINES - SECONDARY DEMAND	D30	30,537,474	19,612,383	852,066	0	9,854,194	24,934	24,675	0
LINES - SECONDARY CUSTOMER	C30	17,341,915	15,081,778	1,215,555	0	967,665	0	39	0
SERVICES	CW369	11,653,877	9,512,131	838,833	17,529	754,862	0	40,475	488,733
METERS	CW370	43,822,587	22,717,306	5,007,430	626,892	9,028,672	202	759,623	5,605,909
STREET LIGHTS	DA373	1,096,561	0	0	3,690	0	0	467	0
INSTALL ON CUST PREMISES	DA371	80,040	0	0	85	0	79,865	17	0
	CWINSTAL		0	0	0	0	0	0	0
CUSTOMER ACCOUNTING									
METER READING	CW902	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
CONSUMER INFORMATION									
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
MISCELLANEOUS									
DEMAND	D99U	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0
OTHER	R01	0	0	0	0	0	0	0	0
SUBSTATION CIAC	CIAC	(22,236,331)	(83,182)	(387,497)	(90,598)	(138,218)	(64)	(6,725,065)	(60,259)
TOTALS		1,882,670,774	783,366,025	44,495,597	40,636,810	380,861,863	835,025	203,578,870	342,575,963

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007
ALLOCATION TO CLASSES

******* SUMMARY OF RATE BASE ******

				(I)	(J)	(K)	(L)	(M)	(N)
FUNCTION	ALLOCATION FACTOR		TOTAL RATE BASE	UNMETERED GEN SERVICE	MUNICIPAL ST LIGHT	TRAFFIC CONTROL	SC DOE/INL	SC JR SIMPLOT	SC MICRON
PRODUCTION				(40)	(41)	(42)			
DEMAND - POWE	D10		379,731,915	0	0	0	0	0	0
DEMAND - Summ	D10S		264,630,175	201,698	0	67,164	2,440,309	1,770,937	8,729,624
DEMAND - Non-S	D10NS		115,101,594	105,892	0	36,165	1,150,256	1,206,176	4,610,377
ENERGY - POWE	E10		476,587,645	0	0	0	0	0	0
ENERGY - Summ	E10S		187,296,384	184,882	234,571	61,955	2,070,147	1,957,730	7,816,279
ENERGY - Non-S	E10NS		289,291,261	380,584	482,100	127,536	4,835,500	4,272,238	15,338,508
		0	0	0	0	0	0	0	0
TRANSMISSION									
DEMAND - POWE	D11		0	0	0	0	0	0	0
DEMAND - TRAN	D13		386,672,049	287,707	0	97,128	3,401,887	2,937,662	12,732,464
DEMAND - SUBTI	D15		0	0	0	0	0	0	0
DEMAND - DIREC	DA3509		2,066	0	0	0	0	1,342	0
			0						
DISTRIBUTION			0						
SUBSTATIONS -	D20		132,107,995	188,864	239,720	29,944	0	0	0
SUBSTATIONS -	DA3602		18,506,379	0	0	0	0	1,483,242	16,954,896
LINES - PRIMARY	D20		140,355,581	200,655	254,686	31,814	0	0	0
LINES - PRIMARY	C20		79,706,477	294,876	23,750	22,709	0	0	0
LINES - SECOND	DA3647		9,976,242	0	0	0	0	1,056,834	0
LINE TRANS - PR	D50		22,074,818	31,559	40,057	5,004	0	0	0
LINE TRANS - PR	C50		12,536,061	46,377	3,735	3,572	0	0	0
LINE TRANS - SE	DA368		8,079,435	0	0	0	0	655,519	0
LINE TRANS - SE	D60		85,489,521	140,445	178,262	22,267	0	0	0
LINE TRANS - SE	C60		48,548,611	179,704	14,474	13,840	0	0	0
LINES - SECOND	D30		30,537,474	69,701	88,470	11,051	0	0	0
LINES - SECOND	C30		17,341,915	66,414	5,349	5,115	0	0	0
SERVICES	CW369		11,653,877	0	0	0	0	1,314	0
METERS	CW370		43,822,587	605	838	2,699	8,957	12,038	51,416
STREET LIGHTS	DA373		1,096,561	0	1,092,404	0	0	0	0
INSTALL ON CUS	DA371		80,040	0	0	0	0	72	0
	CWINSTAL		0	0	0	0	0	0	0
CUSTOMER ACCC			0						
METER READING	CW902		0	0	0	0	0	0	0
CUSTOMER ACC	CW903		0	0	0	0	0	0	0
UNCOLLECTIBLE	CW904		0	0	0	0	0	0	0
MISC	C10		0	0	0	0	0	0	0
			0						
CONSUMER INFORMATION									
CUSTOMER ASS	C10		0	0	0	0	0	0	0
SALES EXPENSE	C10		0	0	0	0	0	0	0
ADVERTISING	C10		0	0	0	0	0	0	0
MISC	C10		0	0	0	0	0	0	0
MISCELLANEOUS									
DEMAND	D99U		0	0	0	0	0	0	0
ENERGY	E99U		0	0	0	0	0	0	0
CUSTOMER	C10		0	0	0	0	0	0	0
REVENUE	R02		0	0	0	0	0	0	0
OTHER	R01		0	0	0	0	0	0	0
SUBSTATION CI	CIAC		(22,236,331)	(178)	(226)	(28)	0	(70,292)	(14,680,723)
			0						
TOTALS			1,882,670,774	2,379,787	2,658,191	537,935	13,907,056	15,284,812	51,552,839

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007
ALLOCATION TO CLASSES

****** SUMMARY OF EXPENSES EXLUDING INCOME TAXES ******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
FUNCTION	ALLOCATION FACTOR	TOTAL EXPENSES	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV PRIMARY (9-P)	GEN SRV SECONDARY (9-S)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	IRRIGATION SECONDARY (24-S)
PRODUCTION									
DEMAND - POWER SUPPLY	D10	118,962,025	0	0	0	0	0	0	0
DEMAND - Summer	D10S	82,903,102	28,003,608	1,457,731	1,784,631	17,604,553	0	9,713,556	20,200,690
DEMAND - Non-Summer	D10NS	36,058,923	12,054,227	557,038	909,904	8,388,074	0	5,067,762	6,854,859
ENERGY - POWER SUPPLY	E10	316,919,401	0	0	0	0	0	0	0
ENERGY - Summer	E10S	124,547,622	37,242,152	1,685,614	2,808,575	25,598,150	44,347	16,426,776	32,545,801
ENERGY - Non-Summer	E10NS	192,371,779	78,707,322	3,189,988	5,336,349	46,728,439	91,510	31,906,196	9,497,333
TRANSMISSION									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	43,674,202	15,585,825	768,807	953,815	9,225,946	0	5,177,077	9,765,102
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	241	0	0	84	0	0	0	0
DISTRIBUTION									
SUBSTATIONS - GENERAL	D20	14,241,226	5,728,711	248,886	330,021	2,878,377	7,283	1,525,411	3,473,108
SUBSTATIONS - DIRECT	DA3602	1,142,889	0	0	0	0	0	4,214	0
LINES - PRIMARY DEMAND	D20	30,553,323	12,290,456	533,962	708,033	6,175,309	15,625	3,272,638	7,451,254
LINES - PRIMARY CUSTOMER	C20	17,350,915	14,576,816	1,174,856	5,094	935,266	0	4,377	580,202
LINES - SECONDARY DIRECT	DA3647	1,372,152	0	0	263,142	0	44,690	918,961	0
LINE TRANS - PRIMARY DEMAND	D50	1,851,627	744,840	32,360	42,909	374,243	947	198,332	451,569
LINE TRANS - PRIMARY CUST	C50	1,051,520	883,401	71,200	309	56,680	0	265	35,162
LINE TRANS - SECOND DIRECT	DA368	677,691	0	0	169,311	0	0	453,396	0
LINE TRANS - SECOND DEMAND	D60	7,170,834	3,314,745	144,010	0	1,665,485	4,214	4,170	2,009,609
LINE TRANS - SECOND CUSTOMER	C60	4,072,242	3,423,025	275,888	0	219,625	0	9	136,247
LINES - SECONDARY DEMAND	D30	5,219,732	3,352,320	145,643	0	1,684,365	4,262	4,218	0
LINES - SECONDARY CUSTOMER	C30	2,964,231	2,577,909	207,773	0	165,402	0	7	0
SERVICES	CW369	3,316,547	2,707,033	238,721	4,989	214,824	0	11,519	139,087
METERS	CW370	14,593,571	7,565,200	1,667,548	208,764	3,006,682	67	252,966	1,866,851
STREET LIGHTS	DA373	1,508,594	0	0	5,076	0	0	643	0
INSTALL ON CUST PREMISES	CWINSTAL	3,006,468	1,982,914	159,817	692	127,226	646,193	593	78,926
CUSTOMER ACCOUNTING									
METER READING	CW902	9,644,228	7,008,071	616,260	590,782	513,636	0	507,635	394,716
CUSTOMER ACCOUNTS	CW903	17,080,618	14,269,027	1,150,050	55,987	915,518	0	48,107	567,951
UNCOLLECTIBLES	CW904	2,926,405	2,466,737	57,586	0	80,678	2,678	0	318,726
MISC	C10	0	0	0	0	0	0	0	0
CONSUMER INFORMATION									
CUSTOMER ASSIST	C10	8,050,324	6,763,178	545,096	2,364	433,934	0	2,031	269,195
SALES EXPENSE	C10	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
MISCELLANEOUS									
DEMAND	D99U	0	0	0	0	0	0	0	0
ENERGY	E99U	1,944,834	717,304	30,062	52,126	446,398	853	309,998	222,427
CUSTOMER	C10	0	0	0	0	0	0	0	0
REVENUE	R02	0	0	0	0	0	0	0	0
OTHER	INTFUND	50,649	14,805	1,193	0	0	0	0	34,651
RETAIL SALES REVENUE		0	0	0	0	0	0	0	0
TOTALS		629,346,490	261,979,623	14,960,091	14,232,957	127,438,811	862,669	75,810,858	96,893,466

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007
ALLOCATION TO CLASSES

****** SUMMARY OF EXPENSES EXLUDING INCOME TAXES ******

				(I)	(J)	(K)	(L)	(M)	(N)
FUNCTION	ALLOCATION FACTOR		TOTAL EXPENSES	UNMETERED GEN SERVICE	MUNICIPAL ST LIGHT	TRAFFIC CONTROL	SC DOE/INL	SC JR SIMPLOT	SC MICRON
PRODUCTION				(40)	(41)	(42)			
DEMAND - POWE	D10		118,962,025	0	0	0	0	0	0
DEMAND - Summ	D10S		82,903,102	63,188	0	21,041	764,498	554,797	2,734,809
DEMAND - Non-S	D10NS		36,058,923	33,174	0	11,330	360,351	377,870	1,444,335
ENERGY - POWE	E10		316,919,401	0	0	0	0	0	0
ENERGY - Summ	E10S		124,547,622	122,942	155,984	41,199	1,376,598	1,301,844	5,197,639
ENERGY - Non-S	E10NS		192,371,779	253,080	320,585	84,808	3,215,492	2,840,936	10,199,741
			0						
TRANSMISSION									
DEMAND - POWE	D11		0	0	0	0	0	0	0
DEMAND - TRAN	D13		43,674,202	32,496	0	10,970	384,240	331,806	1,438,118
DEMAND - SUBTI	D15		0	0	0	0	0	0	0
DEMAND - DIREC	DA3509		241	0	0	0	0	156	0
DISTRIBUTION									
SUBSTATIONS -	D20		14,241,226	20,360	25,842	3,228	0	0	0
SUBSTATIONS -	DA3602		1,142,889	0	0	0	0	91,600	1,047,075
LINES - PRIMARY	D20		30,553,323	43,680	55,441	6,925	0	0	0
LINES - PRIMARY	C20		17,350,915	64,190	5,170	4,944	0	0	0
LINES - SECOND	DA3647		1,372,152	0	0	0	0	145,359	0
LINE TRANS - PR	D50		1,851,627	2,647	3,360	420	0	0	0
LINE TRANS - PR	C50		1,051,520	3,890	313	300	0	0	0
LINE TRANS - SE	DA368		677,691	0	0	0	0	54,984	0
LINE TRANS - SE	D60		7,170,834	11,780	14,953	1,868	0	0	0
LINE TRANS - SE	C60		4,072,242	15,074	1,214	1,161	0	0	0
LINES - SECOND	D30		5,219,732	11,914	15,122	1,889	0	0	0
LINES - SECOND	C30		2,964,231	11,352	914	874	0	0	0
SERVICES	CW369		3,316,547	0	0	0	0	374	0
METERS	CW370		14,593,571	202	279	899	2,983	4,009	17,122
STREET LIGHTS	DA373		1,508,594	0	1,502,875	0	0	0	0
INSTALL ON CUS	CWINSTAL		3,006,468	8,732	703	672	0	0	0
CUSTOMER ACCC									
METER READING	CW902		9,644,228	0	0	0	4,376	4,376	4,376
CUSTOMER ACC	CW903		17,080,618	62,834	5,061	4,838	415	415	415
UNCOLLECTIBLE	CW904		2,926,405	0	0	0	0	0	0
MISC	C10		0	0	0	0	0	0	0
CONSUMER INFORMATION									
CUSTOMER ASS	C10		8,050,324	29,782	2,399	2,294	18	18	18
SALES EXPENSE	C10		0	0	0	0	0	0	0
ADVERTISING	C10		0	0	0	0	0	0	0
MISC	C10		0	0	0	0	0	0	0
MISCELLANEOUS									
DEMAND	D99U		0	0	0	0	0	0	0
ENERGY	E99U		1,944,834	2,361	2,703	791	31,139	27,213	101,458
CUSTOMER	C10		0	0	0	0	0	0	0
REVENUE	R02		0	0	0	0	0	0	0
OTHER	INTFUND		50,649	0	0	0	0	0	0
SUBSTATION CI		0	0	0	0	0	0	0	0
		0							
TOTALS			629,346,490	793,677	2,112,917	200,450	6,140,109	5,735,756	22,185,105

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007
ALLOCATION TO CLASSES

****** SUMMARY OF OTHER REVENUES ******

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
FUNCTION	ALLOCATION FACTOR	TOTAL OTHER REVENUES	RESIDENTIAL	GEN SRV	GEN SRV PRIMARY	GEN SRV SECONDARY	AREA LIGHTING	LG POWER PRIMARY	IRRIGATION SECONDARY
PRODUCTION			(1)	(7)	(9-P)	(9-S)	(15)	(19-P)	(24-S)
DEMAND - POWER SUPPLY	D10	532,931	0	0	0	0	0	0	0
DEMAND - Summer	D10S	371,393	125,452	6,530	7,995	78,866	0	43,515	90,496
DEMAND - Non-Summer	D10NS	161,538	54,001	2,495	4,076	37,577	0	22,703	30,709
ENERGY - POWER SUPPLY	E10	154,118,883	0	0	0	0	0	0	0
ENERGY - Summer	E10S	60,567,893	18,110,973	819,719	1,365,819	12,448,459	21,566	7,988,392	15,827,123
ENERGY - Non-Summer	E10NS	93,550,990	38,275,614	1,551,301	2,595,083	22,724,184	44,502	15,516,082	4,618,582
TRANSMISSION									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	9,324,159	3,327,473	164,135	203,633	1,969,680	0	1,105,272	2,084,786
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DEMAND - DIRECT	DA3509	25	0	0	9	0	0	0	0
DISTRIBUTION									
SUBSTATIONS - GENERAL	D20	86,202	34,676	1,507	1,998	17,423	44	9,233	21,023
SUBSTATIONS - DIRECT	DA3602	8,797	0	0	0	0	0	32	0
LINES - PRIMARY DEMAND	D20	1,537,124	618,328	26,863	35,621	310,677	786	164,645	374,869
LINES - PRIMARY CUSTOMER	C20	872,917	733,353	59,107	256	47,053	0	220	29,190
LINES - SECONDARY DIRECT	DA3647	48,467	0	0	9,295	0	1,579	32,459	0
LINE TRANS - PRIMARY DEMAND	D50	97,833	39,355	1,710	2,267	19,774	50	10,479	23,859
LINE TRANS - PRIMARY CUST	C50	55,559	46,676	3,762	16	2,995	0	14	1,858
LINE TRANS - SECOND DIRECT	DA368	35,807	0	0	8,946	0	0	23,956	0
LINE TRANS - SECOND DEMAND	D60	378,881	175,139	7,609	0	87,998	223	220	106,181
LINE TRANS - SECOND CUSTOMER	C60	215,163	180,860	14,577	0	11,604	0	0	7,199
LINES - SECONDARY DEMAND	D30	207,139	133,033	5,780	0	66,842	169	167	0
LINES - SECONDARY CUSTOMER	C30	117,632	102,302	8,245	0	6,564	0	0	0
SERVICES	CW369	128,995	105,288	9,285	194	8,355	0	448	5,410
METERS	CW370	25,793	13,371	2,947	369	5,314	0	447	3,300
STREET LIGHTS	DA373	10,098	0	0	34	0	0	4	0
INSTALL ON CUST PREMISES	DA371	6,305	0	0	7	0	6,292	1	0
CUSTOMER ACCOUNTING									
METER READING	CW902	0	0	0	0	0	0	0	0
CUSTOMER ACCOUNTS	CW903	0	0	0	0	0	0	0	0
UNCOLLECTIBLES	CW904	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
CONSUMER INFORMATION									
CUSTOMER ASSIST	C10	0	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0	0
MISCELLANEOUS									
DEMAND	D99U	0	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0	0
REVENUE	R02	4,933,621	4,593,857	191,440	649	60,157	1,630	188	83,604
FACILITIES CHARGE REVENUE	DA454	5,648,745	34,648	435	1,185,953	0	96,465	3,635,498	0
RETAIL SALES REVENUE		0							
TOTALS		178,391,078	66,704,398	2,877,448	5,422,220	37,903,523	173,305	28,553,979	23,308,188

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007
ALLOCATION TO CLASSES

****** SUMMARY OF OTHER REVENUES ******

FUNCTION	ALLOCATION FACTOR	TOTAL OTHER REVENUES	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
PRODUCTION								
DEMAND - POWE	D10	532,931	0	0	0	0	0	0
DEMAND - Summ	D10S	371,393	283	0	94	3,425	2,485	12,252
DEMAND - Non-S	D10NS	161,538	149	0	51	1,614	1,693	6,470
ENERGY - POWE	E10	154,118,883	0	0	0	0	0	0
ENERGY - Summ	E10S	60,567,893	59,787	75,856	20,035	669,444	633,091	2,527,628
ENERGY - Non-S	E10NS	93,550,990	123,073	155,901	41,243	1,563,704	1,381,556	4,960,166
		0						
TRANSMISSION								
DEMAND - POWE	D11	0	0	0	0	0	0	0
DEMAND - TRAN	D13	9,324,159	6,938	0	2,342	82,033	70,838	307,029
DEMAND - SUBTI	D15	0	0	0	0	0	0	0
DEMAND - DIREC	DA3509	25	0	0	0	0	17	0
		0						
DISTRIBUTION								
SUBSTATIONS -	D20	86,202	123	156	20	0	0	0
SUBSTATIONS -	DA3602	8,797	0	0	0	0	705	8,059
LINES - PRIMARY	D20	1,537,124	2,198	2,789	348	0	0	0
LINES - PRIMARY	C20	872,917	3,229	260	249	0	0	0
LINES - SECOND	DA3647	48,467	0	0	0	0	5,134	0
LINE TRANS - PR	D50	97,833	140	178	22	0	0	0
LINE TRANS - PR	C50	55,559	206	17	16	0	0	0
LINE TRANS - SE	DA368	35,807	0	0	0	0	2,905	0
LINE TRANS - SE	D60	378,881	622	790	99	0	0	0
LINE TRANS - SE	C60	215,163	796	64	61	0	0	0
LINES - SECOND	D30	207,139	473	600	75	0	0	0
LINES - SECOND	C30	117,632	450	36	35	0	0	0
SERVICES	CW369	128,995	0	0	0	0	15	0
METERS	CW370	25,793	0	0	2	5	7	30
STREET LIGHTS	DA373	10,098	0	10,060	0	0	0	0
INSTALL ON CUS	DA371	6,305	0	0	0	0	6	0
CUSTOMER ACCC								
METER READING	CW902	0	0	0	0	0	0	0
CUSTOMER ACC	CW903	0	0	0	0	0	0	0
UNCOLLECTIBLE	CW904	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
CONSUMER INFORMATION								
CUSTOMER ASS	C10	0	0	0	0	0	0	0
SALES EXPENSE	C10	0	0	0	0	0	0	0
ADVERTISING	C10	0	0	0	0	0	0	0
MISC	C10	0	0	0	0	0	0	0
MISCELLANEOUS								
DEMAND	D99U	0	0	0	0	0	0	0
ENERGY	E99U	0	0	0	0	0	0	0
CUSTOMER	C10	0	0	0	0	0	0	0
REVENUE	R02	4,933,621	188	83	1,823	0	0	0
OTHER	DA454	0	0	177,574	0	0	518,172	0
SUBSTATION CI	0	0						
TOTALS		178,391,078	198,656	424,365	66,514	2,320,225	2,616,624	7,821,634

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007

****** INCOME TAX ALLOCATION ******

DESCRIPTION	(A) TOTAL SYSTEM	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV PRIMARY (9-P)	(E) GEN SRV SECONDARY (9-S)	(F) AREA LIGHTING (15)	(G) LG POWER PRIMARY (19-P)	(H) IRRIGATION SECONDARY (24-S)
INCOME TAXES - VARIOUS								
TOTAL REVENUES	796,211,346	360,792,008	18,258,776	18,194,917	164,124,733	1,104,452	94,423,453	94,058,847
EXPENSES WITHOUT INCOME TAXES	629,346,490	261,979,623	14,960,091	14,232,957	127,438,811	862,669	75,810,858	96,893,466
INCOME BEFORE INCOME TAXES	166,864,856	98,812,384	3,298,685	3,961,959	36,685,922	241,783	18,612,594	(2,834,619)
**********	**********	**********	**********	**********	**********	**********	**********	**********
INCOME TAXES - ALLOCATED BY RATE BASE								
TOTAL STATE INCOME TAX	2,849,268	1,185,560	67,340	61,500	576,403	1,264	308,100	518,461
TOTAL FEDERAL INCOME TAX	46,753,611	19,453,848	1,104,989	1,009,161	9,458,195	20,737	5,055,609	8,507,416
TOTAL INCOME TAXES	49,602,879	20,639,408	1,172,329	1,070,661	10,034,598	22,000	5,363,709	9,025,877
PERCENT OF TOTAL	100.00%	41.61%	2.36%	2.16%	20.23%	0.04%	10.81%	18.20%
**********	**********	**********	**********	**********	**********	**********	**********	**********
INCOME TAXES - ALLOCATED BY INCOME BEFORE TAXES (NO NEGATIVE TAX ALLOWED)								
STATE INCOME TAX - FIRST PASS	2,897,670	1,687,252	56,326	67,652	626,423	4,129	317,816	0
STATE INCOME TAX - SECOND PASS	(48,402)	(28,183)	(941)	(1,130)	(10,464)	(69)	(5,309)	0
STATE INCOME TAX - THIRD PASS	0	0	0	0	0	0	0	0
TOTAL STATE INCOME TAX	2,849,268	1,659,068	55,385	66,522	615,960	4,060	312,507	0
FEDERAL INCOME TAX - FIRST PASS	47,561,636	27,694,126	924,522	1,110,417	10,281,956	67,765	5,216,548	0
FEDERAL INCOME TAX - SECOND PASS	(808,025)	(470,496)	(15,707)	(18,865)	(174,680)	(1,151)	(88,624)	0
FEDERAL INCOME TAX - THIRD PASS	0	0	0	0	0	0	0	0
TOTAL FEDERAL INCOME TAX	46,753,611	27,223,630	908,815	1,091,553	10,107,275	66,613	5,127,924	0
TOTAL INCOME TAXES	49,602,879	28,882,699	964,200	1,158,074	10,723,235	70,673	5,440,431	0
PERCENT OF TOTAL	100.00%	58.23%	1.94%	2.33%	21.62%	0.14%	10.97%	0.00%
**********	**********	**********	**********	**********	**********	**********	**********	**********
INCOME TAXES - ALLOCATED BY INCOME BEFORE TAXES (WITH NEGATIVE TAX ALLOWED)								
TOTAL STATE INCOME TAX	2,849,268	1,687,252	56,326	67,652	626,423	4,129	317,816	(48,402)
TOTAL FEDERAL INCOME TAX	46,753,611	27,686,092	924,254	1,110,095	10,278,973	67,745	5,215,035	(794,228)
TOTAL INCOME TAXES	49,602,879	29,373,344	980,580	1,177,747	10,905,396	71,873	5,532,850	(842,630)
PERCENT OF TOTAL	100.00%	59.22%	1.98%	2.37%	21.99%	0.14%	11.15%	-1.70%
**********	**********	**********	**********	**********	**********	**********	**********	**********

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007

****** INCOME TAX ALLOCATION ******

DESCRIPTION	TOTAL SYSTEM	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
INCOME TAXES - VARIOUS							
TOTAL REVENUES	796,211,346	1,079,266	2,480,511	255,057	7,705,074	7,274,505	26,459,748
EXPENSES WITHOUT INCOME TAXES	629,346,490	793,677	2,112,917	200,450	6,140,109	5,735,756	22,185,105
INCOME BEFORE INCOME TAXES	166,864,856	285,590	367,594	54,607	1,564,964	1,538,749	4,274,643
INCOME TAXES - ALLOCATED BY RATE BASE							
TOTAL STATE INCOME TAX	2,849,268	3,602	4,023	814	21,047	23,132	78,021
TOTAL FEDERAL INCOME TAX	46,753,611	59,099	66,013	13,359	345,363	379,578	1,280,246
TOTAL INCOME TAXES	49,602,879	62,700	70,036	14,173	366,410	402,710	1,358,267
PERCENT OF TOTAL	100.00%	0.13%	0.14%	0.03%	0.74%	0.81%	2.74%
INCOME TAXES - ALLOCATED BY INCOME BEFORE TAXES (NO NEGATIVE TAX ALLOWED)							
STATE INCOME TAX - FIRST PASS	2,897,670	4,877	6,277	932	26,722	26,275	72,991
STATE INCOME TAX - SECOND PASS	(48,402)	(81)	(105)	(16)	(446)	(439)	(1,219)
STATE INCOME TAX - THIRD PASS	0	0	0	0	0	0	0
TOTAL STATE INCOME TAX	2,849,268	4,795	6,172	917	26,276	25,836	71,772
FEDERAL INCOME TAX - FIRST PASS	47,561,636	80,042	103,026	15,305	438,612	431,265	1,198,053
FEDERAL INCOME TAX - SECOND PASS	(808,025)	(1,360)	(1,750)	(260)	(7,452)	(7,327)	(20,354)
FEDERAL INCOME TAX - THIRD PASS	0	0	0	0	0	0	0
TOTAL FEDERAL INCOME TAX	46,753,611	78,682	101,275	15,045	431,161	423,938	1,177,699
TOTAL INCOME TAXES	49,602,879	83,477	107,447	15,961	457,437	449,774	1,249,471
PERCENT OF TOTAL	100.00%	0.17%	0.22%	0.03%	0.92%	0.91%	2.52%
INCOME TAXES - ALLOCATED BY INCOME BEFORE TAXES (WITH NEGATIVE TAX ALLOWED)							
TOTAL STATE INCOME TAX	2,849,268	4,877	6,277	932	26,722	26,275	72,991
TOTAL FEDERAL INCOME TAX	46,753,611	80,019	102,996	15,300	438,485	431,140	1,197,706
TOTAL INCOME TAXES	49,602,879	84,895	109,272	16,233	465,207	457,414	1,270,696
PERCENT OF TOTAL	100.00%	0.17%	0.22%	0.03%	0.94%	0.92%	2.56%

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007
ALLOCATION TO CLASSES

****** TABLE 22 - ALLOCATION FACTOR SUMMARY ******

FUNCTION	FACTOR NAME	(A) TOTAL FACTOR	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV PRIMARY (9-P)	(E) GEN SRV SECONDARY (9-S)	(F) AREA LIGHTING (15)	(G) LG POWER PRIMARY (19-P)	(H) IRRIGATION SECONDARY (24-S)
PRODUCTION									
DEMAND - POWER SUPPLY	D10	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
DEMAND - Summer	D10S	0.6969	0.2354	0.0123	0.0150	0.1480	0.0000	0.0817	0.1698
DEMAND - Non-Summer	D10NS	0.3031	0.1013	0.0047	0.0076	0.0705	0.0000	0.0426	0.0576
ENERGY - POWER SUPPLY	E10	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
ENERGY - Summer	E10S	0.3930	0.1175	0.0053	0.0089	0.0808	0.0001	0.0518	0.1027
ENERGY - Non-Summer	E10NS	0.6070	0.2484	0.0101	0.0168	0.1474	0.0003	0.1007	0.0300
ENERGY - ANNUAL	E10	1.0000	0.3659	0.0154	0.0257	0.2282	0.0004	0.1525	0.1327
TRANSMISSION									
DEMAND - POWER SUPPLY	D11	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
DEMAND - TRANSMISSION	D13	1.0000	0.3569	0.0176	0.0218	0.2112	0.0000	0.1185	0.2236
DEMAND - SUBTRANSMISSION	D15	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
DEMAND - DIRECT	DA3509	3,392	0	0	1,189	0	0	0	0
DISTRIBUTION									
SUBSTATIONS - GENERAL	D20	3,202,946	1,288,425	55,976	74,224	647,366	1,638	343,075	781,125
SUBSTATIONS - DIRECT	DA3602	17,063,250	0	0	0	0	0	62,920	0
LINES - PRIMARY DEMAND	D20	3,202,946	1,288,425	55,976	74,224	647,366	1,638	343,075	781,125
LINES - PRIMARY CUSTOMER	C20	459,789	386,277	31,133	135	24,784	0	116	15,375
LINES - SECONDARY DIRECT	DA3647	14,180,018	0	0	2,719,351	0	461,829	9,496,677	0
LINE TRANS - PRIMARY DEMAND	D50	3,202,946	1,288,425	55,976	74,224	647,366	1,638	343,075	781,125
LINE TRANS - PRIMARY CUST	C50	459,789	386,277	31,133	135	24,784	0	116	15,375
LINE TRANS - SECOND DIRECT	DA368	12,673,643	0	0	3,166,317	0	0	8,479,059	0
LINE TRANS - SECOND DEMAND	D60	2,787,268	1,288,425	55,976	0	647,366	1,638	1,621	781,125
LINE TRANS - SECOND CUSTOMER	C60	459,539	386,277	31,133	0	24,784	0	1	15,375
LINES - SECONDARY DEMAND	D30	2,006,143	1,288,425	55,976	0	647,366	1,638	1,621	0
LINES - SECONDARY CUSTOMER	C30	444,164	386,277	31,133	0	24,784	0	1	0
SERVICES	CW369	47,149,600	38,484,459	3,393,776	70,921	3,054,044	0	163,753	1,977,330
METERS	CW370	48,089,582	24,929,285	5,495,002	687,932	9,907,792	222	833,587	6,151,755
STREET LIGHTS	DA373	3,821,476	0	0	12,858	0	0	1,629	0
INSTALL ON CUST PREMISES	DA371	2,315,417	0	0	2,462	0	2,310,373	495	0
INSTALL ON CUST PREM	CWINSTAL	1,459,163	962,390	77,566	336	61,748	313,624	288	38,306
CUSTOMER ACCOUNTING									
METER READING	CW902	4,962,976	3,606,394	317,131	304,020	264,320	0	261,232	203,123
CUSTOMER ACCOUNTS	CW903	9,761,117	8,154,368	657,223	31,995	523,194	0	27,492	324,569
UNCOLLECTIBLES	CW904	2,926,347	2,466,688	57,585	0	80,676	2,678	0	318,720
MISC	C10	459,792	386,277	31,133	135	24,784	0	116	15,375
CONSUMER INFORMATION									
CUSTOMER ASSIST	C10	459,792	386,277	31,133	135	24,784	0	116	15,375
SALES EXPENSE	C10	459,792	386,277	31,133	135	24,784	0	116	15,375
ADVERTISING	C10	459,792	386,277	31,133	135	24,784	0	116	15,375
MISC	C10	459,792	386,277	31,133	135	24,784	0	116	15,375
MISCELLANEOUS									
DEMAND	D99U	21,522,090	0	0	861,123	9,628,751	0	4,174,327	5,190,205
ENERGY	E99U	13,459,200,892	4,964,097,044	208,043,392	360,734,755	3,089,296,204	5,902,712	2,145,340,040	1,539,304,092
CUSTOMER	C10	459,792	386,277	31,133	135	24,784	0	116	15,375
MISC. REVENUE	R02	4,846,408	4,512,650	188,056	638	59,094	1,601	185	82,126
RETAIL SALES REVENUE	R01	617,820,268	294,087,610	15,381,328	12,772,697	126,221,210	931,147	65,869,474	70,750,659
SUBSTATION CIAC	CIAC	(22,235,004)	(83,177)	(387,474)	(90,593)	(138,210)	(64)	(6,724,664)	(60,255)
FACILITIES CHARGE REVENUE	DA454	5,648,745	34,648	435	1,185,953	0	96,465	3,635,498	0
INTERVENOR FUNDING	INTFUND	50,649	14,805	1,193	0	0	0	0	34,651

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007
ALLOCATION TO CLASSES

****** TABLE 22 - ALLOCATION FACTOR SUMMARY ******

	FACTOR NAME	TOTAL FACTOR	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) DOE/INL	(M) JR SIMPLOT	(N) SC MICRON
PRODUCTION								
DEMAND - POWER SUPPLY	D10	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
DEMAND - Summer	D10S	0.6969	0.0005	0.0000	0.0002	0.0064	0.0047	0.0230
DEMAND - Non-Summer	D10NS	0.3031	0.0003	0.0000	0.0001	0.0030	0.0032	0.0121
ENERGY - POWER SUPPLY	E10	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
ENERGY - Summer	E10S	0.3930	0.0004	0.0005	0.0001	0.0043	0.0041	0.0164
ENERGY - Non-Summer	E10NS	0.6070	0.0008	0.0010	0.0003	0.0101	0.0090	0.0322
ENERGY - ANNUAL	E10	1.0000	0.0012	0.0015	0.0004	0.0145	0.0131	0.0486
TRANSMISSION		0.0000						
DEMAND - POWER SUPPLY	D11	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
DEMAND - TRANSMISSION	D13	1.0000	0.0007	0.0000	0.0003	0.0088	0.0076	0.0329
DEMAND - SUBTRANSMISSION	D15	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
DEMAND - DIRECT	DA3509	3,392	0	0	0	0	2,203	0
DISTRIBUTION								
SUBSTATIONS - GENERAL	D20	3,202,946	4,579	5,812	726	0	0	0
SUBSTATIONS - DIRECT	DA3602	17,063,250	0	0	0	0	1,367,579	15,632,751
LINES - PRIMARY DEMAND	D20	3,202,946	4,579	5,812	726	0	0	0
LINES - PRIMARY CUSTOMER	C20	459,789	1,701	137	131	0	0	0
LINES - SECONDARY DIRECT	DA3647	14,180,018	0	0	0	0	1,502,161	0
LINE TRANS - PRIMARY DEMAND	D50	3,202,946	4,579	5,812	726	0	0	0
LINE TRANS - PRIMARY CUST	C50	459,789	1,701	137	131	0	0	0
LINE TRANS - SECOND DIRECT	DA368	12,673,643	0	0	0	0	1,028,267	0
LINE TRANS - SECOND DEMAND	D60	2,787,268	4,579	5,812	726	0	0	0
LINE TRANS - SECOND CUSTOMER	C60	459,539	1,701	137	131	0	0	0
LINES - SECONDARY DEMAND	D30	2,006,143	4,579	5,812	726	0	0	0
LINES - SECONDARY CUSTOMER	C30	444,164	1,701	137	131	0	0	0
SERVICES	CW369	47,149,600	0	0	0	0	5,317	0
METERS	CW370	48,089,582	664	920	2,962	9,829	13,210	56,422
STREET LIGHTS	DA373	3,821,476	0	3,806,989	0	0	0	0
INSTALL ON CUST PREMISES	DA371	2,315,417	0	0	0	0	2,087	0
INSTALL ON CUST PREM	CWINSTAL	1,459,163	4,238	341	326	0	0	0
CUSTOMER ACCOUNTING								
METER READING	CW902	4,962,976	0	0	0	2,252	2,252	2,252
CUSTOMER ACCOUNTS	CW903	9,761,117	35,908	2,892	2,765	237	237	237
UNCOLLECTIBLES	CW904	2,926,347	0	0	0	0	0	0
MISC	C10	459,792	1,701	137	131	1	1	1
0								
CONSUMER INFORMATION								
CUSTOMER ASSIST	C10	459,792	1,701	137	131	1	1	1
SALES EXPENSE	C10	459,792	1,701	137	131	1	1	1
ADVERTISING	C10	459,792	1,701	137	131	1	1	1
MISC	C10	459,792	1,701	137	131	1	1	1
MISCELLANEOUS								
DEMAND	D99U	21,522,090	0	0	0	366,600	285,559	1,015,525
ENERGY	E99U	13,459,200,892	16,337,412	18,704,636	5,474,735	215,500,001	188,325,624	702,140,245
CUSTOMER	C10	459,792	1,701	137	131	1	1	1
MISC. REVENUE	R02	4,846,408	185	82	1,791	0	0	0
RETAIL SALES REVENUE	R01	617,820,268	880,610	2,056,146	188,543	5,384,849	4,657,881	18,638,114
SUBSTATION CIAC	CIAC	(22,235,004)	(178)	(226)	(28)	0	(70,288)	(14,679,847)
FACILITIES CHARGE REVENUE	DA454	5,648,745	0	177,574	0	0	518,172	0
INTERVENOR FUNDING	INTFUND	50,649	0	0	0	0	0	0

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007

	FACTOR NAME	(A) TOTAL FACTOR	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV PRIMARY (9-P)	(E) GEN SRV SECONDARY (9-S)	(F) AREA LIGHTING (15)	(G) LG POWER PRIMARY (19-P)	(H) IRRIGATION SECONDARY (24-S)
PRODUCTION - DEMAND (KW)									
DEMAND - POWER SUPPLY	D10	0	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0.6969	0.2354	0.0123	0.0150	0.1480	0.0000	0.0817	0.1698
DEMAND - Non-Summer	D10NS	0.3031	0.1013	0.0047	0.0076	0.0705	0.0000	0.0426	0.0576
		1.0000							
TRANSMISSION - DEMAND (KW)									
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	1.0000	0.3569	0.0176	0.0218	0.2112	0.0000	0.1185	0.2236
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0	0
DISTRIBUTION - DEMAND (KW)									
SUBSTATIONS - GENERAL	D20	3,202,946	1,288,425	55,976	74,224	647,366	1,638	343,075	781,125
LINES - PRIMARY DEMAND	D20	3,202,946	1,288,425	55,976	74,224	647,366	1,638	343,075	781,125
LINE TRANS - PRIMARY DEMAND	D50	3,202,946	1,288,425	55,976	74,224	647,366	1,638	343,075	781,125
LINE TRANS - SECOND DEMAND	D60	2,787,268	1,288,425	55,976	0	647,366	1,638	1,621	781,125
LINES - SECONDARY DEMAND	D30	2,006,143	1,288,425	55,976	0	647,366	1,638	1,621	0
SUBSTATION CIAC	CIAC	(22,235,004)	(83,177)	(387,474)	(90,593)	(138,210)	(64)	(6,724,664)	(60,255)
PRODUCTION - ENERGY									
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0.3930	0.1175	0.0053	0.0089	0.0808	0.0001	0.0518	0.1027
ENERGY - Non-Summer	E10NS	0.6070	0.2484	0.0101	0.0168	0.1474	0.0003	0.1007	0.0300
ENERGY - ANNUAL	E10	1.0000	0.3659	0.0154	0.0257	0.2282	0.0004	0.1525	0.1327
SPECIFIC ASSIGNMENTS									
TRANS SUBS - DIR (RB) 350:359	DA3509	3,392			1,189				
DISTR SUBS - DIR (RB)360:362	DA3602	17,063,250						62,920	
LINES - PRI DIR (RB)	DA3647	14,180,018			2,719,351		461,829	9,496,677	
PRI LT - DIR (RB)	DA368	12,673,643			3,166,317			8,479,059	
STREET LIGHTS (373)	DA373	3,821,476			12,858			1,629	
INSTALL ON CUST PREM	DA371	2,315,417			2,462		2,310,373	495	
INSTALL ON CUST PREM	CWINSTAL	1,459,163	962,390	77,566	336	61,748	313,624	288	38,306
FACILITIES CHARGE REVENUE	DA454	5,648,745	34,648	435	1,185,953	0	96,465	3,635,498	0
INTERVENOR FUNDING	INTFUND	50,649	14,805	1,193	0	0	0	0	34,651
SALES REVENUES									
FROM - RETAIL SALES		589,139,424	589,139,424						
OPEN		0	0	0	0	0	0	0	0
OPEN		0	0	0	0	0	0	0	0
TOTAL RETAIL SALES	R01	617,820,268	294,087,610	15,381,328	12,772,697	126,221,210	931,147	65,869,474	70,750,659
REVENUE - #447-FIRM		0	0	0	0	0	0	0	0
REVENUE - #447-SYSTEM		0	0	0	0	0	0	0	0
TOTAL MISC. REVENUES	R02	4,846,408	4,512,650	188,056	638	59,094	1,601	185	82,126

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007

	FUNCTION/DESCRIPTION	FACTOR NAME	(A) TOTAL FACTOR	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV PRIMARY (9-P)	(E) GEN SRV SECONDARY (9-S)	(F) AREA LIGHTING (15)	(G) LG POWER PRIMARY (19-P)	(H) IRRIGATION SECONDARY (24-S)
69	AVERAGE CUSTOMERS	C10	459,792	386,277	31,133	135	24,784	0	116	15,375
70	AVERAGE FIXTURES									
71	CUSTOMER WEIGHTS									
72	LINES-PRI CUSTOMER	C20	459,789	386,277	31,133	135	24,784	0	116	15,375
73	PRI LINE TRANS-CUSTOMER	C50	459,789	386,277	31,133	135	24,784	0	116	15,375
74	SEC LINE TRANS-CUSTOMER	C60	459,539	386,277	31,133	0	24,784	0	1	15,375
75	LINES-SEC CUSTOMER	C30	444,164	386,277	31,133	0	24,784	0	1	0
76	SERVICES	CW369	47,149,600	38,484,459	3,393,776	70,921	3,054,044	0	163,753	1,977,330
77	METERS	CW370	48,089,582	24,929,285	5,495,002	687,932	9,907,792	222	833,587	6,151,755
78	CA METER READING	CW902	4,962,976	3,606,394	317,131	304,020	264,320	0	261,232	203,123
79	CA CUSTOMER ACCOUNTS	CW903	9,761,117	8,154,368	657,223	31,995	523,194	0	27,492	324,569
80	CA UNCOLLECTIBLES	CW904	2,926,347	2,466,688	57,585	0	80,676	2,678	0	318,720
81	CA MISC	C10	459,792	386,277	31,133	135	24,784	0	116	15,375
82	CI CUSTOMER ASSIST	C10	459,792	386,277	31,133	135	24,784	0	116	15,375
83	S DEMO & SELLING	C10	459,792	386,277	31,133	135	24,784	0	116	15,375
84	CI&S ADVERTISING	C10	459,792	386,277	31,133	135	24,784	0	116	15,375
85	CI&S MISC	C10	459,792	386,277	31,133	135	24,784	0	116	15,375
88	BILLING UNITS (KW & KWH)									
89	PRODUCTION FUNCTION									
90	DEMAND - POWER SUPPLY	D99U	21,522,090	0	0	861,123	9,628,751	0	4,174,327	5,190,205
91	DEMAND - Summer	D99US	7,044,263	0	0	234,758	2,643,288	0	1,140,408	3,025,809
92	DEMAND - Non-Summer	D99UW	12,810,143	0	0	626,365	6,985,463	0	3,033,919	2,164,396
93	ENERGY - POWER SUPPLY	E99U	12,306,815,527	4,964,097,044	208,043,392	360,734,755	3,089,296,204	0	2,145,340,040	1,539,304,092
94	ENERGY - Summer	E99US	3,877,757,139	1,228,355,483	58,681,959	95,218,949	827,392,135	0	558,708,042	1,109,400,571
95	ENERGY - Non-Summer	E99UW	8,429,058,388	3,735,741,561	149,361,433	265,515,806	2,261,904,069	0	1,586,631,998	429,903,521
96	ENERGY - ANNUAL	E99U	13,459,200,892	4,964,097,044	208,043,392	360,734,755	3,089,296,204	5,902,712	2,145,340,040	1,539,304,092
97	TRANSMISSION									
98	DEMAND - POWER SUPPLY	D11U	21,522,090	0	0	861,123	9,628,751	0	4,174,327	5,190,205
99	DEMAND - TRANSMISSION	D13U	21,522,090	0	0	861,123	9,628,751	0	4,174,327	5,190,205
100	DEMAND - SUBTRANSMISSION	D15U	21,522,090	0	0	861,123	9,628,751	0	4,174,327	5,190,205
102	BASIC LOAD CAPACITY									
103	SUBSTATIONS - GENERAL	D10U	18,100,743	0	0	1,043,325	12,215,389	0	4,842,029	
104	LINES - PRIMARY DEMAND	D11U	18,100,743	0	0	1,043,325	12,215,389	0	4,842,029	0
105	LINE TRANS - PRIMARY DEMAND	D12U	18,100,743	0	0	1,043,325	12,215,389	0	4,842,029	0
106	LINE TRANS - SECOND DEMAND	D13U	18,100,743	0	0	1,043,325	12,215,389	0	4,842,029	0
107	LINES - SECONDARY DEMAND	D14U	18,100,743	0	0	1,043,325	12,215,389	0	4,842,029	0
109	NUMBER OF BILLINGS	B100	5,516,360	4,623,896	374,514	1,591	296,325	0	1,395	195,076

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007

FUNCTION	FACTOR NAME	(I) TOTAL FACTOR	(J) UNMETERED GEN SERVICE (40)	(K) MUNICIPAL ST LIGHT (41)	(L) TRAFFIC CONTROL (42)	(M) SC DOE/INL	(N) SC JR SIMPLOT	(O) SC MICRON
PRODUCTION - DEMAND (KW)								
DEMAND - POWER SUPPLY	D10	0	0	0	0	0	0	0
DEMAND - Summer	D10S	0.6969	0.0005	0.0000	0.0002	0.0064	0.0047	0.0230
DEMAND - Non-Summer	D10NS	0.3031	0.0003	0.0000	0.0001	0.0030	0.0032	0.0121
TRANSMISSION - DEMAND (KW)								
DEMAND - POWER SUPPLY	D11	0	0	0	0	0	0	0
DEMAND - TRANSMISSION	D13	1.0000	0.0007	0.0000	0.0003	0.0088	0.0076	0.0329
DEMAND - SUBTRANSMISSION	D15	0	0	0	0	0	0	0
DISTRIBUTION - DEMAND (KW)								
SUBSTATIONS - GENERAL	D20	3,202,946	4,579	5,812	726	0	0	0
LINES - PRIMARY DEMAND	D20	3,202,946	4,579	5,812	726	0	0	0
LINE TRANS - PRIMARY DEMAND	D50	3,202,946	4,579	5,812	726	0	0	0
LINE TRANS - SECOND DEMAND	D60	2,787,268	4,579	5,812	726	0	0	0
LINES - SECONDARY DEMAND	D30	2,006,143	4,579	5,812	726	0	0	0
	CIAC		(178)	(226)	(28)		(70,288)	(14,679,847)
PRODUCTION - ENERGY								
ENERGY - POWER SUPPLY	E10	0	0	0	0	0	0	0
ENERGY - Summer	E10S	0.3930	0.0004	0.0005	0.0001	0.0043	0.0041	0.0164
ENERGY - Non-Summer	E10NS	0.6070	0.0008	0.0010	0.0003	0.0101	0.0090	0.0322
ENERGY - ANNUAL	E10	1.0000	0.0012	0.0015	0.0004	0.0145	0.0131	0.0486
SPECIFIC ASSIGNMENTS								
TRANS SUBS - DIR (RB) 350:359	DA3509	3,392	0	0	0	0	2,203	0
DISTR SUBS - DIR (RB)360:362	DA3602	17,063,250	0	0	0	0	1,367,579	15,632,751
LINES - PRI DIR (RB)	DA3647	14,180,018	0	0	0	0	1,502,161	0
PRI LT - DIR (RB)	DA368	12,673,643	0	0	0	0	1,028,267	0
STREET LIGHTS (373)	DA373	3,821,476	0	3,806,989	0	0	0	0
INSTALL ON CUST PREM	DA371	2,315,417				0	2,087	0
INSTALL ON CUST PREM	CWINSTAL	1,459,163	4,238	341	326	0	0	0
FACILITIES CHARGE REVENUE	DA454	5,648,745	0	177,574		0	518,172	0
INTERVENOR FUNDING	INTFUND	50,649	0	0	0	0	0	0
SALES REVENUES								
FROM - RETAIL SALES		589,139,424						
OPEN		0	0	0	0	0	0	0
OPEN		0	0	0	0	0	0	0
TOTAL RETAIL SALES	R01	617,820,268	880,610	2,056,146	188,543	5,384,849	4,657,881	18,638,114
REVENUE - #447-FIRM		0	0	0	0	0	0	0
REVENUE - #447-SYSTEM		0	0	0	0	0	0	0
TOTAL MISC. REVENUES	R02	4,846,408	185	82	1,791	0	0	0

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007

	FUNCTION/DESCRIPTION	FACTOR NAME	TOTAL	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
69	AVERAGE CUSTOMERS	C10	459,792	1,701	137	131	1	1	1
70	AVERAGE FIXTURES								
71	CUSTOMER WEIGHTS								
72	LINES-PRI CUSTOMER	C20	459,789	1,701	137	131	0	0	0
73	PRI LINE TRANS-CUSTOMER	C50	459,789	1,701	137	131	0	0	0
74	SEC LINE TRANS-CUSTOMER	C60	459,539	1,701	137	131	0	0	0
75	LINES-SEC CUSTOMER	C30	444,164	1,701	137	131	0	0	0
76	SERVICES	CW369	47,149,600	0	0	0	0	5,317	0
77	METERS	CW370	48,089,582	664	920	2,962	9,829	13,210	56,422
78	CA METER READING	CW902	4,962,976	0	0	0	2,252	2,252	2,252
79	CA CUSTOMER ACCOUNTS	CW903	9,761,117	35,908	2,892	2,765	237	237	237
80	CA UNCOLLECTIBLES	CW904	2,926,347	0	0	0	0	0	0
81	CA MISC	C10	459,792	1,701	137	131	1	1	1
82	CI CUSTOMER ASSIST	C10	459,792	1,701	137	131	1	1	1
83	S DEMO & SELLING	C10	459,792	1,701	137	131	1	1	1
84	CI&S ADVERTISING	C10	459,792	1,701	137	131	1	1	1
85	CI&S MISC	C10	459,792	1,701	137	131	1	1	1
86									
87									
88	BILLING UNITS (KW & KWH)								
89	PRODUCTION FUNCTION								
90	DEMAND - POWER SUPPLY	D99U	21,522,090	0	0	0	366,600	285,559	1,015,525
91	DEMAND - Summer	D99US	7,044,263	0	0	0	0	0	0
92	DEMAND - Non-Summer	D99UW	12,810,143	0	0	0	0	0	0
93	ENERGY - POWER SUPPLY	E99U	12,306,815,527	0	0	0	0	0	0
94	ENERGY - Summer	E99US	3,877,757,139	0	0	0	0	0	0
95	ENERGY - Non-Summer	E99UW	8,429,058,388	0	0	0	0	0	0
96	ENERGY - ANNUAL	E99U	13,459,200,892	16,337,412	18,704,636	5,474,735	215,500,001	188,325,624	702,140,245
97	TRANSMISSION								
98	DEMAND - POWER SUPPLY	D11U	21,522,090	0	0	0	366,600	285,559	1,015,525
99	DEMAND - TRANSMISSION	D13U	21,522,090	0	0	0	366,600	285,559	1,015,525
100	DEMAND - SUBTRANSMISSION	D15U	21,522,090	0	0	0	366,600	285,559	1,015,525
101									
102	BASIC LOAD CAPACITY								
103	SUBSTATIONS - GENERAL	D10U	18,100,743	0	0	0	0	0	0
104	LINES - PRIMARY DEMAND	D11U	18,100,743	0	0	0	0	0	0
105	LINE TRANS - PRIMARY DEMAND	D12U	18,100,743	0	0	0	0	0	0
106	LINE TRANS - SECOND DEMAND	D13U	18,100,743	0	0	0	0	0	0
107	LINES - SECONDARY DEMAND	D14U	18,100,743	0	0	0	0	0	0
108									
109	NUMBER OF BILLINGS		5,516,360	20,410	1,551	1,566	12	12	12

IDAHO POWER COMPANY
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2007

Month	Marginal Cost	Total IPUC Jurisdiction	Residential (1)	General Service (7)	General Service (9-Primary)	General Service (9-Secondary)	Area Lighting (15)	Large Power Service (19-Primary)	Irrigation Service (24-Secondary)
CAPACITY RELATED ALLOCATION FACTORS									
Monthly Coincident Demands @ Generation Level									
January		2,210,437	1,193,549	36,884	49,136	490,137	1,298	286,265	1,031
February		2,250,001	1,201,564	38,337	50,741	512,824	323	296,694	1,334
March		2,017,048	1,027,500	32,203	49,326	475,629	0	281,005	7,382
April		1,823,237	807,559	26,757	48,623	431,261	0	282,639	84,561
May		2,247,643	751,370	34,722	56,717	522,850	0	315,886	427,281
June		2,752,148	902,106	47,867	58,891	587,087	0	320,269	698,440
July		2,883,810	1,065,895	52,458	63,257	603,494	0	345,202	609,905
August		2,708,910	1,030,939	43,392	61,072	577,905	0	323,835	528,095
September		2,426,855	859,348	39,344	66,129	540,273	0	312,115	470,243
October		1,777,799	787,609	24,130	55,098	403,060	0	299,455	66,383
November		2,020,505	978,746	33,318	56,780	491,048	679	300,966	9,454
December		2,260,109	1,172,831	36,809	57,743	521,122	1,174	316,280	1,623
Total		27,378,503	11,779,016	446,222	673,513	6,156,690	3,474	3,680,611	2,905,733
Ratio		1.0000	0.4302	0.0163	0.0246	0.2249	0.0001	0.1344	0.1061
Actual	D10S	0.3048	0.1095	0.0052	0.0067	0.0646	0.0000	0.0361	0.0671
Actual	D10NS	0.6952	0.3207	0.0110	0.0179	0.1603	0.0001	0.0983	0.0391
Monthly Coincident Demands Weighted by Marginal Demand Costs									
Power Supply Service - Generation									
January	0.00	0	0	0	0	0	0	0	0
February	0.00	0	0	0	0	0	0	0	0
March	0.00	0	0	0	0	0	0	0	0
April	0.00	0	0	0	0	0	0	0	0
May	0.35	786,675	262,980	12,153	19,851	182,997	0	110,560	149,548
June	0.50	1,376,074	451,053	23,934	29,446	293,543	0	160,134	349,220
July	0.15	432,572	159,884	7,869	9,489	90,524	0	51,780	91,486
August	0.00	0	0	0	0	0	0	0	0
September	0.00	0	0	0	0	0	0	0	0
October	0.00	0	0	0	0	0	0	0	0
November	0.00	0	0	0	0	0	0	0	0
December	0.00	0	0	0	0	0	0	0	0
Total		2,595,322	873,917	43,955	58,785	567,065	0	322,475	590,254
Ratio		1.0000	0.3367	0.0169	0.0227	0.2185	0.0000	0.1243	0.2274
Weighted	**D10S**	**0.6969**	**0.2354**	**0.0123**	**0.0150**	**0.1480**	**0.0000**	**0.0817**	**0.1698**
Weighted	**D10NS**	**0.3031**	**0.1013**	**0.0047**	**0.0076**	**0.0705**	**0.0000**	**0.0426**	**0.0576**
Average	D10S	0.5008	0.1725	0.0088	0.0108	0.1063	0.0000	0.0589	0.1184
Average	D10NS	0.4992	0.2110	0.0079	0.0128	0.1154	0.0001	0.0704	0.0483
Total Ratio		1.0000	0.3835	0.0166	0.0236	0.2217	0.0001	0.1293	0.1668

IDAHO POWER COMPANY
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2007

Month	Marginal Cost	Unmetered Service (40)	Municipal Street Light (41)	Traffic Control (42)	Total Tariff Customers	DOE/INL	Simplot	Micron	Total Special Contracts
CAPACITY RELATED ALLOCATION FACTORS									
Monthly Coincident Demands @ Generation Level									
January		2,068	4,458	706	2,065,531	37,132	23,494	84,280	144,906
February		2,289	1,119	706	2,105,932	35,907	23,748	84,414	144,070
March		2,068	0	706	1,875,819	34,351	22,892	83,985	141,229
April		2,137	0	706	1,684,243	30,953	23,940	84,101	138,994
May		2,068	0	706	2,111,599	22,462	23,554	90,029	136,044
June		2,137	0	706	2,617,504	26,231	17,156	91,257	134,644
July		2,068	0	706	2,742,985	23,752	23,504	93,569	140,825
August		2,068	0	706	2,568,013	24,519	24,021	92,357	140,897
September		2,137	0	704	2,290,292	23,253	22,556	90,754	136,564
October		2,068	0	704	1,638,506	29,932	23,883	85,478	139,293
November		2,134	2,413	726	1,876,265	34,844	23,161	86,235	144,240
December		2,071	4,165	692	2,114,509	35,922	23,630	86,047	145,599
Total		25,311	12,154	8,475	25,691,198	359,260	275,539	1,052,507	1,687,305
Ratio		0.0009	0.0004	0.0003	0.9384	0.0131	0.0101	0.0384	0.0616
Actual	D10S	0.0002	0.0000	0.0001	0.2896	0.0027	0.0024	0.0101	0.0152
Actual	D10NS	0.0007	0.0004	0.0002	0.6488	0.0104	0.0077	0.0283	0.0464
Monthly Coincident Demands Weighted by Marginal Demand Costs									
Power Supply Service - Generation									
January	0.00	0	0	0	0	0	0	0	0
February	0.00	0	0	0	0	0	0	0	0
March	0.00	0	0	0	0	0	0	0	0
April	0.00	0	0	0	0	0	0	0	0
May	0.35	724	0	247	739,060	7,862	8,244	31,510	47,615
June	0.50	1,068	0	353	1,308,752	13,116	8,578	45,628	67,322
July	0.15	310	0	106	411,448	3,563	3,526	14,035	21,124
August	0.00	0	0	0	0	0	0	0	0
September	0.00	0	0	0	0	0	0	0	0
October	0.00	0	0	0	0	0	0	0	0
November	0.00	0	0	0	0	0	0	0	0
December	0.00	0	0	0	0	0	0	0	0
Total		2,102	0	706	2,459,260	24,540	20,347	91,174	136,061
Ratio		0.0008	0.0000	0.0003	0.9476	0.0095	0.0078	0.0351	0.0524
Weighted	**D10S**	**0.0005**	**0.0000**	**0.0002**	**0.6628**	**0.0064**	**0.0047**	**0.0230**	**0.0341**
Weighted	**D10NS**	**0.0003**	**0.0000**	**0.0001**	**0.2848**	**0.0030**	**0.0032**	**0.0121**	**0.0183**
Average	D10S	0.0004	0.0000	0.0001	0.4762	0.0046	0.0035	0.0166	0.0246
Average	D10NS	0.0005	0.0002	0.0002	0.4668	0.0067	0.0054	0.0202	0.0324
Total Ratio		0.0009	0.0002	0.0003	0.9430	0.0113	0.0090	0.0368	0.0570

IDAHO POWER COMPANY
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2007

Month	Marginal Cost	Total IPUC Jurisdiction	Residential (1)	General Service (7)	General Service (9-Primary)	General Service (9-Secondary)	Area Lighting (15)	Large Power Service (19-Primary)	Irrigation Service (24-Secondary)
CAPACITY RELATED ALLOCATION FACTORS									
Monthly Coincident Demands @ Generation Level									
January		2,210,437	1,193,549	36,884	49,136	490,137	1,298	286,265	1,031
February		2,250,001	1,201,564	38,337	50,741	512,824	323	296,694	1,334
March		2,017,048	1,027,500	32,203	49,326	475,629	0	281,005	7,382
April		1,823,237	807,559	26,757	48,623	431,261	0	282,639	84,561
May		2,247,643	751,370	34,722	56,717	522,850	0	315,886	427,281
June		2,752,148	902,106	47,867	58,891	587,087	0	320,269	698,440
July		2,883,810	1,065,895	52,458	63,257	603,494	0	345,202	609,905
August		2,708,910	1,030,939	43,392	61,072	577,905	0	323,835	528,095
September		2,426,855	859,348	39,344	66,129	540,273	0	312,115	470,243
October		1,777,799	787,609	24,130	55,098	403,060	0	299,455	66,383
November		2,020,505	978,746	33,318	56,780	491,048	679	300,966	9,454
December		2,260,109	1,172,831	36,809	57,743	521,122	1,174	316,280	1,623
Total		27,378,503	11,779,016	446,222	673,513	6,156,690	3,474	3,680,611	2,905,733
Actual	D13	1.0000	0.4302	0.0163	0.0246	0.2249	0.0001	0.1344	0.1061
Monthly Coincident Demands Weighted by Marginal Transmission Costs									
Transmission Service									
January	0.00	0	0	0	0	0	0	0	0
February	0.00	0	0	0	0	0	0	0	0
March	0.00	0	0	0	0	0	0	0	0
April	0.00	0	0	0	0	0	0	0	0
May	0.00	0	0	0	0	0	0	0	0
June	0.35	963,252	315,737	16,754	20,612	205,480	0	112,094	244,454
July	0.50	1,441,906	532,948	26,229	31,628	301,747	0	172,601	304,953
August	0.15	406,337	154,641	6,509	9,161	86,686	0	48,575	79,214
September	0.00	0	0	0	0	0	0	0	0
October	0.00	0	0	0	0	0	0	0	0
November	0.00	0	0	0	0	0	0	0	0
December	0.00	0	0	0	0	0	0	0	0
Total		2,811,493	1,003,326	49,491	61,401	593,913	0	333,270	628,621
Weighted	**D13**	**1.0000**	**0.3569**	**0.0176**	**0.0218**	**0.2112**	**0.0000**	**0.1185**	**0.2236**
Average	D13	1.0000	0.3935	0.0170	0.0232	0.2181	0.0001	0.1265	0.1649

IDAHO POWER COMPANY
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2007

Month	Marginal Cost	Unmetered Service (40)	Municipal Street Light (41)	Traffic Control (42)	Total Tariff Customers	DOE/INL	Simplot	Micron	Total Special Contracts
CAPACITY RELATED ALLOCATION FACTORS									
Monthly Coincident Demands @ Generation Level									
January	0.00	2,068	4,458	706	2,065,531	37,132	23,494	84,280	144,906
February	0.00	2,289	1,119	706	2,105,932	35,907	23,748	84,414	144,070
March	0.00	2,068	0	706	1,875,819	34,351	22,892	83,985	141,229
April	0.00	2,137	0	706	1,684,243	30,953	23,940	84,101	138,994
May	0.00	2,068	0	706	2,111,599	22,462	23,554	90,029	136,044
June	0.00	2,137	0	706	2,617,504	26,231	17,156	91,257	134,644
July	0.00	2,068	0	706	2,742,985	23,752	23,504	93,569	140,825
August	0.00	2,068	0	706	2,568,013	24,519	24,021	92,357	140,897
September	0.00	2,137	0	704	2,290,292	23,253	22,556	90,754	136,564
October	0.00	2,068	0	704	1,638,506	29,932	23,883	85,478	139,293
November	0.00	2,134	2,413	726	1,876,265	34,844	23,161	86,235	144,240
December	0.00	2,071	4,165	692	2,114,509	35,922	23,630	86,047	145,599
Total		25,311	12,154	8,475	25,691,198	359,260	275,539	1,052,507	1,687,305
Actual	D13	0.0009	0.0004	0.0003	0.9384	0.0131	0.0101	0.0384	0.0616
Monthly Coincident Demands Weighted by Marginal Transmission Costs									
Transmission Service									
January	0.00	0	0	0	0	0	0	0	0
February	0.00	0	0	0	0	0	0	0	0
March	0.00	0	0	0	0	0	0	0	0
April	0.00	0	0	0	0	0	0	0	0
May	0.00	0	0	0	0	0	0	0	0
June	0.35	748	0	247	916,127	9,181	6,005	31,940	47,125
July	0.50	1,034	0	353	1,371,493	11,876	11,752	46,784	70,413
August	0.15	310	0	106	385,202	3,678	3,603	13,854	21,135
September	0.00	0	0	0	0	0	0	0	0
October	0.00	0	0	0	0	0	0	0	0
November	0.00	0	0	0	0	0	0	0	0
December	0.00	0	0	0	0	0	0	0	0
Total		2,092	0	706	2,672,822	24,735	21,360	92,578	138,673
Weighted	**D13**	**0.0007**	**0.0000**	**0.0003**	**0.9507**	**0.0088**	**0.0076**	**0.0329**	**0.0493**
Average	D13	0.0008	0.0002	0.0003	0.9445	0.0110	0.0088	0.0357	0.0555

IDAHO POWER COMPANY
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2007

Month	Marginal Cost	Total IPUC Jurisdiction	Residential (1)	General Service (7)	General Service (9-Primary)	General Service (9-Secondary)	Area Lighting (15)	Large Power Service (19-Primary)	Irrigation Service (24-Secondary)
ENERGY RELATED ALLOCATION FACTORS									
Monthly Energy Requirements @ Generation Level									
January		1,247,214	598,762	23,513	29,634	295,314	545	193,284	753
February		1,121,172	527,975	20,869	27,784	268,854	542	178,808	880
March		1,077,183	459,945	19,556	29,978	275,122	547	183,814	5,390
April		1,038,774	390,531	16,686	29,144	263,791	544	179,296	59,753
May		1,159,421	358,799	15,786	32,037	271,100	548	186,039	193,624
June		1,357,569	364,300	17,870	31,635	282,711	544	192,692	376,089
July		1,624,165	493,954	22,092	35,201	320,285	546	204,499	444,234
August		1,511,625	464,457	20,596	35,186	324,288	544	203,336	360,944
September		1,182,565	350,944	16,220	36,136	279,878	543	193,456	209,080
October		1,065,848	386,664	16,335	33,941	278,412	546	201,058	48,471
November		1,105,792	485,864	17,909	32,275	270,156	547	191,964	6,681
December		1,293,607	629,321	23,588	33,631	299,819	550	199,061	1,185
Total		14,784,934	5,511,515	231,020	386,583	3,429,730	6,546	2,307,305	1,707,083
Ratio		1.0000	0.3728	0.0156	0.0261	0.2320	0.0004	0.1561	0.1155
Actual	E10S	0.3039	0.0895	0.0041	0.0069	0.0627	0.0001	0.0406	0.0799
Actual	E10NS	0.6961	0.2833	0.0115	0.0192	0.1693	0.0003	0.1154	0.0356
Monthly Energy Requirements Weighted by Marginal Energy Costs									
Power Supply Service - Generation									
January	64.34	80,245,729	38,524,373	1,512,830	1,906,658	19,000,522	35,046	12,435,890	48,420
February	64.78	72,629,536	34,202,207	1,351,919	1,799,835	17,416,390	35,133	11,583,168	57,001
March	64.97	69,984,562	29,882,641	1,270,523	1,947,695	17,874,656	35,552	11,942,378	350,208
April	55.33	57,475,360	21,608,062	923,231	1,612,565	14,595,531	30,096	9,920,423	3,306,108
May	54.86	63,605,816	19,683,701	866,012	1,757,564	14,872,522	30,084	10,206,076	10,622,190
June	58.68	79,662,135	21,377,107	1,048,627	1,856,362	16,589,510	31,906	11,307,177	22,068,920
July	127.75	207,487,074	63,102,647	2,822,282	4,496,887	40,916,402	69,727	26,124,787	56,750,862
August	111.10	167,941,504	51,601,184	2,288,241	3,909,143	36,028,436	60,408	22,590,647	40,100,929
September	77.66	91,837,995	27,254,273	1,259,618	2,806,358	21,735,311	42,199	15,023,789	16,237,126
October	71.37	76,069,607	27,596,217	1,165,837	2,422,382	19,870,267	38,950	14,349,493	3,459,402
November	78.92	87,269,095	38,344,383	1,413,375	2,547,146	21,320,694	43,184	15,149,784	527,225
December	80.24	103,799,056	50,496,718	1,892,709	2,698,547	24,057,461	44,130	15,972,629	95,096
Total		1,158,007,470	423,673,515	17,815,203	29,761,141	264,277,700	496,414	176,606,239	153,623,487
Ratio		1.0000	0.3659	0.0154	0.0257	0.2282	0.0004	0.1525	0.1327
Weighted	**E10S**	**0.3930**	**0.1175**	**0.0053**	**0.0089**	**0.0808**	**0.0001**	**0.0518**	**0.1027**
Weighted	**E10NS**	**0.6070**	**0.2484**	**0.0101**	**0.0168**	**0.1474**	**0.0003**	**0.1007**	**0.0300**
Average	E10S	0.3485	0.1035	0.0047	0.0079	0.0717	0.0001	0.0462	0.0913
Average	E10NS	0.6515	0.2658	0.0108	0.0180	0.1584	0.0003	0.1081	0.0328
Total Ratio		1.0000	0.3693	0.0155	0.0259	0.2301	0.0004	0.1543	0.1241

IDAHO POWER COMPANY
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2007

Month	Marginal Cost	Unmetered Service (40)	Municipal Street Light (41)	Traffic Control (42)	Total Tariff Customers	DOE/INL	Simplot	Micron	Total Special Contracts
ENERGY RELATED ALLOCATION FACTORS									
Monthly Energy Requirements @ Generation Level									
January		1,510	1,871	506	1,145,692	22,758	17,313	61,451	101,522
February		1,510	1,878	506	1,029,606	20,282	15,792	55,492	91,566
March		1,510	1,885	506	978,253	19,967	17,461	61,502	98,930
April		1,510	1,892	506	943,652	18,302	17,071	59,749	95,122
May		1,510	1,900	506	1,061,847	17,525	17,567	62,480	97,573
June		1,510	1,907	506	1,269,765	16,569	10,258	60,977	87,804
July		1,510	1,914	506	1,524,741	17,281	17,470	64,672	99,424
August		1,510	1,922	506	1,413,289	16,652	17,310	64,374	98,335
September		1,510	1,929	504	1,090,200	14,955	16,532	60,878	92,365
October		1,510	1,936	504	969,378	16,944	16,970	62,557	96,471
November		1,508	1,944	520	1,009,367	19,299	16,671	60,455	96,425
December		1,512	1,951	496	1,191,113	22,507	17,327	62,660	102,494
Total		18,118	22,929	6,071	13,626,903	223,043	197,742	737,247	1,158,032
Ratio		0.0012	0.0016	0.0004	0.9217	0.0151	0.0134	0.0499	0.0783
Actual	E10S	0.0003	0.0004	0.0001	0.2846	0.0034	0.0030	0.0129	0.0193
Actual	E10NS	0.0009	0.0012	0.0003	0.6371	0.0117	0.0103	0.0370	0.0590
Monthly Energy Requirements Weighted by Marginal Energy Costs									
Power Supply Service - Generation									
January	64.34	97,144	120,363	32,553	73,713,798	1,464,267	1,113,920	3,953,744	6,531,931
February	64.78	97,808	121,669	32,776	66,697,907	1,313,852	1,023,022	3,594,755	5,931,630
March	64.97	98,095	122,464	32,872	63,557,083	1,297,282	1,134,431	3,995,767	6,427,479
April	55.33	83,540	104,706	27,995	52,212,256	1,012,652	944,521	3,305,931	5,263,104
May	54.86	82,830	104,212	27,757	58,252,947	961,446	963,744	3,427,679	5,352,869
June	58.68	88,598	111,906	29,690	74,509,804	972,256	601,950	3,578,126	5,152,332
July	127.75	192,883	244,549	64,636	194,785,662	2,207,710	2,231,823	8,261,880	12,701,412
August	111.10	167,744	213,504	56,212	157,016,448	1,850,055	1,923,099	7,151,903	10,925,057
September	77.66	117,255	149,821	39,143	84,664,894	1,161,415	1,283,874	4,727,812	7,173,101
October	71.37	107,758	138,201	35,984	69,184,490	1,209,326	1,211,132	4,464,659	6,885,117
November	78.92	118,994	153,409	41,032	79,659,227	1,523,077	1,315,647	4,771,144	7,609,868
December	80.24	121,316	156,554	39,773	95,574,934	1,805,928	1,390,346	5,027,848	8,224,122
Total		1,373,965	1,741,359	460,423	1,069,829,447	16,779,266	15,137,508	56,261,248	88,178,023
Ratio		0.0012	0.0015	0.0004	0.9239	0.0145	0.0131	0.0486	0.0761
Weighted	**E10S**	**0.0004**	**0.0005**	**0.0001**	**0.3681**	**0.0043**	**0.0041**	**0.0164**	**0.0249**
Weighted	**E10NS**	**0.0008**	**0.0010**	**0.0003**	**0.5557**	**0.0101**	**0.0090**	**0.0322**	**0.0513**
Average	E10S	0.0003	0.0004	0.0001	0.3264	0.0039	0.0036	0.0146	0.0221
Average	E10NS	0.0009	0.0011	0.0003	0.5964	0.0109	0.0096	0.0346	0.0552
Total Ratio		0.0012	0.0015	0.0004	0.9228	0.0148	0.0132	0.0492	0.0772