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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

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

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

MICHAEL J. YOUNGBLOOD

1 Q. Please state your name and business address.

2 A. My name is Michael J. Youngblood and my

3 business address is 1221 W. Idaho Street. in Boise, Idaho.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by Idaho Power Company as a

6 Senior Pricing Analyst in the Pricing and Regulatory Services

7 Department.

8 Q. Please describe your educational background.

9 A. In May of 1977, I received a Bachelor of

10 Science Degree in Mathematics and Computer Science from the

11 University of Idaho. From 1994 through 1996, I was a graduate

12 student in the MBA program of Colorado State University.

13 Q. Please describe your work experience with Idaho

14 Power Company.

15 A. I became employed by Idaho Power Company in

16 1977. During my career, I have worked in several departments

17 and subsidiaries of the Company, including Systems

18 Development, Demand Planning, Strategic Planning and IDACORP

19 Solutions. Most relevant to this testimony though, is my

20 experience within the Pricing and Regulatory Services

21 Department. From 1981 to 1988, I worked as a Rate Analyst in

22 the Rates and Planning Department where I was responsible for

23 the preparation of electric rate design studies and bill

24 frequency analyses. I was also responsible for the validation

25 and analysis of the load research data used for cost of

1 service allocations.

2 From 1988 through 1991, I worked in Demand

3 Planning and was responsible for the load research and load

4 forecasting functions of the Company including sample design,

5 implementation, data retrieval, analysis, and reporting. I

6 was responsible for the preparation of the five-year and

7 twenty-year load forecasts used in revenue projections and

8 resource plans as well as the presentation of these forecasts

9 to the public and regulatory commissions.

10 In 2001, I returned to the Pricing and

11 Regulatory Services Department and have worked on special

12 projects related to deregulation, the Company's Integrated

13 Resource Plan, and filings with this Commission and the Oregon

14 Public Utility Commission.

15 Q. What is the purpose of your testimony in this

16 case?

17 A. The purpose of my testimony is to describe a

18 Fixed Cost Adjustment ("FCA") mechanism that would true-up

19 fixed cost recovery for residential and small commercial

20 customers. The proposed FCA is an effort to reduce or remove

21 a currently existing disincentive to pursue conservation

22 measures for those two classes of customers. Mr. Ralph

23 Cavanagh first discussed the disincentive to pursue

24 conservation measures in Case No. IPC-E-03-13 (the Company's

25 last general rate case).

1 Q. What has been your involvement with the
2 development of an FCA mechanism?
3 A. I began working on the development of a fixed
4 cost true-up mechanism in 2004 during Case No. IPC-E-03-13
5 shortly after the Company read Mr. Cavanagh's testimony in
6 that proceeding. I was designated as the Project Manager
7 responsible for the review of existing mechanisms and
8 identification of a true-up mechanism that Idaho Power could
9 support. As part of this review process, the Company hired a
10 consultant, Mr. Eric Hirst, to write a "white paper" which he
11 titled "Decoupling for Idaho Power Company". I have included
12 this white paper as Exhibit No. 5.
13 Q. Did you work with Mr. Hirst in the preparation
14 of this white paper?
15 A. Yes. At Mr. Hirst's request, I gathered 2003
16 test year information regarding the fixed costs associated
17 with the Company's five largest rate classifications
18 (residential, small commercial, large commercial, irrigation,
19 and industrial classes). With this information Mr. Hirst and
20 I were able to identify the portion of those fixed costs that
21 are recovered as a component of each specific rate class's
22 volumetric rate (energy charge). Because conservation
23 measures encourage the reduction of energy consumption, fixed
24 costs normally recovered through a volumetric rate are not
25 recovered when such conservation measures are pursued. Mr.

1 Hirst also provided a description of various types of
2 recoupling mechanisms used for recovery of these lost fixed
3 costs and developed conclusions that I reviewed.
4 Q. Have you had any additional involvement in the
5 review of fixed cost recovery true-up mechanisms since 2004?
6 A. Yes. The Idaho Public Utilities Commission, in
7 review of its Order No. 29505 in Case No. IPC-03-13 found it
8 reasonable to initiate an investigation of financial
9 disincentives to investment in energy efficiency by Idaho
10 Power. In Order No. 29558, the Commission established Docket
11 No. IPC-04-15 for such an investigation and stated that the
12 scope of the investigation should be focused on decoupling and
13 performance based ratemaking. The Company, along with the
14 Northwest Energy Coalition, the Commission Staff, the
15 Industrial Customers of Idaho Power, and other interested
16 parties, held several workshops to discuss the issues and
17 prepare a report for the Commission of the workshops'
18 findings. I was a participant at these workshops and prepared
19 much of the analyses that were used during the investigation.
20 Q. Were the findings of Mr. Hirst's white paper
21 used as part of the workshop's investigation?
22 A. Yes. Mr. Hirst attended the very first
23 workshop and made a presentation of his study to the group.
24 This provided all of the participants with an understanding of
25 the fixed costs associated with the Company's energy charges,

1 and provided a springboard for further discussions into the
2 concerns and various mechanisms that may be considered for
3 fixed cost recovery associated with additional investment in
4 DSM.
5 Q. What was the result of the workshop effort?
6 A. The final report by the workshop participants
7 was filed with the Commission on February 14, 2005. The
8 report provided the Commission with an overview of the
9 workshops, the issues discussed, and the recommendations of
10 the workshop participants. One of the action items resulting
11 from this process was a direction for the Company to simulate
12 the potential impacts of a broader fixed cost true-up
13 mechanism that could be utilized until Idaho Power's next
14 general rate case. I was responsible for developing and
15 maintaining that simulation (Exhibit No. 6), the results of
16 which are the genesis of the FCA mechanism the Company is
17 proposing in this case.
18 Q. Please describe the fixed cost true-up
19 simulation that you developed as a workshop assignment.
20 A. The Natural Resources Defense Council and
21 Northwest Energy Coalition proposed a true-up mechanism to
22 restore lost fixed-cost revenues to Idaho Power that resulted
23 when conservation measures reduced future energy consumption.
24 Rather than recommending the actual implementation of such a
25 mechanism, the workshop participants agreed to a "simulation"

1 of the true-up proposal to help illuminate the potential
2 impacts a true-up mechanism might have had on Idaho Power and
3 its customers if a true-up mechanism had been in place. The
4 simulation was to review the years from 1994 to the next
5 general rate case, using the fixed-cost revenue requirements
6 approved in the Company's last two general rate cases as
7 starting points, and then comparing those with actual fixed
8 cost revenues recovered through energy sales. At the time of
9 the writing of this testimony, the year-end numbers for 2005
10 are not yet final; therefore, the simulation currently reviews
11 the years from 1994 through 2004. For the period of 1994
12 through May 31, 2004, the simulation uses as a base the fixed
13 cost revenue requirements established in IPC-E-94-5. From
14 June 1, 2004 forward, the analysis uses the fixed cost revenue
15 requirements established in IPC-E-03-13, the Company's last
16 general rate case.
17 The simulation was to assume an annual level of
18 efficiency savings of 0.5 percent of the previous year's
19 consumption (roughly equivalent to the level of savings
20 achievable under the Northwest Power & Conservation Council's
21 ("NWPCC") Fifth Power Plan).
22 For the residential and commercial classes, the
23 allowed fixed cost recovery included in the simulation was
24 allowed to increase each year based upon the growth in actual
25 customer count. For the industrial and irrigation classes,

1 the allowed fixed cost recoveries were allowed to increase
2 based upon the forecasted energy sales in the most recent IRP
3 for any given year (i.e., the 2000 IRP for years 2000 and
4 2001, the 2002 IRP for years 2002 and 2003, etc.).
5 For purposes of the simulation, Idaho Power was
6 to continue to absorb the risks or benefits of purely weather-
7 related effects on fixed-cost revenue recovery, as it always
8 has. Actual sales were to be weather-normalized before making
9 the annual true-up calculation. The maximum annual average
10 rate impact of the true-up mechanism for any customer class
11 was to be capped at 2 percent, with any additional amounts
12 carried over to the next year's true-up.
13 Q. What were the results of the simulation that
14 are relevant to this FCA filing?
15 A. The results of the simulation that are relevant
16 to this filing are those for the residential and small
17 commercial classes. Each class would have received both
18 positive and negative adjustments during the 1994 through 2004
19 simulation period. The results demonstrate the two-way nature
20 of this adjustment, similar to the Company's Power Cost
21 Adjustment ("PCA"). In years where customer growth was
22 greater than energy growth, an under-collection of authorized
23 fixed costs occurred, which would have triggered a rate
24 adjustment to collect the lost fixed costs from the customers
25 in the following year. During years when energy growth was

1 greater than customer growth (even with the 0.5 percent DSM
2 energy savings assumption), an over-collection of fixed costs
3 would have been returned to the customers through a rate
4 reduction the following year.
5 Q. What was the largest annual FCA calculated for
6 the simulation?
7 A. The largest adjustment for both the residential
8 and small commercial classes in the simulation was 2 percent
9 because of the constraint capping any one-year rate change.
10 That cap came into play in 4 out of 10 years for the
11 residential class and 4 out of 10 years for small commercial.
12 However, one of those years for the small commercial class
13 represented a 2 percent cap on the reduction in rates. The
14 highest positive adjustments for both classes occurred in 2002
15 and 2003, very possibly reflecting the higher energy costs
16 observed by Idaho Power's customers and a consequent reduction
17 in energy sales.
18 Q. Had a cap not been in place, what would have
19 been the range of percentage changes in FCA rates for the
20 simulation period?
21 A. With no restriction on the amount of change on
22 adjusted rates from year to year, the percent change to
23 residential rates ranged from a reduction of 0.17 percent to
24 an increase of 3.94 percent, with an average increase for the
25 ten years of 1.35 percent. For the small commercial class,

1 the largest decrease in fixed cost adjustments occurred as a
2 result of 2001 customer growth at 0.44 percent with a
3 concurrent increase in normalized energy growth of 6.39
4 percent (including the 0.5 percent DSM assumption). This
5 would have resulted in an over-collection of fixed costs and a
6 3.56 percent reduction in adjusted rates.
7 Without the 2 percent cap in place, the largest
8 increase the small commercial sector would have seen would
9 have occurred following a 7.36 percent reduction in 2002
10 normalized energy sales combined with a 3.34 percent growth in
11 customers. The net result of the FCA would have been a 7.4
12 percent increase in rates. The average percentage change for
13 the ten-year period would have been a 1.27 percent increase in
14 rates.
15 Q. In your opinion, were the assumptions for the
16 level of conservation applied to the historical loads in the
17 simulation reasonable?
18 A. Yes, I believe they were reasonable for the
19 following reasons. The assumptions for the level of
20 conservation on historical loads were used for the simulation
21 period in order to see the effects a fixed cost mechanism
22 would have had if an effective conservation plan had been in
23 place. The workshop consensus to use 0.5 percent each year
24 for the simulation was because it was considered to be roughly
25 equivalent to the level of savings determined to be achievable

1 under the NWPCC's Fifth Power Plan. I believe that it is
2 reasonable to expect future conservation impacts on Idaho
3 Power loads to be consistent with regional expectations of
4 conservation impacts, and therefore it was reasonable to use
5 these estimates in the simulation. Ms. Darlene Nemnich, the
6 Company's Energy Efficiency Leader, has informed me that she
7 also believes the 0.5 percent annual Demand Side Management
8 ("DSM") estimate is reasonable. Ms. Nemnich believes the 0.5
9 percent savings is achievable with the Company's energy
10 efficiency programs that are currently in place, again
11 validating the assumed level used in the simulation. Even
12 assuming the somewhat higher level of savings assumed by Mr.
13 Cavanagh (adding another 0.5 percent per year), the Company
14 views the proposed cap on rate adjustments as reasonable.
15 Q. Is the Company's proposal for an FCA mechanism
16 in this case based upon the same assumptions as contained in
17 the workshop simulation?
18 A. Yes. Essentially, the FCA mechanism proposed
19 is the same as the true-up mechanism suggested by the workshop
20 participants and used in the simulation. There are just a few
21 small variations in the mechanism as proposed in this filing.
22 While the simulation modeled the largest five
23 rate classes, the Company is proposing an FCA mechanism for
24 the residential and small commercial classes, Schedules 1 and
25 7 respectively. Mr. Gale's testimony discusses the reasons

1 the Company has chosen these two classes at this time.

2 In the simulation, any upward or downward

3 movement in rates as a result of a FCA was capped at 2

4 percent. For the proposed FCA mechanism, the Company is

5 proposing a 3 percent cap on the FCA rate adjustment, and only

6 on rate adjustment increases. While most of the rate

7 adjustments in the simulation were less than the cap,

8 averaging 1.35 percent for residential and 1.27 percent for

9 small commercial when no cap was imposed, there were four

10 years out of ten when the 2 percent cap was applied. The

11 effect of the cap is to defer the remainder of the FCA to the

12 following years. With a 3 percent cap, applied at the

13 Commission's discretion, the effects of a deferral carry-over

14 would be minimized. With a 3 percent cap in place,

15 residential rate adjustments would have exceeded the cap in

16 only one of ten years. Small commercial rate adjustments

17 would have hit a 3 percent ceiling in two years. Even by

18 moving the cap to 3 percent, the impact on a customer's

19 average monthly bill would be less than $2.00.

20 Q. Are there any other variations from the

21 methodology used in the simulation?

22 A. Yes. In the simulation, fixed cost recovery

23 adjustments were determined based on an annual deviation. In

24 order to better match cause and effect for accounting

25 purposes, the Company is proposing to book adjustments on a

1 monthly basis. The ultimate balance in the account will be
2 determined annually, but will be booked to Company accounts on
3 a monthly basis. This is similar to PCA accounting practices.
4 Over the course of a year, an FCA balancing
5 account may show both positive and negative monthly amounts,
6 depending on the respective growth rates of customer counts
7 and energy usage. For example, while residential customer
8 counts may grow at a constant rate during the year, the
9 monthly consumption of energy over the course of the same year
10 will not be as constant. Residential customers may use more
11 energy during the winter and summer months and less during the
12 spring and fall. If one were to look at the balance in the
13 FCA deferral account for a month early in the year, it may
14 appear that the Company has over-collected its fixed costs
15 because energy usage had grown faster than customer growth.
16 Yet by year-end, if customer growth continues to grow at a
17 consistent pace, the FCA may result in an under-collection of
18 fixed costs.
19 Q. Please describe the Fixed Cost Adjustment
20 mechanism the Company is proposing in this filing.
21 A. For both the residential and small commercial
22 classes (Schedules 1 and 7), the FCA mechanism would be the
23 same. The formula used to determine the FCA amount would be:
24 FCA = (CUST X FCC) - (NORM X FCE)
25 Where:

FCA = Fixed Cost Adjustment;

CUST = Actual number of customers, by class;

FCC = Fixed Cost per Customer, by class;

NORM = Weather-normalized energy, by class;

FCE = Fixed Cost per Energy, by class.

Q. What values are required to implement the FCA mechanism?

A. As outlined in the above formula, for each class (residential and small commercial), the actual number of customers (CUST), the fixed cost per customer (FCC), weather-normalized energy (NORM), and the Fixed Cost per Energy ("FCE") are required to determine the FCA amount. Two of these variables "CUST and NORM) would be determined monthly based upon actual data as it occurs. The other two variables (FCC and FCE) would be determined as part of this case.

Q. What is the Company's proposed method for determining the FCC and FCE?

A. The Fixed Cost per Customer (FCC) and the Fixed Cost per Energy (FCE) would be established using the data filed during the Company's general rate case filing. In order to determine the FCC and FCE rates, we would establish principal base level values determined in class cost of service and revenue requirement calculations, both of which are established during the Company's general rate case.

Q. How are these principal base level values for

1 the FCA mechanism determined in the current application?

2 A. The principal base level values for the FCA

3 mechanism use 2005 test year numbers, which are found in the

4 data submitted for the IPC-E-05-28 general rate case currently

5 filed. They will most accurately represent the Company's

6 current fixed costs. While the numbers may change for

7 subsequent general rate cases, the methodology would remain

8 the same.

9 The first base level determination necessary

10 for the FCA is a determination of the 2005 test year fixed

11 cost recovery embedded in the energy charges for residential

12 and small commercial customers. For the residential class,

13 $138,388,237 of fixed costs would be recovered from Schedule 1

14 energy charges. For the small commercial class, $8,712,552 of

15 fixed costs would be recovered from Schedule 7 energy charges

16 (Exhibit No. 7).

17 Q. Do these fixed cost amounts for the residential

18 and small commercial classes include more than their actual

19 class cost of service?

20 A. Yes. There is a difference between the class

21 cost of service numbers and the amount of requested revenue

22 requirement. This difference is primarily a result of cross-

23 class subsidies that are currently present in the Company's

24 rate structure.

25 Q. Why is it important to include these fixed cost

1 subsidies for the residential and small commercial classes?

2 A. As I mentioned before, when fixed costs are

3 recovered through a volumetric rate, the effects of any

4 conservation program that reduces energy consumption results

5 in a loss in the recovery of those fixed costs. In the case

6 of both the residential and the small commercial classes, the

7 reduction of energy consumption through conservation measures

8 not only prevents the Company from recovering the fixed costs

9 associated with those classes but, in addition, prevents the

10 fixed cost recovery of the subsidies which are incorporated in

11 their energy rates.

12 Q. How are the other principle base level values

13 for the FCA mechanism determined in the current application?

14 A. The second base level determination necessary

15 for the FCA is a determination of customer counts for the

16 residential customer class and the small commercial class.

17 Based upon Case No. IPC-E-05-28 data, 2005 average customer

18 counts are 359,802 for the residential customer class and

19 30,899 for the small commercial class.

20 With these two principle base level values, the

21 FCC rate can be determined. The annual fixed cost recovery

22 amounts divided by the customer count results in an annual

23 authorized recovery per customer. This amount divided by 12

24 results in the authorized recovery per customer per month, or

25 the monthly FCC rate. For the residential class, the

1 authorized fixed cost recovery per customer per month is
2 $32.05 ($138,388,237 / 359,802 / 12). For the small
3 commercial class, the authorized fixed cost recovery per
4 customer per month is $23.50 ($8,712,552 / 30,899 / 12).
5 The third base level determination necessary
6 for the FCA is a determination of base level residential and
7 small commercial weather-normalized energy consumption for the
8 test year 2005. Based upon Case No. IPC-E-05-28 data, 2005
9 weather-normalized annual energy consumption for the
10 residential customer class is 4,503,865,230 kWh and annual
11 energy consumption for the small commercial class is
12 218,605,825 kWh. The monthly weather-normalized consumption
13 for these two classes (totaling up to their respective annual
14 weather-normalized consumption) would be used in determining
15 the monthly FCE rates.
16 With these additional principle base level
17 values, the FCE rates can be determined. The annual fixed
18 cost recovery amounts divided 12 (for the average monthly
19 fixed cost amount to be recovered) divided by the monthly
20 normalized energy results is an authorized fixed cost recovery
21 per kWh per month, or the monthly FCE rates. The following
22 table provides those monthly rates for each class:

	Residential		Small Commercial	
	Energy	**FCE**	**Energy**	**FCE**
January	521,441,918	$0.022116	22,212,875	$0.032686
February	474,386,901	$0.024310	21,028,201	$0.034527
March	422,463,431	$0.027298	19,175,405	$0.037863
April	364,339,261	$0.031653	16,668,063	$0.043559
May	311,538,986	$0.037017	15,583,867	$0.046590
June	289,411,745	$0.039848	15,550,690	$0.046689
July	325,367,237	$0.035444	17,433,880	$0.041646
August	367,476,844	$0.031383	18,644,764	$0.038941
September	340,623,099	$0.033857	17,865,158	$0.040640
October	299,584,302	$0.038495	16,504,791	$0.043990
November	339,226,389	$0.033996	17,300,035	$0.041968
December	448,005,117	$0.025742	20,638,096	$0.035180
TOTAL	**4,503,865,230**		**218,605,825**	

Q. How would the proposed FCA work for the residential and small commercial classes, going forward?

A. Once these principle base level rates of FCC and FCE are determined, the FCA would work identically for both the residential and small commercial classes. For each class, the actual number of customers per month would be multiplied by the monthly FCC rate. This product would represent the "allowed fixed cost recovery" amount. This amount would be compared with the amount of fixed costs actually recovered by the Company. To determine this "actual

1 fixed costs recovered" amount, the Company would take monthly
2 weather-normalized sales for each class and multiply that by
3 the respective monthly FCE rate. The difference between these
4 two numbers (the "allowed fixed cost recovery" amount minus
5 the "actual fixed costs recovered" amount) would be the FCA
6 for each class.
7 Q. Is this information sufficient in order to make
8 monthly bookings in the deferral account?
9 A. Yes.
10 Q. How would monthly customer counts be
11 determined?
12 A. Each month the Company would determine the
13 number of active service points for the residential and small
14 commercial classes. This count of action service points is
15 the same information that is used in determining customer
16 counts for FERC Form 1 reporting requirements.
17 Q. How would monthly weather-normalized energy be
18 determined?
19 A. In order to determine weather-normalized
20 monthly energy, heating and cooling degree-day information
21 would be gathered from the National Weather Service Forecast
22 Office. These numbers are used in the Company's weather
23 normalization model to determine monthly weather-normalized
24 energy.
25 Q. Can the FCA deferral amount be negative, and if

1 so, what does this mean?

2 A. Yes, it can. The FCA can be either positive or

3 negative. If the adjustment amount were positive, that would

4 mean the Company's authorized fixed cost recovery amount was

5 greater than the fixed costs recovered through the class

6 energy rate. This would stem from the fact that the growth

7 rate in weather-normalized energy was less than the growth

8 rate in customers, i.e., the use per customer had decreased.

9 This would indicate that the Company had under-collected fixed

10 costs and therefore, additional dollars would be collected

11 from the customer in order to make the Company whole. In a

12 similar fashion, if the FCA were negative, that would indicate

13 that the Company had over-collected fixed costs, and would

14 result in a refund of the adjustment amount back to the

15 customer.

16 Q. Would you please describe how the deferral

17 balance would work and when the deferral balance would be

18 collected from or refunded to the customer?

19 A. The deferral balance for the FCA would be

20 accumulated in a regulatory account in similar fashion to the

21 PCA. On a monthly basis, the FCA would be determined and

22 booked to the regulatory account. At year-end, the balance in

23 the account would be the FCA associated with that year. The

24 Company proposes to begin collecting/refunding the deferral

25 balance on June 1 of the following year, concurrent with rate

1 changes associated with the PCA. The adjusted rate would
2 remain in effect for one year, through May 31 of the following
3 year. The Company proposes that the same carrying charge used
4 for PCA purposes would be applied to the deferral balance.
5 Q. What would be the impact on the deferral
6 balance if a 3 percent FCA cap were reached?
7 A. If the 3 percent FCA cap was exceeded, and the
8 Commission chose to implement the cap, then the FCA would not
9 recover the full amount in the deferral account. The balance
10 of the deferral would remain in the account, subject to the
11 carrying charge, and would become part of the deferral balance
12 for the following year.
13 Q. Please describe the possible rate impacts to
14 the average customer's bill.
15 A. From a review of the historical simulation,
16 looking at the possible rate impacts to an average customer's
17 bill, the effects of the FCA would be small. Looking at the
18 period of 1994 through 2004, with the assumptions of the
19 simulation as stated before, the average monthly impact to a
20 residential customer's bill would be $0.64. For an average
21 small commercial customer over the same period, their monthly
22 bill would see an average change of $0.31. I've calculated
23 these averages based upon the information shown for the
24 "Monthly Bill Effect for Average Customer" in Exhibit No. 8.
25 Q. Are you proposing any reporting requirements

1 for the Company to this Commission?

2 A. Yes. I would propose to report to the

3 Commission, on a monthly basis, the status of the balancing

4 account for the FCA. This would be done in the same manner as

5 is currently performed for reporting of the Company's Power

6 Cost Adjustment balance. The timing of the two reports could

7 be concurrent.

8 Q. Are you providing an example of a new tariff

9 for the FCA?

10 A. Yes. I have included Exhibit No. 9 as an

11 example of an FCA tariff. This Exhibit is for discussion

12 purposes only. An actual tariff would not be filed with the

13 Commission until June 2007.

14 Q. Does this conclude your testimony?

15 A. Yes, it does.

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IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-04-15

IDAHO POWER COMPANY

EXHIBIT NO. 5

MICHAEL J. YOUNGBLOOD

Decoupling for Idaho Power Company
(Eric Hurst Study)

DECOUPLING FOR IDAHO POWER COMPANY

Eric Hirst
Consulting in Electric-Industry Restructuring
Bellingham, Washington

March 30, 2004

Prepared for
Idaho Power Company
Boise, Idaho
Mike Youngblood, Project Manager

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1. INTRODUCTION

Decoupling severs the link between a utility's kWh sales and its recovery of revenues to cover fixed costs. Advocates of energy-efficiency programs favor decoupling because current ratemaking practices collect substantial revenues for fixed costs through a utility's energy charge ($/MWh). As a consequence, utility programs that improve customer energy efficiency create tension between the interests of customers (whose bills go down) and shareholders (whose earnings decline).

Although decoupling may be motivated by the desire to expand electric-utility energy-efficiency programs, its effects are broader. That is, decoupling will affect customer bills and rates, as well as utility revenues, even if no utility DSM programs are implemented.

During the early 1990s, various forms of decoupling were deployed in Maine, New York, California, and Washington. During the mid-1990s, these efforts were largely abandoned as utilities and state regulators anticipated a restructured, competitive electricity industry, although Oregon began decoupling in the late 1990s. Recently, California reinstituted decoupling. Appendix A provides details on the states' experiences with decoupling. Readers interested in additional background on decoupling should see the references by Carter;[*] Eto, Stoft and Belden;[#] Hirst;[§] Moskovitz, Harrington and Austin;[†] and Nadel, Reid and Wolcott.[**]

Decoupling involves two major steps. The first is the policy decision to break the link between sales and revenues. The second, analytically more difficult, step is to *recouple* utility revenues (more precisely, revenues to cover fixed costs) to something other than actual kWh sales. Decoupling also involves other issues, such as:

- whether to decouple for all or only some rate classes,
- whether to recouple on a class-specific or system-wide basis,
- whether to apply the decoupling-induced rate adjustments to energy charges only or to both energy and demand charges, and

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[*] S. Carter, "Breaking the Consumption Habit: Ratemaking for Efficient Resource Decisions," *The Electricity Journal* **14**(10), 66-74, December 2001.

[#] J. Eto, S. Stoft and T. Belden, *The Theory and Practice of Decoupling*, LBL-34555, Lawrence Berkeley Laboratory, Berkeley, CA, January 1994.

[§] E. Hirst, *Statistical Recoupling: A New Way to Break the Link Between Electric-Utility Sales and Revenues*, ORNL/CON-372, Oak Ridge National Laboratory, Oak Ridge, TN, September 1993.

[†] D. Moskovitz, C. Harrington and T. Austin, "Weighing Decoupling vs Lost Revenues: Regulatory Considerations," *The Electricity Journal* **5**(9), 58-63, November 1992.

[**] S. N. Nadel, M. W. Reid and D. R. Wolcott (editors), *Regulatory Incentives for Demand-Side Management*, American Council for an Energy-Efficient Economy, Washington, DC, 1992.

- the frequency with which rates are adjusted for decoupling.

The next section describes the current (2003) situation that Idaho Power Company (IPC) faces with respect to recovery of its fixed costs. Section 3 focuses on class-specific rate structures and how they affect recovery of fixed costs. Section 4 briefly reviews alternative ways to recouple utility revenues to something other than energy sales. Section 5 explains the analytical method developed to examine alternative recoupling mechanisms for IPC, with additional details in Appendix B. Section 6 presents model results. And the final section summarizes the results, findings, conclusions, and recommendations from this study.

2. CURRENT SITUATION

This paper focuses on (and deals only with) the following rate classes: Residential (Schedule 1), Small General (7), Large General (9), Large Power (19), and Irrigation (24). Together, these five classes account for 99% of IPC's 2003 proposed revenue requirement.

Based on information from the current IPC rate case, 56% of the 2003 cost-of-service revenue requirement covers fixed costs ($303 million of the $541 million total), with the remaining 44% for variable energy costs ($237 million for fuel, purchased power, and variable operations and maintenance at generating stations).* As shown in Fig. 1, the fixed-cost (FC) component is greatest for Schedule 7 (70%) and smallest for Schedule 19 (36%); this difference is probably a consequence primarily of differences in load factors among classes. This suggests that the net-revenue-loss problem associated with utility energy-efficiency programs might be greatest for the Small General class of customers.

Figure 1 also shows fixed costs as a share of proposed revenue requirements. Because of the large proposed cost shift from the irrigation class to the other classes (25% of the irrigation cost of service), the share of revenue requirement from fixed costs is much greater for this class than the share

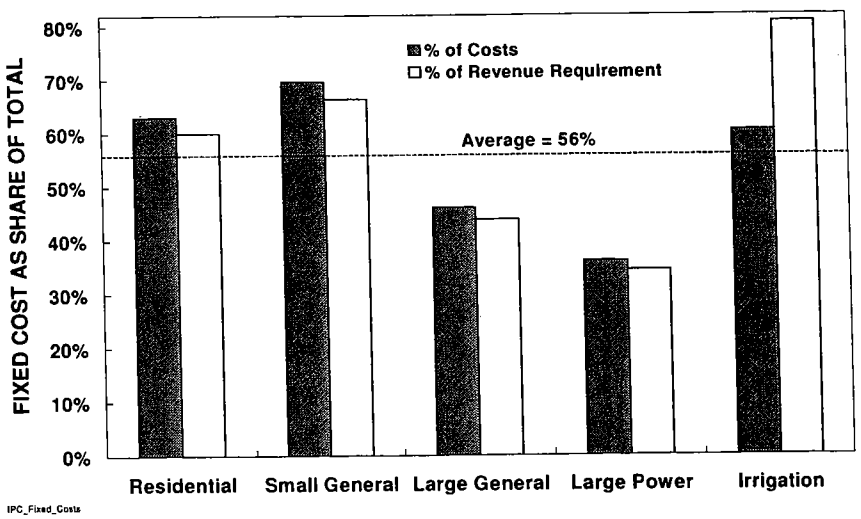

Fig. 1. Percentage of 2003 costs and proposed revenue requirement from fixed costs, by rate class.

*I assume that the only variable costs IPC experiences are for energy production.

of total costs.* The effects of the shift from cost of service to revenue requirements is much smaller (about 5%) for the other four classes. The remainder of this paper uses proposed revenue requirements as the basis for calculating and adjusting fixed costs.

Table 1 provides key statistics, based on the 2003 rate case, for each customer class. The Residential class accounts for just over half of the company's total fixed costs. Normalizing the fixed costs for each class by the number of customers in each class shows substantial differences, ranging from $420/customer for Small General to $206,000 for Large Power. The difference between the proposed energy charge and variable energy cost is greatest for Small General ($40/MWh) and smallest for Large Power ($3/MWh), with an average of $16/MWh.

Table 1. Fixed- and variable-cost characteristics of IPC rate classes[a]

	Rate Class					
	1	7	9	19	24	Total
Fixed costs, million $	153.1	13.5	54.3	21.6	60.8	303.4
Fixed costs as percentage of total cost	63.0	69.7	46.1	36.1	60.4	56.1
Fixed costs as percentage of revenue requirement	60.0	66.4	43.9	34.4	80.7	56.5
Fixed costs/customer, $	457	420	3,186	206,278	4,253	756
Variable cost, $/MWh	21.7	22.1	21.1	19.3	24.6	21.5
Energy charge, $/MWh	51.9	62.0	26.2	22.1	35.3	37.3

[a]The 2003 cost of service for class 24 is $100.7 million, but the proposed revenue requirement is only $75.4 million, a 25% reduction.

3. COLLECTION OF FIXED COSTS THROUGH VARIABLE RATES

The relative importance of decoupling for different rate classes depends on the relationship between fixed and variable costs (Fig. 1) and the rate design for that class (discussed here). Rates for classes 1 and 7 include per-customer and energy charges, while those for the other classes also include several demand charges.#

*The assumption that all of the class 24 fixed costs are to be recovered from the proposed rates implies that the energy charge for this class is much too low. Thus, the substantial subsidy of class 24 costs make the results presented here suspect for that class.

#To keep this discussion from becoming too complicated and to focus on the issues rather than the details, the Schedule 9 and 19 subclasses (Secondary, Primary, and Transmission) are combined into one average class. Similarly, the demand charges are aggregated for each class into one average charge.

For schedule 1, 74% of the class-specific fixed costs are collected through the energy charge (top of Fig. 2), amounting to $113 million for 2003 (bottom of Fig. 2). For Schedule 7, the percentage of fixed costs collected by the energy charge is almost as high (71%), but IPC's exposure is much lower ($10 vs $113 million) because Schedule 7 accounts for less than 10% of the revenues of Schedule 1.

Interpreting the rate schedules for the other three classes is more complicated because of their demand charges. Should these demand charges be considered variable or fixed? That is, do they vary with energy (volumetrically) or are they fixed? The answer is probably class and charge specific and likely falls part way between 100% variable and 100% fixed.* For example, the peak demand for Schedule 9 customers may have a large weather-sensitive component, in which case summer demand (MW) and summer energy consumption (MWh) are likely to be highly correlated. On the other hand, demand for Schedule 19 customers might be dominated by industrial processes, which are independent of weather. If these processes are either on or off, demand will be largely independent of energy sales. This issue is complicated by the fact that the proposed rate schedules include on- and off-peak demand charges as well as basic (12-month average) demand charges.

To some extent, the treatment of demand charges is an empirical issue. We could analyze historical data by rate class to determine how tightly coupled (i.e., correlated) energy sales and demand are. To some extent, this is a policy issue: deciding whether to adjust rates for decoupling through energy charges only or through energy and demand charges.

If the revenues collected through demand charges are largely independent of energy sales, then energy-efficiency programs aimed at Schedules 1, 7, and 24 have much greater effects on FC recovery per kWh of energy saved than do such programs aimed at Schedules 9 and 19 (top of Fig. 2). Weighting each class by its contribution to total revenue shows the importance of IPC's exposure to FC losses from each class. Clearly, the Residential class ($113 million, bottom of Fig. 2) is the most important, and Large Power ($3 million) is the least important. Overall, 58% ($177 million) of IPC's FC revenues are collected through energy charges, and an additional 25% ($76 million) is collected through demand charges.

On the other hand, if the revenues from demand charges are proportional to those from energy charges, all five customer classes create exposures of 70% or more. Indeed, in this case, more than 90% of fixed costs are collected through variable charges for Schedules 9, 19, and 24. Overall, $252 million of fixed costs are collected through energy and demand charges, accounting for 47% of IPC revenues.

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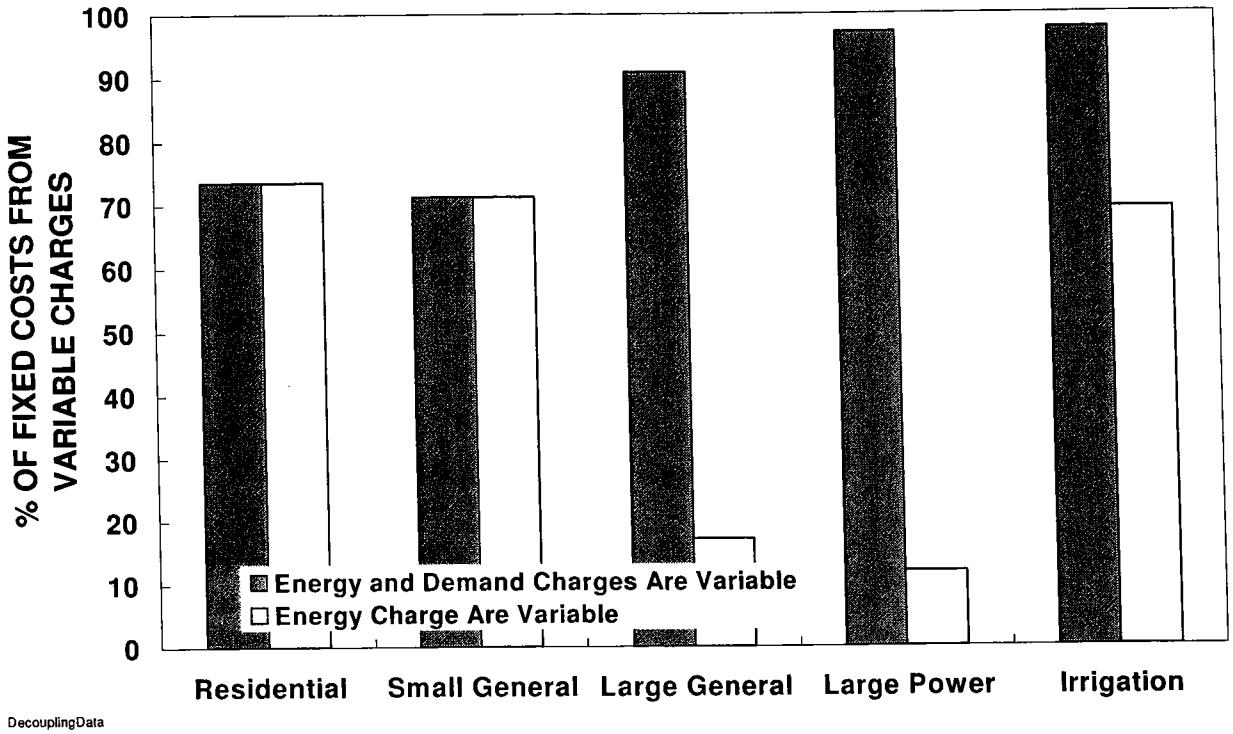
*In the long run (say, 10 to 20 years), all costs are variable.



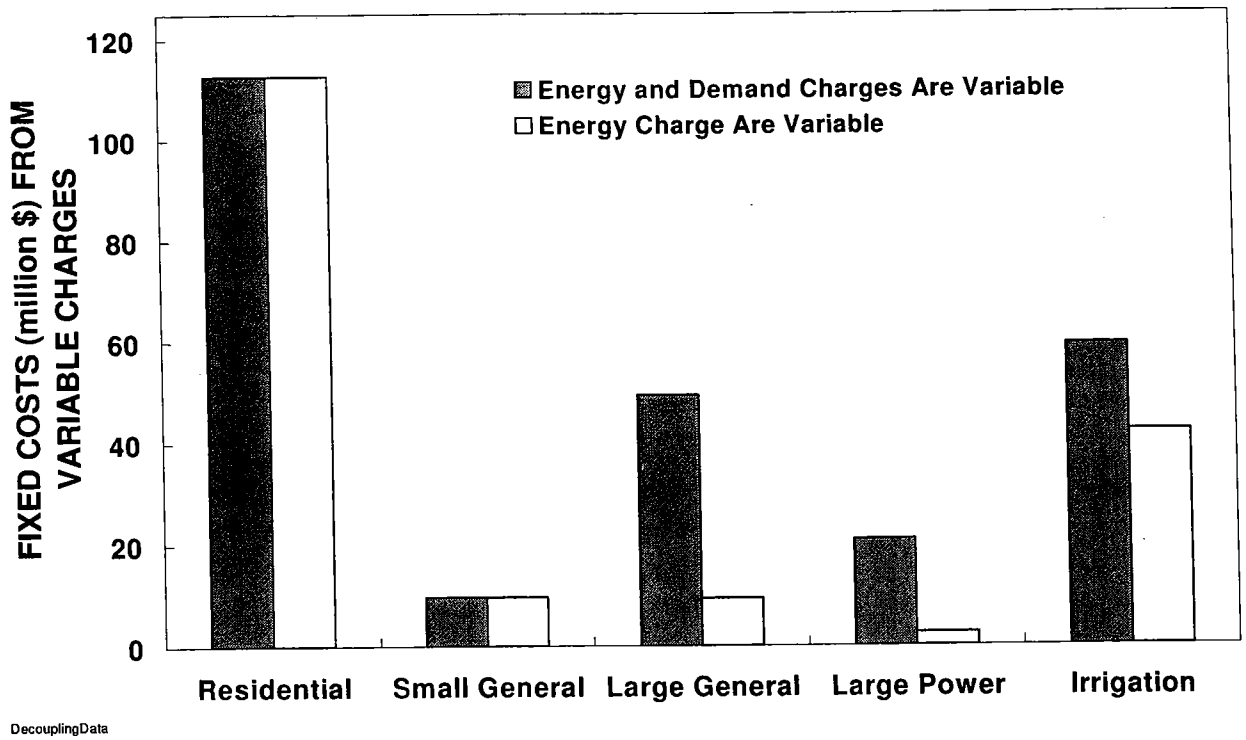


Fig. 2. **Collection of fixed costs through variable charges (energy plus demand or energy only) by rate class. The top chart shows the percentage of fixed costs collected through variable charges, and the bottom chart shows the year 2003 dollar amounts collected through variable charges.**

Figure 3 presents this information in yet another way. This figure shows the net revenue loss (the loss in FC recovery) to IPC per MWh of energy reduction.* Again, results are shown for two cases: demand changes are proportional to energy changes, and demand changes are independent of energy changes. On a per MWh basis, the company is most exposed to energy-efficiency programs aimed at the Residential and Small General classes, with losses of $27 and $36 per MWh. At the other end of the spectrum, if demand-related revenues are independent of energy sales, the losses for the Large General and Large Power classes are only $3 and $1 per MWh. Averaged over all five classes, the company would lose $16 for every MWh reduction in sales.

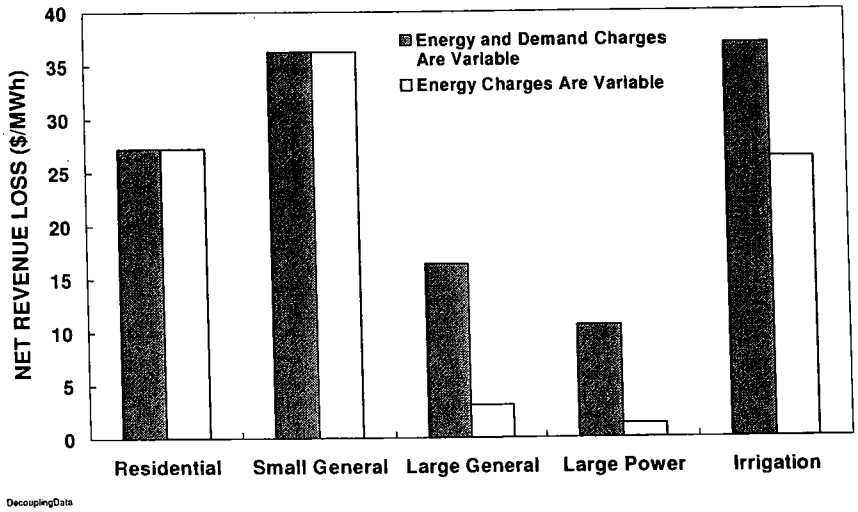


Fig. 3. Loss of fixed-cost revenues per MWh of sales reduction by rate class.

These results suggest that, if IPC decides not to implement decoupling for all rate classes, it might focus initially on schedules 1 and 7. Because the residential class accounts for more than half of IPC's fixed costs and residential customers pay for much of their fixed costs through the energy charge, IPC's earnings losses are quite high, both in absolute terms and on a per MWh basis. Although Schedule 7 accounts for only 4% of IPC's fixed costs, its energy charge of $62/MWh is the highest of all rate schedules.

4. POSSIBLE RECOUPLING MECHANISMS

Decoupling mechanisms, of necessity, recouple utility revenues to something other than sales. Possible recoupling mechanisms include explicit attrition adjustments intended to track the determinants of fixed costs (e.g., the cost of capital), the number of utility customers (which seems most applicable to distribution costs), inflation (perhaps with a productivity offset), the determinants of electricity sales, or some other mechanism. A key policy issue here is whether recoupling should focus on tracking fixed costs (which seems the most reasonable but could

*The numbers shown in Fig. 3 are based on the proposed rate structures, while those in Table 1 are based on actual costs. The only substantial discrepancy occurs for Irrigation customers; Figure 3 shows a net revenue loss of $26.3/MWh while Table 1 shows only $10.7/MWh.

be quite complicated[*]) or on some proxy for sales (consistent with the traditional treatment of fixed costs). A third option is to agree upfront on the level of allowed fixed costs for a few years and to then have frequent rate cases. The Oregon PUC chose this approach in the mid-1990s for decoupling mechanisms implemented by PacifiCorp and PGE, with rate cases to be held every two years.

Two statistical analyses of data from several utilities showed little connection between changes in a utility's fixed costs and its electricity sales:[#]

- In the long-run the relationship between [fixed] cost and customer growth is stronger or no worse than the corresponding relationship between costs and sales.
- The short-term analysis of year-to-year changes in sales vs. base costs shows no statistically significant relationship. Yet, ... the assumed existence of a strong correlation between these two factors is the foundation of traditional sales-based regulation.

Similarly, Eto, Stoft, and Belden wrote, "Relying on 25 years of aggregate financial statistics from 160 investor-owned utilities, we find that one-year changes in load or numbers of customers are both poorly-correlated with changes in nonfuel costs. Hence, the proponents of RPC [revenue per customer decoupling] are correct in arguing that RPC does no worse than traditional ratemaking in tracking nonfuel costs (indeed, we find it does slightly better)."[§]

These analyses show that decoupling replaces one set of factors unrelated to the determinants of fixed costs with another set of factors unrelated to those costs. Decoupling, on average, should have no positive or adverse effect on a utility's opportunity to recover its fixed costs. On a year to year basis, decoupling might (or might not) stabilize FC recovery.

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[*]C. Marnay and G. A. Comnes, "California's ERAM Experience," Chapter 3 in *Regulatory Incentives for Demand-Side Management*, edited by S. M. Nadel, M. W. Reid, and D. R. Wolcott, 39-62, American Council for an Energy-Efficient Economy, Washington, DC, 1992.

[#]D. Moskovitz and G. B. Swofford, "Revenue-per-Customer Decoupling," Chapter 4 in *Regulatory Incentives for Demand-Side Management*, edited by S. M. Nadel, M. W. Reid, and D. R. Wolcott, 63-77, American Council for an Energy-Efficient Economy, Washington, DC, 1992.

[§]J. Eto, S. Stoft, and T. Belden, *The Theory and Practice of Decoupling*, LBL-34555, Lawrence Berkeley Laboratory, Berkeley, CA, January 1994.

5. ANALYSIS OF RECOUPLING MECHANISMS FOR IPC

I developed an Excel workbook to quantify the effects of different recoupling mechanisms on customer electricity bills and rates and on IPC revenues. The workbook calculates the interactions between a particular recoupling mechanism and alternative forecasts of the number of customers, peak demand, and energy sales. These analyses use data for 2003 from the IPC rate case to simulate results for 2004, 2005, and 2006 (Fig. 4).

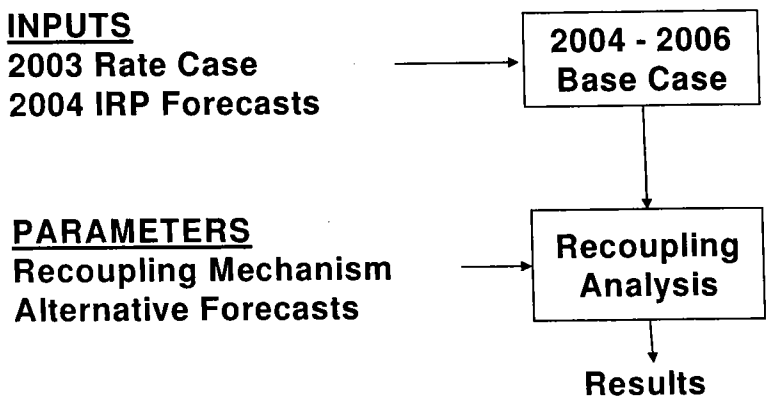


Fig. 4. Diagram of recoupling model.

The workbook is set up to test three forms of recoupling:*

- Revenue-per customer (RPC) decoupling, in which the amount of allowed FC recovery is based on the number of customers each year. This method can be implemented on a class-specific basis or on an aggregate basis (across the five rate classes) each year.

- Inflation, in which the amount of allowed FC recovery is increased each year according to the overall inflation index based on Gross Domestic Product (GDP).

- Forecast growth, in which the amount of allowed FC recovery is predetermined on the basis of the IRP forecasts of number of customers, electricity sales, and peak demand for each year. Combined with the rate structures proposed in the 2003 rate case, these forecast values determine the amount of FC revenues expected to be collected each year.

Table 2 shows the forecasts prepared for the company's 2004 IRP used to simulate these three recoupling mechanisms. Over the 4-year period from 2003 to 2006, growth is highest for forecast revenue (7.3%) and lowest for inflation (6.1%). Because of the relative magnitudes of these forecasts, decoupling on the basis of forecast load growth will yield more revenue to cover IPC's fixed costs than would RPC decoupling, which, in turn, would yield more revenue than would use of the GDP inflation factor.

*Other forms of recoupling might be feasible, but have not yet been incorporated into the workbook or tested.

Table 2. Year-to-year growth for three IPC recoupling mechanisms

	Revenue per customer	GDP inflation	Forecast revenue
2004	1.024	1.020	1.027
2005	1.023	1.020	1.023
2006	1.023	1.021	1.021
2004 to 2006	1.071	1.061	1.073

The workbook considers two forms of recoupling: (1) all five rate classes face the same changes in energy and demand charges because of decoupling, or (2) recoupling is done on a class-specific basis. In the latter case, some classes could face rate increases at the same time other classes face rate decreases. Although this might be hard to explain to the public, class-specific decoupling might be more equitable because it considers separately the contribution from each class to FC recovery.

Finally, the workbook adjusts rates in one of two ways: (1) energy and demand charges or (2) energy charges only. This distinction is irrelevant for classes 1 and 7 (Residential and Small General) because these two classes do not face demand charges. Customers in the three other rate classes with high load factors would prefer a mechanism that adjusted both energy and demand charges, while customers with low load factors would favor adjustments to only the energy charge.

Appendix B contains additional detail on this workbook. The workbook contains many assumptions necessary to conduct the calculations and to focus on the essentials rather than the details. The key assumptions include:

- All year-to-year changes in variable energy costs are recovered through the Power Cost Adjustment (PCA) clause.
- None of the transmission and distribution costs are variable; all of these costs are fixed.
- The schedule 9 and 19 subclasses (Secondary, Primary, and Transmission) can be combined into single classes to simplify the present analyses.
- The various demand components (basic, summer, and nonsummer) can similarly be combined into one demand component (and charge) for each relevant schedule (9, 19, and 24).
- The basic demand component varies from year to year with the IRP forecasts of average peak monthly demand (average of the 12 monthly peaks) each year.

- The summer and nonsummer demand components vary from year to year with the IRP forecasts of maximum monthly demand (maximum of the 12 monthly peaks) each year.

- Only five rate classes are considered here (1, 7, 9, 19, and 24); the other classes (which, together, account for only 1% of IPC's revenues) are ignored.

- The decoupling rate adjustments occur without any lag (i.e., in the same year the costs change). That is, this analysis ignores the complications of balancing accounts and after-the-fact trueups that would affect rates in subsequent years.

- The decoupling mechanisms considered here are all weather-normalized. That is, they—unlike current ratemaking—compensate the company for its fixed costs on the basis of normal weather conditions.*

6. IPC DECOUPLING-MODEL RESULTS

BASE CASE

The base case is defined as the situation forecast for the 2004 IRP in terms of annual growth in the number of customers, peak demand, and energy use for each customer class. The effects on customers and on IPC's FC recovery is exactly as expected, based on the three-year growth in the three recoupling mechanisms.

With forecast recoupling, there are no adjustments (by definition); i.e., actual growth in customers, energy, and demand match expected growth in these factors. Company losses (and customer bill reductions) are greater with inflation recoupling than with RPC recoupling, Table 3 and Fig. 5 show the effects of these two decoupling mechanisms on each rate class when decoupling is implemented on a class-specific basis and when it is implemented in aggregate (last column in Table 3). The results show both percentage and absolute changes in customer bills (and IPC FC revenues), demand charges, and energy charges. (Because classes

*Similarly, customer payments for fixed costs are weather normalized. For example, if the weather one year is extreme, the company will collect (and consumers will pay) less money for transmission and distribution with decoupling than it (they) would under traditional ratemaking. Adding a weather-adjustment component to a recoupling mechanism is feasible but complicates the calculations. Doing so would require use of the IPC computer models that weather adjust sales for each customer class and development of assumptions on "actual" weather (heating and cooling degree days) in future years.

1 and 7 do not have demand charges, these numbers are always zero.)* Annualized changes are one-third the 3-year totals presented here.

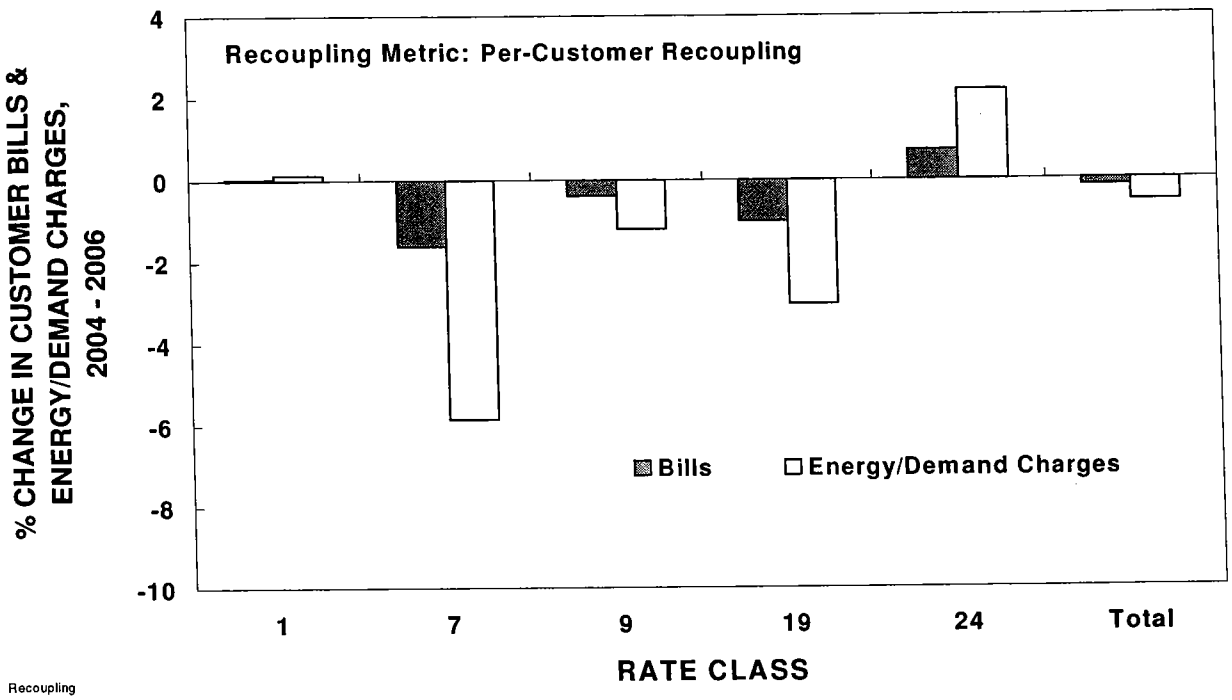
Table 3. Base-case results (3-year changes in electric bills and rates relative to case with no decoupling) for RPC and inflation recoupling, 2004 to 2006[a]

	Rate Class						Aggre-gate[b]
	1	7	9	19	24	Total[b]	
Revenue-per-customer recoupling							
% Electric Bill	0.04	-1.60	-0.38	-1.01	0.72	-0.16	-0.05
$ Electric Bill (thousand $)	320	-1058	-1539	-2009	1593	-2694	-801
% E/D Charges	0.14	-5.85	-1.20	-3.04	2.18	-0.53	-0.16
Energy Charge (¢/kWh)	0.01	-0.36	-0.03	-0.07	0.08	-0.02	-0.01
Demand Charge ($/kW-month)	0.00	0.00	-0.02	-0.07	0.05	-0.01	0
Inflation recoupling							
% Electric Bill	-0.37	-2.39	-0.91	-0.64	0.82	-0.45	-0.45
$ Electric Bill (thousand $)	-2999	-1578	-3637	-1280	1813	-7681	-7,681
% E/D Charges	-1.33	-8.72	-2.81	-1.93	2.48	-1.51	-1.51
Energy Charge (¢/kWh)	-0.07	-0.54	-0.07	-0.04	0.09	-0.06	-0.06
Demand Charge ($/kW-month)	0.00	0.00	-0.05	-0.04	0.06	-0.03	-0.03

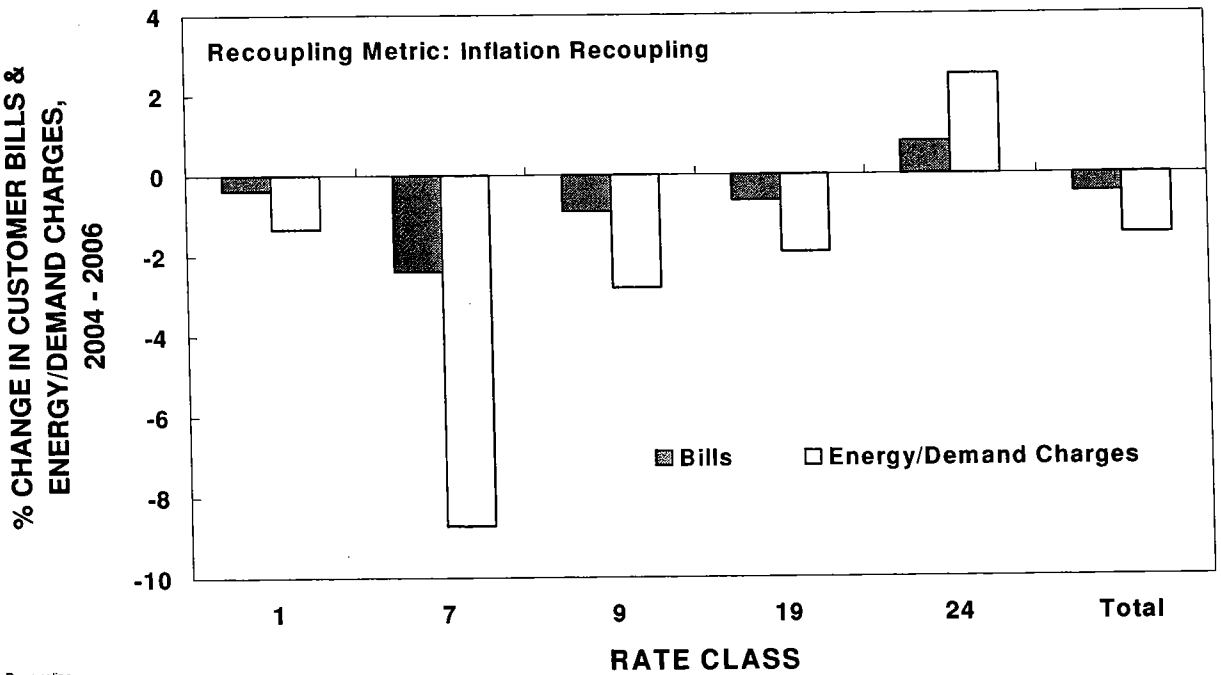
[a]Results for forecast recoupling are not shown because it *is* the base case.

[b]These percentage and dollar changes are the same as those IPC would experience in its recovery of fixed costs.

*All the results shown in this section apply the same percentage change to energy and demand charges. It would be possible (and the Recoupling model is set up) to adjust energy charges only. It is not possible to adjust demand charges only because classes 1 and 7 pay no demand charges.



Recoupling



Recoupling

Fig. 5. **Three-year effects of two recoupling mechanisms on customer bills and energy/demand charges by rate class. With RPC decoupling, IPC collects $2.7 million less than it would with no decoupling mechanism. With Inflation decoupling, IPC collects $7.7 million less over this 3-year period. Under these base-case conditions, the forecast load growth recoupling mechanism yields no changes in customer bills or rates.**

The effects are much greater for inflation decoupling than for RPC decoupling because the assumed growth in inflation is lower than the assumed growth in the number of customers (6.1 v 7.1% over the 3-year analysis period). With class-specific recoupling, customer bills (and IPC FC recovery) are cut by $2.7 million with RPC decoupling and by $7.7 million with inflation decoupling, compared with the base-case recovery of fixed costs (absent any decoupling mechanism) of $946 million over the 3-year period. These reductions represent 0.05 and 0.45% of total customer bills for this 3-year period.

The effects of the two mechanisms under base-case conditions are greatest for Class 7 but result in bill and rate *increases* for class 24.* The percentage changes in the energy and demand charges are greater than those in overall bills because customer bills increase under base-case conditions and because the customer charge is unaffected by decoupling.

Although there are substantial differences in the results between the two recoupling mechanisms, among rate classes when implemented on a class-specific basis, and between the total and aggregate results for RPC decoupling, these effects are all small. For example, the 3-year effect on customer bills is well under 1 percent. The effects on rates, although larger in percentage terms, are also small.

I next tested each of the three recoupling mechanisms against different growth rates for customers, demand, and energy. The results of these analyses are discussed below, separately for each of the three recoupling mechanisms.

REVENUE PER CUSTOMER RECOUPLING

Because this recoupling mechanism is based on one component of customer bills (the monthly customer charge), the results differ according to differences in growth rates among the three billing components (customers, demand, and energy).

As noted above, the base case results when all classes are treated the same (aggregate) are quite different than when the classes are treated separately. The effects are much larger for the class-specific recoupling, presumably because of the large differences among classes in the fixed-cost-per-customer amounts, ranging from $420 for class 7 to $206,000 for class 19, and because the results for class 24 (and sometimes for class 1) are of the opposite sign than those of the other classes and the aggregate.

Appendix Table A-3 shows results for cases in which one or more of the billing determinants is increased by 1%/year for all three years, six cases in all. In addition, the table shows these results relative to the base-case results, the focus of this discussion.

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*As noted earlier, the results for Schedule 24 are suspect.

The results, for both customers and IPC, are symmetrical about the base case. That is, increasing, say, energy use by 1%/year over its base-case values has exactly the same effects but with the opposite sign of *de*creasing energy use by 1%/year relative to the base case. This symmetry applies to the two other recoupling mechanisms also.

Increasing (or decreasing) the growth rates for all three billing determinants by the same amount has the same effects on FC recovery as does the base case. If growth in the number of customers is higher (lower) by 1%/year than in the base case, FC revenues are higher (lower) by 0.5%, independent of whether decoupling is class specific or aggregate. Customer bills increase most for class 19 (0.8%) and least for class 9 (0.3%) with the class-specific application of this recoupling mechanism.

Increasing demand and/or energy growth, while leaving customer growth unchanged, lowers FC revenues. The results are much more sensitive to changes in energy use than to changes in peak demand, probably because classes 1 and 7 have no demand charges.

The effects of changes in any of these three factors are additive. For example, the effects of increasing peak demands by 1%/year plus the effects of increasing electricity use by 1%/year are the same as the effects of increasing both demand and energy by 1%/year.

INFLATION RECOUPLING

Inflation recoupling is completely independent of the three billing determinants. As with RPC, the effects of changes in customer, demand, and energy growth are symmetrical around the base case. That is, increasing growth in the number of customers, peak demand, or energy use have the same effects, but with the opposite sign, as do decreasing growth in these three factors.

Unlike RPC, the effects of inflation recoupling are the same regardless of whether it is implemented in aggregate or on a customer-specific basis. Also unlike RPC, the effects on each customer class are similar. Specifically, none of the six cases analyzed shows a difference in the direction of effect across customer classes. For example, increasing all three growth rates by 1%/year leads to a reduction in customer bills that ranges from −0.3% for class 9 to −0.8% for class 19, with an average of −0.6%.

Table A-4 shows results for the same set of cases discussed above for RPC, in which one or more of the billing determinants is increased by 1%/year for all three years. Changes in energy growth rates have a much larger effect than do changes in demand, which, in turn, have a larger effect than do changes in the number of customers. The effects of changes in the three factors are additive.

FORECAST-LOAD-GROWTH RECOUPLING

Forecast recoupling depends on changes in all three billing determinants. Comparing the right-hand sides of Tables A-4 and A-5 shows that the effects of forecast recoupling, relative to the base case, are identical to those for inflation recoupling.

As with the other two mechanisms, the results are symmetrical around the base case. Similarly, the effects are additive across all three billing determinants.

EFFECTS OF DSM PROGRAMS

When the only change from base-case conditions is slower growth in energy sales (and perhaps peak demand), the company's collection of FC revenues increases (as intended) by the same amount regardless of the recoupling mechanism in place. If demand growth is unaffected by the assumed IPC DSM program (i.e., its only effects are on energy sales), the decoupling adjustment is smaller (as expected, because revenue collection through demand charges is unaffected). Table 4 shows the effects on IPC FC recovery for DSM programs that cut energy and demand by 1%/year (i.e., 1% in 2004, 2% in 2005, and 3% in 2006) and programs that cut energy use only.* The effects of even such a large and effective DSM program on IPC revenues are very small, less than 1% of base revenues over this 3-year period. In these cases, decoupling works exactly as intended to ensure the company suffers no loss in FC revenue because of reductions in energy use or peak demand.

Table 4. Increase in IPC fixed-cost recovery (relative to base case) associated with reductions of 1% per year in energy use or energy use and demand

Reductions in	Increase in IPC fixed-cost recovery, 2004–2006	
	million $	Percentage[a]
Energy only	11	0.7
Energy and demand	16	0.9

[a]IPC fixed-cost revenue for the 3-year period 2004–2006 in the base case is $946 million.

The reductions in energy sales and demand described above, relative to the base case, lead to a 0.9% increase in customer electricity bills and a 3% increase in energy and demand charges over this 3-year period. As shown in Fig. 6, the percentage rate increases are highest for classes 7 and 24 and lowest for classes 9 and 19.

*The same results would obtain for such reductions in energy and demand regardless of the motivation for the energy and demand cuts.

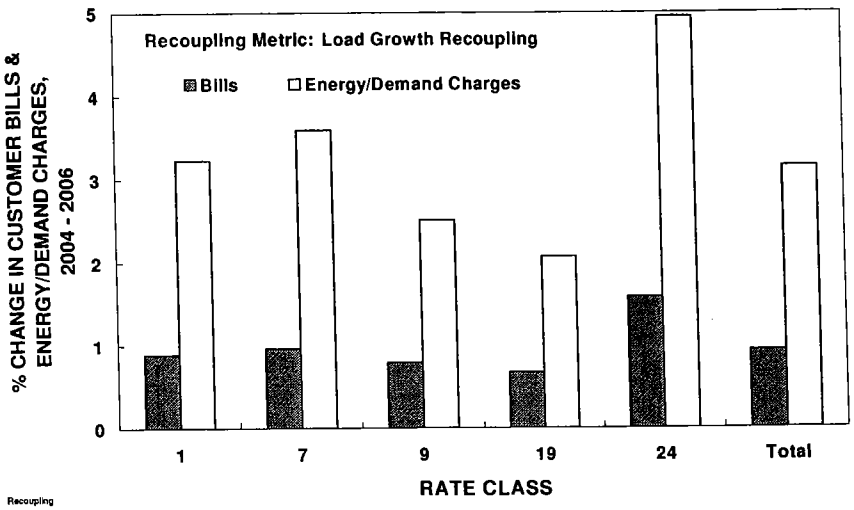

Fig. 6. **Effects of 1% per year reductions in energy use and peak demands for three years on electricity bills and rates, relative to the base case.**

7. CONCLUSIONS

Current electric-utility ratemaking, as practiced in most jurisdictions throughout the United States, collects substantial revenues to recover fixed costs from variable energy charges. This practice makes little economic sense. Specifically, a utility's ability to recover its prudently incurred fixed costs depends on factors that are (a) unrelated to those costs and (b) largely outside its control, including economic and population growth in its service area, which, in turn, affect energy sales.

This long-standing quirk in ratemaking unintentionally, but unavoidably, penalizes utilities that encourage their customers to use electricity more efficiently. Thus, utilities face a clear disincentive to help their customers improve energy efficiency.

Decoupling is a mechanism that breaks the link between electricity sales and utility revenues. To implement decoupling, utility revenues need to be recoupled to some other factor(s). This recoupling is necessary to ensure that the utility has an opportunity to recover its fixed costs. However, many of the factors considered for recoupling—such as the number of customers, inflation, or forecast revenues—may have no more logical connection to fixed costs than does kWh sales.

Although decoupling is intended to remove the penalties in existing ratemaking for utility DSM programs, its effects can be much broader. That is, depending on the recoupling

method chosen, utility revenues (and, therefore, customer rates and bills) can vary from year to year independent of a utility's DSM programs.*

Decoupling is a zero-sum effort. If the company is paid more money to cover its fixed costs (good for IPC), consumers will, unavoidably, pay more for transmission and distribution services (bad for consumers). The reverse is also true.

The amount of the decoupling adjustment each year depends on how far from actual conditions the recoupling mechanism is. For example, if recoupling is tied to inflation and the actual growth in billing determinants differs substantially from inflation for that year, the decoupling adjustment will be large. If the year-to-year changes in the number of customers, peak demand, and energy sales yield changes in non-PCA revenues very different from the inflation rate, the decoupling adjustment will be much larger than if the inflation rate and actual revenues move together. Thus, decoupling does not necessarily stabilize FC recovery nor does it make such recovery more predictable than traditional ratemaking.

Preparation of this paper was motivated by the advocacy of decoupling by the Natural Resources Defense Council and the Northwest Energy Coalition.# Cavanagh proposes that the Idaho PUC allow the company and other interested parties three to six months to develop "design recommendations for the Commission's consideration." These recommendations are to consider the recoupling mechanism, separate v combined treatment of rate classes, weather-normalization of the recoupling mechanism, and the frequency with which true-ups are to occur. Cavanagh suggests there is ample "analysis and experience" to support a workable mechanism.

I agree with Cavanagh that such a mechanism can be developed. Indeed, this paper examined three such alternatives. The larger questions, in my view, are:

- Does decoupling make sense to IPC at this time? IPC's DSM programs currently operate at a very modest level, yielding only small effects on energy use. The 2004 IRP might propose additional, stronger programs. But those programs are likely to focus on reductions in summer peak demand more than on year-round energy efficiency. As such, the new programs may have little effect on IPC's kilowatt-hour sales.

- What unintended effects might decoupling have? Although decoupling would completely sever the link between energy sales and utility revenues, it can and will affect utility revenues for other reasons. In particular, the combination of a recoupling

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*Indeed, regulators in Maine and Washington abandoned decoupling in the mid-1990s largely for reasons independent of the utilities' energy-efficiency programs. Decoupling in both states led to large rate increases because of a slowdown in the economy (Maine) or high power costs (Washington).

#R. Cavanagh, *Direct Testimony of Ralph Cavanagh*, Case No. IPC-E-033-13, before the Idaho Public Utilities Commission, February 20, 2004.

mechanism and large changes in the factors affecting that mechanism could yield nontrivial year-to-year changes in IPC revenues and, therefore, in customer bills and rates.

Given the uncertain answers to these two questions, I recommend that IPC maintain an open mind about decoupling. Specifically, I suggest the company accept Cavanagh's suggestion and form a decoupling collaborative to work on these issues at the conclusion of the current rate case. Hopefully, this paper will serve as useful background for that collaborative.

There is no way to know what IPC's actual fixed costs and FC recovery would be in the future. They might be higher (or lower), more (or less) predictable, and more (or less) stable than without decoupling. Absent detailed information on expected fixed costs and the determinants of these costs, function by function, the potential benefits of decoupling with respect to revenue predictability and stability remain unknown.

From a theoretical perspective, the recoupling mechanism should be tied to factors that directly affect a utility fixed costs. Such factors are surely function specific, with different factors affecting fixed costs for generation, transmission, and distribution. Developing such a mechanism could be time consuming and complicated (as evidenced by the Electric Revenue Adjustment Mechanism used in California from the early 1980s through the early 1990s). Absent such a detailed understanding of utility fixed costs and their determinants, recoupling uses mechanisms that relate to fixed costs no better than do kilowatt-hour sales, the current approach to ratemaking.

My bottom line, based on past experience and the analyses presented here, is that decoupling is likely to have only modest effects on IPC revenues and customer bills. It could have slightly larger effects on the energy and demand rates for particular customer classes, depending on the specifics of the recoupling mechanism.

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APPENDIX A: PAST EXPERIENCE WITH DECOUPLING

This brief discussion is divided into three parts, the first dealing with decoupling during the mid-1980s to early 1990s, the second covering the Oregon decoupling collaboratives in the early- to mid-1990s, and the third dealing with decoupling implemented after the Western electricity crisis of 2000/2001.

MID-1980s TO EARLY 1990s

California was the first state, in 1981, to implement a decoupling system, called the Electric Revenue Adjustment Mechanism (ERAM) (Marnay and Comnes 1992). Once every three years, the California PUC set rates for each of the state's utilities in a general rate case. The rate-case process, based on a future test year, included a determination of the amount of money the utility could collect for its fixed costs. The ERAM mechanism was used to ensure that for the years between rate cases the utility collected the correct amount of money to cover these costs.

The PUC used attrition mechanisms to determine the amount of money the utility could collect each year. Financial attrition adjusted for changes in the utility's cost of capital. These adjustments were handled in annual proceedings that set interest rates and return on equity for all the California utilities.

Operational attrition adjusted for changes in operating costs, such as wage rates and the costs for certain materials. These costs were adjusted on the basis of price indices.

Finally, rate-base attrition adjusted for changes in the utility's ratebase. These adjustments were based primarily on forecasts of capital expenditures developed during the general rate cases.

During the first decade of operation, ERAM had very small effects on utility rates and volatility.

New York, during the late 1980s and early 1990s, used decoupling mechanisms similar to California's ERAM.

Washington and Maine adopted decoupling mechanisms in 1991 (Washington Utilities and Transportation Commission 1992; Maine PUC 1993). Neither state used the California approach. Instead, these states adjusted allowed fixed costs on the basis of growth in the number of electricity customers.

The mechanisms adopted in Washington and Maine were used for only a few years. The commissions abandoned decoupling because of substantial rate increases. These rate increases had nothing to do with the utility's DSM programs. In Washington, power-supply costs (which

were part of the decoupling mechanism) increased sharply, which led to decoupling-related price increases. In Maine, slower than expected economic growth led to rate increases.

MID-1990s

PGE (1993) and PacifiCorp (1993) conducted decoupling collaboratives, in response to an order from the Oregon PUC. The PGE collaborative proposal included the following steps:

- Establish base revenues using a 2-year test period,
- Establish monthly revenue benchmarks and incremental power cost estimates,
- Restate actual sales and revenues as if normal weather had occurred,
- Implement decoupling rate adjustments every six months,
- Amortize decoupling adjustments over 18 months,
- Spread decoupling adjustment among customer classes using the rate spread adopted by the PUC in the 1991 general rate case.

In March 1995, the Oregon PUC adopted the PGE collaborative mechanism. The following year, the PUC declined to adopt a decoupling mechanism for PacifiCorp. However, in 1998, the PUC ordered PacifiCorp to adopt an Alternative Form of Regulation that applied decoupling only to the distribution function.

In 2001, PGE (Lesh 2001) proposed a distribution-only decoupling mechanism for residential and small nonresidential consumers only. The mechanisms would apply on a per customer basis. The PUC rejected the PGE proposal.

EARLY 2000s

During the past two years, the California PUC, in response to state legislation, has reintroduced decoupling for the California utilities (Bachrach and Carter 2004). Southern California Edison currently has a decoupling mechanism in place for distribution costs only, using a revenue-per-customer approach. The company proposed to add fixed-generation costs to a new decoupling mechanism, using ERAM-like mechanisms. PG&E proposed to decouple fixed costs for distribution and generation using an inflation index. SDG&E proposed a revenue-per-customer mechanism.

As of now, decoupling operates in California and in Oregon only. While other states may be considering decoupling, none has such mechanisms in place.

SUMMARY

Four states adopted decoupling mechanisms during the mid-1980s through early 1990s. These experiences suggest the following lessons. The California ERAM mechanisms worked

as expected and yielded very small rate adjustments. However, these mechanisms can be complicated, and the annual mini-rate cases required for implementation can be contentious. The Washington and Maine experiences show that decoupling can have effects that go well beyond those related to utility DSM programs. In particular, nontrivial changes in other factors included in the decoupling mechanism (power-supply costs in Washington and changes in the trend of per-customer electricity use in Maine) can lead to politically unacceptable rate increases.

The Oregon experience during the mid-1990s included different decoupling mechanisms for PGE and PacifiCorp. More recently, the California PUC is, once again, implementing decoupling, and other states are considering such mechanisms.

Although the initial decoupling experiments were reasonably well documented (especially California's), that is not the case for the more recent experiments. In particular, I had a tough time finding (and understanding) information on the Oregon and recent California experiences. Perhaps more important, I could find no study on the effects and effectiveness of decoupling on utility DSM programs. As a consequence, we have no idea what the practical effect, if any, is of decoupling on a utility's incentive to run cost-effective programs.

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APPENDIX B. DETAILS ON RECOUPLING WORKBOOK

The Recoupling workbook contains three sheets: I&O, Base, and Calc. The top part of the first sheet (I&O, which stands for inputs and outputs) contains all the user inputs, while the bottom part contains the decoupling results. The user inputs include class-specific or aggregate growth rates (%/year relative to the base case discussed below) for the number of customers, peak demand, and electricity sales. In addition, the user specifies which of the three forms of recoupling to use, whether results are calculated on a class-specific basis or in aggregate, and whether differences between actual and allowed fixed cost-recovery are collected or refunded through energy and demand charges or through energy charges only.

The bottom part of I&O contains results for the particular decoupling case chosen (left-hand side) as well as the base case (right-hand side). Decoupling results (all of which are presented relative to the no-decoupling base case) include:

- Percentage and dollar changes in annual electric bills,
- Changes in IPC recovery of fixed costs,* and
- Percentage and actual changes in energy (¢/kWh) and demand ($/kW-month) charges.

The Base sheet contains information from the 2003 rate-case filing, in particular data from Brilz exhibits 42 and 43; see Table A-1. These data include characteristics of each rate class (number of customers, basic demand, summer and nonsummer demand, and summer and nonsummer energy use); proposed rate structures for each class; year 2003 revenues for each customer class based on the proposed rate structures; and the fixed and variable costs for each class. Table 1 summarized these results for each rate class.

In addition, the Base sheet contains the company's IRP forecasts for 2004, 2005, and 2006 of the number of customers, maximum monthly demand, annual average of the maximum monthly demands each year, and electricity sales for each of the five rate classes, as well as the overall inflation rate. Table A-2 shows these results.

These two sets of inputs are combined to calculate base-case results on class-specific and total revenues, including recovery of fixed costs.

The Calc sheet calculates decoupling results given the inputs provided in I&O. These results, for 2004, 2005, and 2006, include the number of customers, the three demand components, annual energy use, revenues collected from retail customers, revenues collected for fixed costs (i.e., those not collected through the PCA), and allowed FC recovery (based on the form of recoupling selected in I&O).

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*Changes in IPC recovery of fixed costs are equal in magnitude and opposite in sign to the changes in annual customer electric bills.

Table A-1. Inputs to Recoupling workbook from 2003 rate case

		Rate Class					Total or
		1	7	9	19	24	Average
Rate Class Characteristics							
	# of customers	334,917	32,152	17,076	105	13,684	397,934
Demand, MW	Basic			11,737	4,530		16,267
	Summer			2,399	997	3,040	6,436
	Nonsummer			6,709	2,908	3,515	13,131
	Total			20,845	8,434	6,555	35,834
Energy, MWh	Summer	932,072	68,475	800,214	505,668	1,226,233	3,532,662
	Nonsummer	3,209,321	196,860	2,214,213	1,473,156	312,462	7,406,012
	Total	4,141,393	265,335	3,014,427	1,978,824	1,538,695	10,938,674
2003 Proposed Idaho Rates							
	Customer, $/month	10.00	10.00	24.19	500.00	8.37	
Demand, $/kW-mo	Basic			0.69	1.11		
	Summer			3.99	3.94	5.40	
	Non-summer			3.34	3.25	0.00	
	Average			1.92	2.18	2.50	2.09
Energy, $/kWh	Summer	0.0614	0.0729	0.0290	0.0249	0.0326	
	Non-summer	0.0491	0.0583	0.0252	0.0212	0.0457	
	Total	0.0519	0.0620	0.0262	0.0221	0.0353	0.0373
Fixed Cost Percentages							
of total costs		63.0	69.7	46.1	36.1	60.4	56.1
of requested rev req		60.0	66.4	43.9	34.4	80.7	56.5
2003 Proposed Revenues (thousand $)							
	Customer	40,190	3,858	4,957	628	1,374	51,008
	Demand	0	0	40,087	18,379	16,416	74,882
	Energy	214,787	16,463	78,961	43,773	54,306	408,291
	Total	254,977	20,321	124,006	62,780	72,096	534,180
Costs, thousand $							
	Variable	101,888	6,832	69,595	41,197	13,893	233,406
	Fixed	153,089	13,489	54,411	21,583	58,203	300,775
	Total	254,977	20,321	124,006	62,780	72,096	534,180
	Variable, $/MWh	0.0246	0.0257	0.0231	0.0208	0.0090	0.0213
Fixed-Cost Revenue/Customer		457.1	419.5	3,186	206,278	4,253	755.8

Table A-2. Base-case growth rates (%/year) from IRP

	Rate Class					Total or
	1	7	9	19	24	Average
			Customers			
2004	2.41	2.63	2.63	1.11	2.05	2.42
2005	2.26	2.59	2.59	1.75	1.80	2.29
2006	2.24	2.55	2.55	1.72	1.77	2.26
Cumulative	1.07	1.08	1.08	1.05	1.06	1.07
			Maximum MW			
2004			2.48	3.41	2.38	2.58
2005			3.03	3.26	2.85	2.98
2006			2.12	1.36	2.62	2.24
Cumulative			1.08	1.08	1.08	1.08
			Average MW			
2004			3.57	3.57	2.49	3.57
2005			2.48	2.47	2.69	2.48
2006			2.13	2.10	2.25	2.12
Cumulative			1.08	1.08	1.08	1.08
			Sales			
2004	2.49	4.87	4.87	2.83	1.77	3.16
2005	2.09	4.02	4.03	3.05	0.45	2.63
2006	2.06	3.51	3.51	3.31	-0.17	2.43
Cumulative	1.07	1.13	1.13	1.09	1.02	1.08

	Price Deflator	
Year	PCWGDP	Inflation, %/yr
2003	1.127	
2004	1.149	1.96
2005	1.171	1.97
2006	1.195	2.06
Cumulative		1.061

Table A-3. IPC Decoupling Results: Revenue-per-customer Decoupling, 2004 - 2006

	Rate Class						
	1	7	9	19	24	Total	Aggreg.
C, D, E Growth Rates, %/year = 0,0,0							
% Electric Bill	0.04	-1.60	-0.38	-1.01	0.72	-0.16	-0.05
$ Electric Bill	320	-1058	-1539	-2009	1593	-2694	-801
% E/D Charges	0.14	-5.85	-1.20	-3.04	2.18	-0.53	-0.16
$ Energy Charge	0.01	-0.36	-0.03	-0.07	0.08	-0.02	-0.01
$ Demand Charge	0.00	0.00	-0.02	-0.07	0.05	-0.01	0.00

Differences from 0,0,0 Base Case

	Rate Class						
	1	7	9	19	24	Total	Aggreg.
C, D, E Growth Rates, %/year = 1,1,1							
% Electric Bill	0.04	-1.62	-0.39	-1.02	0.72	-0.16	-0.05
$ Electric Bill	323	-1069	-1555	-2030	1609	-2721	-809
% E/D Charges	0.14	-5.85	-1.20	-3.04	2.18	-0.53	-0.16
$ Energy Charge	0.01	-0.36	-0.03	-0.07	0.08	-0.02	-0.01
$ Demand Charge	0.00	0.00	-0.02	-0.07	0.05	-0.01	0.00
C, D, E Growth Rates, %/year = 1,0,0							
% Electric Bill	0.48	-1.14	0.01	-0.68	1.51	0.30	0.42
$ Electric Bill	3867	-754	23	-1363	3364	5137	7050
% E/D Charges	1.72	-4.15	0.02	-2.05	4.62	1.00	1.38
$ Energy Charge	0.09	-0.26	0.00	-0.05	0.16	0.04	0.05
$ Demand Charge	0.00	0.00	0.00	-0.04	0.12	0.02	0.03
C, D, E Growth Rates, %/year = 0,1,0							
% Electric Bill	0.04	-1.60	-0.70	-1.30	0.48	-0.30	-0.19
$ Electric Bill	320	-1058	-2811	-2594	1075	-5069	-3175
% E/D Charges	0.14	-5.85	-2.18	-3.91	1.47	-1.00	-0.63
$ Energy Charge	0.01	-0.36	-0.06	-0.09	0.05	-0.04	-0.02
$ Demand Charge	0.00	0.00	-0.04	-0.09	0.04	-0.02	-0.01
C, D, E Growth Rates, %/year = 0,0,1							
% Electric Bill	-0.40	-2.08	-0.46	-1.05	0.16	-0.48	-0.37
$ Electric Bill	-3224	-1373	-1846	-2091	356	-8178	-6285
% E/D Charges	-1.42	-7.53	-1.42	-3.14	0.48	-1.59	-1.23
$ Energy Charge	-0.07	-0.47	-0.04	-0.07	0.02	-0.06	-0.05
$ Demand Charge	0.00	0.00	-0.03	-0.07	0.01	-0.03	-0.03
C, D, E Growth Rates, %/year = 0,1,1							
% Electric Bill	-0.40	-2.08	-0.78	-1.34	-0.07	-0.62	-0.51
$ Electric Bill	-3224	-1373	-3117	-2676	-162	-10553	-8659
% E/D Charges	-1.42	-7.53	-2.40	-4.01	-0.23	-2.05	-1.69
$ Energy Charge	-0.07	-0.47	-0.06	-0.09	-0.01	-0.08	-0.06
$ Demand Charge	0.00	0.00	-0.05	-0.09	-0.01	-0.04	-0.04

	1	7	9	19	24	Total	Aggreg.
C, D, E Growth Rates, %/year = 1,1,1							
% Electric Bill	0.00	-0.02	0.00	-0.01	0.01	0.00	0.00
$ Electric Bill	3	-11	-15	-20	16	-27	-8
% E/D Charges	0.00	0.00	0.00	0.00	0.00	0.00	0.00
$ Energy Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00
$ Demand Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C, D, E Growth Rates, %/year = 1,0,0							
% Electric Bill	0.44	0.46	0.39	0.32	0.80	0.46	0.46
$ Electric Bill	3547	304	1562	647	1771	7831	7850
% E/D Charges	1.58	1.70	1.22	0.98	2.44	1.54	1.54
$ Energy Charge	0.08	0.11	0.03	0.02	0.09	0.06	0.06
$ Demand Charge	0.00	0.00	0.02	0.02	0.06	0.03	0.03
C, D, E Growth Rates, %/year = 0,1,0							
% Electric Bill	0.00	0.00	-0.32	-0.29	-0.23	-0.14	-0.14
$ Electric Bill	0	0	-1271	-585	-518	-2375	-2375
% E/D Charges	0.00	0.00	-0.98	-0.88	-0.72	-0.46	-0.46
$ Energy Charge	0.00	0.00	-0.03	-0.02	-0.03	-0.02	-0.02
$ Demand Charge	0.00	0.00	-0.02	-0.02	-0.02	-0.01	-0.01
C, D, E Growth Rates, %/year = 0,0,1							
% Electric Bill	-0.44	-0.48	-0.08	-0.04	-0.56	-0.32	-0.32
$ Electric Bill	-3544	-315	-306	-82	-1237	-5484	-5484
% E/D Charges	-1.56	-1.68	-0.23	-0.10	-1.71	-1.06	-1.07
$ Energy Charge	-0.08	-0.10	-0.01	0.00	-0.06	-0.04	-0.04
$ Demand Charge	0.00	0.00	0.00	0.00	-0.04	-0.02	-0.02
C, D, E Growth Rates, %/year = 0,1,1							
% Electric Bill	-0.44	-0.48	-0.39	-0.33	-0.79	-0.47	-0.47
$ Electric Bill	-3544	-315	-1578	-667	-1755	-7858	-7858
% E/D Charges	-1.56	-1.68	-1.20	-0.97	-2.41	-1.52	-1.52
$ Energy Charge	-0.08	-0.10	-0.03	-0.02	-0.09	-0.06	-0.06
$ Demand Charge	0.00	0.00	-0.02	-0.02	-0.06	-0.03	-0.03

Table A-4. IPC Decoupling Results: Inflation Decoupling, 2004 - 2006

	Rate Class 1	7	9	19	24	Total	Aggreg.
C, D, E Growth Rates, %/year = 0,0,0							
% Electric Bill	-0.37	-2.39	-0.91	-0.64	0.82	-0.45	-0.45
$ Electric Bill	-2999	-1578	-3637	-1280	1813	-7681	-7681
% E/D Charges	-1.33	-8.72	-2.81	-1.93	2.48	-1.51	-1.51
$ Energy Charge	-0.07	-0.54	-0.07	-0.04	0.09	-0.06	-0.06
$ Demand Charge	0.00	0.00	-0.05	-0.04	0.06	-0.03	-0.03
C, D, E Growth Rates, %/year = 1,1,1							
% Electric Bill	-0.98	-3.05	-1.34	-0.98	0.01	-1.01	-1.015
$ Electric Bill	-7806	-2015	-5371	-1966	15	-17143	-17143
% E/D Charges	-3.44	-11.04	-4.12	-2.95	0.01	-3.33	-3.328
$ Energy Charge	-0.18	-0.69	-0.11	-0.07	0.00	-0.12	-0.124
$ Demand Charge	0.00	0.00	-0.08	-0.06	0.00	-0.07	-0.070
C, D, E Growth Rates, %/year = 1,0,0							
% Electric Bill	-0.53	-2.58	-0.95	-0.65	0.80	-0.55	-0.55
$ Electric Bill	-4262	-1700	-3794	-1299	1770	-9284	-9284
% E/D Charges	-1.89	-9.40	-2.94	-1.96	2.42	-1.82	-1.82
$ Energy Charge	-0.10	-0.58	-0.08	-0.04	0.09	-0.07	-0.07
$ Demand Charge	0.00	0.00	-0.06	-0.04	0.06	-0.04	-0.04
C, D, E Growth Rates, %/year = 0,1,0							
% Electric Bill	-0.37	-2.39	-1.22	-0.93	0.58	-0.60	-0.60
$ Electric Bill	-2999	-1578	-4909	-1864	1295	-10055	-10055
% E/D Charges	-1.33	-8.72	-3.79	-2.81	1.76	-1.97	-1.97
$ Energy Charge	-0.07	-0.54	-0.10	-0.06	0.06	-0.07	-0.07
$ Demand Charge	0.00	0.00	-0.07	-0.06	0.04	-0.04	-0.04
C, D, E Growth Rates, %/year = 0,0,1							
% Electric Bill	-0.82	-2.87	-0.98	-0.68	0.26	-0.78	-0.78
$ Electric Bill	-6543	-1893	-3943	-1362	576	-13165	-13165
% E/D Charges	-2.88	-10.37	-3.03	-2.04	0.77	-2.56	-2.56
$ Energy Charge	-0.15	-0.64	-0.08	-0.05	0.03	-0.10	-0.10
$ Demand Charge	0.00	0.00	-0.06	-0.04	0.02	-0.05	-0.05
C, D, E Growth Rates, %/year = 0,1,1							
% Electric Bill	-0.82	-2.87	-1.30	-0.97	0.03	-0.92	-0.92
$ Electric Bill	-6543	-1893	-5215	-1946	58	-15539	-15539
% E/D Charges	-2.88	-10.37	-4.00	-2.92	0.07	-3.02	-3.02
$ Energy Charge	-0.15	-0.64	-0.10	-0.06	0.00	-0.11	-0.11
$ Demand Charge	0.00	0.00	-0.08	-0.06	0.00	-0.06	-0.06

Differences from 0,0,0 Base Case

	Rate Class 1	7	9	19	24	Total	Aggreg.
C, D, E Growth Rates, %/year = 1,1,1							
% Electric Bill	-0.60	-0.66	-0.43	-0.34	-0.81	-0.56	-0.56
$ Electric Bill	-4807	-437	-1734	-686	-1798	-9462	-9462
% E/D Charges	-2.10	-2.32	-1.31	-1.01	-2.47	-1.82	-1.82
$ Energy Charge	-0.11	-0.14	-0.03	-0.02	-0.09	-0.07	-0.07
$ Demand Charge	0.00	0.00	-0.03	-0.02	-0.06	-0.04	-0.04
C, D, E Growth Rates, %/year = 1,0,0							
% Electric Bill	-0.16	-0.18	-0.04	-0.01	-0.02	-0.09	-0.09
$ Electric Bill	-1263	-122	-157	-19	-43	-1603	-1603
% E/D Charges	-0.56	-0.68	-0.12	-0.03	-0.06	-0.31	-0.31
$ Energy Charge	-0.03	-0.04	0.00	0.00	0.00	-0.01	-0.01
$ Demand Charge	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01
C, D, E Growth Rates, %/year = 0,1,0							
% Electric Bill	0.00	0.00	-0.32	-0.29	-0.23	-0.14	-0.14
$ Electric Bill	0	0	-1271	-585	-518	-2375	-2375
% E/D Charges	0.00	0.00	-0.98	-0.88	-0.72	-0.46	-0.46
$ Energy Charge	0.00	0.00	-0.03	-0.02	-0.03	-0.02	-0.02
$ Demand Charge	0.00	0.00	-0.02	-0.02	-0.02	-0.01	-0.01
C, D, E Growth Rates, %/year = 0,0,1							
% Electric Bill	-0.44	-0.48	-0.08	-0.04	-0.56	-0.32	-0.32
$ Electric Bill	-3544	-315	-306	-82	-1237	-5484	-5484
% E/D Charges	-1.55	-1.65	-0.22	-0.11	-1.71	-1.05	-1.05
$ Energy Charge	-0.08	-0.10	-0.01	0.00	-0.06	-0.04	-0.04
$ Demand Charge	0.00	0.00	0.00	0.00	-0.04	-0.02	-0.02
C, D, E Growth Rates, %/year = 0,1,1							
% Electric Bill	-0.44	-0.48	-0.39	-0.33	-0.79	-0.47	-0.47
$ Electric Bill	-3544	-315	-1578	-667	-1755	-7858	-7858
% E/D Charges	-1.55	-1.65	-1.19	-0.98	-2.42	-1.51	-1.51
$ Energy Charge	-0.08	-0.10	-0.03	-0.02	-0.09	-0.06	-0.06
$ Demand Charge	0.00	0.00	-0.02	-0.02	-0.06	-0.03	-0.03

Table A-5. IPC Decoupling Results: Forecast Growth Decoupling, 2004 - 2006

	Rate Class 1	7	9	19	24	Total	Aggreg.
C, D, E Growth Rates, %/year = 0,0,0							
% Electric Bill	0.00	0.00	0.00	0.00	0.00	0.00	0.00
$ Electric Bill	0	0	0	0	0	0	0
% E/D Charges	0.00	0.00	0.00	0.00	0.00	0.00	0.00
$ Energy Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00
$ Demand Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C, D, E Growth Rates, %/year = 1,1,1							
% Electric Bill	-0.60	-0.66	-0.43	-0.34	-0.81	-0.56	-0.560
$ Electric Bill	-4807	-437	-1734	-686	-1798	-9462	-9462
% E/D Charges	-2.12	-2.41	-1.34	-1.03	-2.45	-1.84	-1.838
$ Energy Charge	-0.11	-0.15	-0.04	-0.02	-0.09	-0.07	-0.069
$ Demand Charge	0.00	0.00	-0.03	-0.02	-0.06	-0.04	-0.038
C, D, E Growth Rates, %/year = 1,0,0							
% Electric Bill	-0.16	-0.18	-0.04	-0.01	-0.02	-0.09	-0.09
$ Electric Bill	-1263	-122	-157	-19	-43	-1603	-1603
% E/D Charges	-0.56	-0.68	-0.12	-0.03	-0.06	-0.31	-0.31
$ Energy Charge	-0.03	-0.04	0.00	0.00	0.00	-0.01	-0.01
$ Demand Charge	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01
C, D, E Growth Rates, %/year = 0,1,0							
% Electric Bill	0.00	0.00	-0.32	-0.29	-0.23	-0.14	-0.14
$ Electric Bill	0	0	-1271	-585	-518	-2375	-2375
% E/D Charges	0.00	0.00	-0.99	-0.88	-0.71	-0.47	-0.47
$ Energy Charge	0.00	0.00	-0.03	-0.02	-0.03	-0.02	-0.02
$ Demand Charge	0.00	0.00	-0.02	-0.02	-0.02	-0.01	-0.01
C, D, E Growth Rates, %/year = 0,0,1							
% Electric Bill	-0.44	-0.48	-0.08	-0.04	-0.56	-0.32	-0.32
$ Electric Bill	-3544	-315	-306	-82	-1237	-5484	-5484
% E/D Charges	-1.56	-1.74	-0.24	-0.12	-1.69	-1.07	-1.07
$ Energy Charge	-0.08	-0.11	-0.01	0.00	-0.06	-0.04	-0.04
$ Demand Charge	0.00	0.00	0.00	0.00	-0.04	-0.02	-0.02
C, D, E Growth Rates, %/year = 0,1,1							
% Electric Bill	-0.44	-0.48	-0.39	-0.33	-0.79	-0.47	-0.47
$ Electric Bill	-3544	-315	-1578	-667	-1755	-7858	-7858
% E/D Charges	-1.56	-1.74	-1.22	-1.00	-2.39	-1.53	-1.53
$ Energy Charge	-0.08	-0.11	-0.03	-0.02	-0.08	-0.06	-0.06
$ Demand Charge	0.00	0.00	-0.02	-0.02	-0.06	-0.03	-0.03

Differences from 0,0,0 Base Case

	Rate Class 1	7	9	19	24	Total	Aggreg.
C, D, E Growth Rates, %/year = 1,1,1							
% Electric Bill	-0.60	-0.66	-0.43	-0.34	-0.81	-0.56	-0.56
$ Electric Bill	-4807	-437	-1734	-686	-1798	-9462	-9462
% E/D Charges	-2.12	-2.41	-1.34	-1.03	-2.45	-1.84	-1.84
$ Energy Charge	-0.11	-0.15	-0.04	-0.02	-0.09	-0.07	-0.07
$ Demand Charge	0.00	0.00	-0.03	-0.02	-0.06	-0.04	-0.04
C, D, E Growth Rates, %/year = 1,0,0							
% Electric Bill	-0.16	-0.18	-0.04	-0.01	-0.02	-0.09	-0.09
$ Electric Bill	-1263	-122	-157	-19	-43	-1603	-1603
% E/D Charges	-0.56	-0.68	-0.12	-0.03	-0.06	-0.31	-0.31
$ Energy Charge	-0.03	-0.04	0.00	0.00	0.00	-0.01	-0.01
$ Demand Charge	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01
C, D, E Growth Rates, %/year = 0,1,0							
% Electric Bill	0.00	0.00	-0.32	-0.29	-0.23	-0.14	-0.14
$ Electric Bill	0	0	-1271	-585	-518	-2375	-2375
% E/D Charges	0.00	0.00	-0.99	-0.88	-0.71	-0.47	-0.47
$ Energy Charge	0.00	0.00	-0.03	-0.02	-0.03	-0.02	-0.02
$ Demand Charge	0.00	0.00	-0.02	-0.02	-0.02	-0.01	-0.01
C, D, E Growth Rates, %/year = 0,0,1							
% Electric Bill	-0.44	-0.48	-0.08	-0.04	-0.56	-0.32	-0.32
$ Electric Bill	-3544	-315	-306	-82	-1237	-5484	-5484
% E/D Charges	-1.56	-1.74	-0.24	-0.12	-1.69	-1.07	-1.07
$ Energy Charge	-0.08	-0.11	-0.01	0.00	-0.06	-0.04	-0.04
$ Demand Charge	0.00	0.00	0.00	0.00	-0.04	-0.02	-0.02
C, D, E Growth Rates, %/year = 0,1,1							
% Electric Bill	-0.44	-0.48	-0.39	-0.33	-0.79	-0.47	-0.47
$ Electric Bill	-3544	-315	-1578	-667	-1755	-7858	-7858
% E/D Charges	-1.56	-1.74	-1.22	-1.00	-2.39	-1.53	-1.53
$ Energy Charge	-0.08	-0.11	-0.03	-0.02	-0.08	-0.06	-0.06
$ Demand Charge	0.00	0.00	-0.02	-0.02	-0.06	-0.03	-0.03

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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-04-15

IDAHO POWER COMPANY

EXHIBIT NO. 6

MICHAEL J. YOUNGBLOOD

Simulation

Historical Fixed Cost Simulation Results

RESIDENTIAL

Year	Actual Customer Count	Customer Growth	Allowed Fixed Cost Recovery Based on Actual Customer Count	DSM Energy Savings (MWH)	Weather Normalized Energy (MWH) Less DSM Energy Savings	Energy Growth	Difference	Actual Fixed Cost Revenue Recovered	Amount of True-Up
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				0.50%					
1993	245,474		$103,007,702		3,524,040			$103,007,702	$0
1994	246,586	0.45%	$103,474,244	17,620	3,572,247	1.37%	(0.92%)	$104,416,786	($942,542)
1995	264,456	7.25%	$111,175,661	17,861	3,699,926	3.57%	3.67%	$108,346,096	$2,829,565
1996	272,622	3.09%	$114,947,746	18,500	3,757,861	1.57%	1.52%	$110,368,374	$4,579,372
1997	280,588	2.92%	$118,306,290	18,789	3,846,132	2.35%	0.57%	$112,960,910	$5,345,380
1998	288,999	3.00%	$121,852,881	19,231	3,968,358	3.18%	(0.18%)	$116,550,678	$5,302,202
1999	298,803	3.39%	$126,337,802	19,842	4,056,437	2.22%	1.17%	$119,469,857	$6,867,945
2000	307,559	2.93%	$130,252,635	20,282	4,140,715	2.08%	0.85%	$122,151,096	$8,101,538
2001	318,293	3.49%	$134,798,371	20,704	4,121,961	(0.45%)	3.94%	$121,597,857	$13,200,514
2002	327,192	2.80%	$138,566,906	20,610	4,079,658	(1.03%)	3.82%	$120,349,923	$18,216,983
2003	335,604	2.57%	$142,129,817	20,398	4,199,809	2.95%	(0.37%)	$123,894,364	$18,235,453
2004	346,949	3.38%	$136,627,149	20,999	4,351,300	3.61%	(0.23%)	$129,991,644	$6,635,504

SMALL COMMERCIAL

Year	Actual Customer Count	Customer Growth	Allowed Fixed Cost Recovery Based on Actual Customer Count	DSM Energy Savings (MWH)	Weather Normalized Energy (MWH) Less DSM Energy Savings	Energy Growth	Difference	Actual Fixed Cost Revenue Recovered	Amount of True-Up
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				0.50%					
1993	24,406	0.00%	$9,507,698	0	229,877	0.00%	0.00%	$9,507,698	$0
1994	25,215	3.31%	$9,822,516	1,149	230,531	0.28%	3.03%	$9,534,763	$287,753
1995	26,363	4.55%	$10,224,415	1,153	236,997	2.80%	1.75%	$9,758,858	$465,557
1996	27,687	5.02%	$10,660,404	1,185	248,538	4.87%	0.15%	$10,160,242	$500,162
1997	28,932	4.50%	$11,139,997	1,243	255,383	2.75%	1.74%	$10,440,053	$699,944
1998	29,778	2.92%	$11,465,661	1,277	261,803	2.51%	0.41%	$10,702,494	$763,167
1999	30,127	1.17%	$11,684,104	1,309	266,490	1.79%	(0.62%)	$10,973,034	$711,071
2000	30,183	0.18%	$11,754,998	1,332	269,702	1.21%	(1.02%)	$11,152,184	$602,815
2001	30,317	0.44%	$11,807,284	1,349	286,924	6.39%	(5.94%)	$11,864,288	($57,004)
2002	31,331	3.34%	$12,202,217	1,435	265,806	(7.36%)	10.70%	$10,991,096	$1,211,120
2003	32,342	3.23%	$12,596,127	1,329	273,673	2.96%	0.27%	$11,316,375	$1,279,752
2004	33,426	3.35%	$11,624,521	1,368	287,958	5.22%	(1.87%)	$11,731,943	($107,422)

LARGE COMMERCIAL

Year	Actual Customer Count	Customer Growth	Allowed Fixed Cost Recovery Based on Actual Customer Count	DSM Energy Savings (MWH)	Weather Normalized Energy (MWH) Less DSM Energy Savings	Energy Growth	Difference	Actual Fixed Cost Revenue Recovered	Amount of True-Up
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				0.50%					
1993	11,597	0.00%	$32,615,451	0	2,068,196	0.00%	0.00%	$32,615,451	$0
1994	12,185	5.07%	$34,268,350	10,341	1,911,398	(7.58%)	12.65%	$30,142,754	$4,125,596
1995	13,061	7.18%	$37,271,238	9,557	2,263,424	18.42%	(11.23%)	$36,219,999	$1,051,239
1996	13,509	3.43%	$39,459,583	11,317	2,353,663	3.99%	(0.56%)	$38,553,006	$906,577
1997	13,953	3.29%	$40,758,583	11,768	2,452,008	4.18%	(0.89%)	$40,163,890	$594,693
1998	14,605	4.67%	$42,661,417	12,260	2,580,652	5.25%	(0.58%)	$42,271,081	$390,337
1999	15,117	3.51%	$43,766,277	12,903	2,711,684	5.08%	(1.57%)	$44,024,382	($258,105)
2000	15,451	2.21%	$44,500,593	13,558	2,840,574	4.75%	(2.54%)	$45,875,273	($1,374,680)
2001	16,197	4.82%	$46,646,906	14,203	2,962,895	4.31%	0.52%	$47,850,749	($1,203,844)
2002	17,101	5.58%	$49,251,340	14,814	2,934,711	(0.95%)	6.53%	$47,395,585	$1,855,755
2003	17,198	0.57%	$49,531,521	14,674	3,005,724	2.42%	(1.85%)	$48,542,446	$989,075
2004	17,197	(0.01%)	$48,074,110	15,029	3,050,001	1.47%	(1.48%)	$48,312,355	($238,245)

Historical Fixed Cost Simulation Results

INDUSTRIAL

Year	Forecasted Energy from Historical IRPs (MWH)	Forecasted Energy Growth	Allowed Fixed Cost Recovery Based on Forecasted Energy	DSM Energy Savings (MWH)	Weather Normalized Energy (MWH) Less DSM Energy Savings	Energy Growth	Difference	Actual Fixed Cost Revenue Recovered	Amount of True-Up
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				0.50%					
1993	1,880,462	0.00%	$18,409,719	0	1,880,462	0.00%	0.00%	$18,409,719	$0
1994	1,985,287	5.57%	$19,435,956	9,402	1,775,897	(5.56%)	11.14%	$17,386,032	$2,049,924
1995	1,880,357	(5.29%)	$18,458,822	8,879	1,668,893	(6.03%)	0.74%	$16,382,948	$2,075,874
1996	1,952,786	3.85%	$19,254,467	8,344	1,732,825	3.83%	0.02%	$17,085,655	$2,168,812
1997	2,056,208	5.30%	$20,274,211	8,664	1,818,779	4.96%	0.34%	$17,933,163	$2,341,048
1998	2,127,265	3.46%	$20,974,828	9,094	1,911,967	5.12%	(1.67%)	$18,851,999	$2,122,829
1999	2,194,621	3.17%	$21,791,083	9,560	1,879,224	(1.71%)	4.88%	$18,659,410	$3,131,672
2000	2,222,505	1.27%	$22,158,370	9,396	1,933,734	2.90%	(1.63%)	$19,279,324	$2,879,046
2001	2,349,614	5.72%	$23,425,655	9,669	2,017,030	4.31%	1.41%	$20,109,791	$3,315,864
2002	2,136,545	(9.07%)	$21,301,358	10,085	1,918,544	(4.88%)	(4.19%)	$19,127,885	$2,173,473
2003	2,239,701	4.83%	$22,329,819	9,593	1,976,985	3.05%	1.78%	$19,710,538	$2,619,281
2004	2,138,111	(4.54%)	$20,841,909	9,885	1,992,469	0.78%	(5.32%)	$19,422,219	$1,419,690

IRRIGATION

Year	Forecasted Energy from Historical IRPs (MWH)	Forecasted Energy Growth	Allowed Fixed Cost Recovery Based on Forecasted Energy	DSM Energy Savings (MWH)	Weather Normalized Energy (MWH) Less DSM Energy Savings	Energy Growth	Difference	Actual Fixed Cost Revenue Recovered	Amount of True-Up
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				0.50%					
1993	1,620,515	0.00%	$31,583,841	0	1,620,515	0.00%	0.00%	$31,583,841	$0
1994	1,582,693	(2.33%)	$30,846,696	8,103	1,632,834	0.76%	(3.09%)	$31,823,932	($977,236)
1995	1,553,878	(1.82%)	$30,154,892	8,164	1,557,930	(4.59%)	2.77%	$30,364,051	($209,159)
1996	1,524,626	(1.88%)	$29,379,549	7,790	1,624,957	4.30%	(6.18%)	$31,670,415	($2,290,866)
1997	1,605,811	5.32%	$30,943,976	8,125	1,538,128	(5.34%)	10.67%	$29,978,110	$965,866
1998	1,629,434	1.47%	$31,399,190	7,691	1,588,471	3.27%	(1.80%)	$30,959,309	$439,881
1999	1,652,021	1.39%	$32,240,433	7,942	1,670,605	5.17%	(3.78%)	$32,560,086	($319,653)
2000	1,511,326	(8.52%)	$29,712,668	8,353	1,827,588	9.40%	(17.91%)	$35,619,699	($5,907,030)
2001	1,518,243	0.46%	$29,848,667	9,138	1,660,369	(9.15%)	9.61%	$32,360,592	($2,511,925)
2002	1,520,805	0.17%	$29,899,032	8,302	1,632,697	(1.67%)	1.84%	$31,821,270	($1,922,238)
2003	1,582,424	4.05%	$31,110,457	8,163	1,611,305	(1.31%)	5.36%	$31,404,332	($293,875)
2004	1,568,551	(0.88%)	$35,258,287	8,057	1,616,744	0.34%	(1.21%)	$31,510,342	$3,747,945

TOTAL COMPANY

Year			Allowed Fixed Cost Recovery	DSM Energy Savings (MWH)	Weather Normalized Energy (MWH) Less DSM Energy Savings			Actual Fixed Cost Revenue Recovered	Amount of True-Up
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				0.50%					
1993			$195,124,410		9,323,090			$195,124,410	$0
1994			$197,847,762	46,615	9,122,908			$193,304,267	$4,543,495
1995			$207,285,028	45,615	9,427,169			$201,071,952	$6,213,075
1996			$213,701,749	47,136	9,717,845			$207,837,692	$5,864,057
1997			$221,423,057	48,589	9,910,430			$211,476,125	$9,946,931
1998			$228,353,978	49,552	10,311,252			$219,335,561	$9,018,417
1999			$235,819,700	51,556	10,584,441			$225,686,769	$10,132,931
2000			$238,379,265	52,922	11,012,314			$234,077,576	$4,301,689
2001			$246,526,883	55,062	11,049,179			$233,783,277	$12,743,606
2002			$251,220,852	55,246	10,831,417			$229,685,759	$21,535,093
2003			$257,697,741	54,157	11,067,496			$234,868,054	$22,829,687
2004			$252,425,975	55,337	11,298,472			$240,968,502	$11,457,473

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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-04-15

IDAHO POWER COMPANY

EXHIBIT NO. 7

MICHAEL J. YOUNGBLOOD

Fixed Cost of Service

IDAHO POWER COMPANY
Fixed Costs Determination
IPC-E-05-28 Filed 10/28/05

Class Cost of Service Functionalized Costs

	COS Revenue Requirement	Distribution and Customer Fixed Costs	Transmission Fixed Costs	Generation Fixed Costs	Total Fixed Costs	% Fixed Dist. And Cust. Costs	% Fixed Transmission Costs	% Fixed Inc. Gen. Costs	% Total Fixed Costs
Residential	262,813,641	101,433,971	24,086,559	31,645,223	157,165,753	38.6%	9.2%	12.0%	59.8%
Small Commercial	15,745,359	7,494,288	1,235,958	1,685,025	10,415,271	47.6%	7.8%	10.7%	66.1%
Large Commercial	134,951,228	26,369,279	14,351,900	19,709,240	60,430,418	18.4%	10.7%	14.8%	43.9%
Industrial	66,875,308	7,403,554	6,404,380	9,101,934	22,909,868	11.1%	9.6%	13.6%	34.3%
Irrigation	91,881,446	25,942,453	10,426,865	15,843,405	52,212,722	28.2%	11.3%	17.2%	56.8%
	572,266,982	**168,643,545**	**56,505,661**	**77,984,826**	**303,134,032**				

Requested Revenue Requirement with Functionalized Fixed Costs

	Requested Revenue Requirement	Total Fixed Costs	Fixed Costs Recovered from Fixed Charges	Fixed Costs Recovered from Demand Charges	Fixed Costs Recovered from Energy Charges	% Fixed Costs Recovered from Fixed Charges	% Fixed Costs Recovered from Demand Charges	% Fixed Costs Recovered from Energy Charges	% Fixed Costs of Revenue Req.
Residential	278,647,874	157,165,753	26,236,626	-	130,929,127	16.7%	0.0%	83.3%	56.4%
Small Commercial	16,880,628	10,415,271	2,238,573	-	8,176,698	21.5%	0.0%	78.5%	61.7%
Large Commercial	136,055,529	60,430,418	3,307,947	24,365,320	32,757,151	5.5%	40.3%	54.2%	44.4%
Industrial	66,392,091	22,909,868	275,224	16,967,799	5,666,845	1.2%	74.1%	24.7%	34.5%
Irrigation	74,995,320	52,212,722	1,455,487	16,322,730	34,434,505	2.8%	31.3%	66.0%	69.6%
	572,971,442	**303,134,032**	**33,513,857**	**57,655,849**	**211,964,326**				

IDAHO POWER COMPANY
Fixed Costs Determination
IPC-E-05-28 Filed 10/28/05

Class Fixed Cost Rate Determination

Rate Schedule	Base Rate Revenue	COS	Difference	Total Fixed	FC Recovered from Fixed Charges	FC Recovered from Demand Charges	FC Loss Rev/MWh (Demand)	FC Recovered from Energy Charges	FC Loss Rev/MWh (Energy)
Rate 01	278,647,874	262,813,641	15,913,575	157,165,753	26,236,626		-	130,929,127	$ 29.07
Rate 07	16,880,628	15,745,359	1,143,213	10,415,271	2,238,573		-	8,176,698	$ 37.40
Rate 09S	124,112,816	122,849,136	1,274,349	55,466,985	3,014,889	21,021,014	7.25	31,431,082	$ 10.85
Rate 09P,T	11,942,713	12,102,092	(159,329)	4,963,433	293,058	3,344,306	10.15	1,326,069	$ 4.02
Rate 19 S,P,T	66,392,091	66,875,308	(456,680)	22,909,868	275,224	16,967,799	8.25	5,666,845	$ 2.76
Rate 24S	74,995,320	91,881,446	(16,877,862)	52,212,722	1,455,487	16,322,730	10.37	34,434,505	$ 21.88
Area Lighting	938,956	421,341	517,615		938,956			(938,956)	
Un-Mtr Gen Svc	873,387	812,180	61,207		873,387			(873,387)	
Muni St-Lght	2,041,607	1,951,790	89,817		2,041,607		(2,041,607)	42,100	
Traffic Ctrl	282,148	281,793	355		282,148		(282,148)	166	
INEL	5,392,999	5,642,975	(249,976)		5,392,999		(5,392,999)	(117,170)	
Simplot	4,852,804	5,203,022	(350,218)		4,852,804		(4,852,804)	(164,156)	
Micron	18,717,917	19,491,523	(773,606)		18,717,917		(18,717,917)	(362,610)	
Total	**606,071,260**	**606,071,606**	**346**						

Rate Schedule	Additional Fixed Recovery	Addt'l FC Lost Rev/MWh (Energy)	Total FC Lost Rev/MWh (Energy)	VC Recovery	Additional VC Recovery	MWh	Total Base Rate	Customer Adj.	Total Base Rate Revenue Req.
Rate 01	7,459,110	$ 1.66	$ 30.73	105,647,888	8,454,465	4,503,865	$ 56.06	(79,342)	$ 278,647,874
Rate 07	535,854	$ 2.45	$ 39.86	5,330,088	607,359	218,606	$ 67.02	(7,944)	$ 16,880,628
Rate 09S	597,321	$ 0.21	$ 11.05	67,382,152	677,028	2,897,592	$ 41.80	(10,669)	$ 124,112,816
Rate 09P,T	(74,681)	$ (0.23)	$ 3.80	7,138,658	(84,647)	329,527	$ 35.35	(50)	$ 11,942,713
Rate 19 S,P,T	(214,058)	$ (0.10)	$ 2.65	43,965,439	(242,622)	2,056,659	$ 32.16	(26,537)	$ 66,392,091
Rate 24S	(7,911,097)	$ (5.03)	$ 16.85	39,668,724	(8,966,765)	1,574,100	$ 46.72	(8,264)	$ 74,995,320
	-							**Total Metered Rates**	**$ 572,971,442**
								Total Non-Metered & Specials	**$ 33,099,818**
								Total Requested Revenue Requirement	**$ 606,071,260**

Fixed & Variable % Calc	Fixed Cost	Variable	Total
Rate 09P,T	4,963,433	7,138,658	12,102,092
Rate 19 S,P,T	22,909,868	43,965,439	66,875,308
Rate 24S	52,212,722	39,668,724	91,881,446
Total	80,086,024	90,772,822	170,858,845
Percentage	46.87%	53.13%	100.00%

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BEFORE THE

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CASE NO. IPC-E-04-15

IDAHO POWER COMPANY

EXHIBIT NO. 8

MICHAEL J. YOUNGBLOOD

Monthly Bill Affect

Fixed Cost Recovery True-up Mechanism
(Simulation for Case No. IPC-E-04-15)

Class Rate Change Percentages

Year	Residential	Small Commercial	Large Commercial	Industrial	Irrigation
1993					
1994					
1995	(0.17%)	2.00%	2.00%	2.00%	(1.31%)
1996	2.00%	1.86%	0.12%	2.00%	1.88%
1997	1.38%	0.13%	(0.21%)	1.12%	(2.00%)
1998	0.30%	1.11%	(0.38%)	0.11%	2.00%
1999	0.25%	0.56%	0.19%	0.18%	1.52%
2000	0.86%	(0.19%)	(0.39%)	1.98%	(0.86%)
2001	0.58%	(0.82%)	(1.03%)	(0.65%)	(2.00%)
2002	2.00%	(2.00%)	0.15%	1.02%	(1.57%)
2003	2.00%	2.00%	2.00%	(2.00%)	0.93%
2004	2.00%	2.00%	0.86%	1.89%	2.00%

Monthly Bill Effect for Average Customer

Year	Residential	Small Commercial	Large Commercial	Industrial	Irrigation
1993					
1994					
1995	($0.10)	$0.93	$10.36	$801.25	($8.95)
1996	$1.16	$0.88	$0.65	$835.21	$11.06
1997	$0.81	$0.06	($1.13)	$490.54	($8.32)
1998	$0.18	$0.52	($2.05)	$49.04	$8.30
1999	$0.15	$0.27	$1.02	$80.19	$6.59
2000	$0.51	($0.09)	($2.20)	$938.56	($4.02)
2001	$0.33	($0.42)	($5.69)	($316.92)	($8.60)
2002	$1.11	($0.92)	$0.77	$467.22	($5.91)
2003	$1.14	$0.90	$10.50	($946.00)	$3.48
2004	$1.16	$0.93	$4.66	$833.04	$7.17

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CASE NO. IPC-E-04-15

IDAHO POWER COMPANY

EXHIBIT NO. 9

MICHAEL J. YOUNGBLOOD

Example of Fixed Cost Adjustment Tariff

SCHEDULE 54
FIXED COST ADJUSTMENT

APPLICABILITY

This schedule is applicable to the electric energy delivered to all Idaho retail Customers served under the Company's Residential Service (Schedules 1, 4, and 5) or Small General Service (Schedule 7).

FIXED COST PER CUSTOMER RATE

The Fixed Cost per Customer rate (FCC) is determined by dividing the Company's fixed cost components for Residential and Small General Service customers by the average annual number of Residential and Small General Service customers, respectively. The monthly FCC rate is $32.05 per customer for Schedules 1, 4 and 5 and $23.50 per customer for Schedule 7.

FIXED COST PER ENERGY RATE

The Fixed Cost per Energy rate (FCE) is determined by dividing the Company's fixed cost components for Residential and Small General Service customers by the weather-normalized energy load for Residential and Small General Service customers, respectively. The monthly FCE rates per kWh for Residential (Schedules 1, 4, and 5) and Small Commercial (Schedule 7) are:

	Residential	Small Commercial
January	2.2116¢	3.2686¢
February	2.4310¢	3.4527¢
March	2.7298¢	3.7863¢
April	3.1653¢	4.3559¢
May	3.7017¢	4.6590¢
June	3.9848¢	4.6689¢
July	3.5444¢	4.1646¢
August	3.1383¢	3.8941¢
September	3.3857¢	4.0640¢
October	3.8495¢	4.3990¢
November	3.3996¢	4.1968¢
December	2.5742¢	3.5180¢

ALLOWED FIXED COST RECOVERY AMOUNT

The Allowed Fixed Cost Recovery amount will be computed monthly by multiplying the average number of Residential and Small General Service customers by the appropriate Residential and Small General Service FCC rate.

ACTUAL FIXED COSTS RECOVERED AMOUNT

The Actual Fixed Costs Recovered amount will be computed monthly by multiplying the weather-normalized energy load for Residential and Small General Service customers by the appropriate Residential and Small General Service FCE rate.

FIXED COST ADJUSTMENT

The Fixed Cost Adjustment (FCA) is the difference between the year-end Allowed Fixed Cost Recovery balance and the year-end Actual Fixed Costs Recovered balance, the result divided by the estimated consumption for the following year.

The monthly Fixed Cost Adjustment applied to the Energy rate for Residential Service (Schedules 1, 4, and 5) is _____ cents per kWh. The monthly Fixed Cost Adjustment applied to the Energy rate for Small General Service (Schedule 7) is _____ cents per kWh.

EXPIRATION

The Fixed Cost Adjustment included on this schedule will expire May 31, 2008.