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IDAHO PUBLIC
UTILITIES COMMISSION

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 FINAL REPORT ON WORKSHOP PROCEEDINGS

INTRODUCTION

This is a final report to the Idaho Public Utilities Commission on the workshop proceedings undertaken in the above-captioned matter. This Final Report is intended to provide the Commission with an overview of the workshops and the issues discussed, and the recommendations of the workshop participants. Attached hereto are summaries of all five (5) workshops, which provide substantially more detail.

The workshops were successful in that they included an open and well-informed discussion of the nature and extent of fixed-cost revenue losses caused by demand-side management (DSM) programs, and possible means to neutralize those losses or create other incentives for strong performance in DSM programs. The participants in the workshops came to

a general consensus that Idaho Power should apply to the Commission to undertake a performance-based incentive pilot to allow the Company to fully recover fixed-cost losses and to possibly acquire incentive benefits achieved by its two residential programs covering the new construction market segment. These two programs are: (1) ENERGY STAR® Homes Northwest, its residential new construction energy efficiency program, and (2) Rebate Advantage for New Manufactured Homes, its program directed at the manufactured housing market. In addition, it was the general consensus of the workshop participants that the potential impacts of a broader fixed cost true-up mechanism should be simulated until Idaho Power's next general rate case.

BACKGROUND

On May 25, 2004, the Idaho Public Utilities Commission (Commission) in Order No. 29505 (Idaho Power Company general rate case No. IPC-E-03-13) determined that a separate "proceeding to assess financial disincentives inherent in Company-sponsored conservation programs is appropriate and should proceed by informal workshops." The Commission's Order provided in relevant part as follows:

> The Commission specifically directs the parties (Idaho Power, NW Energy Coalition, Industrial Customers of Idaho Power (ICIP) and Commission Staff) to address possible revenue adjustment when annual energy consumption is both above and below normal. The parties should also consider how much adjustment is necessary to remove DSM investment disincentives and whether (and to what extent) performance-based incentives such as revenue sharing could or should be incorporated into the resolution of this issue. The Commission is interested in proposals that could provide Idaho Power the opportunity to share and retain benefits gained from efficiencies, especially... technologies... In short, the Commission believes opportunities exist for improvements in operating efficiency that would benefit the Company shareholders and its customers, and we encourage the parties to creatively consider the options for a performance-based mechanism to present to the Commission. *The parties to the agreement are directed to propose a workshop schedule and initiate a proceeding.* (emphasis added)

Order No. 29505 at pp. 68, 69.

As a follow up to the Commission's Order, the NW Energy Coalition on June 18, 2004 formally requested that a proceeding be initiated and that a workshop schedule be established. The Commission in Order No. 29558 established this docket to investigate financial disincentives that hinder Idaho Power's investment in cost-effective energy efficiency resources. The Commission stated that the scope of the investigation should be focused on true-up mechanisms and performance based ratemaking.

As directed by the Commission, the participating parties provided a written status report to the Commission on December 15, 2004 to update the Commission on the status of the investigative workshops.

PROCESS

The parties participated in five workshops to date: August 24, September 27, November 8, December 1, and December 13, 2004. These workshops included presentations by participants, group discussion, and sensing for areas of agreement and disagreement. Susan Hayman (North Country Resources) facilitated the workshops. Workshops were designed in cooperation with four designated workshop coordinators representing each of the four major interests at the table (Idaho Power Company, Idaho Public Utilities Commission Staff, Industrial Customers of Idaho Power, and Northwest Energy Coalition). Copies of all workshop summaries are provided as attachments to this Final Report.

PARTICIPANTS

The following people attended one or more workshops, received meeting materials and summaries, and were considered active workshop participants:

Name and Affiliation	Name and Affiliation
IPUC Staff	**Northwest Energy Coalition**
Lynn Anderson	Nancy Hirsh, NW Energy Coalition
Randy Lobb	Bill Eddie, Advocates for the West
Terri Carlock	Ralph Cavanagh, Natural Resources Defense Council
David Schunke	
Scott Woodbury	
Idaho Power	**Industrial Customers of Idaho Power**
Ric Gale	Peter Richardson, Industrial Customers of Idaho Power
Bart Kline	David Hawk, J.R. Simplot Co
Maggie Brilz	Don Reading, Ben Johnson Associates
Darlene Nemnich	
Greg Said	**Other Interested Parties**
Tim Tatum	Brad Purdy, Community Action Partnership Association of Idaho
Mike Youngblood	Laura Nelson, IPUC Policy Strategist

NATURE AND EXTENT OF LOST FIXED COST REVENUES

The underlying problem addressed in the workshops was described in the Direct Testimony of Ralph Cavanagh submitted in case number IPC-E-03-13: Successful implementation of DSM programs generally results in fewer sales of kilowatt-hours and/or reductions in demand for energy than would occur without the programs. Because Idaho Power primarily recovers its fixed costs of service as a portion of kilowatt-hour sales and/or demand charges, many DSM programs result in reduced fixed-cost revenue recovery.

The workshops first focused on identifying the nature and extent of fixed-cost revenue recovery impacts associated with varying levels of DSM investment by Idaho Power. These impacts are highly dependent on the type, level and effectiveness of DSM programs. For the

workshop proceedings, IPUC Staff analyzed expected fixed-cost revenue losses over a 9-year period (with 2 assumed intervening rates cases) under the level of DSM investment recommended in the Northwest Power and Conservation Council's Fifth Plan. The Fifth Plan's level of DSM investment is approximately equal to savings on the order of 0.5% per year (including Northwest Energy Efficiency Alliance efforts, fuel conversions, building codes, appliance standards, and other DSM for which utilities have limited, little, or no control). Under Staff's contention that except for 6-month regulatory lag any future fixed-cost revenue losses from installed efficiency measures are "zeroed out" after each assumed rate case, the 9-year total fixed-cost revenue loss is $54.6 million. The present value of the $54.6 million is about $39 million, and the levelized loss is $6 million per year.

IPUC Staff conducted a similar 9-year analysis under the level of DSM investment anticipated under Idaho Power's 2004 Integrated Resource Plan. The 2004 IRP DSM plan does not include efficiency gains achieved under regional efforts such as NEEA, code changes, or other advancements, but does include a substantial increase in utility-managed DSM programs. Again assuming that any future fixed-cost revenue losses from installed efficiency measures are "zeroed out" after each rate case, the Staff-quantified 9-year total fixed-cost revenue loss is $3 million; the present value is about $2 million; and the levelized value is about $0.3 million per year. This $0.3 million amount is illustrative of the Staff-calculated fixed-cost revenue losses expected under potential levels of DSM activity identified by Idaho Power's 2004 Integrated Resource Plan (IRP).

However, as the discussion of NWPCC's Fifth Plan partly demonstrates, the amount of fixed-cost revenue losses would be much higher if the calculation accounted for other energy efficiency advances undertaken outside of Idaho Power's programs and for persisting energy

efficiency measures across rate cases. In the workshops, NRDC and NWEC contended these analyses understated potential losses from aggressive Idaho Power DSM programs. For example, Ralph Cavanagh of NRDC reviewed with the group the basis for the conclusion in his filed testimony that programs saving just one percent of system-wide electricity consumption annually would eliminate about $45 million in fixed-cost recovery within just five years. And NRDC/NWEC contended that even regular rate cases could not remove the continuing adverse effects of long-term electricity savings on the Company's balance sheet.

The amount of fixed-cost losses incurred under all of these scenarios varies by customer class due to the differing fixed costs of service for each class, and the amount of fixed costs recovered from energy and/or demand charges that vary with consumption. More than other classes, the fixed costs of serving the residential and small commercial customers are recovered through variable energy charges – and DSM programs for this class result in the largest fixed cost revenue losses. Moreover, in the residential class, energy usage per customer generally has been declining in recent years from a high mark of an average 14,474 kWh customer/year in 1991 to 12,635 kWh customer/year in 2003.

POTENTIAL MECHANSIMS TO ADDRESS LOST FIXED-COST REVENUES

In light of the expected loss of fixed-cost revenues from DSM programs described above, the workshop participants agreed that material financial disincentives to the implementation of DSM programs do exist. However, not all participants agreed that restoration of lost fixed-cost revenues – such as through an annual true-up mechanism – would directly result in additional or more effective investment in DSM programs by Idaho Power. The Commission's order initiating this matter identified possible solutions to address the disincentives to investment in DSM programs created due to lost fixed-cost revenues, including a true-up mechanism to restore

lost fixed costs, as well as performance based mechanisms to allow Idaho Power Company to share some of the benefits of successful DSM programs.

The workshop participants came to agreement on a set of criteria to evaluate different approaches to address lost fixed-cost revenues incurred by the Company due to successful DSM programs, or to provide incentives for DSM programs. The criteria are:

1. Stakeholders are better off than they would be without the mechanism.
2. Minimize cross subsidies across customer classes.
3. Removes financial disincentives.
4. Optimizes the acquisition of all cost-effective DSM.
5. Promotes rate stability.
6. Simple mechanism.
7. Administrative costs and impacts of the mechanism are known, manageable, and not subject to unexpected fluctuation.
8. Monitors short and long term effects to customers and company.
9. Avoids perverse incentives.
10. Close link between mechanism and desired DSM outcomes.

These criteria generally governed the workshop participants' consideration of mechanisms to address the lost fixed-cost revenues issue. For example, so-called "lost revenue recovery" mechanisms limited to DSM savings can be criticized because they turn program evaluation into a high-stakes adversarial process, and because they create an incentive for a utility to fashion a program that "looks good on paper," but does not actually perform well.

Likewise, a mechanism that simply trues up a utility's recovery of its authorized fixed-cost revenue requirement may be easy to implement and monitor, but only removes the financial

disincentive to DSM while other barriers may remain. For that reason, a true-up mechanism on its own may not drive a utility to acquire all cost-effective DSM available in its territory. In addition, a true-up mechanism may shift the current allocation of risks from changes in sales due to weather, economic shifts, or technological advances.

The workshop participants gave careful consideration to two mechanisms: a true-up mechanism to ensure that Idaho Power recovered no more or less than its authorized fixed-cost revenue requirement; and a pilot program to provide an incentive to the Company to achieve substantial cost-effective savings in one important category of DSM programs.

True-up mechanism: The Natural Resources Defense Council and NW Energy Coalition proposed a true-up mechanism to restore lost fixed-cost revenues to Idaho Power. The starting point for the proposal was the fixed-cost revenue requirement and retail rates approved by the Commission for Idaho Power's most recent rate case. The fixed-cost revenue requirement would then be automatically adjusted annually (until reestablished in the next rate case) as follows: (a) for the Industrial and Agricultural sectors, the fixed cost revenue requirement would be adjusted to reflect the same rate of increase (or decrease) shown for retail electricity sales, net of any DSM programs, in the load forecast section of Idaho Power's latest Integrated Resource Plan; or (b) for the Residential and Commercial sectors, the fixed cost revenue requirement would be adjusted to reflect the actual changes in annual customer count for the residential and commercial sectors (in other words, the fixed cost revenue requirement per customer would remain fixed until the next rate case). Concurrent with each annual power cost adjustment case, true ups would occur by customer class based on any divergence between the total fixed-cost revenue recovery that forecast sales of kilowatt-hours and demand charges (for Agricultural and Industrial sectors) or actual customer growth (for Residential and Commercial) would have

delivered versus the fixed-cost revenues actually recovered through actual sales. Idaho Power would continue to absorb the risk or benefits of purely weather-related effects on fixed-cost revenue recovery, as it does now. Actual sales would be weather-normalized before making the annual true-up calculation. The maximum annual average rate impact of the true up mechanism for any customer class would be capped at 2% annually, with any additional amounts carried over to the next year's true up.

Rather than actual implementation, the workshop participants agreed to a "Simulation" of the true-up proposal to help illuminate its potential impacts under the criteria described above. The Simulation would include both retrospective and prospective components by using the fixed-cost revenue requirements approved in the 1994 and 2004 rate cases as starting points. It would apply an assumed level of efficiency savings of 0.5% annually (roughly equivalent to the level of savings achievable under the NWPCC's Fifth Plan) each year starting in 1994 and 2004.

To illuminate the impacts of the true-up proposal, the Simulation would calculate the: (1) annual rate impact to each customer class for the true-up; (2) the impact of DSM savings on the PCA; (3) the annual impact to average customer bill amounts (assuming the 0.5% annual efficiency savings and the annual net benefit estimates developed in the energy efficiency assessment provided as an addendum to the 2004 IRP); and (4) total impact of true-up mechanism to IdaCorp shareholders.

Pilot Incentive: At the group's request the IPUC Staff developed a strawman proposal for a performance based Pilot Incentive. Staff chose to target the ENERGY STAR® Homes Northwest program for the strawman and at the group's request, Idaho Power and IPUC Staff later collaboratively refined it into a proposal. This DSM program, which was included in the Company's 2004 IRP, offers an incentive to builders to achieve a standard of 30% energy

savings over and above existing code requirements. The original program proposal targeted a specific number of homes in which to achieve these savings in 2005. With further refinement, Idaho Power adopted a MWH reduction target, encouraging the company to achieve even greater savings as well as putting the focus of the program on energy savings rather than a specific number of homes. The energy target to be achieved through this program in 2005 is a reduction of 1,070 annual MWH. The Idaho Energy Division conducts quality assurance for the program, and NEEA provides builder training. Under the Pilot Incentive, Idaho Power would recover fixed-cost revenues lost due to the validated energy savings provided by the program, and earn an additional incentive if the energy savings achieved by the program exceed 100% of the targeted savings. As described below, Idaho Power is expected to submit an application to the Commission to implement this program.

The ENERGY STAR® Homes Northwest program was chosen for the Pilot Incentive, because residential rates have a high fixed-cost component recovered through variable energy charges and because it is a relatively small program so any potential unanticipated impacts of the Pilot Incentive will be small. Also, this program is projected to be very cost effective and its results are expected to be relatively easy to monitor. The workshop participants also agreed to recommend adding Idaho Power's Energy Efficient Manufactured Home Incentives program to the Pilot Incentive. The targeted savings for this project is 555 annual MWH.

RECOMMENDATIONS OF THE WORKSHOP PARTICIPANTS

Idaho Power Company anticipates filing an application with the Commission to implement the pilot program described above. The workshop participants are supportive of the pilot as described in the workshops, but reserve their rights to comment on the proposal as filed with the Commission.

In addition, Idaho Power has agreed to implement a Simulation of the true-up mechanism proposed by NRDC and NW Energy Coalition, as described above, until Idaho Power's next general rate case. This action does not require action by the Commission; however, the results of the Simulation will be provided to workshop participants and the Commission contemporaneously with each annual PCA filing. Idaho Power will work with workshop participants as the Company prepares its next rate case filing to analyze the results of the Simulation and evaluate incorporation of a true-up mechanism into the rate filing.

This Final Report to the Commission has been reviewed and approved by Commission Staff and Idaho Power Company.

Dated this 14th day of February, 2005. Respectfully submitted,

William Eddie
Attorney for NW Energy Coalition

CERTIFICATE OF SERVICE

I hereby certify that on this 14th day of February 2005, true and correct copies of the foregoing FINAL REPORT were delivered to the following persons via hand delivery (for Commission recipients) and U.S. Mail (for all others):

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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 ATTACHMENTS TO FINAL REPORT ON WORKSHOP PROCEEDINGS

Attached hereto are summaries of all five (5) workshops conducted in the above matter. Due to the volume of material, one original printed copy is provided to the Commission, together with a computer disc providing electronic copies of the same. Additional computer discs can be obtained by contacting the undersigned counsel.

Dated: February 14, 2005

Respectfully submitted,

William M. Eddie
Attorney for NW Energy Coalition

DECOUPLING FOR IDAHO POWER COMPANY

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August 2004

TOPICS TO COVER:

- Basics of rate setting
- Regulatory reforms to support utility DSM programs
- Basics of decoupling
- Idaho Power Company costs and rates, fixed vs. variable costs
- Recoupling mechanisms
- IPC model results
- Conclusions and suggestions

2

SETTING RATES

3

SETTING RATES HAS TWO STEPS

1. Determine Revenue Requirements:
   - RR = Expenses + Return on Rate Base
   - Expenses = Fuel + Other Variable Costs + Fixed Costs
   - Fixed Costs = Fixed Operating Costs + Depreciation + Taxes + Interest Payments
   - Return on Rate Base = Overall Return (equity + debt)*Rate Base

4

SETTING RATES HAS TWO STEPS

2. Design rates
   - Functionalization: Generation, Transmission, Distribution, Other
   - Classification: Energy, Demand, Customer Service
   - Allocation: Residential, Small Commercial, Large Commercial, Industrial, Irrigation, etc...

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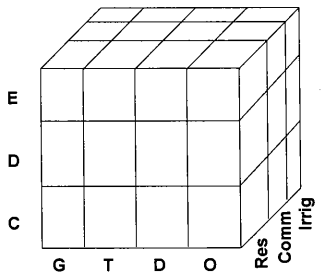
COST ASSIGNMENT IN RATE DESIGN



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TYPICAL RATE MIGHT HAVE SEVERAL ELEMENTS

- Monthly customer charge, $/month
- Energy charge(s), ¢/kWh
  - Time invariant, seasonal, time-of-use, or hourly
- Demand charge(s), $/kW-month
  - Coincident and/or noncoincident peak demands

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SETTING RATES INVOLVES MANY ASSUMPTIONS AND JUDGMENTS

- Historical vs. future test year
- Average vs. marginal costs
- Split generation costs into fixed vs. variable
- Inflation and interest rates
- Capital structure

8

REFORMS TO PROMOTE UTILITY DSM PROGRAMS

9

THREE-LEGGED STOOL FOR DEMAND SIDE MANAGEMENT

- Prompt and assured recovery of prudently incurred costs for program design and operation
- Protection against net lost revenues (e.g., decoupling)
- Incentives (share-the-savings) for exemplary programs
- Environmentalists focus on these key obstacles to utility implementation of cost-effective DSM
  - Align utility financial incentives with actions that benefit customers

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IPC RESIDENTIAL CLASS COST $243 MILLION IN 2003

	Customer	Demand	Energy
Generation		33	90
Transmission		21	
Distribution	49	23	
Customer	27		

$153 million

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RESIDENTIAL CLASS: 2003 PROPOSED RATES

- Rates include monthly and energy charges, no demand charges
  - $10/month + 5.19 ¢/kWh
  - 335,000 customers 4,140 GWh
  - $40 + $215 = $255 million
- 74% of fixed costs collected from energy rate
- Proposed revenues > costs to offset subsidy for irrigation customers

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IPC SHAREHOLDERS LOSE MONEY IF RESIDENCES CUT CONSUMPTION

- Energy charge: 5.19 ¢/kWh
- IPC energy cost: 2.17 ¢/kWh
- IPC shareholder loss from energy savings: 3.02 ¢/kWh

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NO LOGIC TO CURRENT SYSTEM

- Two studies (early 1990s) showed no link between changes in utility fixed costs and electricity sales
- Few reasons for current system of recovering fixed costs through variable charges:
  - Tradition
  - Convenience
- Should utility shareholders benefit from weather extremes (and lose money during mild winters and summers)?

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TRADITIONAL FIXED-COST RECOVERY DEPENDS ON FACTORS

- Largely unrelated to fixed costs
- Largely outside the utility's control (e.g., weather and economic growth)

15

HOW TO TREAT LOST REVENUE?

- Drop all utility energy-efficiency programs
- Run aggressive marketing programs
- Conduct annual rate cases
- Modify rate design (shift from energy to customer charges)
- Adopt net-lost-revenue adjustment mechanism
- Adopt decoupling mechanism
- Other ?

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RATE REFORM WOULD ELIMINATE LOST-REVENUE PROBLEM

- Cut energy charge from 5.19 to 2.17 ¢/kWh
- Increase monthly customer charge from $10 to $41
- IPC revenue unchanged, still $255 million
- IPC has no incentive to either discourage conservation or promote sales growth
  - Revenues from increased sales exactly cover increased variable costs

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DECOUPLING BASICS

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DECOUPLING HAS TWO PARTS

1. Policy decision to sever link between revenues (and utility earnings) and sales (kWh and perhaps kW)
2. Recouple revenues (more precisely, revenues to cover fixed costs) to something else:
   - Number of customers
   - Inflation
   - Determinants of fixed costs (cost of capital, labor rates, etc)
   - Forecasts of billing determinants
   - Other ??

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DECOUPLING MECHANICS

- Bill customers under current tariffs (existing customer, demand, and energy charges)
- Calculate allowed revenues with recoupling mechanism
- Put differences between actual and allowed revenues in balancing account
- Refund (surcharge) amount in imbalance account

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DECOUPLING ISSUES

- Decouple rates for all or only some rate classes
- Recouple on a class-specific or systemwide basis
- Select recoupling mechanism(s)
- Whether to weather-normalize adjustments
- Frequency of rate adjustments for decoupling
- Limits on magnitude of such rate adjustments

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POSSIBLE DECOUPLING CRITERIA

- Remove disincentive to customer energy efficiency
- Remove incentive for uneconomic load building
- Align incentives with IRP
- Retain incentives to
  - control costs, improve customer service, etc.
- Simple to understand and administer
- Difficult to manipulate
- Minimize volatility of electricity prices and utility earnings

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IPC COSTS AND RATES

23

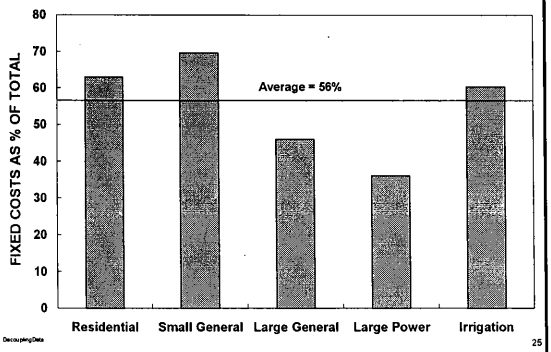
CLASSES DIFFER SUBSTANTIALLY

(these 5 account for 99% of IPC revenue)

	% of customers	% of energy
Residential (1)	84	38
Small general (7)	8	2
Large general (9)	4	28
Large Power (19)	0	18
Irrigation (24)	3	14

24

56% OF IPC'S COSTS ARE FIXED



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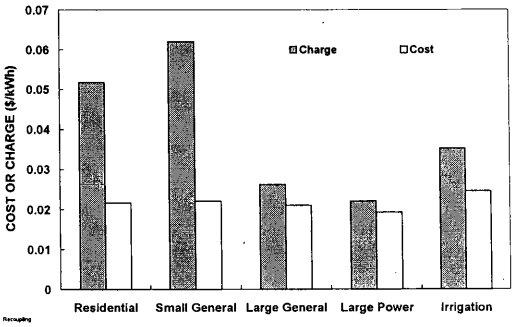
BIG DIFFERENCES BETWEEN ENERGY COSTS AND CHARGES



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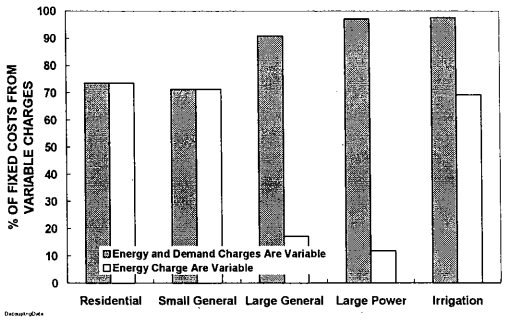
FRACTION OF FIXED COSTS FROM VARIABLE CHARGES



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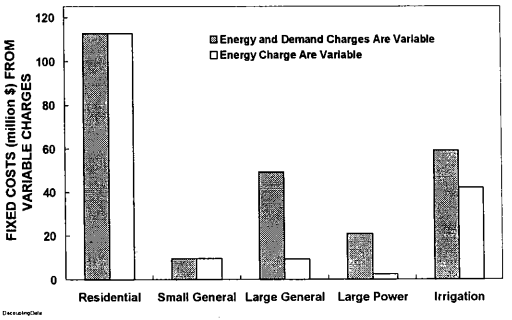
RESIDENTIAL CLASS: 2/3 OF FIXED COSTS FROM ENERGY CHARGES



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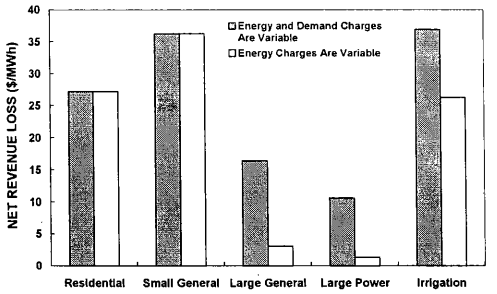
RESIDENTIAL AND SMALL COMMERCIAL CREATE LARGE EXPOSURE



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RECOUPLING MECHANISMS

30

SEVERAL RECOUPLING OPTIONS POSSIBLE

- Conduct rate cases with future test year every year or two (Oregon proposal)
- Recouple revenues to number of customers
  - Aggregate or class specific
- Recouple revenues to inflation
  - National or regional deflator, or industry specific indices (Handy Whitman)
- Forecast growth rates (using approved IRP forecasts for customers, energy, and demand)
- California-style attrition mechanisms

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MORE GENERALLY, SHOULD RECOUPLING TRACK

- Determinants of fixed costs
- Determinants of sales growth

?

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IPC MODEL RESULTS

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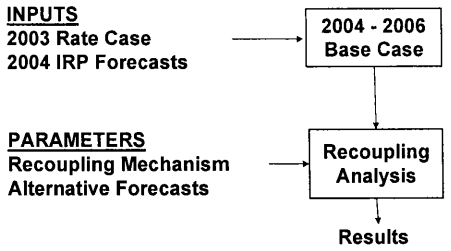
DEVELOPED EXCEL WORKBOOK TO ANALYZE DECOUPLING FOR IPC



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TESTED THREE RECOUPLING MECHANISMS WITH MODEL

- Revenue-per customer (RPC)
  - Class specific
  - Aggregate
- Inflation
- Forecast growth in customers, kWh and kW from 2004 IRP, by class
- Used 2003 as base, analyzed 2004 to 2006
  - 2003 results from IPC rate case, including proposed (not approved) rate structures
  - 2004 – 2006 growth rates from IRP
    - Customers, energy, demand, inflation

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AS WITH ALL ANALYSES, SEVERAL ASSUMPTIONS MADE

- All year-to-year changes in variable energy costs covered by Power Cost Adjustment, not analyzed here
- All T&D costs fixed
- Schedule 9 and 19 subclasses combined into single classes
- Seasonal and other demand components combined into one demand charge for each schedule
- Decoupling rate adjustments occur with no time lag
- Decoupling mechanisms weather normalized
  - Unlike current system, compensate for fixed costs based on normal weather.

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IRP FORECASTS AFFECT DECOUPLING REVENUES

	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

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CONDUCTED TWO SETS OF ANALYSES

- Base case (IRP growth rates by class) comparison across three recoupling mechanisms
- Effects of changes in individual growth rates on recoupling amounts for each mechanism

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BASE CASE ASSUMES IRP GROWTH RATES FOR BILLING DETERMINANTS

three-year (2004-2006) effects

RPC
- Bills down 0.05%
- IPC revenues down $2.7 million
- Energy/demand charges down 0.2%

- Inflation
  - Bills down 0.5%
  - IPC revenues down $7.7 million
  - Energy/demand charges down 1.5%

- Forecast growth
  - No changes in bills or rates (by definition)

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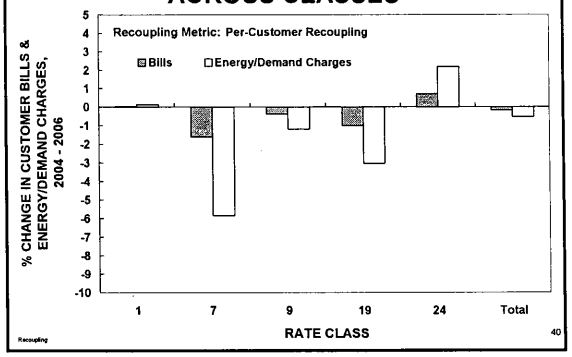
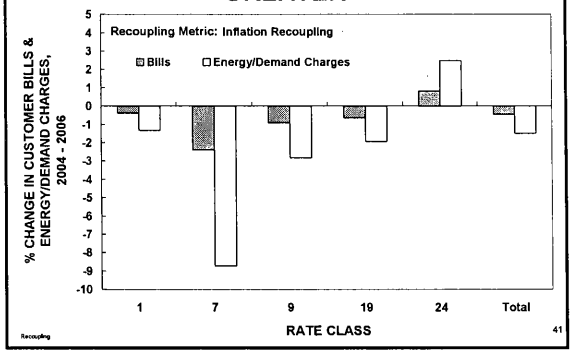
BASE-CASE RPC EFFECTS DIFFER ACROSS CLASSES



40

BASE-CASE INFLATION EFFECTS GREATER



41

RPC RESULTS VARY ACROSS CLASSES

- Fixed costs per customer vary from $420 for Sch 7 to $4,300 from Sch 24 and $206,300 for Sch 19
- Results, relative to base case, are symmetrical for higher (lower) growth in customers, energy, or demand
- Effects are additive for changes in multiple factors
- Effects differ in sign (as well as magnitude) among classes
- Overall, effects are small, < 1% of 3-year bills

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INFLATION RECOUPLING HAS LARGER EFFECTS

- Again, results, relative to base case, are symmetrical for higher (lower) growth in customers, energy, or demand
- Effects are additive for changes in multiple factors
- Unlike RPC, results are same for class-specific and aggregate decoupling
- Effects are similar across customer classes
- Although larger than RPC, effects are small (< 1% of bills over 3 years)

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FORECAST GROWTH RECOUPLING RESULTS SIMILAR TO INFLATION

- Relative to base case, forecast recoupling results are identical with inflation recoupling
- Again, overall effects small
  - 3-year change in customer bills < 1%

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DECOUPLING WORKS AS INTENDED FOR DSM PROGRAMS

- Tested slower growth in energy and demand (by 1%/year for three years)
- IPC fixed-cost recovery increases (over 3 years) by $16 million (0.9%) relative to no-decoupling case
  - Larger programs run for longer times (with no rate cases) yield larger losses for IPC
- % increase in rates > % increase in bills (next slide)

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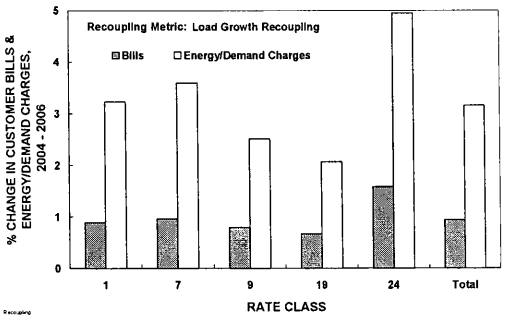
DECOUPLING WORKS AS INTENDED FOR DSM PROGRAMS



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CONCLUSIONS

- Current rate-making collects substantial revenues to cover *fixed* costs from *variable* kWh and kW charges
  - Makes no sense
  - Penalizes utility shareholders if customers use energy more efficiently
- Decoupling breaks link between revenue and sales, removes utility disincentive to customer efficiency
- Decoupling has other effects; customer rates and bills can vary with decoupling independent of DSM programs
  - Effects likely to be small

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SUGGESTIONS TO COLLABORATIVE

- Develop independent model of decoupling for IPC
  - Select new recoupling mechanisms
  - Use actual PUC-approved rate structures
- Search for metrics related to determinants of fixed costs
  - Meet environmental goal of decoupling
  - Increase stability of utility earnings
- Consider decoupling for one or two rate classes (e.g., Sch. 1 and 7)
- Review recent utility experiences with
  - DSM programs
  - Decoupling

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Assessing Financial Disincentives and Resolution Opportunities, Workshop #2

September 27, 2004, 9:30 a.m. to 12:30 p.m.
Idaho Power Corporate Headquarters, Boise, ID

Facilitation Susan Hayman, North Country Resources, Inc.
Documentation Natalie Chavez, Chavez Writing & Editing, Inc.

Workshop Objectives

1) Develop operational protocols for the remaining workshops
2) Continue investigating the nature and extent of financial disincentives to energy conservation programs (DSM)
3) Explore a potential decoupling mechanism to address DSM investment disincentives

Workshop Decisions and Outcomes

The next meeting will be held November 8, 2004, from 9:30am - 3:30pm at IPC. The morning will be spent reviewing results of action items 1 through 3 (below), while the afternoon will be reserved for discussing performance-based incentives.

Action Items

1) Run a model of the following: a) IRP—rate impacts by class b) NWPCC—rate impacts by class c) Estimate of savings from conservation (using Aurora)	Randy Lobb, Ric Gale, and Ralph Cavanagh
2) Discuss development of a tool to poll customers about energy-conservation/efficiency programs.	David Hawk and Ric Gale
3) Recalculate numbers with an interim rate case but in the absence of a true-up mechanism.	Lynn Anderson
4) List ideas for possible performance-based incentives, and develop a "strawman" if an idea stands out.	All
5) Make requested changes to "Operational Protocol" and to "Definitions." E-mail revised documents to participants.	Susan Hayman

Workshop Operational Issues

Susan Hayman welcomed participants (Appendix 1), had them introduce themselves, and then reviewed the agenda (Appendix 2). Participants had no changes to the agenda. Hayman had compiled an operational protocol for the series of workshops, based on conversations she had with participants. The group reviewed and made the following revisions to (decisions about) the operational protocols for the workshops (Appendix 3):

- Workshop Purpose statement 1—add "and customers" to the end of the clause
- Workshop Purpose statement 2—retain "performance-based ratemaking" since that language appeared in the IPUC order (Order No. 29558, p. 2), but add "incentives" in parentheses following that phrase

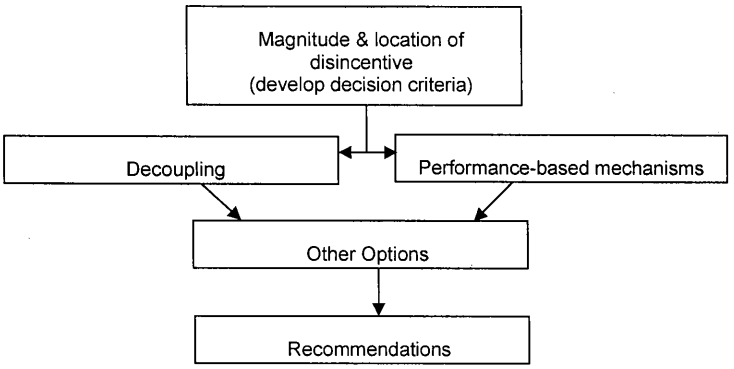
- Roles and Responsibilities statement 2f—designate coordinators: IPC–Mike Youngblood, IPUC–Lynn Anderson, NWEC–Bill Eddie, and Industrial Customers–Peter Richardson
- Analysis statement—replace the question with "Analysis needs will be identified and assigned as they emerge."

Hayman also provided a definitions list for review (Appendix 4). Following are the revised definitions for "demand side management" and "true-up." Definitions for "performance-based incentives" and "decoupling" stood as worded.

- Demand Side Management (DSM): Management tools and actions that are designed to result in decreases or shifts in customer energy demand and/or consumption.
- True-Up: A decoupling mechanism where a periodic adjustment in electric rates is used to correct for disparities between a utility's actual fixed-cost recovery and its authorized fixed-cost recovery.

NATURE & EXTENT OF FINANCIAL DISINCENTIVES

Hayman distributed questions raised in conversations with participants and grouped into categories (Appendix 5). These questions could be revisited after today's discussions to see which had been answered and which remained. Some could also be assigned for analysis, if appropriate. She also shared a flowchart she had drawn on the whiteboard and asked if there was any dissension about the process. Workshop participants accepted the flowchart.



Fixed-Cost Revenue Loss Analyses

Prior to the workshop, Lynn Anderson, IPUC, had e-mailed participants a memo and Excel worksheet (Appendix 6). He had calculated IPC's fixed-cost revenue losses under three 9-year scenarios that he had developed to try to quantify the nature and extent of financial disincentives. These calculations are gross estimates that are not adjusted for taxes, cost changes, offsetting benefits, etc. They also assume no intervening rate cases, which would reset the base rates upon which the fixed-cost revenue loss would be calculated on a going forward basis. He shared that information with the whole group and answered questions.

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Integrated Resource Plan Scenario

- Under the IRP scenario, the fixed-cost revenue loss grows to about $1.3 million per year by 2013.
- The 9-year total for all rate classes is about $6 million, with a net present value of about $4 million. The residential 9-year total is about $2 million. These figures are based solely on energy charges, not energy and demand charges. Adding fixed-cost revenue loss from demand savings would increase the $6 million by about a third.

- Northwest Energy Efficiency Alliance (NEEA) efforts were excluded from the scenario.

Northwest Power and Conservation Council Scenario

- Under the NWPCC scenario, the fixed-cost revenue loss grows to about $23 million per year by 2013. The 9-year total for all rate classes is about $114 million, with a net present value of about $75 million. The residential 9-year total is about $51 million.
- Results from this analysis are consistent with numbers that Ralph Cavanagh came up with. His calculations show $45 million in fixed-cost revenue loss over the first five years, his number includes demand charge losses as well as energy charge losses. Anderson arrived at $38 million using only energy charge losses.
- For the commercial class, the loss/MWh unsold jumped from $9.70 under the IRP scenario to $41.50 under the NWPCC scenario. This class included both schedule 07 and 09 rate classes though. If the analysis were fine-tuned, this discrepancy would need to be addressed.
- IPC's share of 6.5% is based on sales. The potential is greater since IPC hasn't done much DSM in the last several years.
- How rate cases would affect the $114 million was uncertain. Intervening rate cases reset fixed-cost revenue requirements but do not allow IPC to recover revenue losses incurred since the previous rate case. Ric Gale said that an analysis of what would happen would be fairly simple to do.

Historical Residential Scenario

- Under this scenario, only residential fixed-cost revenue losses are calculated. Using weather-normalized kWh per customer consumption data, the hypothetical fixed-cost revenue loss grows to $18 million in 2003, the 9th year following IPC's 1994 rate case.
- The $18 million shown for 2003 is almost identical to what the IPUC will give IPC for the rate increase for residential customers under the just-completed rate case, despite the scenario being an oversimplification.
- Average monthly per customer usage decreased by 143 kWh in the 9-year period. During this time, IPC had very little residential DSM; its participation in NEEA probably accounts for less that 5% of the reduction. The reductions are mostly focused into two years (2001 and 2002) when there was also a nationwide reduction in electricity consumption. There were also 40% PCA increases in those two years. These electricity savings may have been offset by increased gas consumption.

Summary—Areas of Agreement

After the three scenarios were presented and discussed, participants listed their conclusions about the magnitude of the problem and the location of disincentives. Below are issues that were raised during this discussion:

- IPC's historical lost revenues are a disincentive to something, but it's difficult to say that they are a disincentive to energy efficiency since the lost revenues in the third scenario are not associated with DSM.
- If there is a relatively aggressive DSM program and it achieves energy-efficiency objectives, there is a cost to the company. What remains unknown is how much it would cost to "fix" the problem and whether that price is tolerable. In addition, it is important to understand what IPC would do differently if the company recovered costs incurred through DSM.
- "Demand reduction" occurs with higher pricing. But higher pricing isn't the solution that people are looking for. They would like to know how to separate demand reduction due to energy-efficiency programs from that due to higher prices. Also, what are the impacts of different energy-efficiency programs?

"STRAWMAN" PROPOSAL FOR AN IDAHO POWER TRUE-UP MECHANISM

Ralph Cavanagh introduced a strawman proposal for a true-up mechanism (Appendix 8). A true-up mechanism is "not about paying the company anything; it simply provides IPC a means for recovering fixed costs." It is designed around an authorized fixed-cost revenue requirement.

Under his proposal, the starting point would be the fixed-cost revenue requirement and retail rates approved by the IPUC in the latest IPC rate case. If, after the first year, changes in retail electricity use lead to under- or overrecovery of the fixed-cost revenue requirement, then a rate true-up would occur in the following year on the same schedule as IPC's current PCA. Until reestablished in the next IPC rate case, the currently approved fixed-cost revenue requirement would be automatically adjusted annually to reflect the same rate of increase or decrease shown for retail electricity sales, net of any DSM programs, in IPC's latest IRP. True-ups would occur annually based on any divergence between the total fixed-cost revenue recovery that forecast sales would have delivered and the fixed-cost revenues actually recovered. The true-ups would be done for each customer class based on divergence between actual and forecast sales to each customer class. IPC would continue to absorb the risk or benefits of purely weather-related effects on fixed-cost revenue recovery, as it does now. Actual sales would be weather normalized before the annual true-up calculation was made. Cavanagh emphasized that the maximum annual anticipated rate impact of the true-up mechanism, up or down, under extreme conditions would be 1.5%.

Several issues were raised during the presentation and associated discussion (Appendix 9):

- This mechanism does not include figuring out how much of the difference is attributable to different factors.
- Because the fixed-cost revenue requirement would track forecasted sales rather than historical sales, IPC would not be paying extra if DSM programs were successful. Every year, the company would be truing up to a number known in advance at the same schedule that is now used.
- Although Cavanagh proposed truing up for every customer class (except special contracts because of other complexities), the mechanism would work in part (for certain customer classes).
- At one point, IPC classified DSM as a supply side investment: the money was capitalized and amortized over a number of years. But the benefits didn't materialize for a number of reasons.
- Basing the true-up mechanism on forecasted sales might motivate IPC to inflate its forecasted numbers. Deterrents might include having the forecast adopted independently or using a different index after the next general rate case.
- To better understand the effects of DSM on fixed-cost revenue loss, people suggested rerunning the scenarios and running the Aurora model, given some of the discussion points raised during the workshop. The following action items resulted from this discussion and were assigned to Randy Lobb, Ric Gale, and Ralph Cavanagh to coordinate:
    - Rerun the IRP scenario with rate impacts by class
    - Rerun the NWPCC scenario with rate impacts by class
    - Use Aurora to estimate changes in power supply costs that may result from increased levels of energy conservation
    - Recalculate scenario numbers with an interim rate case (assigned to Lynn Anderson)
- A poll of customers' appetite for energy-efficiency programs might help in estimating potential savings from conservation. David Hawk and Ric Gale will discuss the value and development of a poll.

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NEXT STEPS/WRAP-UP

Hayman reviewed action items that need to be done before the next workshop. This workshop was set for November 8, 2004, from 9:30am - 3:30pm at IPC. The morning will be spent reviewing results of the model runs and Anderson's scenarios with an interim rate case included. The afternoon will be reserved for discussing performance-based incentives. Gale encouraged people to develop other strawmen if they

have ideas. Cavanagh offered to circulate a proposal for a performance-based mechanism in advance of the workshop.

During a quick workshop evaluation, participants asked that people who will be sharing information distribute that information in advance so that people have a chance to review it.

APPENDIX 1—PARTICIPANTS

Name and Affiliation	E-mail Address	Phone No.
Peter Richardson, Industrial Customers of Idaho	peter@richardsonandoleary.com	938-7901
Don Reading, Ben Johnson Associates	dreading@mudspring.com	342-1700
Mike Youngblood, Idaho Power	myoungblood@idahopower.com	388-2882
Maggie Brilz, Idaho Power	mbrilz@idahopower.com	388-2848
Greg Said, IPC	gsaid@idahopower.com	388-2288
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Randy Lobb, IPUC	rlobb@puc.state.id.us	334-0350
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Scott Woodbury, IPUC	swoodbu@puc.state.id.us	334-0320
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Bill Eddie, Advocates for the West	billeddie@rmci.net	342-7024 x 3
Ric Gale, Idaho Power	rgale@idahopower.com	388-2887
Terri Carlock, IPUC	tcarloc@puc.state.id.us	334-0356
David Hawk, J.R. Simplot Co.	david.hawk@simplot.com	389-7306

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APPENDIX 2—AGENDA

ASSESSING FINANCIAL DISINCENTIVES AND RESOLUTION OPPORTUNITIES
WORKSHOP #2

September 27, 2004
9:30am-12:30pm
Auditorium East
Idaho Power Corporate Headquarters
Boise, Idaho

Objectives:

1) Develop operational protocols, objectives and outcomes for this effort;
2) Continue investigating the nature and extent of financial disincentives to energy conservation programs (DSM);
3) Explore a potential decoupling mechanism to address financial disincentives.

Draft Agenda

Time	Topic	Process
9:00am	*Coffee/Tea available in meeting room*	
9:30am	**Welcome/Introductions/Meeting Overview** – Susan Hayman, Facilitator	Information
9:40am	**Workshop Operational Issues** – Susan Hayman • Workshop series purpose and products (incl. terminology) • Participant roles & responsibilities • Decision-making • Documentation	Information/Discussion
10:20am	**Nature & Extent of Financial Disincentives** • Fixed-Cost Revenue Loss Analyses – Lynn Anderson – Important Omissions, Caveats and Disclaimers – DSM-caused losses under IRP projection – DSM-caused losses under NWPCC draft DSM projection – Residential historical declining kWh per customer • Areas of agreement on the current situation	Presentation Discussion
11:20am	**BREAK**	
11:30am	**"Strawman" Proposal for an Idaho Power True-Up Mechanism** – Ralph Cavanagh	Presentation Discussion
12:10pm	**Wrap-Up** – Susan Hayman • Workshop schedule • Agenda items for next workshop – Susan Hayman • Evaluation	Discussion
12:30pm	**Adjourn**	

APPENDIX 3—OPERATIONAL PROTOCOLS

Workshop Series – Operational Protocol

Workshop Name: Assessing Financial Disincentives and Resolution Opportunities

Workshop Purpose:

1) To investigate the nature and extent of financial disincentives to investment in energy efficiency by Idaho Power Company and customers;
2) To investigate decoupling and performance-based ratemaking (incentives) as mechanisms to address financial disincentives (IPUC Order # 29558, 8/10/2004). *Other mechanisms can be subsequently explored if the participants agree that this would be useful.*

Workshop Products: A written report to the Idaho Public Utilities Commission to update the Commission on the status of the investigative workshops. This report will include a summarized assessment of:

1) The nature and extent of financial disincentives to investment in energy efficiency by Idaho Power Company;
2) Recommendations regarding specific decoupling and/or performance-based mechanisms that may reduce/remove these financial disincentives.
3) Recommendations for next steps.

Workshop Tenure: August 24 through December 15, 2004

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1) **Composition of Workshop Participants**
   While workshops will be open to the public, it is expected that participants will generally represent the Idaho Public Utilities Commission, Idaho Power Company, Northwest Energy Coalition, representatives of industrial customers, representatives of residential customers, and representatives of irrigation customers.

2) **Roles & Responsibilities of Workshop Participants**
   a) Be active in the discussion, be solutions-oriented, and act in "good-faith."
   b) Help others at the table to understand your interests, and actively seek to understand the interests of others.
   c) Be informed – Review the previous workshop summary, the agenda and prework in advance of the next workshop.
   d) Follow-through in a timely manner with any assigned action items.
   e) Attend workshops regularly – the group will not revisit decisions/discussions missed by others.
   f) **Workshop Coordinators:** One representative each from Idaho Power Company (Mike Youngblood), Idaho Public Utility Commission (Lynn Anderson), ~~and~~ Northwest Energy Coalition (Bill Eddie), and industrial customers (Peter Richardson). Responsibilities include coordination with the facilitator on the workshop objectives, outcomes, agenda and process.

3) **Role & Responsibilities of the Facilitator**
   a) Manage the workshops, serve as a process coach, maintain neutrality and impartiality, and reinforce the collaborative process.
   b) Refine the objectives and outcomes for each workshop, in cooperation with the workshop coordinators. Propose a workshop agenda and appropriate processes to reach the identified

objectives and outcomes, and finalize this with the coordinators. The agenda, and any prework materials, will be distributed to participants at least one week prior to each workshop.

c) Communicate with participants outside of workshops as needed.

d) Maintain a record of workshop participants, and a summary of workshop discussions (see #6, Record Keeping).

e) Assist in preparation/compilation of the written report to the Idaho Public Utilities Commission.

4) **Analysis**

~~*Who is going to provide analysis support for this workshop (collect data, develop and analyze scenarios, etc.)?*~~ Analysis needs will be identified and assigned as they emerge.

5) **Decision-Making**

a) **Entities with multiple representatives:** While each individual participant will have input into the workshop deliberations, it is desirable that each entity represented speak with one voice in decision-making. Therefore, while numerous individuals may represent a given entity at a workshop, it is expected that one person will speak on behalf of the entity when decisions are made. Each entity should designate that person in advance. The facilitator will provide time for representatives to consult with each other as needed prior to critical decisions.

b) **Types of decisions:** There are two types of decisions participants will make:

- *Workshop decisions:* These decisions are related to workshop topics, process and schedule. Workshop decisions already made by the IPUC in Orders 29505 and 29558 will be honored. Decisions at the discretion of the group will be made by consensus.
- *Product decisions:* These decisions are related to the findings and recommendations workshop participants will present in their written report to the IPUC on December 15, 2004. Consensus will be the goal – However, if consensus cannot be reached, areas of agreement and disagreement on the findings and recommendations will be provided in the written report.

6) **Record-Keeping**

a) The facilitator will arrange for notes to be taken on a laptop computer during the workshop. The distributed workshop will include key discussion points, decisions, areas of agreement and disagreement, action items, etc. They will not be a transcription of "who said what."

b) The facilitator will be responsible for preparing the workshop summary and distributing it to participants within three business days after each workshop.

c) The facilitator will maintain a file of all workshop summaries, handouts, and products.

7) **Principles of Meeting Conduct**

a) Focus attention on the speaker (no side conversations)

b) Be specific, but succinct, in questions and comments

c) Participate fully, but don't dominate the discussion.

d) Respect other's contributions, and learn from them.

e) Challenge ideas, not people

f) Be on time

g) Turn cell phones, pagers or other electronic devices off or inaudible during meetings.

APPENDIX 4—DEFINITIONS (WITH REVISIONS)

Definitions

Demand Side Management (DSM): Management tools and actions that are designed to result in decreases or shifts in customer energy demand and/or consumption~~Anything that a utility does that affects customer energy demand, consumption and/or time of use~~.

Performance-Based Incentives (PBI): Mechanisms that allow a utility to share and retain benefits gained from energy efficiencies, as well as provide consequences for failing to meet efficiency goals.

Decoupling: Severing the link between a utility's kWh sales and its recovery of revenues to cover fixed costs.

True-Up: A decoupling mechanism where a periodic adjustment in electric rates is used to correct for disparities between a utility's actual fixed cost ~~recoveries~~recovery~~.~~ and its authorized fixed-cost recovery~~rate of return~~.

APPENDIX 5—QUESTIONS RAISED IN PARTICIPANT CONVERSATIONS

Questions Raised in Participant Conversations

Financial Disincentives

- What effects do disincentives have on customers and on IPC?
- What is the projected loss of revenue to IPCO from DSM programs over the next 10years?
- What are the NWPC projections of demand over the next 10 years (relevant to IPCO)?
- What would the removal of disincentives accomplish for customers and IPCO?
- Should IPCO be "made whole" when they encourage customers to use less of their products (it mean to be "made whole")?
- What should be the basis for reimbursement of lost kWh and out-of-pocket cost to support D
- If disincentives were not in place, could IPCO invest more in DSM?
- Are there disincentives to DSM other than financial?

DSM Programs

- What effect does DSM have on resource acquisition?
- If customers ultimately have to pay more (to decouple fixed costs from variable energy use), programs will be created?
- Should there be consequences for not investing in DSM?
- If funds are invested to support DSM programs...

  -- How will these funds be administered?

  -- How will the efficacy of administration be measured/monitored?

Questions Raised in Participant Conversations (cont'd)

Decoupling and/or Performance-Based Mechanisms

- What effects would decoupling have on customers and on IPCO?
- If decoupling would have been in place during the last 10 years, what would have been the customers and IPCO (state assumptions)
- If decoupling were adopted at IPCO, what would be the options for structuring (rate classes system-wide, apply to energy charges or both energy and demand charges, etc.)
- What are the side effects to decoupling?
- What effects would performance based mechanisms have on customers and on IPCO?
- What are the side effects to performance-based incentives?
- What criteria will we use to evaluate decoupling and performance-based mechanisms?

Other Mechanisms

- Are there more appropriate mechanisms than decoupling and/or performance-based mecha IPCO financial disincentives?

APPENDIX 6—FIXED-COST REVENUE LOSS ANALYSES

IPC DSM F-C Revenue Loss - IRP

Only DSM Selected in the 2004 IRP *(2004-2013 Planning Period)*
Idaho Power IPC-E-04-018, IRP Technical Appendix
Energy Savings (Excluding NEEA)
Net of Free Riders, Includes Losses

	Year	Energy Savings (Megawatt-hours) Residential	Commercial	Irrigation	Industrial	Total MWh	(Numbers by IPC 9/21/04) Peak Reduction (MW) Res.	Com.	Irrig.	Ind.	Total
	2005	1,070	389	5,767	9,427	16,653	0.6	0.1	2.9	1.2	4.9
	2006	2,625	1,087	11,534	18,853	34,100	1.5	0.4	5.8	2.4	10.1
	2007	4,193	1,900	17,300	28,280	51,674	2.5	0.7	8.7	3.6	15.4
	2008	5,784	2,810	23,067	37,706	69,367	3.4	1.1	11.5	4.8	20.8
	2009	7,397	3,801	28,834	47,133	87,166	4.3	1.5	14.4	6.0	26.2
	2010	9,205	4,861	34,601	56,559	105,226	5.3	1.9	17.3	7.2	31.7
	2011	11,028	5,980	40,368	65,986	123,363	6.3	2.4	20.2	8.4	37.2
	2012	12,872	7,149	46,134	75,412	141,566	7.3	2.8	23.1	9.6	42.8
End of IRP Planning Period	2013	14,734	8,359	51,901	84,839	159,833	8.3	3.3	26.0	10.8	48.3
					aMW (2004 IRP)=	18.25	8.3	3.3	26.0	10.8	48.3
	Total	68,908	36,337	259,506	424,195	788,946					

Peak MW (Energy Programs)	48.3
Peak MW (Demand Response)	75.6
Total Peak MW Selected DSM	123.9

Calculation of Fixed Cost Lost Revenue per MWh for Various Rate Schedules

	Residential	Commercial'	Irrigation	Industrial**
Energy Rate ($/MWh)	51.9	30.0	32.6	21.8
Variable Cost ($/MWh)	20.7	20.3	23.5	18.5
Loss/MWh unsold	**$31.20**	**$9.70**	**$9.10**	**$3.30**

(*) Commercial rate is a weighted avg. of schedules 07 & 09S based on energy use.
(**) Ind. rate is a wghtd. avg. of schs. 09 P & T and 19 S, P & T based on energy use.

Note that the $/MWH here are diff for com. & indust. than on NWPCC sheet.

Fixed Costs Not Recovered Due to DSM Selected in IRP

	Year	Residential	Commercial	Irrigation	Industrial	Total
	2005	$33,370	$3,775	$52,480	$31,109	$120,734
	2006	81,905	10,548	104,959	62,215	259,627
	2007	130,837	18,432	157,430	93,324	400,023
	2008	180,467	27,256	209,910	124,430	542,063
	2009	230,799	36,871	262,389	155,539	685,599
	2010	287,187	47,156	314,869	186,645	835,857
	2011	344,084	58,008	367,349	217,754	987,194
	2012	401,601	69,341	419,819	248,860	1,139,621
End of IRP Planning Period	2013	459,689	81,082	472,299	279,969	1,293,038
	Total	$2,149,939	$352,469	$2,361,505	$1,399,844	$6,263,756
WACC = 7.20%						
PV 9-yr. (2005-2013)		$1,434,141	$ 232,128	$1,593,395	$ 944,526	$ 4,204,190
Avg Annual		429,988	70,494	472,301	279,969	1,252,751
Levelized (9-yr.)		214,415	34,705	238,224	141,214	628,557

The fixed-costs not recoverd at left are the product of multiplying each year's energy savings (excluding NEEA) in the top box by the loss/MWh unsold in the middle box (IPC adj. of Eric Hirst numbers). The "losses" are not adjusted for income taxes, cost changes, offsetting benefits, etc. All losses assume no rate cases 2005-2013.

NWPCC Draft 5th Plan -- Not Reviewed By Council

Achievable, Cost-Effective DSM Potential by 2025

IPC DSM F-C Revenue Loss - NWPCC

			Potential DSM in NW 2005-2025 Total aMW	IPC's 20-yr. aMW @ 6.50%	IPC's annual aMW	IPC's annual MWh	Idaho Power's Fixed-Cost Revenue Losses ($millions) 2005	2006	2007	2008	2009	2010	2011	2012	201
Res.	Refrigerators		5												
Res.	Clothes Washers		135												
Res.	Dishwashers		10												
Res.	Water Heaters		80												
Res.	H.P. Water Heaters		195												
Res.	H.W. Heat Recovery		20												
Res.	Compact Flourescent		535												
Res.	New Space Cond.		40												
Res.	Existing Space Cond.		95												
Res.	HVAC Upgrades		65												
Res.	HVAC Conversion		70												
Res.	HVAC Commission		20												
	Res. Total	44.8%	1,270	82.6	4.13	36,157	1.1	2.3	3.4	4.5	5.6	6.8	7.9	9.0	10.
Com.	Equipment, new/repl.		85												
Com.	HVAC, new/repl.		150												
Com.	Infrastructure, new/repl.		20												
Com.	Lighting, new/repl.		245												
Com.	Shell, new/repl.		15												
Com.	Equipment, retrofit		110												
Com.	HVAC, retrofit		120												
Com.	Infrastructure, retrofit		110												
Com.	Lighting, retrofit		115												
Com.	Shell, retrofit		10												
	AC/DC power conv.		155												
	Com. Total	40.0%	1,135	73.8	3.69	32,313	1.3	2.7	4.0	5.4	6.7	8.0	9.4	10.7	12.
Irrig.	All Agriculture		80												
	Irrig. Total	2.8%	80	5.2	0.26	2,278	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.
Ind.	All Non-Aluminum		350												
	Ind. Total	12.3%	350	22.8	1.14	9,965	0.0	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.
	Total	100.0%	2,835	184.3	9.21	80,712	2.5	5.1	7.6	10.2	12.7	15.2	17.8	20.3	22.

	2005	2006	2007	2008	2009	2010	2011	2012	201
Cumulative Total	$2.5	$7.6	$15.2	$25.4	$38.1	$53.3	$71.1	$91.4	$114.

$/MWh From IPC's 3/30/04 Eric Hirst Decoupling Report, p. 5 -- IPC Updated	Res.	Com. -7	Irrig.	Indust. -all 9 & 19 sch. (wt. avg.)	
Energy Charge	51.90	62.60	32.60	24.40	Note that the $/MWH here
Variable Cost	20.70	21.10	23.50	19.50	are diff. for com. & indust.
Loss/MWh unsold	$31.20	$41.50	$9.10	$4.90	than on IRP-selected sheet.

Idaho Power's 6.5% share is based on its current NEEA allocation, which may represent its potential for each program customer class.

All revenue losses assume no interv rate cases and no customer growth.

Idaho Power-Idaho Only Sales and Customers

IPC DSM F-C Revenue Loss - Historical

Residential Only

Year	Residential Revenue	Weather Normalized MWh Sold	Customers	Weather Norm. kWh Cust./mo.	Hypothetical Fixed-Cost Revenue Loss
1987	$129,436,545		217,104		
1988	140,569,164		219,005		
1989	155,211,941		221,617		
1990	153,080,652		226,323		
1991	162,388,156		231,347		
1992	158,306,311		237,837		
1993	173,124,151	3,524,040	246,278	1,192	
1994	174,880,654	3,589,867	255,735	1170	
1995	184,321,208	3,717,787	264,901	1170	23,324
1996	191,716,079	3,776,360	273,834	1,149	2,108,207
1997	190,655,639	3,864,922	282,054	1,142	2,945,197
1998	201,626,186	3,987,589	290,532	1,144	2,831,082
1999	203,972,260	4,076,279	300,072	1,132	4,242,165
2000	215,560,768	4,160,997	309,499	1,120	5,727,683
2001	250,774,139	4,142,665	318,076	1,085	10,056,112
2002	296,274,337	4,100,268	326,788	1,046	15,194,468
2003	266,499,664	4,141,393	336,204	1,027	18,035,272
				9-year total=	$61,163,509

Post 1994 "Hypothetical Fixed-Cost Revenue Loss" calculation uses 1,170 kWh per month as the residential weather normalized consumption base.

The average consumption decrease of 143 kWh from 1,170 in 1994 to 1,027 in 2003 represents a 1.4% average annual decrease. Idaho Power had very little residential DSM during this time period. It is likely that increased natural gas penetration is responsible for most of the decreased electricity use.

The calculation uses $31.20 as the residential "loss/MWh unsold" (IPC's update to Hirst's number) and assumes the fixed-cost lost revenue recovery formula would have compensated IPC for all weather normalized declining kWh sales per customer.

Total Retail Sales, All Classes

	Revenue	MWh	Customers
1994	434,690,290	11,622,194	306,881
1995	438,527,438	11,395,255	317,760
1996	458,675,200	12,410,881	328,676
1997	454,141,771	12,594,311	339,022
1998	488,226,974	12,720,471	349,339
1999	489,565,724	13,077,842	360,021
2000	537,735,312	13,895,478	370,101
2001	624,448,755	12,391,914	380,593

$/MWh From IPC's 3/30/04 Eric Hirst Decoupling Report, p. 5 -- IPC Updated

	Res.	Com. -7	Irrig.	Indust. -all 9 & 19 sch. (wt. avg.)	
Energy Charge	51.90	62.60	32.60	24.40	Note that the $/MWH here
Variable Cost	20.70	21.10	23.50	19.50	are diff. for com. & indust.
Loss/MWh unsold	$31.20	$41.50	$9.10	$4.90	than on IRP-selected sheet.

Year	1-yr. Avg. Bill	Revenue per kWh	Actual Kwh sold	Actual 1-yr. Avg. kWh/cust. per month	Actual 3-yr. Avg. kWh/cust. per month	Weather Norm. kWh Sold
1987	49.68	0.0432	2,995,218,168	1,150		
1988	53.49	0.0446	3,148,903,043	1,198		
1989	58.36	0.0469	3,306,433,702	1,243	1,197	
1990	56.37	0.0474	3,230,831,759	1,190	1,210	
1991	58.49	0.0473	3,430,432,527	1,236	1,223	
1992	55.47	0.0481	3,289,387,264	1,153	1,193	
1993	58.58	0.0483	3,582,828,720	1,212	1,200	3,524,040,421
1994	56.99	0.0484	3,610,314,912	1,176	1,180	3,589,867,417
			8-yr. Average, 1987 to 1994 =		**1,195**	
1995	57.98	0.0518	3,556,816,130	1,119	1,169	3,717,787,134
1996	58.34	0.0508	3,775,150,065	1,149	1,148	3,776,360,493
1997	56.33	0.0496	3,843,356,042	1,136	1,134	3,864,921,749
1998	57.83	0.0518	3,891,822,308	1,116	1,134	3,987,588,792
1999	56.65	0.0510	3,997,632,389	1,110	1,121	4,076,279,049
2000	58.04	0.0515	4,189,182,972	1,128	1,118	4,160,997,320
2001	65.70	0.0609	4,117,127,872	1,079	1,106	4,142,664,831
2002	75.55	0.0706	4,197,803,194	1,070	1,092	4,100,268,216
2003	66.06	0.0629	4,238,675,325	1,051	1,067	4,141,393,426

APPENDIX 7—FLIP CHARTS REGARDING ANALYSES

Financial Disincentives

(Lynn Anderson's Presentation)

1) Add in lost demand charge to calculating of total financial loss (IRP scenario)
2) $6 million loss in revenue under IRP DSM projections. IRP—no tax impact if company made whole
3) Lynn's projections do not include savings from NEEA.
4) $114 million loss in revenue under NWPCC scenario.

Financial Disincentives (cont.)

5) 6.5% kWh sold in NWPCC attributed to IPC
6) Intervening rate cases reset fixed-cost requirements, but do not allow IPCO to recover lost $$ since previous rate case.
7) (hist) NEEA effects < 5% customer use—has occurred without utility DSM programs.
8) Over 9-year period, utility had no active residential DSM program.

Conclusions—Financial Disincentives

1) IPCo historical lost revenues is a disincentive to something. Historically, not tied to DSM.
2) If there is a relatively aggressively DSM program, and achieves objectives, there is a cost to company.
3) "Demand destruction" occurs with higher pricing.
4) Lost revenues occur with successful DSM programs
   —is it a disincentive

APPENDIX 8—"STRAWMAN" PROPOSAL FOR AN IDAHO POWER TRUE-UP MECHANISM

"STRAWMAN" PROPOSAL FOR AN IDAHO POWER TRUE-UP MECHANISM

Submitted by Ralph Cavanagh, NRDC (9/22/04)

1. Starting point: fixed-cost revenue requirement and retail rates approved by Idaho PUC in latest Idaho Power rate case.

2. If, after initial year, changes in retail electricity use lead to under- or over-recovery of fixed cost revenue requirement, a rate true-up would occur in the following year on the same schedule as the Company's current Power Cost Adjustment.

3. Until reestablished in the next Idaho Power rate case, the currently approved fixed cost revenue requirement would be automatically adjusted annually to reflect the same rate of increase (or decrease) shown for retail electricity sales, net of any DSM programs, in Idaho Power's latest IRP. True ups would occur annually based on any divergence between the total fixed-cost revenue recovery that forecast sales would have delivered and the fixed-cost revenues actually recovered (so if, for example, sales were forecasted to increased by 2 percent and actually increased by a larger percentage, Idaho Power would refund the difference at the time of the next Power Cost Adjustment; if retail sales increased by a smaller percentage than forecast, Idaho Power would get back the lost revenues at the time of the next Power Cost Adjustment).

4. True-ups would occur by customer class based on divergence between actual and forecast sales to each customer class.

5. Idaho Power would continue to absorb the risk or benefits of purely weather-related effects on fixed-cost revenue recovery, as it does now. This would mean weather normalizing actual sales before making the annual true-up calculation.

MAXIMUM ANNUAL ANTICIPATED RATE IMPACT OF THE TRUE UP MECHANISM, UP OR DOWN, UNDER EXTREME CONDITIONS = 1.5 PERCENT.

APPENDIX 9—FLIP CHARTS REGARDING STRAWMAN PROPOSAL

Strawman Proposal

1) True-up by each customer class
2) Mechanism could be applied to individual/selected classes and still be acceptable*
3) Remove special contracts from mechanism.
4) *Plea to not exclude industrial class
5) Predicted load growth in each class to establish authorized revenue requirement.

Strawman Proposal (cont.)

6) True-up would result in surcharges/benefits by rate class
7) Forecast of fixed-costs may, potentially, create an incentive to inflate the forecast in the future.
8) Because this rate case is already decided, fixed-cost projections would be established without consideration of true-up mechanism effect
   --May be a challenge in the future
   --May apply inflation factor in future

ASSESSING FINANCIAL DISINCENTIVES AND RESOLUTION OPPORTUNITIES, WORKSHOP #3

NOVEMBER 8, 2004, 9:30 A.M. TO 3:30 P.M.
AUDITORIUM EAST, IDAHO POWER CORPORATE HEADQUARTERS, BOISE, ID

Facilitation Susan Hayman, North Country Resources, Inc.
Documentation Natalie Chavez, Chavez Writing & Editing, Inc.

WORKSHOP OBJECTIVES

1) Continue investigating the nature and extent of financial disincentives to energy conservation programs; identify areas of agreement and any additional information needs.
2) Identify criteria that workshop participants would use to evaluate the applicability/desirability of potential mechanisms to address disincentives.[1]
3) Brainstorm potential mechanisms to address disincentives, including additional true-up mechanisms, performance-based incentives, etc.[1]

WORKSHOP DECISIONS AND OUTCOMES

The next meeting is scheduled for December 1, 9:30am to 3:30pm at IPC. An additional meeting is set for December 13. If people with action items are unable to complete them in time for the December 1 meeting to be productive, that meeting will be cancelled and all parties notified by Susan Hayman, facilitator.

ACTION ITEMS

	What?	Who?	When?
1)	Check with Commission regarding scope of performance-based incentive discussion (is it DSM-related only?) and provide response to the workshop participants	Randy	ASAP
2)	Talk with Bill Eddie about report coordination; reply to Hayman	Nancy	November 9
3)	E-mail proposed report coordination assignments to the workshop participants	Susan	In next few days
4)	Coordinate timing of status report	Susan	Next meeting or e-mail
5)	Develop PBR strawman suitable for Idaho and successfully demonstrated elsewhere	IPUC	Next meeting
6)	Refine true-up mechanism	Ralph	Next meeting
7)	Analyze the refined true-up strawman and PBR strawman	IPC	Deferred

[1] With the approval of workshop participants, Workshop Objectives 2 and 3 were deferred to the December 1 workshop to allow for more extensive presentation and discussion of financial disincentives information at this workshop.

WORKSHOP INTRODUCTION

Susan Hayman, North Country Resources, welcomed participants (Appendix 1), had them introduce themselves, and then reviewed the agenda (Appendix 2). She distributed revised copies of the operational protocols (Appendix 3) and reviewed posters showing purpose, products, definitions, and principles of meeting conduct (Appendix 4). Although three key participants representing the NWEC perspective were absent[2], the group decided to listen to planned presentations, discuss the information, and represent the NWEC perspectives as best they could, but not draw any conclusions until the others were present.

CONTINUED EXPLORATION OF FINANCIAL DISINCENTIVES

Scenarios with Interim Rate Cases

Before the workshop, Lynn Anderson, IPUC e-mailed participants a memo and two Excel worksheets (Appendices 5 and 6). He had incorporated three interim rate cases to recalculate IPC's fixed-cost revenue losses under two of the three 9-year scenarios that he had presented at the September 27 workshop. Under both scenarios, forward-looking revenue losses from past DSM efforts are eliminated (except for an assumed six-month lag between the end of the rate case test year and rate implementation), even though past DSM savings are assumed to persist into the future. DSM efforts that occur after each rate case test year result in new fixed-cost revenue losses that accrue until the next rate case. As a surrogate for rate case adjustments, the levels of fixed-cost revenues per MWh are increased by the average MWh growth rate projected in the IRP for each rate class.

Anderson first showed results of his recalculations of the IRP level of DSM (which excludes NEEA). The IRP rate-case adjusted, 9-year total fixed-cost revenue loss is $3 million, or about half of the $6.2 million presented previously. The present value of the $3 million is about $2 million, and the levelized loss is $0.3 million per year.

Next, he showed results under IPC's 6.5% share of the NWPCC level of DSM (which includes NEEA, fuel conversions, building codes, appliance standards, and other DSM for which utilities have limited, little, or no control). The NWPCC rate-case adjusted, 9-year total fixed cost revenue loss is $54.6 million, compared with the $114.2 million presented previously. The present value of the $54.6 million is about $39 million, and the levelized loss is $6 million per year.

Prior to the meeting, Cavanagh e-mailed a response to Anderson's recalculations (Appendix 7). Copies were made and distributed to those who had not received the e-mail. First, Cavanagh reminded people that NWPCC projections were not the upper limits of energy efficiency targets. Second, he disagreed with Anderson's elimination of continued revenue losses after a rate case. According to Cavanagh, using this approach understates IPC's losses from persistent savings and rewards short-lived efficiency measures while discouraging durable savings.

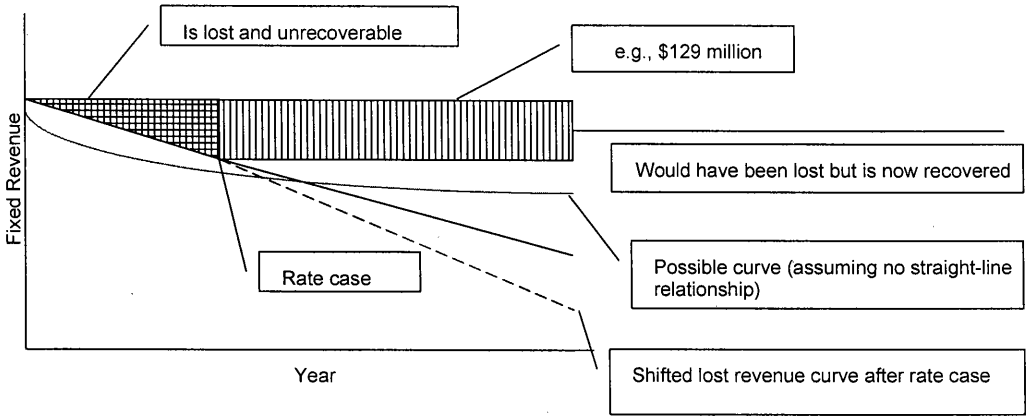
Following the presentation, participants raised and discussed the following issues:

- IPC loses fixed cost revenues when consumption declines. It is still uncertain how much reduced consumption is due specifically to DSM rather than to other factors. Therefore, some participants aren't certain whether this situation is best resolved by a true-up mechanism or some other disincentive/incentive mechanism.
- A decoupling/recoupling or true-up mechanism is not an incentive but a removal of a disincentive.
- More frequent rate cases would reduce fixed cost lost revenue even more than the hypothetical 3-year interval rate cases included in this analysis.
- Fixed cost revenues may be over-collected in the case where kWh sales, less DSM savings, are greater than the forecasted kWh growth, resulting in a refund for the customers under this true-up

[2] Ralph Cavanagh (Natural Resources Defense Council), Bill Eddie (Advocates for the West), and Nancy Hirsh (NW Energy Coalition) were absent at the beginning of the meeting. Their absence left no representatives of the NWEC stakeholder group. Hirsh arrived before lunch break, and Cavanagh participated via conference call in the afternoon. Eddie was unable to participate at all.

mechanism. At the same time, increased kWh sales will usually mean an increase in customer growth, which may require IPC to spend money for a new distribution plant and equipment. IPC is concerned about the possible scenario where they are giving a refund to customers at the same time as expending dollars in capital investment.

- What level of fixed costs, if recovered, would encourage or allow IPC to do what it wouldn't do otherwise with DSM or other programs?
- Greg Said, IPC, illustrated what happens between rate cases (see below) in the absence of a true-up mechanism. Lost fixed cost revenues from DSM could accumulate over a 10-year period unless a rate case adjusts the rates up to recover the lost fixed costs. This adjustment would change the angle of the lost revenue line down (in blue) so that future fixed cost losses are accelerated. For the sake of illustration, Said assumed a straight-line reduction, although it would likely be curved (in red). Anderson said that the surrogate for the blue dotted line was captured in his analysis.



Rate Impacts by Class under IRP and NWPCC Projections

Mike Youngblood, IPC, distributed a 10-page packet with rate impacts under the true-up mechanism for both IRP and NWPCC energy efficiency projections (Appendix 8) and a single sheet regarding fixed cost lost revenue per MWh by customer class (Appendix 9) prepared by Tim Tatum, IPC. Under this model, the true-up mechanism is based on forecasted sales as the method for IPC to recover fixed costs. Youngblood showed the assumptions he could change to analyze various scenarios.

Using the residential rate class, he walked participants through the model, which also included high- and low-growth scenarios to illustrate a range around the base case. The following issues were raised during the discussion (see Appendix 10 for flip chart notes):

- If energy sales grow faster than forecasted and DSM equals growth, there will be no apparent divergence from the base case.
- Although this model is not based on customer counts, increased kWh growth likely means increased customer growth. If so, IPC has to make capital investments for new customers. Youngblood commented that his numbers reflect divergence from an assumed 2% growth rate. Hypothetically, an increase in kWh use and an increase in the number of customers may result in a refund to customers <u>and</u> the requirement for IPC to add facility investment.
- For DSM, the percentage of class increase is still relatively small on an annual basis in the short term. Regular rate cases would adjust recovery so that the long-term effect wouldn't be as high as modeled.
- Trends of true-up are similar among rate classes.

Youngblood then presented a similar model of the true-up mechanism based on customer counts rather than forecasted sales. Youngblood did not provide this dynamic model as a handout but demonstrated it to the group. Appendix 11 includes one scenario based on certain input assumptions. For this analysis, he used weather-adjusted numbers, $30.14 as the total fixed cost per MWh, and 12,549 kWh to represent the average consumption for a residential user. The high and low scenarios represent 1% increase above and decrease below that average use per customer. Again, people could chose from among a number of assumptions to see their effects. Trends were similar to those under the forecasted sales true-up mechanism although magnitudes changed. The impact over a 20-year period, all else being equal, is a slight increase to rates, which is consistent with recovery of lost fixed revenues. Youngblood commented that the customer count mechanism works better with residential and small commercial customers, while the forecasted sales approach works better for industrial and irrigation customers.

Power Supply Costs under Increased Energy Conservation

Tim Tatum, IPC, distributed a four-page handout (Appendix 12) with results from the Aurora model conducted to analyze impacts of increasing levels of DSM on power supply costs. Mike Rufo of Quantum Consulting provided IPC an assessment of residential and commercial DSM potential within the Company's service territory by 2013. For the analysis, Portfolio 11 from the Company's 2004 IRP was modified to include Quantum Consulting's estimates of achievable DSM. The original Portfolio 11 was then used as the base case in the analysis. Tatum pointed out that Northwest Power and Conservation Council (NWPCC) estimates of achievable DSM are higher because they include market transformation, tax credits, and other mechanisms necessary to achieve those numbers. The IRP only accounts for direct acquisition program savings and does not include savings attributable to the Northwest Energy Efficiency Alliance (NEEA). When the 2004 IRP DSM resources are combined with Quantum Consulting's assessment findings and IPC's share of NEEA market transformation savings, the total is greater than NWPCC estimates of achievable DSM for IPC.

IPC decided to include the higher level of DSM (excluding NEEA) into a modified portfolio to allow them to analyze impacts to energy and capacity constraints (see Appendix 13 for flip chart notes). The first sheet of the handout (Appendix 12) shows the higher level of DSM, which allows IPC to defer resources (shown in orange blocks). The deferral of these resources results in an increase in variable supply costs due to decreased market sales potential. However, the fixed cost benefit of the deferral results in net savings. The second sheet shows the impact to power supply costs, excluding fixed costs. Factoring in DSM savings, power supply costs are reduced in all years except 2007, which is when the first Combined Heat and Power (CHP) resource is deferred. The third sheet shows portfolio fixed costs comparisons, with and without DSM fixed costs, between the base case and increased DSM portfolios. In the two years with CHP deferrals (2007 and 2010), there is a net decrease in fixed costs. The yellow columns show the costs to achieve DSM. Results showing the impacts of increasing levels of DSM on power supply costs are included on the last page. By increasing levels of DSM and organizing the portfolio for deferrals, the net present value between the two portfolios from now through 2033 is $36.3 million. This analysis indicates conservation has occurred and IPC will spend $36 million less in resources as a result. Extra costs would be incurred to the system for the first several years, and the break-even point would occur in 2022. The analysis showed that increased DSM could reduce power supply costs in the long run, but the disincentive needs to be removed early on.

COMMISSION REPORT

The participants expressed concern that there is not enough time before the December 15 deadline given in the IPUC order to complete the investigation of the issues and draft a complete report. They decided to submit a status report instead, which IPUC staff said will be sufficient as long as it describes the group's progress and anticipated due date for the completed report. Responsibility for drafting the status report will be assigned at the next meeting.

Nancy Hirsh will talk with Bill Eddie about serving as report coordinator. Once written and compiled, drafts will be circulated to all participants, though suggested revisions from participants should be coordinated by each party (ICIP, IPC, IPUC, NWEC) before being sent back to the report coordinator. In the meantime, work group members brainstormed the following outline for the report:

I. **History**—events leading up to the order and the parties involved in the work group.
The IPUC volunteered to write this section

II. **What the work group did**—issues raised, studies performed, mechanisms explored, assumptions made, and possible solutions detailed.
The outline should allow means for showing the areas of agreement as well as areas of disagreement.

III. **Conclusions and recommendations**—conclusions drawn from the studies.
This would reflect study information and perhaps respond to the four material questions discussed at this workshop (see Appendix 15).

IV. **Ancillary information**—figures, tables, study details, workshop summaries, and any other attachments needed to clarify or substantiate information.

After developing the draft outline (see Appendix 14 for flip chart notes), participants raised the need to include information about performance-based ratemaking (PBR) alternatives. The order had charged the work group with looking at alternatives to promoting DSM, one being decoupling and another being PBR. IPUC staff volunteered to develop a PBR strawman that is centered on DSM for the next meeting. If there is time to deliver the strawman to IPC for analysis before the December 1 meeting, the IPUC will do so. Otherwise, analysis will be conducted before the December 13 meeting.

QUESTIONS RAISED

The following questions were developed before or during the workshop and discussed once Cavanagh was able to participate via conference call (see Appendix 15 for flip chart notes):

- Are there financial disincentives to energy conservation?
- If there are financial disincentives, where are they (nature) and what is their extent?
- Is fixed cost recovery the issue/best way to address DSM?
- How much lost revenue (recovered) will cause the company to do something otherwise?
- What other information do we need?

Question 1—Existence of Financial Disincentives

All parties agreed that lost fixed cost revenue was associated with every kWh not sold.

Question 2—Nature and Extent of Financial Disincentives

Participants generally accepted the following conclusions:

- The nature and extent of the financial disincentive depends on the frequency of rate cases and the magnitude of IPC's energy efficiency program.
- The loss/fixed margin associated with every unsold kWh is needed to recover the fixed costs set in a rate case. However, over the last 10 years, IPC has implemented no DSM but experienced a huge loss/fixed margin.
- IPC could exert huge effort on programs that don't materialize. Nor would removal of disincentives guarantee energy conservation.

Question 3—Best Approach for Addressing DSM

Participants agreed that this question couldn't be answered yet since performance-based ratemaking alternatives haven't been explored.

Question 4—Amount of Lost Revenue Recovery to Effect Change

While striving to answer this question, the following issues were raised:

- Ric Gale, IPC, talked about IPC's commitment to re-energize DSM programs from a good faith stance. But out-of-pocket expenses for DSM (the immediate need) are a bigger concern than lost

revenue recovery at this time. If a mechanism for eliminating the financial disincentive could be implemented cleanly, the company would want to pursue it. In the meantime, IPC has made significant strides in DSM proposals and savings that can be achieved without lost revenue recovery.

- One the other hand, management does ask Darlene Nemnich, IPC, about lost revenues any time she takes a DSM program to management for funding. Lost revenues are an issue at the programmatic implementation level.
- The IPUC is concerned about allowing the company to collect fixed costs that may not be associated with DSM efforts.
- IPC may not be as concerned about lost revenues given the amount of DSM projected in the IRP, which is less than half the NWPCC's target.
- Although fuel costs, which are given to IPC as fuel recovery, can be volatile and can affect the company as adversely as lost fixed cost revenue, the approach does differ.

Question 5—Information Needs

The analyses presented today addressed some of the questions that people had. However, the need still exists for a way of determining the amount of savings resulting from DSM. In the future, monitoring and evaluation results of DSM programs may contribute to understanding the amount of fixed costs associated with DSM. Because a true-up mechanism may address some but not all concerns, participants want to see similar analyses of PBR alternatives. IPUC volunteered to develop a PBR strawman for the next meeting.

NEXT STEPS/WRAP-UP

Hayman reviewed action items to be completed before the next workshop (Appendix 16). This workshop is scheduled for December 1, 2004, from 9:30am to 3:30pm at IPC. During this meeting, participants will hear strawman presentations, discuss evaluation criteria, and develop the status report for the Commissioners. If people with action items are unable to complete them for the meeting, Hayman will notify participants that the meeting will be postponed until December 13.

APPENDIX 1—PARTICIPANTS (shading indicates work group participants unable to participate in person or by phone in workshop #3)

Name and Affiliation	Name and Affiliation
Lynn Anderson, IPUC	Laura Nelson, IPUC
Maggie Brilz, Idaho Power	Darlene Nemnich, Idaho Power
Terri Carlock, IPUC	Molly O'Leary, Industrial Customers of Idaho (sitting in for Peter Richardson)
Ralph Cavanagh, Natural Resources Defense Council	Brad Purdy, Community Action Partnership Association of Idaho
Bill Eddie, Advocates for the West	Don Reading, Ben Johnson Associates
Ric Gale, Idaho Power	Greg Said, IPC
David Hawk, J.R. Simplot Co.	David Schunke, IPUC
Nancy Hirsh, NW Energy Coalition	Tim Tatum, Idaho Power
Bart Kline, Idaho Power	Mike Youngblood, Idaho Power
Randy Lobb, IPUC	Scott Woodbury, IPUC

APPENDIX 2—AGENDA

ASSESSING FINANCIAL DISINCENTIVES AND RESOLUTION OPPORTUNITIES WORKSHOP #3

November 8, 2004
9:30am-3:30pm
Auditorium East
Idaho Power Corporate Headquarters
Boise, Idaho

Objectives:

1) Continue investigating the nature and extent of financial disincentives to energy conservation programs; identify areas of agreement and any additional information needs.
2) Identify criteria that workshop participants would use to evaluate the applicability/desirability of potential mechanisms to address disincentives. ***Deferred***
3) Brainstorm potential mechanisms to address disincentives, including additional true-up mechanisms, performance-based incentives, etc. ***Deferred***

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Final Agenda

Time	Topic	Process
9:15am	*Coffee/Tea available in meeting room*	
9:30am	**Welcome/Introductions/Meeting Overview** – Susan Hayman, Facilitator	Information
9:45am (We will take a morning break when it is most convenient to the group)	**Continued Exploration of Financial Disincentives** • Action item reports: ➢ IRP, NWPCC and historical residential scenarios calculated with an interim rate case (but without a true-up mechanism) – Lynn Anderson ➢ Rate impacts by class under IRP and NWPCC projections – Mike Youngblood ➢ Potential changes in power supply costs from increased energy conservation (using Aurora model) – Tim Tatum • Areas of agreement and additional information needs *Are there financial disincentives? If so, what is their nature and extent? Is additional information required to assess this?*	Presentations / Discussion
11:45pm	**Lunch** (on your own)	
12:45pm	**Mechanism Evaluation Criteria** – Susan Hayman ***Deferred***	Exercise / Discussion
1:45pm	**Potential Mechanisms to Address Disincentives** ***Deferred*** • True-ups (different kinds?) • Performance Based Incentives (different kinds?) • Others?	Brainstorming exercise / Discussion
2:30pm	**Next Steps, Action Items, Evaluation** – Susan Hayman	Discussion
3:30pm	**Adjourn**	

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APPENDIX 3—REVISED OPERATIONAL PROTOCOLS

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Workshop Series – Operational Protocol

Workshop Name: Assessing Financial Disincentives and Resolution Opportunities

Workshop Purpose:

1) To investigate the nature and extent of financial disincentives to investment in energy efficiency by Idaho Power Company and customers;
2) To investigate decoupling and performance-based ratemaking (incentives) as mechanisms to address financial disincentives (IPUC Order # 29558, 8/10/2004). *Other mechanisms can be subsequently explored if the participants agree that this would be useful.*

Workshop Products: A written report to the Idaho Public Utilities Commission to update the Commission on the status of the investigative workshops. This report will include a summarized assessment of:

1) The nature and extent of financial disincentives to investment in energy efficiency by Idaho Power Company;
2) Recommendations regarding specific decoupling and/or performance-based mechanisms that may reduce/remove these financial disincentives.
3) Recommendations for next steps.

Workshop Tenure: August 24 through December 15, 2004

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1) **Composition of Workshop Participants**

While workshops will be open to the public, it is expected that participants will generally represent the Idaho Public Utilities Commission, Idaho Power Company, Northwest Energy Coalition, representatives of industrial customers, representatives of residential customers, and representatives of irrigation customers.

2) **Roles & Responsibilities of Workshop Participants**

a) Be active in the discussion, be solutions-oriented, and act in "good-faith."
b) Help others at the table to understand your interests, and actively seek to understand the interests of others.
c) Be informed – Review the previous workshop summary, the agenda and prework in advance of the next workshop.
d) Follow-through in a timely manner with any assigned action items.
e) Attend workshops regularly – the group will not revisit decisions/discussions missed by others.
f) **Workshop Coordinators:** One representative each from Idaho Power Company (Mike Youngblood), Idaho Public Utility Commission (Lynn Anderson), Northwest Energy Coalition (Bill Eddie), and industrial customers (Peter Richardson). Responsibilities include coordination with the facilitator on the workshop objectives, outcomes, agenda and process.

3) **Role & Responsibilities of the Facilitator**

a) Manage the workshops, serve as a process coach, maintain neutrality and impartiality, and reinforce the collaborative process.
b) Refine the objectives and outcomes for each workshop, in cooperation with the workshop coordinators. Propose a workshop agenda and appropriate processes to reach the identified

Page 1 of 1 – Operational Protocol

041108

objectives and outcomes, and finalize this with the coordinators. The agenda, and any prework materials, will be distributed to participants at least one week prior to each workshop.

c) Communicate with participants outside of workshops as needed.

d) Maintain a record of workshop participants, and a summary of workshop discussions (see #6, Record Keeping).

e) Assist in preparation/compilation of the written report to the Idaho Public Utilities Commission.

4) **Analysis**

Analysis needs will be identified and assigned as they emerge.

5) **Decision-Making**

a) **Entities with multiple representatives:** While each individual participant will have input into the workshop deliberations, it is desirable that each entity represented speak with one voice in decision-making. Therefore, while numerous individuals may represent a given entity at a workshop, it is expected that one person will speak on behalf of the entity when decisions are made. Each entity should designate that person in advance. The facilitator will provide time for representatives to consult with each other as needed prior to critical decisions.

b) **Types of decisions:** There are two types of decisions participants will make:

- *Workshop decisions:* These decisions are related to workshop topics, process and schedule. Workshop decisions already made by the IPUC in Orders 29505 and 29558 will be honored. Decisions at the discretion of the group will be made by consensus.
- *Product decisions:* These decisions are related to the findings and recommendations workshop participants will present in their written report to the IPUC on December 15, 2004. Consensus will be the goal – However, if consensus cannot be reached, areas of agreement and disagreement on the findings and recommendations will be provided in the written report.

6) **Record-Keeping**

a) The facilitator will arrange for notes to be taken on a laptop computer during the workshop. The distributed workshop will include key discussion points, decisions, areas of agreement and disagreement, action items, etc. They will not be a transcription of "who said what."

b) The facilitator will be responsible for preparing the workshop summary and distributing it to participants within three business days after each workshop.

c) The facilitator will maintain a file of all workshop summaries, handouts, and products.

7) **Principles of Meeting Conduct**

a) Focus attention on the speaker (no side conversations)

b) Be specific, but succinct, in questions and comments

c) Participate fully, but don't dominate the discussion.

d) Respect other's contributions, and learn from them.

e) Challenge ideas, not people

f) Be on time

g) Turn cell phones, pagers or other electronic devices off or inaudible during meetings.

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APPENDIX 4—POSTERS WITH OPERATIONAL INFORMATION

Principles of Meeting Conduct

1) Focus attention on the speaker (no side conversations)
2) Be specific, but succinct, in questions and comments
3) Participate fully, but don't dominate the discussion
4) Respect others' contributions, and learn from them
5) Challenge ideas, not people
6) Be on time
7) Turn cell phones, pagers or other electronic devices off or inaudible during meetings

Workshop Series—Purpose and Products
(excerpts from Operational Protocol, adopted 9/27/04)

Workshop Purpose:

1) To investigate the nature and extent of financial disincentives to investment in energy efficiency by Idaho Power Company and customers;
2) To investigate decoupling and performance-based ratemaking (incentives) as mechanisms to address financial disincentives (IPUC Order #29558, 8/10/2004). *Other mechanisms can be subsequently explored if the participants agree that this would be useful.*

Workshop Products: A written report to the Idaho Public Utilities Commission to update the Commission on the status of the investigative workshops. This report will include a summarized assessment of:

1) The nature and extent of financial disincentives to investment in energy efficiency by Idaho Power Company;
2) Recommendations regarding specific decoupling and/or performance-based mechanisms that may reduce/remove these financial disincentives;
3) Recommendations for next steps.

Definitions

Demand Side Management (DSM): Management tools and actions that are designed to result in decreases or shifts in customer energy demand and/or consumption.

Performance-Based Incentives (PBI): Mechanisms that allow a utility to share and retain benefits gained from energy efficiencies, as well as provide consequences for failing to meet efficiency goals.

Decoupling: Severing the link between a utility's kWh sales and its recovery of revenues to cover fixed costs.

True-Up: A decoupling mechanism where a periodic adjustment in electric rates is used to correct for disparities between a utility's actual fixed cost recovery and its authorized fixed cost recovery.

APPENDIX 5—ANDERSON'S RECALCULATION OF FIXED COST REVENUE LOSS USING IRP INFORMATION AND THREE INTERIM RATE CASES

IPC DSM F-C Revenue Loss - IRP with 3 rate cases (REVISED 10/29/04)

DSM Selected in the 2004 IRP *(2004-2013 Planning Period)*
Idaho Power IPC-E-04-018, IRP Technical Appendix
MWh Energy Savings, Net of Free Riders, Incl. Losses, Excl. NEEA

	Year	Residential	Commercial	Irrigation	Industrial	Total MWh
	2005	1,070	389	5,767	9,427	16,653
	2006	2,625	1,087	11,534	18,853	34,100
	2007	4,193	1,900	17,300	28,280	51,674
	2008	5,784	2,810	23,067	37,706	69,367
	2009	7,397	3,801	28,834	47,133	87,166
	2010	9,205	4,861	34,601	56,559	105,226
	2011	11,028	5,980	40,368	65,986	123,363
	2012	12,872	7,149	46,134	75,412	141,566
End of IRP Planning Period	2013	14,734	8,359	51,901	84,839	159,833
					aMW (2004 IRP)=	18.25
	Total	68,908	36,337	259,506	424,195	788,946

(Numbers by IPC 9/21/04)
Peak Reduction (MW)

Res.	Com.	Irrig.	Ind.	Total
0.6	0.1	2.9	1.2	4.9
1.5	0.4	5.8	2.4	10.1
2.5	0.7	8.7	3.6	15.4
3.4	1.1	11.5	4.8	20.8
4.3	1.5	14.4	6.0	26.2
5.3	1.9	17.3	7.2	31.7
6.3	2.4	20.2	8.4	37.2
7.3	2.8	23.1	9.6	42.8
8.3	3.3	26.0	10.8	48.3
8.3	3.3	26.0	10.8	48.3
Peak MW (Energy Programs)				48.3
Peak MW (Demand Response)				75.6
Total Peak MW Selected DSM				123.9

Normalz. MWh	2003	4,141,393	2,932,712	1,620,931	2,325,875	11,020,911
IRP Avg. Growth/Year		1.9%	3.2%	0.2%	3.0%	2.2%

Calculation of 2003 Rate Case Test Year Fixed-Cost Lost Revenue per MWh for Various Rate Schedules

	Residential	Commercial*	Irrigation	Industrial**
Energy Rate ($/MWh)	51.9	30.0	32.6	21.8
Variable Cost ($/MWh)	20.7	20.3	23.5	18.5
Loss/MWh unsold	**$31.20**	**$9.70**	**$9.10**	**$3.30**

(*) Commercial rate is a weighted avg. of schedules 07 & 09S based on energy use.
(**) Ind. rate is a wghtd. avg. of schs. 09 P & T and 19 S, P & T based on energy use.

Note that the $/MWH here are diff for com. & indust. than on NWPCC sheet.
The losses/MWh are increased as result of each rate case by IRP average growth per year.

Fixed Costs Not Recovered Due to DSM Selected in IRP

Year	Residential	Commercial	Irrigation	Industrial	Total
2005	$33,370	$3,775	$52,480	$31,109	$120,734
2006	81,905	10,548	104,959	62,215	259,627
1st rate case resets rates to recover MWh savings through June 2006.					
2007	76,713	12,195	79,104	50,255	218,267
2008	128,725	21,742	131,846	83,756	366,070
2009	181,473	32,146	184,588	117,260	515,468
2nd rate case resets rates to recover MWh savings through June 2009.					
2010	90,443	17,945	79,585	54,919	242,893
2011	153,542	30,848	132,642	91,535	408,567
2012	217,329	44,322	185,690	128,146	575,487
3rd rate case resets rates to recover MWh savings through June 2012.					
2013	101,957	22,752	80,053	100,012	304,774
9-yearTotal	$1,065,457	$196,274	$1,030,949	$719,207	$3,011,886
				Avg. Annual	$334,654
			WACC = 7.20%		
				PV 9-yr. (2005-2013)	$2,134,081
				Levelized (9-yr.)	$319,061

The fixed-costs not recoverd are the product of multiplying each year's energy savings in the top box by the loss/MWh unsold in the middle box (IPC adj. of Eric Hirst numbers and later years rate case est changes). The "losses" are not adjusted for income taxes, cost changes, any offsetting benefits, etc. and do not include demand charge fixed-cost revenue losses. With each rate case annual losses are reset to zero, except with 6-month rate case lag, and fixed cost losses per MWh are increased by IRP avg. MWh growth in each class.

APPENDIX 6—ANDERSON'S RECALCULATION OF FIXED COST REVENUE LOSS USING NWPCC INFORMATION AND THREE INTERIM RATE CASES

NWPCC Draft 5th Plan -- Not Reviewed By Council
Achievable, Cost-Effective DSM Potential by 2025

IPC DSM F-C Revenue Loss - NWPCC with three rate cases

			Northwest Potential DSM 20-Year aMW	IPC's 20-yr. aMW @ 6.50%	IPC's annual aMW	IPC's annual MWh	Idaho Power's Fixed-Cost Revenue Losses ($millions) 2005	2006	2007	2008	2009	2010	2011	2012	2013	Total 9-year F-C Rev. Loss
Res.	Refrigerators		5					R			R			R		
Res.	Clothes Washers		135					A			A			A		
Res.	Dishwashers		10					T			T			T		
Res.	Water Heaters		80					E			E			E		
Res.	H.P. Water Heaters		195													
Res.	H.W. Heat Recovery		20					C			C			C		
Res.	Compact Flourescent		535					A			A			A		
Res.	New Space Cond.		40					S			S			S		
Res.	Existing Space Cond.		95					E			E			E		
Res.	HVAC Upgrades		65													
Res.	HVAC Conversion		70					R			R			R		
Res.	HVAC Commission		20					E			E			E		
	Res. Total	44.8%	1,270	82.6	4.13	36,157	$1.1	$2.3 D	$1.8	$3.0	$4.1 D	$1.9	$3.1	$4.4 D	$2.0	$23.6
Com.	Equipment, new/repl.		85					U			U			U		
Com.	HVAC, new/repl.		150					C			C			C		
Com.	Infrastructure, new/repl.		20					E			E			E		
Com.	Lighting, new/repl		245					S			S			S		
Com.	Shell, new/repl.		15													
Com.	Equipment, retrofit		110					F			F			F		
Com.	HVAC, retrofit		120					-			-			-		
Com.	Infrastructure, retrofit		110					C			C			C		
Com.	Lighting, retrofit		115													
Com.	Shell, retrofit		10													
	AC/DC power conv		155					R			R			R		
	Com. Total	40.0%	1,135	73.8	3.69	32,313	$1.3	$2.7 E	$2.2	$3.6	$5.1 E	$2.4	$4.0	$5.6 E	$2.6	$29.5
Irrig.	All Agriculture		80					V.			V.			V.		
	Irrig. Total	2.8%	80	5.2	0.26	2,278	$0.0	$0.0	$0.0	$0.1	$0.1	$0.0	$0.1	$0.1	$0.0	$0.4
Ind.	All Non-Aluminum		350					L			L			L		
	Ind. Total	12.3%	350	22.8	1.14	9,965	$0.0	$0.1 O	$0.1	$0.1	$0.2 O	$0.1	$0.1	$0.2 O	$0.1	$1.1
								S			S			S		
	Total	100.0%	2,835	184.3	9.21	80,712	$2.5	$5.1 S	$4.1	$6.8	$9.5 S	$4.4	$7.3	$10.2 S	$4.7	$54.6

$6.1 Avg. Annual
WACC = 7.20%
$39.0 ***PV 9-yr. (2005-2013)***
$6.0 Levelized (9-yr.)

$/MWh From IPC's 3/30/04 Eric Hirst Decoupling Report, p. 5 -- IPC Updated	Res.	Com. -7	Irrig.	Indust. -all 9 & 19 sch. (wt. avg.)
Energy Charge	51.90	62.60	32.60	24.40
Variable Cost	20.70	21.10	23.50	19.50
Loss/MWh unsold	$31.20	$41.50	$9.10	$4.90

Note that the $/MWH here are diff. for com. & indust. than on IRP-selected sheet.

	Res.	Com.	Irrig.	Indust.	Total
IRP Avg. Growth/Year	1.9%	3.2%	0.2%	3.0%	2.2%

Idaho Power's 6.5% share is based on its current NEEA allocation, which may not represent its potential for each program or customer class.

With each rate case, annual losses are reset to zero, except with 6-month rate case lag, and fixed cost losses per MWh are increased by IRP's avg. MWh growth in each class.

APPENDIX 7—CAVANAGH'S RESPONSE TO ANDERSON'S ANALYSES

---------- Forwarded Message: ----------
From: "Cavanagh, Ralph" <rcavanagh@nrdc.org>
To: "Lynn Anderson" <landers@puc.state.id.us>, <north_country@att.net>, "Randy Lobb" <rlobb@puc.state.id.us>, "Brad Purdy" <bmpurdy@hotmail.com>, "Mike Youngblood" <myoungblood@idahopower.com>, "Greg Said" <gsaid@idahopower.com>, "Bart Kline" <bkline@idahopower.com>, "Ric Gale" <rgale@idahopower.com>, "Dave Schunke" <dschunk@puc.state.id.us>, "Alden Holm" <aholm@puc.state.id.us>, "David Hawk" <david.hawk@simplot.com>, "Bill Eddie" <billeddie@rmci.net>, "Scott Woodbury" <swoodbu@puc.state.id.us>, "Peter Richardson" <peter@richardsonandoleary.com>, "Darlene Nemnich" <dnemnich@idahopower.com>, "Laura Nelson" <lnelson@puc.state.id.us>, "Maggie Brilz" <mbrilz@idahopower.com>, "Terri Carlock" <tcarloc@puc.state.id.us>, "Nancy Hirsh" <nancy@nwenergy.org>, <ttatum@idahopower.com>, <dreading@mindspring.com>
Subject: Comments on Lynn's Analysis
Date: Wed, 3 Nov 2004 23:32:04 +0000
COLLEAGUES:

I am grateful to Lynn for timely circulation of his revised analysis, and (after a discussion with him) offer these additional thoughts:

1. The NWPCC energy efficiency projections, although more aggressive than the Company's current IRP, is not by any means the upper bound of the possible; as a fraction of system electricity use, for example, the Council targets are only about half the targets that California's utilities are planning to meet (equivalent to about one percent of their systemwide retail consumption annually). I would never suggest to this group that Idaho should copy California, but neither would I want to imply that it's impossible for Idaho to OUTPERFORM California.

2. On the question of whether potential revenue losses from increased DSM investments are material, I think that the point is now well established even with Lynn's revised numbers ($54.5 million over nine years sure gets my attention, and for that matter so does $3 million). But I want to emphasize that Lynn's new, somewhat lower numbers reflect a crucial assumption with which I do not agree. As Lynn forthrightly says, his analysis assumes that every time you have a rate case, "forward-looking revenue losses from past DSM efforts are eliminated," "even though past DSM savings are assumed to persist in the future." Here is the difficulty: those persisting DSM savings continue to inflict revenue losses on the Company even after the rate case, in the sense that the unsold kWh return no fixed costs to the Company, and the Company clearly would be better off financially if those old savings disappeared instead of persisting. The only sense in which anything is "eliminated" is that each rate case resets rates based on actual consumption in the year closest to the rate case, so that the sales base <u>for that test year</u> incorporates the impact of previous years' energy efficiency investments <u>in that year</u>. But in subsequent years, if the savings persist, the Company continues to lose revenues COMPARED TO A SCENARIO UNDER WHICH THOSE SAME SAVINGS DISAPPEARED, and Lynn's analysis isn't picking those incremental losses up at all – it's disregarding them (unlike his initial analysis, which counted them). So, in my view, Lynn is understating the losses to the company from persistent savings and missing a

perfectly perverse feature of the status quo: the Company is rewarded for installing short-lived efficiency measures and penalized for finding durable savings. **THIS IS ANOTHER VERY GOOD REASON TO ADOPT A TRUE-UP MECHANISM THAT ELIMINATES THE LINKAGE BETWEEN RETAIL ELECTRICITY CONSUMPTION AND IDAHO POWER'S FIXED COST RECOVERY.**

-----Original Message-----
From: Lynn Anderson [mailto:landers@puc.state.id.us]
Sent: Wednesday, November 03, 2004 1:04 PM
To: north_country@att.net; Randy Lobb; Brad Purdy; Mike Youngblood; Greg Said; Bart Kline; Ric Gale; Dave Schunke; Alden Holm; David Hawk; Cavanagh, Ralph; Bill Eddie; Scott Woodbury; Peter Richardson; Darlene Nemnich; Laura Nelson; Maggie Brilz; Terri Carlock; Nancy Hirsh; ttatum@idahopower.com; dreading@mindspring.com
Subject: Rate Cases Effects on F-C Rev. Losses

Hello, Decoupling Workgroup,

Attached is a two-tab, two-scenario worksheet that calculates fixed-cost revenue losses assuming rate cases occur every three years. (Idaho Power's last rate case test year was 2003.) Under both scenarios, forward-looking revenue losses from past DSM efforts are eliminated (except for an assumed 6-month lag between the end of the rate case test year and rate implementation) even though past DSM savings are assumed to persist into the future. DSM efforts that occur after each rate case test year result in new fixed-cost revenue losses that accrue until the next rate case. Each rate case is assumed to result in the loss per MWh unsold increasing by the IRP-projected average MWh sales growth rate for each customer class.

The first tab shows results under Idaho Power's IRP-level of DSM (which excludes NEEA). The IRP rate-case adjusted, 9-year total fixed cost revenue loss is $3 million compared to $6.2 million shown in the IRP worksheet we reviewed at the September 27 workshop. The present value of the $3 million is about $2 million and the levelized loss is $0.3 million per year.

The second tab shows results under Idaho Power's 6.5% share of the NWPCC-level of DSM (which includes NEEA, fuel conversions, building codes, appliance standards and other DSM for which utilities have limited, little or no control.) The NWPCC rate-case adjusted, 9-year total fixed cost revenue loss is $54.6 million compared to $114.2 million shown in the NWPCC worksheet we reviewed at the September 27 workshop. The present value of the $54.6 million is about $39 million and the levelized loss is $6 million per year.

The analyses in both scenarios are admittedly very simplified, but fairly straightforward. I doubt that adding complexity for greater accuracy would change the results significantly. A brief recap from September's workshop: Ralph Cavanagh pointed out that adding demand-related revenue losses could increase the losses by about 10%, but I countered that accounting for income taxes would reduce them by a greater amount, and Greg Said reminded us that if lost revenues are recovered then the taxes have to also be recovered. In short, I think the two scenarios represent a low-side and a high-side of potential fixed-cost revenue losses, although the possible range is even wider.

Lynn Anderson, IPUC
208-334-0353

APPENDIX 8—MODEL OF RATE IMPACTS BY CLASS UNDER IRP AND NWPCC PROJECTIONS

	RESIDENTIAL												
	Total System			Idaho Jurisdictional Energy 95.62%							Total Fixed Cost per MWH (Class & Subsidy)		
Year	Base Case Energy (MWH)	High Growth Scenario (MWH)	Low Growth Scenario (MWH)	Base Case Energy (MWH)	Base Growth Rate	High Growth Scenario (MWH)	High Growth Rate	Low Growth Scenario (MWH)	Low Growth Rate	Base Rate Class Revenue Requirement	Base Revenue	High Revenue	Low Revenue
				(1)*95.62%		(2)*95.62%		(3)*95.62%		(10)* 1+(5)	(4)*30.14	(6)*30.14	(8)*30.14
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2000	4,313,062			4,124,252	1.47%								
2001	4,347,260			4,156,953	0.79%								
2002	4,290,810			4,102,974	(1.30%)								
Weather Adj. 2003	4,412,329	4,412,329	4,412,329	4,219,174	2.83%	4,219,174		4,219,174		$232,325,720	$127,161,141	$127,161,141	$127,161,141
Forecasted 2004	4,489,282	4,584,106	4,395,051	4,292,758	1.74%	4,383,431	3.89%	4,202,652	(0.39%)	$236,377,585	$129,378,889	$132,111,672	$126,663,194
2005	4,582,514	4,721,392	4,448,392	4,381,909	2.08%	4,514,707	2.99%	4,253,658	1.21%	$241,286,600	$132,065,789	$136,068,181	$128,200,449
2006	4,676,944	4,851,016	4,509,747	4,472,205	2.06%	4,638,656	2.75%	4,312,327	1.38%	$246,258,695	$134,787,215	$139,803,871	$129,968,672
2007	4,768,608	4,974,083	4,572,266	4,559,913	1.96%	4,756,336	2.54%	4,372,109	1.39%	$251,088,308	$137,430,555	$143,350,602	$131,770,445
2008	4,871,780	5,106,854	4,647,871	4,658,512	2.16%	4,883,295	2.67%	4,444,405	1.65%	$256,517,543	$140,402,292	$147,177,019	$133,649,357
2009	4,968,035	5,232,455	4,719,570	4,750,553	1.98%	5,003,397	2.46%	4,512,965	1.54%	$261,585,731	$143,176,314	$150,796,755	$136,015,682
2010	5,054,701	5,344,513	4,780,962	4,833,425	1.74%	5,110,550	2.14%	4,571,670	1.30%	$266,149,022	$145,673,985	$154,026,214	$137,784,973
2011	5,139,975	5,457,405	4,844,535	4,914,966	1.69%	5,218,500	2.11%	4,632,459	1.33%	$270,639,019	$148,131,539	$157,279,705	$139,617,103
2012	5,224,063	5,563,180	4,902,875	4,995,373	1.64%	5,319,645	1.94%	4,688,246	1.20%	$275,066,568	$150,554,914	$160,328,102	$141,298,447
2013	5,309,927	5,676,573	4,968,734	5,077,478	1.64%	5,428,074	2.04%	4,751,222	1.34%	$279,587,631	$153,029,472	$163,596,023	$143,196,466
2014	5,390,551	5,782,785	5,028,905	5,154,573	1.52%	5,529,636	1.87%	4,808,758	1.21%	$283,832,788	$155,353,016	$166,656,992	$144,930,561
2015	5,468,847	5,879,722	5,081,545	5,229,441	1.45%	5,622,329	1.68%	4,859,094	1.05%	$287,955,367	$157,609,468	$169,450,678	$146,447,607
2016	5,549,738	5,988,097	5,144,470	5,306,791	1.48%	5,725,961	1.84%	4,919,264	1.24%	$292,214,582	$159,940,707	$172,574,010	$148,261,073
2017	5,631,660	6,095,385	5,206,711	5,385,127	1.48%	5,828,552	1.79%	4,978,780	1.21%	$296,528,084	$162,301,658	$175,665,996	$150,054,826
2018	5,715,076	6,201,530	5,268,161	5,464,891	1.48%	5,930,050	1.74%	5,037,540	1.18%	$300,920,250	$164,705,666	$178,725,019	$151,825,796
2019	5,798,052	6,306,466	5,328,722	5,544,235	1.45%	6,030,392	1.69%	5,095,450	1.15%	$305,289,248	$167,096,993	$181,749,235	$153,571,129
2020	5,880,483	6,410,125	5,388,300	5,623,057	1.42%	6,129,513	1.64%	5,152,420	1.12%	$309,629,551	$169,472,614	$184,736,629	$155,288,146
2021	5,961,577	6,523,970	5,456,458	5,700,601	1.38%	6,238,374	1.78%	5,217,595	1.26%	$313,899,455	$171,809,703	$188,017,580	$157,252,429
2022	6,042,906	6,625,678	5,514,458	5,778,370	1.36%	6,335,631	1.56%	5,273,055	1.06%	$318,181,732	$174,153,565	$190,948,777	$158,923,944
2023	6,123,598	6,725,893	5,571,232	5,855,530	1.34%	6,431,458	1.51%	5,327,344	1.03%	$322,430,470	$176,479,068	$193,836,914	$160,560,145
2024	6,205,960			5,934,286	1.34%					$326,767,139	$178,852,700		
2025	6,288,814			6,013,513	1.34%					$331,129,714	$181,240,512		

RESIDENTIAL

Year	Demand Side Management		Revenue Recovered at Total Fixed Cost per MWH (Class & Subsidy) Rate less DSM unrecoverd costs								
	Energy Savings (MWH)	Fixed Costs Unrecovered	Base Revenue Recovered	Amount of True-Up (Base)	True-Up Percentage of Revenue Requirement (Base)	High Revenue Recovered	Amount of True Up (High)	True-Up Percentage of Revenue Requirement (High)	Low Revenue Recovered	Amount of True-Up (Low)	True-Up Percentage of Revenue Requirement (Low)
	(14)	(14)*30.14 (15)	(11) - (15) (16)	(11) - (16) (17)	(17) / (10) (18)	(12) - (15) (19)	(11) - (19) (20)	(20)/(10) (21)	(13) - (15) (22)	(11) - (22) (23)	(23)/(10) (24)
2000											
2001											
2002											
Weather Adj. 2003											
Forecasted 2004	0	$0	$129,378,889	$0	0.00%	$132,111,672	($2,732,783)	(1.16%)	$126,663,194	$2,715,695	1.15%
2005	25,229	$760,368	$131,305,421	$760,368	0.32%	$135,307,813	($3,242,024)	(1.34%)	$127,440,082	$4,625,707	1.92%
2006	51,859	$1,562,978	$133,224,237	$1,562,978	0.63%	$138,240,893	($3,453,678)	(1.40%)	$128,405,694	$6,381,520	2.59%
2007	79,891	$2,407,831	$135,022,824	$2,407,831	0.96%	$140,942,771	($3,512,116)	(1.40%)	$129,362,614	$8,068,041	3.21%
2008	109,325	$3,294,926	$137,107,366	$3,294,926	1.28%	$143,882,093	($3,479,801)	(1.36%)	$130,654,431	$9,747,861	3.80%
2009	140,160	$4,224,265	$138,952,049	$4,224,265	1.61%	$146,572,491	($3,396,177)	(1.30%)	$131,791,417	$11,384,896	4.35%
2010	173,798	$5,238,088	$140,435,897	$5,238,088	1.97%	$148,788,126	($3,114,141)	(1.17%)	$132,546,885	$13,127,100	4.93%
2011	208,838	$6,294,154	$141,837,385	$6,294,154	2.33%	$150,985,550	($2,854,011)	(1.05%)	$133,322,948	$14,808,591	5.47%
2012	245,280	$7,392,463	$143,162,451	$7,392,463	2.69%	$152,935,639	($2,380,725)	(0.87%)	$133,905,984	$16,648,930	6.05%
2013	282,843	$8,524,566	$144,504,906	$8,524,566	3.05%	$155,071,457	($2,041,985)	(0.73%)	$134,671,900	$18,357,572	6.57%
2014	282,843	$8,524,566	$146,828,450	$8,524,566	3.00%	$158,132,427	($2,779,411)	(0.98%)	$136,405,995	$18,947,021	6.68%
2015	282,843	$8,524,566	$149,084,902	$8,524,566	2.96%	$160,926,112	($3,316,644)	(1.15%)	$137,923,042	$19,686,426	6.84%
2016	282,843	$8,524,566	$151,416,141	$8,524,566	2.92%	$164,049,444	($4,108,737)	(1.41%)	$139,736,507	$20,204,199	6.91%
2017	282,843	$8,524,566	$153,777,092	$8,524,566	2.87%	$167,141,430	($4,839,772)	(1.63%)	$141,530,261	$20,771,398	7.00%
2018	282,843	$8,524,566	$156,181,100	$8,524,566	2.83%	$170,200,453	($5,494,787)	(1.83%)	$143,301,230	$21,404,436	7.11%
2019	282,843	$8,524,566	$158,572,427	$8,524,566	2.79%	$173,224,669	($6,127,675)	(2.01%)	$145,046,563	$22,050,431	7.22%
2020	282,843	$8,524,566	$160,948,048	$8,524,566	2.75%	$176,212,063	($6,739,449)	(2.18%)	$146,763,580	$22,709,034	7.33%
2021	282,843	$8,524,566	$163,285,137	$8,524,566	2.72%	$179,493,014	($7,683,311)	(2.45%)	$148,727,864	$23,081,839	7.35%
2022	282,843	$8,524,566	$165,628,999	$8,524,566	2.68%	$182,424,211	($8,270,646)	(2.60%)	$150,399,378	$23,754,187	7.47%
2023	282,843	$8,524,566	$167,954,502	$8,524,566	2.64%	$185,312,348	($8,833,280)	(2.74%)	$152,035,579	$24,443,490	7.58%
2024											
2025											

COMMERCIAL

Year	Total System			Idaho Jurisdictional Energy 94.28%							Total Fixed Cost per MWH (Class & Subsidy)		
	Base Case Energy (MWH)	High Growth Scenario (MWH)	Low Growth Scenario (MWH)	Base Case Energy (MWH)	Base Growth Rate	High Growth Scenario (MWH)	High Growth Rate	Low Growth Scenario (MWH)	Low Growth Rate	Base Rate Class Revenue Requirement	Base Revenue	High Revenue	Low Revenue
	(1)	(2)	(3)	(1)*94.28% (4)	(5)	(2)*94.28% (6)	(7)	(3)*94.28% (8)	(9)	(10)* 1+(5) (10)	(4)*8.29 (11)	(6)*8.29 (12)	(8)*8.29 (13)
2000	3,315,897			3,126,335	4.73%								
2001	3,485,296			3,267,193	4.51%								
2002	3,420,879			3,229,315	(1.28%)								
Weather Adj. 2003	3,491,588	3,491,588	3,491,588	3,291,982	2.07%	3,291,982		3,291,982		$129,540,068	$27,295,897	$27,295,897	$27,295,897
Forecasted 2004	3,645,464	3,772,139	3,537,754	3,437,061	4.41%	3,556,494	8.04%	3,335,508	1.32%	$135,248,960	$28,498,841	$29,489,137	$27,656,802
2005	3,800,328	3,978,291	3,631,433	3,583,072	4.25%	3,748,975	5.41%	3,423,832	2.65%	$140,994,510	$29,709,508	$31,085,118	$28,389,150
2006	3,933,811	4,158,117	3,720,845	3,708,924	3.51%	3,920,407	4.57%	3,508,133	2.46%	$145,946,812	$30,753,027	$32,508,567	$29,088,143
2007	4,067,539	4,337,086	3,814,653	3,835,007	3.40%	4,089,144	4.30%	3,596,766	2.53%	$150,908,203	$31,798,461	$33,905,674	$29,823,059
2008	4,206,242	4,518,237	3,914,461	3,965,781	3.41%	4,259,940	4.18%	3,690,680	2.61%	$156,054,170	$32,882,788	$35,321,846	$30,601,754
2009	4,339,800	4,694,460	4,011,631	4,091,703	3.18%	4,426,089	3.90%	3,782,484	2.49%	$161,009,254	$33,926,894	$36,689,493	$31,362,959
2010	4,467,278	4,862,165	4,103,163	4,211,894	2.94%	4,584,206	3.57%	3,868,595	2.28%	$165,738,766	$34,923,468	$38,010,545	$32,076,960
2011	4,594,090	5,030,720	4,195,946	4,331,456	2.84%	4,743,125	3.47%	3,956,073	2.26%	$170,443,569	$35,914,835	$39,328,241	$32,802,298
2012	4,721,005	5,198,714	4,288,601	4,451,116	2.76%	4,901,515	3.34%	4,043,431	2.21%	$175,152,194	$36,907,006	$40,641,553	$33,526,638
2013	4,849,664	5,367,576	4,382,045	4,572,420	2.73%	5,060,723	3.25%	4,131,533	2.18%	$179,925,522	$37,912,815	$41,961,650	$34,257,147
2014	4,975,937	5,532,987	4,472,580	4,691,474	2.60%	5,216,678	3.08%	4,216,893	2.07%	$184,610,328	$38,899,989	$43,254,788	$34,964,917
2015	5,102,926	5,701,109	4,565,088	4,811,203	2.55%	5,375,190	3.04%	4,304,112	2.07%	$189,321,699	$39,892,720	$44,569,087	$35,688,109
2016	5,232,780	5,873,754	4,660,646	4,933,615	2.54%	5,537,965	3.03%	4,394,396	2.10%	$194,138,620	$40,907,713	$45,918,759	$36,438,708
2017	5,363,632	6,044,709	4,754,802	5,057,005	2.50%	5,699,147	2.91%	4,482,981	2.02%	$198,994,052	$41,930,820	$47,255,220	$37,171,223
2018	5,496,151	6,222,686	4,853,737	5,181,948	2.47%	5,868,949	2.94%	4,576,259	2.08%	$203,910,588	$42,966,803	$48,646,577	$37,944,654
2019	5,628,971	6,400,034	4,951,559	5,307,175	2.42%	6,034,159	2.85%	4,668,489	2.02%	$208,838,292	$44,005,139	$50,033,017	$38,709,388
2020	5,762,721	6,578,487	5,048,052	5,433,279	2.38%	6,200,524	2.76%	4,759,467	1.95%	$213,800,500	$45,050,745	$51,412,456	$39,463,739
2021	5,896,856	6,751,767	5,143,006	5,559,746	2.33%	6,365,783	2.67%	4,848,992	1.88%	$218,776,991	$46,099,361	$52,782,725	$40,206,052
2022	6,032,810	6,938,365	5,245,688	5,687,928	2.31%	6,541,733	2.76%	4,945,992	2.00%	$223,820,968	$47,162,197	$54,241,632	$41,019,343
2023	6,168,940	7,125,303	5,348,219	5,816,276	2.26%	6,717,965	2.69%	5,042,473	1.95%	$228,871,475	$48,226,409	$55,702,889	$41,810,328
2024	6,307,941			5,947,330	2.25%					$234,028,497	$49,313,066		
2025	6,448,630			6,079,976	2.23%					$239,248,146	$50,412,919		

	COMMERCIAL										
	Demand Side Management		Revenue Recovered at Total Fixed Cost per MWH (Class & Subsidy) Rate less DSM unrecoverd costs								
Year	Energy Savings (MWH)	Fixed Costs Unrecovered	Base Revenue Recovered	Amount of True-Up (Base)	True-Up Percentage of Revenue Requirement (Base)	High Revenue Recovered	Amount of True-Up (High)	True-Up Percentage of Revenue Requirement (High)	Low Revenue Recovered	Amount of True-Up (Low)	True-Up Percentage of Revenue Requirement (Low)
	(14)	(14)*8.29 (15)	(11) - (15) (16)	(11) - (16) (17)	(17) / (10) (18)	(12) - (15) (19)	(11) - (19) (20)	(20)/(10) (21)	(13) - (15) (22)	(11) - (22) (23)	(23)/(10) (24)
2000											
2001											
2002											
Weather Adj. 2003											
Forecasted 2004	0	$0	$28,496,841	$0	0.00%	$29,489,137	($990,296)	(0.73%)	$27,656,802	$842,038	0.62%
2005	22,426	$185,945	$29,523,563	$185,945	0.13%	$30,899,173	($1,189,665)	(0.84%)	$28,203,206	$1,506,303	1.07%
2006	46,253	$383,511	$30,369,516	$383,511	0.26%	$32,123,056	($1,370,029)	(0.94%)	$28,704,632	$2,048,395	1.40%
2007	71,482	$592,699	$31,205,762	$592,699	0.39%	$33,312,975	($1,514,514)	(1.00%)	$29,230,360	$2,568,101	1.70%
2008	98,112	$813,508	$32,069,280	$813,508	0.52%	$34,508,338	($1,625,549)	(1.04%)	$29,788,246	$3,094,542	1.98%
2009	126,144	$1,045,939	$32,880,954	$1,045,939	0.65%	$35,653,553	($1,726,659)	(1.07%)	$30,317,020	$3,609,874	2.24%
2010	156,979	$1,301,614	$33,621,854	$1,301,614	0.79%	$36,708,931	($1,785,463)	(1.08%)	$30,775,347	$4,148,121	2.50%
2011	189,216	$1,568,909	$34,345,926	$1,568,909	0.92%	$37,759,332	($1,844,497)	(1.06%)	$31,233,389	$4,681,447	2.75%
2012	222,854	$1,847,826	$35,059,182	$1,847,826	1.05%	$38,793,726	($1,886,718)	(1.08%)	$31,678,811	$5,228,197	2.98%
2013	257,614	$2,136,041	$35,776,774	$2,136,041	1.19%	$39,825,609	($1,912,794)	(1.06%)	$32,121,106	$5,791,709	3.22%
2014	257,614	$2,136,041	$36,763,928	$2,136,041	1.16%	$41,118,728	($2,218,759)	(1.20%)	$32,828,876	$6,071,093	3.29%
2015	257,614	$2,136,041	$37,756,679	$2,136,041	1.13%	$42,433,047	($2,540,328)	(1.34%)	$33,552,068	$6,340,652	3.35%
2016	257,614	$2,136,041	$38,771,672	$2,136,041	1.10%	$43,782,718	($2,875,005)	(1.48%)	$34,300,667	$6,607,046	3.40%
2017	257,614	$2,136,041	$39,794,779	$2,136,041	1.07%	$45,119,179	($3,188,359)	(1.60%)	$35,035,182	$6,895,638	3.47%
2018	257,614	$2,136,041	$40,830,762	$2,136,041	1.05%	$46,510,536	($3,543,734)	(1.74%)	$35,808,613	$7,158,190	3.51%
2019	257,614	$2,136,041	$41,869,098	$2,136,041	1.02%	$47,896,976	($3,891,638)	(1.86%)	$36,573,347	$7,431,791	3.56%
2020	257,614	$2,136,041	$42,914,704	$2,136,041	1.00%	$49,276,415	($4,225,670)	(1.98%)	$37,327,698	$7,723,047	3.61%
2021	257,614	$2,136,041	$43,963,320	$2,136,041	0.98%	$50,646,684	($4,547,323)	(2.08%)	$38,070,011	$8,029,350	3.67%
2022	257,614	$2,136,041	$45,026,156	$2,136,041	0.95%	$52,105,591	($4,943,394)	(2.21%)	$38,874,302	$8,287,895	3.70%
2023	257,614	$2,136,041	$46,090,368	$2,136,041	0.93%	$53,566,848	($5,340,438)	(2.33%)	$39,674,287	$8,552,122	3.74%
2024											
2025											

INDUSTRIAL

Year	Total System			Idaho Jurisdictional Energy 88.64%							Total Fixed Cost per MWH (Class & Subsidy)		
	Base Case Energy (MWH)	High Growth Scenario (MWH)	Low Growth Scenario (MWH)	Base Case Energy (MWH)	Base Growth Rate	High Growth Scenario (MWH)	High Growth Rate	Low Growth Scenario (MWH)	Low Growth Rate	Base Rate Class Revenue Requirement	Base Revenue	High Revenue	Low Revenue
	(1)	(2)	(3)	(1)*88.64% (4)	(5)	(2)*88.64% (6)	(7)	(3)*88.64% (8)	(9)	(10)* 1+(5) (10)	(4)*2.44 (11)	(6)*2.44 (12)	(8)*2.44 (13)
2000	2,191,471			1,942,523	1.45%								
2001	2,288,638			2,028,652	4.43%								
2002	2,156,428			1,911,461	(5.78%)								
Weather Adj. 2003	2,234,497	2,234,497	2,234,497	1,980,662	3.62%	1,980,662		1,980,662		$56,713,735	$4,825,631	$4,825,631	$4,825,631
Forecasted 2004	2,295,848	2,407,973	2,204,069	2,035,043	2.75%	2,134,431	7.76%	1,953,691	(1.36%)	$58,270,683	$4,958,125	$5,200,270	$4,759,919
2005	2,373,974	2,527,062	2,229,635	2,104,294	3.40%	2,239,992	4.95%	1,976,530	1.17%	$60,253,798	$5,126,846	$5,457,455	$4,815,564
2006	2,452,481	2,647,681	2,271,482	2,173,883	3.31%	2,346,909	4.77%	2,013,445	1.87%	$62,246,383	$5,296,390	$5,717,945	$4,905,504
2007	2,533,350	2,767,939	2,319,017	2,245,566	3.30%	2,453,506	4.54%	2,055,580	2.09%	$64,296,918	$5,471,035	$5,977,655	$5,008,160
2008	2,608,559	2,880,633	2,363,546	2,312,585	2.98%	2,553,397	4.07%	2,095,051	1.92%	$66,217,949	$5,634,321	$6,221,028	$5,104,325
2009	2,683,932	2,990,647	2,408,071	2,379,042	2.87%	2,651,092	3.83%	2,134,518	1.88%	$68,120,838	$5,796,233	$6,459,048	$5,200,482
2010	2,766,009	3,108,342	2,459,588	2,450,908	3.02%	2,755,239	3.93%	2,180,182	2.14%	$70,178,652	$5,971,227	$6,712,791	$5,311,738
2011	2,845,645	3,225,381	2,511,279	2,522,562	2.92%	2,858,983	3.77%	2,226,002	2.10%	$72,230,349	$6,145,901	$6,965,548	$5,423,370
2012	2,924,852	3,340,965	2,562,081	2,592,594	2.78%	2,961,437	3.58%	2,271,033	2.02%	$74,235,634	$6,316,525	$7,215,164	$5,533,084
2013	3,006,130	3,457,252	2,613,463	2,663,752	2.74%	3,064,514	3.48%	2,316,577	2.01%	$76,273,159	$6,489,893	$7,466,298	$5,644,047
2014	3,088,500	3,578,065	2,668,103	2,737,651	2.77%	3,171,603	3.49%	2,365,011	2.09%	$78,389,172	$6,669,940	$7,727,207	$5,762,048
2015	3,171,256	3,696,226	2,720,482	2,811,006	2.68%	3,276,341	3.30%	2,411,440	1.96%	$80,489,601	$6,848,660	$7,982,388	$5,875,166
2016	3,253,963	3,815,043	2,773,010	2,884,318	2.61%	3,381,661	3.21%	2,458,000	1.93%	$82,588,786	$7,027,274	$8,238,966	$5,988,605
2017	3,338,927	3,939,807	2,829,416	2,959,630	2.61%	3,492,251	3.27%	2,507,999	2.03%	$84,745,256	$7,210,763	$8,508,426	$6,110,421
2018	3,424,409	4,068,208	2,886,457	3,035,402	2.56%	3,604,293	3.21%	2,558,560	2.02%	$86,914,873	$7,395,370	$8,781,402	$6,233,605
2019	3,509,178	4,187,711	2,939,486	3,110,541	2.48%	3,711,994	2.99%	2,605,555	1.84%	$89,066,394	$7,578,438	$9,043,802	$6,348,129
2020	3,597,642	4,318,710	2,997,209	3,188,956	2.52%	3,826,338	3.08%	2,656,731	1.96%	$91,311,697	$7,769,485	$9,322,387	$6,472,787
2021	3,688,754	4,447,246	3,055,357	3,269,718	2.53%	3,942,046	3.02%	2,708,274	1.94%	$93,624,210	$7,966,251	$9,604,293	$6,598,365
2022	3,782,050	4,587,751	3,119,632	3,352,415	2.53%	4,066,590	3.16%	2,765,247	2.10%	$95,992,154	$8,167,734	$9,907,729	$6,737,172
2023	3,874,569	4,721,946	3,178,873	3,434,424	2.45%	4,185,540	2.93%	2,817,758	1.90%	$98,340,377	$8,367,538	$10,197,537	$6,865,110
2024	3,966,376			3,515,802	2.37%					$100,670,529	$8,565,805		
2025	4,059,270			3,598,143	2.34%					$103,028,271	$8,766,419		

INDUSTRIAL

Year	Demand Side Management		Revenue Recovered at Total Fixed Cost per MWH (Class & Subsidy) Rate less DSM unrecoverd costs								
	Energy Savings (MWH)	Fixed Costs Unrecovered	Base Revenue Recovered	Amount of True-Up (Base)	True-Up Percentage of Revenue Requirement (Base)	High Revenue Recovered	Amount of True-Up (High)	True-Up Percentage of Revenue Requirement (High)	Low Revenue Recovered	Amount of True-Up (Low)	True-Up Percentage of Revenue Requirement (Low)
	(14)	(14)*2.44 (15)	(11) - (15) (16)	(11) - (16) (17)	(17) / (10) (18)	(12) - (15) (19)	(11) - (19) (20)	(20)/(10) (21)	(13) - (15) (22)	(11) - (22) (23)	(23)/(10) (24)
2000											
2001											
2002											
Weather Adj. 2003											
Forecasted 2004	0	$0	$4,958,125	$0	0.00%	$5,200,270	($242,146)	(0.42%)	$4,759,919	$440,351	0.76%
2005	19,622	$47,807	$5,079,038	$47,807	0.08%	$5,409,647	($282,801)	(0.47%)	$4,767,756	$689,699	1.14%
2006	39,245	$95,615	$5,200,775	$95,615	0.15%	$5,622,330	($325,940)	(0.52%)	$4,809,889	$908,056	1.46%
2007	58,867	$143,422	$5,327,613	$143,422	0.22%	$5,834,233	($363,198)	(0.56%)	$4,864,738	$1,112,917	1.73%
2008	78,490	$191,230	$5,443,091	$191,230	0.29%	$6,029,798	($395,478)	(0.60%)	$4,913,095	$1,307,933	1.98%
2009	98,112	$239,037	$5,557,195	$239,037	0.35%	$6,220,011	($423,778)	(0.62%)	$4,961,445	$1,497,603	2.20%
2010	117,734	$286,845	$5,684,482	$286,845	0.41%	$6,425,948	($454,619)	(0.65%)	$5,024,893	$1,687,898	2.41%
2011	137,357	$334,652	$5,811,248	$334,652	0.46%	$6,630,895	($484,995)	(0.67%)	$5,086,718	$1,876,831	2.60%
2012	156,979	$382,460	$5,934,065	$382,460	0.52%	$6,832,704	($516,180)	(0.70%)	$5,150,624	$2,064,540	2.78%
2013	176,602	$430,267	$6,059,626	$430,267	0.56%	$7,036,030	($546,137)	(0.72%)	$5,213,779	$2,252,518	2.95%
2014	176,602	$430,267	$6,239,672	$430,267	0.55%	$7,296,940	($627,000)	(0.80%)	$5,331,781	$2,395,427	3.06%
2015	176,602	$430,267	$6,418,393	$430,267	0.53%	$7,552,121	($703,461)	(0.87%)	$5,444,899	$2,537,489	3.15%
2016	176,602	$430,267	$6,597,007	$430,267	0.52%	$7,808,719	($781,444)	(0.95%)	$5,558,338	$2,680,648	3.25%
2017	176,602	$430,267	$6,780,496	$430,267	0.51%	$8,078,159	($867,396)	(1.02%)	$5,680,153	$2,828,273	3.34%
2018	176,602	$430,267	$6,965,103	$430,267	0.50%	$8,351,134	($955,764)	(1.10%)	$5,803,338	$2,978,063	3.43%
2019	176,602	$430,267	$7,148,171	$430,267	0.48%	$8,613,535	($1,035,097)	(1.16%)	$5,917,862	$3,125,940	3.51%
2020	176,602	$430,267	$7,339,218	$430,267	0.47%	$8,892,120	($1,122,635)	(1.23%)	$6,042,520	$3,279,867	3.59%
2021	176,602	$430,267	$7,535,984	$430,267	0.46%	$9,174,026	($1,207,775)	(1.29%)	$6,168,097	$3,436,195	3.67%
2022	176,602	$430,267	$7,737,466	$430,267	0.45%	$9,477,462	($1,309,728)	(1.38%)	$6,306,905	$3,600,824	3.75%
2023	176,602	$430,267	$7,937,271	$430,267	0.44%	$9,767,269	($1,399,731)	(1.42%)	$6,434,843	$3,762,694	3.83%
2024											
2025											

IRRIGATION

Year	Total System			Idaho Jurisdictional Energy 97.36%							Total Fixed Cost per MWH (Class & Subsidy)		
	Base Case Energy (MWH)	High Growth Scenario (MWH)	Low Growth Scenario (MWH)	Base Case Energy (MWH)	Base Growth Rate	High Growth Scenario (MWH)	High Growth Rate	Low Growth Scenario (MWH)	Low Growth Rate	Base Rate Class Revenue Requirement	Base Revenue	High Revenue	Low Revenue
	(1)	(2)	(3)	(1)*97.36% (4)	(5)	(2)*97.36% (6)	(7)	(3)*97.36% (8)	(9)	(10)* 1+(5) (10)	(4)*14.76 (11)	(6)*14.76 (12)	(8)*14.76 (13)
2000	1,852,948			1,803,994	7.81%								
2001	1,704,840			1,659,799	(7.99%)								
2002	1,657,946			1,614,144	(2.75%)								
Weather Adj. 2003	1,666,622	1,666,622	1,666,622	1,622,591	0.52%	1,622,591		1,622,591		$69,232,344	$23,950,361	$23,950,361	$23,950,361
Forecasted 2004	1,716,054	1,837,897	1,603,863	1,670,717	2.97%	1,789,341	10.28%	1,561,490	(3.77%)	$71,285,775	$24,660,729	$26,411,684	$23,048,473
2005	1,723,456	1,899,104	1,566,364	1,677,923	0.43%	1,848,931	3.33%	1,524,981	(2.34%)	$71,593,258	$24,767,100	$27,291,274	$22,509,586
2006	1,720,605	1,937,207	1,530,095	1,675,148	(0.17%)	1,886,027	2.01%	1,489,671	(2.32%)	$71,474,826	$24,726,129	$27,838,830	$21,988,386
2007	1,725,219	1,978,650	1,505,819	1,679,640	0.27%	1,926,376	2.14%	1,467,010	(1.52%)	$71,666,494	$24,792,435	$28,434,396	$21,653,900
2008	1,729,101	2,014,578	1,485,634	1,683,419	0.23%	1,961,354	1.82%	1,446,384	(1.41%)	$71,827,755	$24,848,222	$28,950,693	$21,349,452
2009	1,732,997	2,048,390	1,467,289	1,687,212	0.23%	1,994,273	1.68%	1,428,524	(1.23%)	$71,989,596	$24,904,210	$29,436,598	$21,085,828
2010	1,736,830	2,080,951	1,451,293	1,690,944	0.22%	2,025,973	1.59%	1,412,951	(1.09%)	$72,148,821	$24,959,293	$29,904,514	$20,855,958
2011	1,740,993	2,112,910	1,437,370	1,694,997	0.24%	2,057,088	1.54%	1,399,395	(0.96%)	$72,321,754	$25,019,117	$30,363,791	$20,655,865
2012	1,745,012	2,142,031	1,423,521	1,698,910	0.23%	2,085,440	1.38%	1,385,913	(0.96%)	$72,488,706	$25,076,873	$30,782,281	$20,456,861
2013	1,749,050	2,170,609	1,410,979	1,702,841	0.23%	2,113,263	1.33%	1,373,702	(0.88%)	$72,656,446	$25,134,901	$31,192,963	$20,276,615
2014	1,752,949	2,199,474	1,399,998	1,706,637	0.22%	2,141,365	1.33%	1,363,011	(0.78%)	$72,818,413	$25,190,932	$31,607,760	$20,118,810
2015	1,756,796	2,226,791	1,389,198	1,710,383	0.22%	2,167,961	1.24%	1,352,497	(0.77%)	$72,978,219	$25,246,216	$32,000,333	$19,963,618
2016	1,760,949	2,252,625	1,378,499	1,714,426	0.24%	2,193,112	1.16%	1,342,080	(0.77%)	$73,150,737	$25,305,897	$32,371,578	$19,809,856
2017	1,764,612	2,277,021	1,367,834	1,717,992	0.21%	2,216,864	1.08%	1,331,696	(0.77%)	$73,302,900	$25,358,537	$32,722,163	$19,656,592
2018	1,768,228	2,303,453	1,359,181	1,721,513	0.20%	2,242,598	1.16%	1,323,272	(0.63%)	$73,453,110	$25,410,501	$33,102,011	$19,532,245
2019	1,771,737	2,329,044	1,350,710	1,724,929	0.20%	2,267,512	1.11%	1,315,025	(0.62%)	$73,598,876	$25,460,927	$33,469,770	$19,410,511
2020	1,775,194	2,353,823	1,342,381	1,728,294	0.20%	2,291,637	1.06%	1,306,916	(0.62%)	$73,742,482	$25,510,606	$33,825,856	$19,290,828
2021	1,778,549	2,377,813	1,334,163	1,731,561	0.19%	2,314,993	1.02%	1,298,915	(0.61%)	$73,881,850	$25,558,820	$34,170,605	$19,172,721
2022	1,782,063	2,401,033	1,326,026	1,734,982	0.20%	2,337,599	0.98%	1,290,993	(0.61%)	$74,027,824	$25,609,318	$34,504,282	$19,055,790
2023	1,785,347	2,423,496	1,317,947	1,738,179	0.18%	2,359,469	0.94%	1,283,128	(0.61%)	$74,164,243	$25,656,511	$34,827,102	$18,939,691
2024	1,788,793			1,741,534	0.19%					$74,307,391	$25,706,032		
2025	1,792,003			1,744,659	0.18%					$74,440,736	$25,752,162		

IRRIGATION

Year	Demand Side Management		Revenue Recovered at Total Fixed Cost per MWH (Class & Subsidy) Rate less DSM unrecoverd costs								
	Energy Savings (MWH)	Fixed Costs Unrecovered	Base Revenue Recovered	Amount of True-Up (Base)	True-Up Percentage of Revenue Requirement (Base)	High Revenue Recovered	Amount of True-Up (High)	True-Up Percentage of Revenue Requirement (High)	Low Revenue Recovered	Amount of True-Up (Low)	True-Up Percentage of Revenue Requirement (Low)
	(14)	(14)*14.76 (15)	(11) - (15) (16)	(11) - (16) (17)	(17) / (10) (18)	(12) - (15) (19)	(11) - (19) (20)	(20)/(10) (21)	(13) - (15) (22)	(11) - (22) (23)	(23)/(10) (24)
2000											
2001											
2002											
Weather Adj. 2003											
Forecasted 2004	0	$0	$24,660,729	$0	0.00%	$26,411,684	($1,750,955)	(2.48%)	$23,048,473	$1,612,256	2.26%
2005	5,606	$82,754	$24,684,346	$82,754	0.12%	$27,208,521	($2,441,421)	(3.47%)	$22,426,833	$2,340,267	3.27%
2006	11,213	$165,507	$24,560,622	$165,507	0.23%	$27,673,323	($2,947,193)	(4.12%)	$21,622,879	$2,903,251	4.06%
2007	16,819	$248,261	$24,544,175	$248,261	0.35%	$28,186,135	($3,393,699)	(4.74%)	$21,405,639	$3,386,796	4.73%
2008	22,426	$331,015	$24,517,208	$331,015	0.46%	$28,619,679	($3,771,456)	(5.25%)	$21,018,438	$3,829,784	5.33%
2009	28,032	$413,768	$24,490,442	$413,768	0.57%	$29,022,830	($4,118,620)	(5.72%)	$20,672,059	$4,232,151	5.86%
2010	33,638	$496,522	$24,462,771	$496,522	0.69%	$29,407,992	($4,448,700)	(6.17%)	$20,359,436	$4,599,857	6.38%
2011	39,245	$579,275	$24,439,842	$579,275	0.80%	$29,784,516	($4,765,398)	(6.59%)	$20,076,590	$4,942,528	6.83%
2012	44,851	$662,029	$24,414,844	$662,029	0.91%	$30,120,252	($5,043,380)	(6.96%)	$19,794,832	$5,282,041	7.29%
2013	50,458	$744,783	$24,390,116	$744,783	1.03%	$30,448,180	($5,313,279)	(7.31%)	$19,531,832	$5,603,069	7.71%
2014	50,458	$744,783	$24,446,149	$744,783	1.02%	$30,862,977	($5,672,044)	(7.79%)	$19,374,027	$5,816,905	7.99%
2015	50,458	$744,783	$24,501,433	$744,783	1.02%	$31,255,550	($6,009,334)	(8.23%)	$19,218,835	$6,027,381	8.26%
2016	50,458	$744,783	$24,561,114	$744,783	1.02%	$31,626,795	($6,320,898)	(8.64%)	$19,065,073	$6,240,824	8.53%
2017	50,458	$744,783	$24,613,754	$744,783	1.02%	$31,977,390	($6,618,844)	(9.03%)	$18,911,809	$6,446,727	8.79%
2018	50,458	$744,783	$24,665,718	$744,783	1.01%	$32,357,228	($6,946,728)	(9.46%)	$18,787,462	$6,623,039	9.02%
2019	50,458	$744,783	$24,716,144	$744,783	1.01%	$32,724,987	($7,264,060)	(9.87%)	$18,665,728	$6,795,199	9.23%
2020	50,458	$744,783	$24,765,823	$744,783	1.01%	$33,081,074	($7,570,487)	(10.27%)	$18,546,045	$6,964,561	9.44%
2021	50,458	$744,783	$24,814,037	$744,783	1.01%	$33,425,622	($7,867,002)	(10.65%)	$18,427,938	$7,130,681	9.65%
2022	50,458	$744,783	$24,864,535	$744,783	1.01%	$33,759,500	($8,150,182)	(11.01%)	$18,311,007	$7,298,311	9.86%
2023	50,458	$744,783	$24,911,728	$744,783	1.00%	$34,082,320	($8,425,809)	(11.36%)	$18,194,908	$7,461,603	10.06%
2024											
2025											

	Totals												
	Total System			Idaho Jurisdictional Energy %							Total Fixed Cost per MWH (Class & Subsidy)		
Year	Base Case Energy (MWH)	High Growth Scenario (MWH)	High Growth Scenario (MWH)	Base Case Energy (MWH)	Base Growth Rate	High Growth Scenario (MWH)	High Growth Rate	Low Growth Scenario (MWH)	Low Growth Rate	Base Rate Revenue Requirement (less non-metered & Specials)	Base Revenue	High Revenue	Low Revenue
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2000	11,673,378			10,997,104	3.34%								
2001	11,806,034			11,112,598	1.14%								
2002	11,526,063			10,853,895	(2.3[illegible])								
Weather Adj. 2003	11,805,036	11,805,036	11,805,036	11,114,408	2.42%	11,114,408		11,114,408		$487,811,885	$183,233,030	$183,233,030	$183,233,030
Forecasted 2004	12,146,848	12,602,115	11,740,737	11,435,579	2.89%	11,863,697	6.74%	11,053,340	(0.55%)	$501,183,204	$187,496,583	$193,212,763	$182,128,388
2005	12,480,272	13,123,849	11,876,023	11,747,198	2.75%	12,352,605	4.12%	11,179,000	1.14%	$514,128,187	$191,669,243	$199,902,028	$183,914,749
2006	12,783,641	13,564,021	12,032,159	12,030,159	2.43%	12,791,999	3.56%	11,323,576	1.29%	$525,926,715	$195,562,761	$205,867,213	$185,950,705
2007	13,094,776	14,057,758	12,212,955	12,320,126	2.43%	13,225,361	3.39%	11,491,466	1.48%	$537,961,924	$199,492,587	$211,668,327	$188,255,564
2008	13,416,082	14,520,302	12,411,512	12,620,297	2.45%	13,657,996	3.27%	11,676,520	1.61%	$550,617,416	$203,787,623	$217,670,587	$191,004,889
2009	13,724,784	14,966,152	12,606,752	12,908,510	2.30%	14,074,850	3.05%	11,858,491	1.56%	$562,705,419	$207,803,650	$223,391,894	$193,664,951
2010	14,023,616	15,395,971	12,795,007	13,187,171	2.18%	14,475,969	2.85%	12,033,398	1.47%	$574,215,261	$211,528,072	$228,654,063	$196,029,628
2011	14,320,903	15,828,416	12,989,129	13,463,981	2.12%	14,877,696	2.78%	12,213,929	1.50%	$585,834,892	$215,211,393	$233,937,286	$198,498,636
2012	14,614,932	16,244,890	13,177,079	13,737,992	2.05%	15,268,037	2.62%	12,388,623	1.43%	$596,943,093	$218,855,320	$238,967,100	$200,815,029
2013	14,913,771	16,672,010	13,375,220	14,016,491	2.04%	15,666,574	2.61%	12,573,034	1.49%	$608,442,759	$222,567,082	$244,216,933	$203,374,275
2014	15,207,937	17,093,310	13,569,586	14,290,335	1.97%	16,059,282	2.51%	12,753,672	1.44%	$619,650,701	$226,113,657	$249,246,728	$205,776,336
2015	15,499,825	17,503,849	13,756,313	14,562,033	1.92%	16,441,821	2.38%	12,927,142	1.36%	$630,744,885	$229,597,004	$254,002,486	$207,974,500
2016	15,797,410	17,929,520	13,956,824	14,839,150	1.92%	16,838,698	2.41%	13,113,740	1.44%	$642,092,725	$233,181,591	$259,103,333	$210,496,242
2017	16,098,631	18,358,923	14,158,763	15,119,754	1.91%	17,236,814	2.36%	13,301,456	1.43%	$653,570,291	$236,801,778	$264,151,805	$212,993,062
2018	16,403,864	18,793,877	14,367,535	15,403,754	1.89%	17,643,889	2.36%	13,495,632	1.46%	$665,196,822	$240,478,340	$269,255,009	$215,536,300
2019	16,707,938	19,223,256	14,570,476	15,686,880	1.85%	18,044,058	2.27%	13,684,529	1.40%	$676,792,810	$244,141,497	$274,295,823	$218,039,157
2020	17,016,040	19,657,145	14,775,943	15,973,587	1.84%	18,448,012	2.24%	13,875,534	1.40%	$688,484,229	$247,803,450	$279,297,328	$220,515,500
2021	17,325,738	20,100,795	14,988,985	16,261,626	1.82%	18,861,196	2.24%	14,073,776	1.43%	$700,182,505	$251,434,135	$284,575,204	$223,229,567
2022	17,639,829	20,562,846	15,206,004	16,553,695	1.81%	19,281,552	2.23%	14,275,288	1.43%	$712,022,678	$255,092,813	$289,802,420	$225,727,249
2023	17,952,454	20,996,638	15,416,271	16,844,409	1.77%	19,694,433	2.14%	14,470,703	1.37%	$723,806,564	$258,729,527	$294,564,442	$228,175,274
2024	18,269,070			17,138,953	1.76%					$558,274,269			
2025	18,588,717			17,435,292	1.75%					$567,958,639			

	Totals										
	Demand Side Management		Revenue Recovered at Total Fixed Cost per MWH (Class & Subsidy) Rate less DSM unrecoverd costs								
Year	Energy Savings (MWH)	Fixed Costs Unrecovered	Base Revenue Recovered	Amount of True-Up (Base)	True-Up Percentage of Revenue Requirement (Base)	High Revenue Recovered	Amount of True-Up (High)	True-Up Percentage of Revenue Requirement (High)	Low Revenue Recovered	Amount of True-Up (Low)	True-Up Percentage of Revenue Requirement (Low)
	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
2000											
2001											
2002											
Weather Adj. 2003	0										
Forecasted 2004	0	$0	$187,496,583	$0	0.00%	$193,212,763	(5,716,180)	(1.14%)	182,128,388	5,610,340	1.12%
2005	72,883	$1,076,874	$190,592,389	$1,076,874	0.21%	$198,825,155	(7,155,912)	(1.39%)	192,837,876	9,161,976	1.78%
2006	148,570	$2,207,611	$193,356,150	$2,207,611	0.42%	$203,659,602	(8,596,640)	(1.54%)	183,743,094	12,241,222	2.33%
2007	227,059	$3,392,213	$196,100,374	$3,392,213	0.63%	$208,276,114	(8,783,526)	(1.63%)	184,863,351	15,135,856	2.81%
2008	308,352	$4,630,679	$199,136,944	$4,630,679	0.84%	$213,039,907	(9,272,284)	(1.68%)	186,374,209	17,980,121	3.27%
2009	392,448	$5,923,010	$201,880,640	$5,923,010	1.05%	$217,468,884	(9,665,234)	(1.72%)	187,741,942	20,724,524	3.68%
2010	492,150	$7,323,068	$204,205,004	$7,323,068	1.28%	$221,330,995	(9,802,923)	(1.71%)	188,706,560	23,562,976	4.10%
2011	574,656	$8,776,991	$206,434,402	$8,776,991	1.50%	$225,160,294	(9,948,901)	(1.70%)	189,721,645	25,309,396	4.49%
2012	669,965	$10,284,778	$208,570,541	$10,284,778	1.72%	$228,682,321	(9,827,002)	(1.65%)	190,530,251	29,223,709	4.90%
2013	767,516	$11,835,657	$210,731,425	$11,835,657	1.95%	$232,381,277	(9,814,195)	(1.61%)	191,538,618	32,004,868	5.26%
2014	767,516	$11,835,657	$214,278,200	$11,835,657	1.91%	$237,411,071	(11,297,214)	(1.82%)	193,940,679	33,230,445	5.36%
2015	767,516	$11,835,657	$217,761,407	$11,835,657	1.89%	$242,166,829	(12,569,765)	(1.99%)	196,138,843	34,591,949	5.48%
2016	767,516	$11,835,657	$221,345,934	$11,835,657	1.84%	$247,267,676	(14,086,085)	(2.19%)	198,660,585	35,732,717	5.57%
2017	767,516	$11,835,657	$224,968,121	$11,835,657	1.81%	$252,316,148	(15,514,370)	(2.37%)	201,157,405	36,942,038	5.65%
2018	767,516	$11,835,657	$228,642,683	$11,835,657	1.78%	$257,419,352	(16,941,012)	(2.56%)	203,700,644	38,163,728	5.74%
2019	767,516	$11,835,657	$232,305,840	$11,835,657	1.75%	$262,460,167	(18,318,670)	(2.71%)	206,203,500	39,403,361	5.82%
2020	767,516	$11,835,657	$235,967,794	$11,835,657	1.72%	$267,461,671	(19,858,221)	(2.86%)	208,679,843	40,676,509	5.91%
2021	767,516	$11,835,657	$239,598,478	$11,835,657	1.69%	$272,739,547	(21,305,412)	(3.04%)	211,393,910	41,678,266	5.95%
2022	767,516	$11,835,657	$243,257,156	$11,835,657	1.66%	$277,768,764	(22,673,950)	(3.18%)	213,891,592	42,941,217	6.03%
2023	767,516	$11,835,657	$246,893,870	$11,835,657	1.64%	$282,728,785	(23,998,258)	(3.32%)	216,339,617	44,219,908	6.11%
2024											
2025											

APPENDIX 9—FIXED COST LOST REVENUE PER MWH BY CUSTOMER CLASS

Fixed Cost Lost Revenue per MWh by Customer Class					
		Base Rate Components ($/MWh)			
		Residential	**Commercial***	**Irrigation**	**Industrial****
Total Base Energy Cost per MWH	(1)	$51.90	$29.32	$32.57	$21.45
Variable Cost per MWH - *Class*	(2)	$20.69	$20.21	$23.53	$18.41
Variable Cost per MWH - *Subsidy*	(3)	$1.08	$0.81	($5.72)	$0.60
Fixed Cost per MWH - *Class*	(4)	$28.76	$7.25	$22.09	$1.67
Fixed Cost per MWH - *Subsidy*	(5)	$1.38	$1.04	($7.33)	$0.77
Total Fixed Cost per MWH (Class & Subsidy)	(6)	$30.14	$8.29	$14.76	$2.44

(*) Commercial rate is a weighted avg. of schedules 07 & 09 S,P, & T based on energy use.

(**) Industrial rate is a wghtd. avg. of schedule 19 S, P & T based on energy use.

APPENDIX 10—FLIP CHARTS REGARDING MIKE YOUNGBLOOD'S PRESENTATION

Rate Impacts by Class

NWPCC/weather adjusted with true-up

Residential

1) If energy sales faster than forecast and DSM = growth, brings back to base.

   (Ralph's perspective) It is not trying to reward company for increased growth—provides for status quo in rate case

2) For DSM, % class increase still relatively small on an annual basis in short term. Regular rate case would adjust recovery so that effect in long term wouldn't be as high as modeled.

3) With increase kWh use (and increased number of customers), may result in refund to customers plus additional cost for more facility investment.

Results with True-up

1) In high growth, company may be refunding customers and investing in capital/infrastructure.
2) Trends of true-up effects similar between rate classes.

Customer Count Model

(Revenue side only)—Recoupling to revenue per customer

1) Number of customers doesn't affect recover (when use per customer does not change)
2) For high, refund in first few years while use is higher, then positive return to company after first few years.
3) For low case, collecting more than DSM
4) 1.2% over time period in fixed cost recovery
5) For industrial customers, change in number of customers has greater effect (irrigation customers are problematic)—served better by forecast energy
6) Residential, small group—served better by customer count

APPENDIX 11— MODEL OF RATE IMPACTS BY CLASS UNDER CUSTOMER COUNTS

RESIDENTIAL

This is a dynamic model and so the values change. The numbers here represent just one scenario based upon the input assumptions.

Constants:

1*	$30.14	Total Fixed Cost per MWH (Class & Subsidy)
2*	$232,326,720	Class Revenue Requirement
3*	$378.23	Fixed Cost Recovery per Customer
4*	3	DSM Savings Assumptions: (1) DSM Savings Assumptions in 2004 IRP (2) Enhanced Residential and Commercial Numbers (Mike Rufo's Analysis) (3) Northwest Power & Conservation Council's DSM Assumptions
5*	1.0%	Percentage Growth in Customer Count
6*	0.0%	Change in Avg. Use per Cust. (Base)
7*	1.0%	Percentage above Base (High)
8*	(1.0%)	Percentage below Base (Low)
9*	1	Compounded? (0=No, 1=Yes)

Year	Base Case Energy (MWH)	Base Case Fixed Cost Recovery	Number of Customers	Fixed Cost Recovery per Customer	Actual Customer Count		Allowed Fixed Cost Recovery Per Customer Count		Energy Savings (MWH)	Fixed Costs Unrecovered		BASE: Avg. Use / Cust. (Base)	BASE: Actual Fixed Cost Recovery Per MWH (Constant Use/Cust)	BASE: Base Case Fixed Cost Revenue Recovered	BASE: Amount of True-Up (Base)	BASE: Percent of Class Revenue Requirement	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
		(2) X 1*		(3) / (4)	(4) X 5*		(6) X (5)			(10) X 1*		(13) X 6*	(13) X (6) X 1*	(14) - (15)	(8) - (15)	(16) / 2*	
												12,549					
2003	4,219,174	$127,161,141	336,204	$378.23													
2004					339,566		$128,432,753		0	$0		12,549	$128,432,753	$128,432,753	$0	0.00%	
2005					342,962		$129,717,080		25,229	$760,368		12,549	$129,717,080	$128,956,713	$760,368	0.33%	
2006					346,391		$131,014,251		51,859	$1,562,978		12,549	$131,014,251	$129,451,273	$1,562,978	0.67%	
2007					349,855		$132,324,394		79,891	$2,407,831		12,549	$132,324,394	$129,916,563	$2,407,831	1.04%	
2008					353,354		$133,647,637		109,325	$3,294,926		12,549	$133,647,637	$130,352,711	$3,294,926	1.42%	
2009					356,887		$134,984,114		140,150	$4,224,265		12,549	$134,984,114	$130,759,849	$4,224,265	1.82%	
2010					360,456		$136,333,955		173,798	$5,238,088		12,549	$136,333,955	$131,095,867	$5,238,088	2.25%	
2011					364,061		$137,697,295		208,838	$6,294,154		12,549	$137,697,295	$131,403,140	$6,294,154	2.71%	
2012					367,701		$139,074,267		245,290	$7,392,463		12,549	$139,074,267	$131,681,805	$7,392,463	3.18%	
2013					371,378		$140,465,010		282,843	$8,524,566		12,549	$140,465,010	$131,940,444	$8,524,566	3.67%	
2014					375,092		$141,869,660		282,843	$8,524,566		12,549	$141,869,660	$133,345,094	$8,524,566	3.67%	
2015					378,843		$143,288,357		282,843	$8,524,566		12,549	$143,288,357	$134,763,791	$8,524,566	3.67%	
2016					382,631		$144,721,240		282,843	$8,524,566		12,549	$144,721,240	$136,196,675	$8,524,566	3.67%	
2017					386,458		$146,168,453		282,843	$8,524,566		12,549	$146,168,453	$137,643,887	$8,524,566	3.67%	
2018					390,322		$147,630,137		282,843	$8,524,566		12,549	$147,630,137	$139,105,572	$8,524,566	3.67%	
2019					394,226		$149,106,439		282,843	$8,524,566		12,549	$149,106,439	$140,581,873	$8,524,566	3.67%	
2020					398,168		$150,597,503		282,843	$8,524,566		12,549	$150,597,503	$142,072,937	$8,524,566	3.67%	
2021					402,149		$152,103,478		282,843	$8,524,566		12,549	$152,103,478	$143,578,912	$8,524,566	3.67%	
2022					406,171		$153,624,513		282,843	$8,524,566		12,549	$153,624,513	$145,099,947	$8,524,566	3.67%	
2023					410,233		$155,160,758		282,843	$8,524,566		12,549	$155,160,758	$146,636,192	$8,524,566	3.67%	

RESIDENTIAL

	HIGH						LOW				
Year	Avg. Use / Cust. (High)	Percent Increase in Average Use per Customer	High Case Fixed Cost Revenue Recovered	Amount of True-Up (High)	Percent of Class Revenue Requirement (High)		Avg. Use / Cust. (Low)	Percent Decrease in Average Use per Customer	Low Case Fixed Cost Revenue Recovered	Amount of True-Up (Low)	Percent of Class Revenue Requirement (Low)
(1)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)
	(19) X (6*+7*)	(19) X (6) X 1*	(20) - (11)	(8) - (21)	(22) / 2*		(25) X (6*+8*)	(25) X (6) X 1*	(26) - (11)	(8) - (27)	(28) / 2*
2003	**12,549**						**12,549**				
2004	12,675	$129,717,080	$129,717,080	($1,284,328)	(0.55%)		12,424	$127,148,425	$127,148,425	$1,284,326	0.55%
2005	12,802	$132,324,394	$131,564,026	($1,846,946)	(0.79%)		12,300	$127,135,710	$126,375,343	$3,341,738	1.44%
2006	12,930	$134,984,114	$133,421,136	($2,406,885)	(1.04%)		12,177	$127,122,997	$125,560,019	$5,454,232	2.35%
2007	13,059	$137,697,295	$135,289,464	($2,965,070)	(1.28%)		12,055	$127,110,284	$124,702,454	$7,621,940	3.28%
2008	13,190	$140,465,010	$137,170,084	($3,522,446)	(1.52%)		11,934	$127,097,573	$123,802,647	$9,844,990	4.24%
2009	13,321	$143,288,357	$139,064,092	($4,079,976)	(1.76%)		11,815	$127,084,864	$122,860,599	$12,123,515	5.22%
2010	13,455	$146,168,453	$140,930,365	($4,596,410)	(1.98%)		11,697	$127,072,155	$121,834,067	$14,499,888	6.24%
2011	13,589	$149,106,439	$142,812,285	($5,114,990)	(2.20%)		11,580	$127,059,448	$120,765,294	$16,932,001	7.29%
2012	13,725	$152,103,478	$144,711,015	($5,636,746)	(2.43%)		11,464	$127,046,742	$119,654,279	$19,419,988	8.36%
2013	13,862	$155,160,758	$146,636,192	($6,171,182)	(2.66%)		11,349	$127,034,037	$118,509,471	$21,955,539	9.45%
2014	14,001	$158,279,489	$149,754,923	($7,885,263)	(3.39%)		11,236	$127,021,334	$118,496,768	$23,372,892	10.06%
2015	14,141	$161,460,907	$152,936,341	($9,647,984)	(4.15%)		11,124	$127,008,632	$118,484,066	$24,804,291	10.68%
2016	14,282	$164,706,271	$156,181,705	($11,460,465)	(4.93%)		11,012	$126,995,931	$118,471,365	$26,249,875	11.30%
2017	14,425	$168,016,867	$159,492,301	($13,323,849)	(5.73%)		10,902	$126,983,231	$118,458,665	$27,709,787	11.93%
2018	14,570	$171,394,006	$162,869,440	($15,239,303)	(6.56%)		10,793	$126,970,533	$118,445,967	$29,184,170	12.56%
2019	14,715	$174,839,026	$166,314,460	($17,208,021)	(7.41%)		10,685	$126,957,838	$118,433,270	$30,673,169	13.20%
2020	14,862	$178,353,290	$169,828,724	($19,231,221)	(8.28%)		10,578	$126,945,140	$118,420,574	$32,176,929	13.85%
2021	15,011	$181,938,191	$173,413,626	($21,310,147)	(9.17%)		10,473	$126,932,446	$118,407,880	$33,695,596	14.50%
2022	15,161	$185,595,149	$177,070,583	($23,446,070)	(10.09%)		10,368	$126,919,752	$118,395,187	$35,229,326	15.16%
2023	15,313	$189,325,612	$180,801,046	($25,640,286)	(11.04%)		10,264	$126,907,060	$118,382,495	$36,778,263	15.83%

COMMERCIAL

This is a dynamic model and so the values change. The numbers here represent just one scenario based upon the input assumptions.

Constants:

1*	$8.29	Total Fixed Cost per MWH (Class & Subsidy)
2*	$129,540,066	Class Revenue Requirement
3*	$535.30	Fixed Cost Recovery per Customer
4*	3	DSM Savings Assumptions: (1) DSM Savings Assumptions in 2004 IRP (2) Enhanced Residential and Commercial Numbers (Mike Rufo's Analysis) (3) Northwest Power & Conservation Council's DSM Assumptions
5*	1.0%	Percentage Growth in Customer Count
6*	0.0%	Change in Avg. Use per Cust. (Base)
7*	1.0%	Percentage above Base (High)
8*	(1.0%)	Percentage below Base (Low)
9*	1	Compounded? (0=No, 1=Yes)

										BASE				
Year	Base Case Energy (MWH)	Base Case Fixed Cost Recovery	Number of Customers	Fixed Cost Recovery per Customer	Actual Customer Count	Allowed Fixed Cost Recovery Per Customer Count	Energy Savings (MWH)	Fixed Costs Unrecovered	Avg. Use / Cust. (Base)	Actual Fixed Cost Recovery Per MWH (Constant Use/Cust)	Base Case Fixed Cost Revenue Recovered	Amount of True-Up (Base)	Percent of Class Revenue Requirement
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
		(2) X 1*		(3) / (4)	(4) X 5*		(6) X (5)			(10) X 1*		(13) X 6*	(13) X (6) X 1*	(14) - (11)	(8) - (15)	(16) / 2*	
2003	3,291,982	$27,295,897	50,992	$535.30								$4,559					
2004					51,501	$27,568,856		0	$0			64,559	$27,568,856	$27,568,856	$0	0.00%	
2005					52,016	$27,844,545		22,426	$185,945			64,559	$27,844,545	$27,658,600	$185,945	0.14%	
2006					52,537	$28,122,990		46,253	$383,511			64,559	$28,122,990	$27,739,479	$383,511	0.30%	
2007					53,062	$28,404,220		71,482	$592,689			64,559	$28,404,220	$27,811,521	$592,699	0.46%	
2008					53,593	$28,688,262		98,112	$813,508			64,559	$28,688,262	$27,874,754	$813,508	0.63%	
2009					54,129	$28,975,145		126,144	$1,045,939			64,559	$28,975,145	$27,929,206	$1,046,939	0.81%	
2010					54,670	$29,264,896		156,979	$1,301,614			64,559	$29,264,896	$27,963,283	$1,301,614	1.00%	
2011					55,217	$29,557,545		189,216	$1,568,909			64,559	$29,557,545	$27,988,636	$1,568,909	1.21%	
2012					55,769	$29,853,121		222,854	$1,847,826			64,559	$29,853,121	$28,005,294	$1,847,826	1.43%	
2013					56,326	$30,151,652		257,614	$2,136,041			64,559	$30,151,652	$28,015,611	$2,136,041	1.65%	
2014					56,890	$30,453,168		257,614	$2,136,041			64,559	$30,453,168	$28,317,128	$2,136,041	1.65%	
2015					57,459	$30,757,700		257,614	$2,136,041			64,559	$30,757,700	$28,621,659	$2,136,041	1.65%	
2016					58,033	$31,065,277		257,614	$2,136,041			64,559	$31,065,277	$28,929,236	$2,136,041	1.65%	
2017					58,613	$31,375,930		257,614	$2,136,041			64,559	$31,375,930	$29,239,889	$2,136,041	1.65%	
2018					59,200	$31,689,689		257,614	$2,136,041			64,559	$31,689,689	$29,553,648	$2,136,041	1.65%	
2019					59,792	$32,006,586		257,614	$2,136,041			64,559	$32,006,586	$29,870,545	$2,136,041	1.65%	
2020					60,390	$32,326,652		257,614	$2,136,041			64,559	$32,326,652	$30,190,611	$2,136,041	1.65%	
2021					60,993	$32,649,919		257,614	$2,136,041			64,559	$32,649,919	$30,513,878	$2,136,041	1.65%	
2022					61,603	$32,976,418		257,614	$2,136,041			64,559	$32,976,418	$30,840,377	$2,136,041	1.65%	
2023					62,219	$33,306,182		257,614	$2,136,041			64,559	$33,306,182	$31,170,141	$2,136,041	1.65%	

COMMERCIAL

	HIGH						LOW				
Year	Avg. Use / Cust. (High)	Percent Increase in Average Use per Customer	High Case Fixed Cost Revenue Recovered	Amount of True-Up (High)	Percent of Class Revenue Requirement (High)		Avg. Use / Cust. (Low)	Percent Decrease in Average Use per Customer	Low Case Fixed Cost Revenue Recovered	Amount of True-Up (Low)	Percent of Class Revenue Requirement (Low)
(1)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)
	(19) X (6*+7*)	(19) X (6) X 1*	(20) - (11)	(8) - (21)	(22) / 2*		(25) X (6*+8*)	(25) X (6) X 1*	(26) - (11)	(8) - (27)	(28) / 2*
2003	**64,559**						**64,559**				
2004	65,205	$27,844,545	$27,844,545	($275,689)	(0.21%)		63,914	$27,293,168	$27,293,168	$275,689	0.21%
2005	65,857	$28,404,220	$28,218,275	($373,731)	(0.29%)		63,275	$27,290,438	$27,104,493	$740,051	0.57%
2006	66,516	$28,975,145	$28,591,634	($468,644)	(0.36%)		62,642	$27,287,709	$26,904,198	$1,218,792	0.94%
2007	67,181	$29,557,545	$28,964,846	($569,626)	(0.43%)		62,015	$27,284,980	$26,692,281	$1,711,939	1.32%
2008	67,853	$30,151,652	$29,338,143	($649,881)	(0.50%)		61,395	$27,282,252	$26,468,743	$2,219,519	1.71%
2009	68,531	$30,757,700	$29,711,761	($736,615)	(0.57%)		60,781	$27,279,524	$26,233,584	$2,741,561	2.12%
2010	69,216	$31,375,930	$30,074,316	($809,420)	(0.62%)		60,174	$27,276,796	$25,975,182	$3,269,714	2.54%
2011	69,909	$32,006,586	$30,437,677	($880,132)	(0.68%)		59,572	$27,274,068	$25,705,159	$3,852,386	2.97%
2012	70,608	$32,649,919	$30,802,092	($948,971)	(0.73%)		58,976	$27,271,341	$25,423,514	$4,429,606	3.42%
2013	71,314	$33,306,182	$31,170,141	($1,018,489)	(0.79%)		58,386	$27,268,614	$25,132,573	$5,019,079	3.87%
2014	72,027	$33,975,636	$31,839,595	($1,386,427)	(1.07%)		57,802	$27,265,887	$25,129,846	$5,323,323	4.11%
2015	72,747	$34,658,546	$32,522,506	($1,764,805)	(1.36%)		57,224	$27,263,160	$25,127,119	$5,630,581	4.35%
2016	73,475	$35,355,183	$33,219,142	($2,153,865)	(1.66%)		56,652	$27,260,434	$25,124,393	$5,940,884	4.59%
2017	74,209	$36,065,822	$33,929,782	($2,553,852)	(1.97%)		56,086	$27,257,708	$25,121,667	$6,254,263	4.83%
2018	74,951	$36,790,745	$34,654,705	($2,965,015)	(2.29%)		55,525	$27,254,982	$25,118,941	$6,570,748	5.07%
2019	75,701	$37,530,239	$35,394,199	($3,387,612)	(2.62%)		54,970	$27,252,256	$25,116,216	$6,890,370	5.32%
2020	76,458	$38,284,597	$36,148,556	($3,821,904)	(2.95%)		54,420	$27,249,531	$25,113,490	$7,213,162	5.57%
2021	77,222	$39,054,118	$36,918,077	($4,268,158)	(3.29%)		53,876	$27,246,806	$25,110,765	$7,539,153	5.82%
2022	77,995	$39,839,105	$37,703,065	($4,726,647)	(3.65%)		53,337	$27,244,082	$25,108,041	$7,868,377	6.07%
2023	78,775	$40,639,871	$38,503,831	($5,197,649)	(4.01%)		52,804	$27,241,357	$25,105,316	$8,200,865	6.33%

INDUSTRIAL

This is a dynamic model and so the values change. The numbers here represent just one scenario based upon the input assumptions.

Constants:

1*	$2.44	Total Fixed Cost per MWH (Class & Subsidy)
2*	$56,713,735	Class Revenue Requirement
3*	$46,409.29	Fixed Cost Recovery per Customer
4*	3	DSM Savings Assumptions: (1) DSM Savings Assumptions in 2004 IRP (2) Enhanced Residential and Commercial Numbers (Mike Rufo's Analysis) (3) Northwest Power & Conservation Council's DSM Assumptions
5*	1.0%	Percentage Growth in Customer Count
6*	0.0%	Change in Avg. Use per Cust. (Base)
7*	1.0%	Percentage above Base (High)
8*	(1.0%)	Percentage below Base (Low)
9*	1	Compounded? (0=No, 1=Yes)

										BASE				
Year	Base Case Energy (MWH)	Base Case Fixed Cost Recovery	Number of Customers	Fixed Cost Recovery per Customer	Actual Customer Count	Allowed Fixed Cost Recovery Per Customer Count	Energy Savings (MWH)	Fixed Costs Unrecovered	Avg. Use / Cust. (Base)	Actual Fixed Cost Recovery Per MWH (Constant Use/Cust)	Base Case Fixed Cost Revenue Recovered	Amount of True-Up (Base)	Percent of Class Revenue Requirement
(1)	(2)	(3)	(4)	(5)	(6)	(7) (8)	(9) (10)	(11)	(12) (13)	(14)	(15)	(16)	(17) (18)
		(2) X 1*		(3) / (4)	(4) X 5*			(10) X 1*	(13) X 6*	(13) X (6) X 1*	(14) - (11)	(8) - (15)	(15) / 2*
2003	1,980,662	$4,825,631	104	$46,400.29					19,044,825				
2004					105	$4,873,887	0	$0	19,044,825	$4,873,887	$4,873,887	$0	0.00%
2005					106	$4,922,626	19,622	$47,807	19,044,825	$4,922,626	$4,874,818	$47,807	0.08%
2006					107	$4,971,852	39,245	$95,615	19,044,825	$4,971,852	$4,876,237	$95,615	0.17%
2007					108	$5,021,571	58,867	$143,422	19,044,825	$5,021,571	$4,878,148	$143,422	0.25%
2008					109	$5,071,786	78,490	$191,230	19,044,825	$5,071,786	$4,880,556	$191,230	0.34%
2009					110	$5,122,504	98,112	$239,037	19,044,825	$5,122,504	$4,883,467	$239,037	0.42%
2010					112	$5,173,729	117,734	$286,845	19,044,825	$5,173,729	$4,886,884	$286,845	0.51%
2011					113	$5,225,466	137,357	$334,652	19,044,825	$5,225,466	$4,890,814	$334,652	0.59%
2012					114	$5,277,721	156,979	$382,460	19,044,825	$5,277,721	$4,895,261	$382,460	0.67%
2013					115	$5,330,498	176,602	$430,267	19,044,825	$5,330,498	$4,900,231	$430,267	0.76%
2014					116	$5,383,803	176,602	$430,267	19,044,825	$5,383,803	$4,953,536	$430,267	0.76%
2015					117	$5,437,641	176,602	$430,267	19,044,825	$5,437,641	$5,007,374	$430,267	0.76%
2016					118	$5,492,018	176,602	$430,267	19,044,825	$5,492,018	$5,061,750	$430,267	0.76%
2017					120	$5,546,938	176,602	$430,267	19,044,825	$5,546,938	$5,116,671	$430,267	0.76%
2018					121	$5,602,407	176,602	$430,267	19,044,825	$5,602,407	$5,172,140	$430,267	0.76%
2019					122	$5,658,431	176,602	$430,267	19,044,825	$5,658,431	$5,228,164	$430,267	0.76%
2020					123	$5,715,016	176,602	$430,267	19,044,825	$5,715,016	$5,284,748	$430,267	0.76%
2021					124	$5,772,166	176,602	$430,267	19,044,825	$5,772,166	$5,341,899	$430,267	0.76%
2022					126	$5,829,888	176,602	$430,267	19,044,825	$5,829,888	$5,399,620	$430,267	0.76%
2023					127	$5,888,186	176,602	$430,267	19,044,825	$5,888,186	$5,457,919	$430,267	0.76%

INDUSTRIAL

	HIGH						LOW				
Year	Avg. Use / Cust. (High)	Percent Increase in Average Use per Customer	High Case Fixed Cost Revenue Recovered	Amount of True-Up (High)	Percent of Class Revenue Requirement (High)		Avg. Use / Cust. (Low)	Percent Decrease in Average Use per Customer	Low Case Fixed Cost Revenue Recovered	Amount of True-Up (Low)	Percent of Class Revenue Requirement (Low)
(1)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)
	(19) X (6*+7*)	(19) X (6) X 1*	(20) - (11)	(8) - (21)	(22) / 2*		(25) X (6*+8*)	(25) X (6) X 1*	(26) - (11)	(8) - (27)	(28) / 2*
2003	**19,044,825**						**19,044,825**				
2004	19,235,273	$4,922,626	$4,922,626	($48,739)	(0.09%)		18,854,376	$4,825,148	$4,825,148	$48,739	0.09%
2005	19,427,625	$5,021,571	$4,973,763	($51,137)	(0.09%)		18,665,832	$4,824,666	$4,776,858	$145,768	0.26%
2006	19,621,902	$5,122,504	$5,026,889	($55,037)	(0.10%)		18,479,174	$4,824,183	$4,728,568	$243,284	0.43%
2007	19,818,121	$5,225,486	$5,082,044	($60,473)	(0.11%)		18,294,382	$4,823,701	$4,680,278	$341,292	0.60%
2008	20,016,302	$5,330,496	$5,139,268	($67,482)	(0.12%)		18,111,439	$4,823,218	$4,631,988	$439,798	0.78%
2009	20,216,465	$5,437,641	$5,198,604	($76,100)	(0.13%)		17,930,324	$4,822,736	$4,583,699	$538,806	0.95%
2010	20,418,630	$5,546,938	$5,260,093	($86,364)	(0.15%)		17,751,021	$4,822,254	$4,535,409	$638,320	1.13%
2011	20,622,816	$5,658,431	$5,323,779	($98,313)	(0.17%)		17,573,511	$4,821,771	$4,487,119	$738,347	1.30%
2012	20,829,044	$5,772,166	$5,389,706	($111,985)	(0.20%)		17,397,776	$4,821,289	$4,438,829	$838,892	1.48%
2013	21,037,335	$5,888,186	$5,457,919	($127,421)	(0.22%)		17,223,798	$4,820,807	$4,390,540	$939,959	1.66%
2014	21,247,708	$6,006,539	$5,576,272	($192,466)	(0.34%)		17,051,560	$4,820,325	$4,390,058	$993,746	1.75%
2015	21,460,185	$6,127,270	$5,697,003	($259,382)	(0.46%)		16,881,044	$4,819,843	$4,389,576	$1,048,066	1.85%
2016	21,674,787	$6,250,429	$5,820,161	($328,143)	(0.58%)		16,712,234	$4,819,361	$4,389,094	$1,102,924	1.94%
2017	21,891,535	$6,376,062	$5,945,795	($398,857)	(0.70%)		16,545,112	$4,818,879	$4,388,612	$1,158,326	2.04%
2018	22,110,450	$6,504,221	$6,073,954	($471,546)	(0.83%)		16,379,660	$4,818,397	$4,388,130	$1,214,277	2.14%
2019	22,331,555	$6,634,956	$6,204,688	($546,257)	(0.96%)		16,215,864	$4,817,915	$4,387,648	$1,270,783	2.24%
2020	22,554,870	$6,768,318	$6,338,051	($623,035)	(1.10%)		16,053,705	$4,817,434	$4,387,166	$1,327,849	2.34%
2021	22,780,419	$6,904,362	$6,474,094	($701,928)	(1.24%)		15,893,168	$4,816,952	$4,386,685	$1,385,481	2.44%
2022	23,008,223	$7,043,139	$6,612,872	($782,984)	(1.38%)		15,734,236	$4,816,470	$4,386,203	$1,443,685	2.55%
2023	23,238,305	$7,184,706	$6,754,439	($866,253)	(1.53%)		15,576,894	$4,815,989	$4,385,721	$1,502,465	2.65%

IRRIGATION

This is a dynamic model and so the values change. The numbers here represent just one scenario based upon the input assumptions.

Constants:

1*	$14.76	Total Fixed Cost per MWH (Class & Subsidy)
2*	$69,232,344	Class Revenue Requirement
3*	$1,635.62	Fixed Cost Recovery per Customer
4*	3	DSM Savings Assumptions:
		(1) DSM Savings Assumptions in 2004 IRP
		(2) Enhanced Residential and Commercial Numbers (Mike Rufo's Analysis)
		(3) Northwest Power & Conservation Council's DSM Assumptions
5*	1.0%	Percentage Growth in Customer Count
6*	0.0%	Change in Avg. Use per Cust. (Base)
7*	1.0%	Percentage above Base (High)
8*	(1.0%)	Percentage below Base (Low)
9*	1	Compounded? (0=No, 1=Yes)

Year	Base Case Energy (MWH)	Base Case Fixed Cost Recovery	Number of Customers	Fixed Cost Recovery per Customer	Actual Customer Count	Allowed Fixed Cost Recovery Per Customer Count	Energy Savings (MWH)	Fixed Costs Unrecovered	BASE: Avg. Use / Cust. (Base)	BASE: Actual Fixed Cost Recovery Per MWH (Constant Use/Cust)	BASE: Base Case Fixed Cost Revenue Recovered	BASE: Amount of True-Up (Base)	BASE: Percent of Class Revenue Requirement
(1)	(2)	(3)	(4)	(5)	(6)	(8)	(10)	(11)	(13)	(14)	(15)	(16)	(17)
		(2) X 1*		(3) / (4)	(4) X 5*	(6) X (5)		(10) X 1*	(13) X 6*	(13) X (6) X 1*	(14) - (15)	(8) - (15)	(16) / 2*
2003	1,622,691	$23,950,361	14,643	$1,635.62					110,810				
2004					14,789	$24,189,865	0	$0	110,810	$24,189,865	$24,189,865	$0	0.00%
2005					14,937	$24,431,764	5,606	$82,754	110,810	$24,431,764	$24,349,010	$82,754	0.12%
2006					15,087	$24,676,081	11,213	$165,507	110,810	$24,676,081	$24,510,574	$165,507	0.24%
2007					15,238	$24,922,842	16,819	$248,261	110,810	$24,922,842	$24,674,581	$248,261	0.36%
2008					15,390	$25,172,070	22,426	$331,015	110,810	$25,172,070	$24,841,056	$331,015	0.48%
2009					15,544	$25,423,791	28,032	$413,768	110,810	$25,423,791	$25,010,023	$413,768	0.60%
2010					15,699	$25,678,029	33,638	$496,522	110,810	$25,678,029	$25,181,507	$496,522	0.72%
2011					15,856	$25,934,809	39,245	$579,275	110,810	$25,934,809	$25,355,534	$579,275	0.84%
2012					16,015	$26,194,157	44,851	$662,029	110,810	$26,194,157	$25,532,128	$662,029	0.96%
2013					16,175	$26,456,099	50,458	$744,783	110,810	$26,456,099	$25,711,316	$744,783	1.08%
2014					16,337	$26,720,660	50,458	$744,783	110,810	$26,720,660	$25,975,877	$744,783	1.08%
2015					16,500	$26,987,867	50,458	$744,783	110,810	$26,987,867	$26,243,084	$744,783	1.08%
2016					16,665	$27,257,745	50,458	$744,783	110,810	$27,257,745	$26,512,962	$744,783	1.08%
2017					16,832	$27,530,323	50,458	$744,783	110,810	$27,530,323	$26,785,540	$744,783	1.08%
2018					17,000	$27,805,626	50,458	$744,783	110,810	$27,805,626	$27,060,843	$744,783	1.08%
2019					17,170	$28,083,682	50,458	$744,783	110,810	$28,083,682	$27,338,899	$744,783	1.08%
2020					17,342	$28,364,519	50,458	$744,783	110,810	$28,364,519	$27,619,736	$744,783	1.08%
2021					17,515	$28,648,164	50,458	$744,783	110,810	$28,648,164	$27,903,381	$744,783	1.08%
2022					17,690	$28,934,646	50,458	$744,783	110,810	$28,934,646	$28,189,863	$744,783	1.08%
2023					17,867	$29,223,992	50,458	$744,783	110,810	$29,223,992	$28,479,210	$744,783	1.08%

IRRIGATION

	HIGH						LOW				
Year	Avg. Use / Cust. (High)	Percent Increase in Average Use per Customer	High Case Fixed Cost Revenue Recovered	Amount of True-Up (High)	Percent of Class Revenue Requirement (High)		Avg. Use / Cust. (Low)	Percent Decrease in Average Use per Customer	Low Case Fixed Cost Revenue Recovered	Amount of True-Up (Low)	Percent of Class Revenue Requirement (Low)
(1)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)
	(19) X (6*+7*)	(19) X (6) X 1*	(20) - (11)	(8) - (21)	(22) / 2*		(25) X (6*+8*)	(25) X (6) X 1*	(26) - (11)	(8) - (27)	(28) / 2*
2003	**110,810**						**110,810**				
2004	111,918	$24,431,764	$24,431,764	($241,899)	(0.35%)		109,702	$23,947,966	$23,947,966	$241,899	0.35%
2005	113,037	$24,922,842	$24,840,088	($408,325)	(0.59%)		108,605	$23,945,571	$23,862,818	$568,946	0.82%
2006	114,168	$25,423,791	$25,258,284	($582,203)	(0.84%)		107,519	$23,943,177	$23,777,670	$898,412	1.30%
2007	115,309	$25,934,809	$25,686,548	($763,706)	(1.10%)		106,444	$23,940,783	$23,692,522	$1,230,330	1.78%
2008	116,462	$26,456,099	$26,125,084	($953,014)	(1.38%)		105,379	$23,938,389	$23,607,374	$1,564,696	2.26%
2009	117,627	$26,987,867	$26,574,098	($1,150,307)	(1.66%)		104,325	$23,935,995	$23,522,226	$1,901,565	2.75%
2010	118,803	$27,530,323	$27,033,801	($1,355,772)	(1.96%)		103,282	$23,933,601	$23,437,079	$2,240,950	3.24%
2011	119,991	$28,083,682	$27,504,407	($1,569,597)	(2.27%)		102,249	$23,931,208	$23,351,932	$2,582,877	3.73%
2012	121,191	$28,648,164	$27,986,135	($1,791,976)	(2.59%)		101,227	$23,928,815	$23,266,785	$2,927,372	4.23%
2013	122,403	$29,223,992	$28,479,210	($2,023,111)	(2.92%)		100,215	$23,926,422	$23,181,639	$3,274,460	4.73%
2014	123,627	$29,811,395	$29,066,612	($2,345,952)	(3.39%)		99,212	$23,924,029	$23,179,246	$3,541,414	5.12%
2015	124,863	$30,410,604	$29,665,821	($2,677,954)	(3.87%)		98,220	$23,921,637	$23,176,854	$3,811,013	5.50%
2016	126,112	$31,021,857	$30,277,074	($3,019,329)	(4.36%)		97,238	$23,919,244	$23,174,462	$4,083,294	5.90%
2017	127,373	$31,645,396	$30,900,613	($3,370,291)	(4.87%)		96,266	$23,916,853	$23,172,070	$4,358,253	6.30%
2018	128,647	$32,281,468	$31,536,685	($3,731,060)	(5.39%)		95,303	$23,914,461	$23,169,678	$4,635,948	6.70%
2019	129,933	$32,930,326	$32,185,543	($4,101,861)	(5.92%)		94,350	$23,912,069	$23,167,287	$4,916,398	7.10%
2020	131,233	$33,592,226	$32,847,443	($4,482,924)	(6.48%)		93,407	$23,909,679	$23,164,895	$5,199,624	7.51%
2021	132,545	$34,267,429	$33,522,647	($4,874,482)	(7.04%)		92,472	$23,907,287	$23,162,504	$5,485,660	7.92%
2022	133,871	$34,956,205	$34,211,422	($5,276,775)	(7.62%)		91,548	$23,904,897	$23,160,114	$5,774,532	8.34%
2023	135,209	$35,658,824	$34,914,042	($5,690,049)	(8.22%)		90,632	$23,902,506	$23,157,723	$6,066,269	8.76%

APPENDIX 12—DSM ANALYSIS USING THE AURORA MODEL

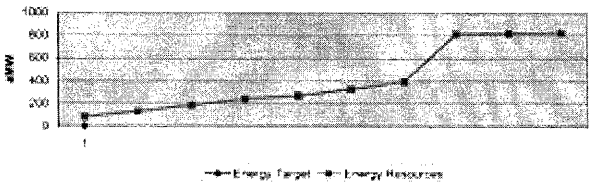
P11 - Balanced 7: CHANGES TO PORTFOLIO FOR DSM ANALYSIS

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Energy Target	66	132	192	236	258	313	412	464	517	511
Capacity Target	54	3	71	163	249	335	429	522	614	709

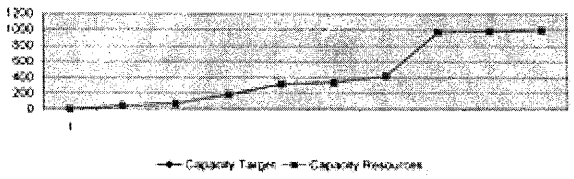
Energy	Increase in Energy with DSM Change	0.0	1.8	4.9	6.4	13.1	17.4	21.1	24.1	26.7	28.0
	Peakers/ mkt purchase for energy	66	130	159	179	99	152	121	0		
	DSM - ALL PROGRAMS	0	4	9	16	21	25	33	38	43	47
	100 MW wind 06			20	20	20	20	20	20	20	20
	100 MW wind 07				20	20	20	20	20	20	20
	12 MW CHP 07				12	12	12	12	12	12	12
	100 MW geothermal 08					100	100	100	100	100	100
	150 MW Wind 10							30	30	30	30
	36 MW CHP 10							0	36	36	36
	62 MW Peakers/DG 10							62	62	62	62
	500 MW coal seasonal 11								500	500	500
	Total Energy	66	134	187	245	271	331	397	817	822	826
		0	2	5	9	13	18	-15	352	305	256
Capacity	Increase in Capacity with DSM Change	0.0	2.9	8.4	18.8	23.8	32.0	38.8	44.5	49.7	54.3
	76 MW DSM A/C & Irrig clipping	0	39	48	57	67	76	76	76	76	76
	DSM - ALL PROGRAMS	0	8	18	31	44	56	70	82	92	103
	100 MW Wind 06			5	5	5	5	5	5	5	5
	100 MW Wind 07				5	5	5	5	5	5	5
	12 MW CHP 07				0	12	12	12	12	12	12
	88 MW peaker (2*44) 07				88	88	88	88	88	88	88
	100 MW geothermal 08					100	100	100	100	100	100
	36 MW CHP 10						0	0	36	36	36
	62 MW Peakers/DG 10							62	62	62	62
	150 MW Wind 10							8	8	8	8
	500 MW coal seasonal 11								500	500	500
	Total Capacity	0	47	72	186	321	344	426	973	983	994
		54	45	1	23	12	8	-4	450	389	288

Notes:
1. Peakers can be run to satisfy monthly energy deficit.
2. Market purchases are also available to satisfy monthly energy deficit.
3. Demand response programs are counted as capacity. Energy efficiency and conservation programs are considered to provide energy and capacity.
4. 75 MW of Red Butte - Borah/Brady transmission is available to reduce NW transmission deficit. If coupled with a firm market purchase of up to 75 MW, the NW transmission deficit (and the capacity requirement) can be reduced by the amount of the purchase.
5. PPL Montana contract expires in 2009. This analysis assumes that some form of contract will replace it thus no reduction of capacity occurs in 2010.
6. Wind project output based on 35% CF and seasonal shaping from NW Power and Conservation Council resource characterization paper 5th PP.
7. Decreased capacity target by 80 MW starting in 2010 to account for continuation of Montana purchases.
9. Included wind capacity credit of 5 MW per 100 MW of nameplate capacity - based on July data.
10. Removed "Market Purchase" from description on cells "C17" and "C31", and deleted reference to a 250 MW coal plant in 2009.
11. Revised DSM efficiency programs based on benefit cost ratio's associated with 5_11_05 DSM analysis (programs were change sets to P0).

P11 Balanced 7 - Energy



P11 Balanced 7 - Capacity



IPC Portfolio Analysis - Totals by Year

2004 IRP Final Portfolio (Portfolio 11) with DSM Modifications

AURORAxmp Portfolio Analysis

Portfolio Power Supply Cost Totals without Fixed Carrying Costs

Base Case - P11 as specified in 2004 IRP

Run ID	Condition	Time Period	Name	Item	Energy (MWh)
Base Case	Average	2004	IPC Portfolio	Total	15,096,930
Base Case	Average	2005	IPC Portfolio	Total	15,231,850
Base Case	Average	2006	IPC Portfolio	Total	15,922,290
Base Case	Average	2007	IPC Portfolio	Total	16,230,630
Base Case	Average	2008	IPC Portfolio	Total	16,584,880
Base Case	Average	2009	IPC Portfolio	Total	16,932,760
Base Case	Average	2010	IPC Portfolio	Total	17,352,230
Base Case	Average	2011	IPC Portfolio	Total	17,747,870
Base Case	Average	2012	IPC Portfolio	Total	18,095,100
Base Case	Average	2013	IPC Portfolio	Total	18,407,350
Base Case	Average	2014	IPC Portfolio	Total	18,641,990
Base Case	Average	2015	IPC Portfolio	Total	19,041,670
Base Case	Average	2016	IPC Portfolio	Total	19,527,800
Base Case	Average	2017	IPC Portfolio	Total	19,877,110
Base Case	Average	2018	IPC Portfolio	Total	20,157,440
Base Case	Average	2019	IPC Portfolio	Total	20,506,230
Base Case	Average	2020	IPC Portfolio	Total	20,792,380
Base Case	Average	2021	IPC Portfolio	Total	21,195,330
Base Case	Average	2022	IPC Portfolio	Total	21,559,550
Base Case	Average	2023	IPC Portfolio	Total	21,974,410
Base Case	Average	2024	IPC Portfolio	Total	22,349,890
Base Case	Average	2025	IPC Portfolio	Total	22,663,530
Base Case	Average	2026	IPC Portfolio	Total	23,033,040
Base Case	Average	2027	IPC Portfolio	Total	23,397,920
Base Case	Average	2028	IPC Portfolio	Total	23,816,490
Base Case	Average	2029	IPC Portfolio	Total	24,118,990
Base Case	Average	2030	IPC Portfolio	Total	24,488,310
Base Case	Average	2031	IPC Portfolio	Total	24,883,040
Base Case	Average	2032	IPC Portfolio	Total	25,348,010
Base Case	Average	2033	IPC Portfolio	Total	25,691,800

Case #2: DSM Comm. & Res. Efficiency Programs Increased

Run ID	Condition	Time Period	Name	Item	Energy (MWh)	Cost ($ x 1,000)	Diff. Case #2 - BC
P11 NEW DSM	Average	2004	IPC Portfolio	Total	15,096,930	$ 138,499.90	$ -
P11 NEW DSM	Average	2005	IPC Portfolio	Total	15,231,850	$ 142,286.60	$ (827.60)
P11 NEW DSM	Average	2006	IPC Portfolio	Total	15,922,290	$ 154,539.40	$ (1,422.90)
P11 NEW DSM	Average	2007	IPC Portfolio	Total	16,230,630	$ 131,916.20	$ 3,411.60
P11 NEW DSM	Average	2008	IPC Portfolio	Total	16,584,880	$ 184,697.00	$ (5,260.80)
P11 NEW DSM	Average	2009	IPC Portfolio	Total	16,932,760	$ 195,242.60	$ (8,273.00)
P11 NEW DSM	Average	2010	IPC Portfolio	Total	17,352,230	$ 181,773.60	$ (3,991.80)
P11 NEW DSM	Average	2011	IPC Portfolio	Total	17,747,870	$ 143,970.20	$ (11,419.90)
P11 NEW DSM	Average	2012	IPC Portfolio	Total	18,095,100	$ 161,089.80	$ (12,430.80)
P11 NEW DSM	Average	2013	IPC Portfolio	Total	18,407,350	$ 158,120.60	$ (15,087.70)
P11 NEW DSM	Average	2014	IPC Portfolio	Total	18,641,990	$ 139,338.50	$ (14,979.80)
P11 NEW DSM	Average	2015	IPC Portfolio	Total	19,041,670	$ 151,049.70	$ (16,674.90)
P11 NEW DSM	Average	2016	IPC Portfolio	Total	19,527,800	$ 110,010.90	$ (20,861.30)
P11 NEW DSM	Average	2017	IPC Portfolio	Total	19,877,110	$ 130,688.30	$ (18,501.90)
P11 NEW DSM	Average	2018	IPC Portfolio	Total	20,157,440	$ 72,295.80	$ (15,016.17)
P11 NEW DSM	Average	2019	IPC Portfolio	Total	20,506,230	$ 75,333.98	$ (18,205.82)
P11 NEW DSM	Average	2020	IPC Portfolio	Total	20,792,380	$ 66,857.09	$ (21,880.45)
P11 NEW DSM	Average	2021	IPC Portfolio	Total	21,195,330	$ 129,776.70	$ (21,263.00)
P11 NEW DSM	Average	2022	IPC Portfolio	Total	21,559,550	$ 90,499.85	$ (24,283.15)
P11 NEW DSM	Average	2023	IPC Portfolio	Total	21,974,410	$ 141,027.40	$ (17,059.60)
P11 NEW DSM	Average	2024	IPC Portfolio	Total	22,349,890	$ 61,299.30	$ (22,301.31)
P11 NEW DSM	Average	2025	IPC Portfolio	Total	22,663,530	$ 60,990.98	$ (22,098.54)
P11 NEW DSM	Average	2026	IPC Portfolio	Total	23,033,040	$ 104,097.50	$ (20,538.20)
P11 NEW DSM	Average	2027	IPC Portfolio	Total	23,397,920	$ 199,410.40	$ (18,911.80)
P11 NEW DSM	Average	2028	IPC Portfolio	Total	23,816,490	$ 260,590.50	$ (9,263.70)
P11 NEW DSM	Average	2029	IPC Portfolio	Total	24,118,990	$ 257,182.70	$ (21,269.80)
P11 NEW DSM	Average	2030	IPC Portfolio	Total	24,488,310	$ 287,486.00	$ (24,014.50)
P11 NEW DSM	Average	2031	IPC Portfolio	Total	24,883,040	$ 307,138.90	$ (21,879.90)
P11 NEW DSM	Average	2032	IPC Portfolio	Total	25,348,010	$ 401,123.00	$ (18,379.20)
P11 NEW DSM	Average	2033	IPC Portfolio	Total	25,691,800	$ 440,239.30	$ (20,963.20)

Portfolio Fixed Carrying Costs (Without DSM Fixed Costs)

Year	Base Case: 2004 IRP ($ x 1,000)	Modified Case #2 ($ x 1,000)	Diff. Case #2 -BC
2004	$ 181,865.38	$ 181,865.38	$ -
2005	$ 185,603.99	$ 185,603.99	$ -
2006	$ 204,711.78	$ 204,711.78	$ -
2007	$ 237,451.73	$ 235,153.21	$ (2,298.52)
2008	$ 301,164.19	$ 301,319.77	$ 155.58
2009	$ 289,819.82	$ 289,943.09	$ 123.27
2010	$ 333,387.70	$ 326,076.33	$ (7,311.37)
2011	$ 424,052.32	$ 424,669.72	$ 617.40
2012	$ 413,828.35	$ 414,337.29	$ [illegible]
2013	$ 406,729.32	$ 407,219.82	$ 490.50
2014	$ 399,462.22	$ 399,935.34	$ 473.12
2015	$ 392,701.03	$ 393,161.25	$ 460.22
2016	$ 386,552.66	$ 386,999.39	$ 446.73
2017	$ 380,061.65	$ 380,495.15	$ 433.51
2018	$ 373,734.78	$ 374,166.93	$ 432.15
2019	$ 367,443.73	$ 367,870.26	$ 426.53
2020	$ 361,558.05	$ 361,977.63	$ 419.58
2021	$ 355,781.42	$ 356,194.04	$ 412.61
2022	$ 350,023.30	$ 350,428.93	$ 405.63
2023	$ 344,371.46	$ 344,770.11	$ 398.65
2024	$ 340,095.84	$ 340,487.45	$ 391.61
2025	$ 336,825.37	$ 337,209.95	$ 384.58
2026	$ 332,879.68	$ 333,257.21	$ 377.53
2027	$ 329,283.49	$ 329,626.10	$ 342.61
2028	$ 326,084.78	$ 326,407.91	$ 323.13
2029	$ 322,851.79	$ 323,183.60	$ 331.82
2030	$ 319,955.21	$ 320,190.51	$ 235.30
2031	$ 318,457.86	$ 318,646.61	$ 188.75
2032	$ 317,570.21	$ 317,803.47	$ 233.26
2033	$ 443,816.35	$ 445,012.77	$ 1,196.42

DSM Fixed Costs

Year	Base Case: 2004 IRP ($ x 1,000)	Case #2 ($ x 1,000)	Diff. Case #2 -BC
2004	$ -	$ -	$ -
2005	$ 11,777.63	$ 18,473.65	$ 6,696.02
2006	$ 12,169.54	$ 22,816.80	$ 10,647.26
2007	$ 12,858.07	$ 25,693.39	$ 12,835.32
2008	$ 13,522.28	$ 28,582.06	$ 15,059.78
2009	$ 14,326.89	$ 31,140.39	$ 16,813.49
2010	$ 13,154.32	$ 28,484.88	$ 15,330.56
2011	$ 13,468.48	$ 27,860.72	$ 14,392.24
2012	$ 13,790.62	$ 27,715.80	$ 13,925.18
2013	$ 14,119.25	$ 27,717.50	$ 13,598.25
2014	$ 14,590.78	$ 27,984.65	$ 13,393.87
2015	$ 3,790.28	$ 6,607.97	$ 2,817.70
2016	$ 3,838.74	$ 6,244.85	$ 2,406.12
2017	$ 3,888.42	$ 5,972.83	$ 2,084.41
2018	$ 3,939.35	$ 5,863.40	$ 1,924.05
2019	$ 4,099.02	$ 5,994.52	$ 1,895.50
2020	$ 4,151.83	$ 5,925.70	$ 1,773.87
2021	$ 4,206.71	$ 5,877.60	$ 1,670.89
2022	$ 4,262.97	$ 5,859.56	$ 1,596.59
2023	$ 4,320.66	$ 5,917.52	$ 1,596.86
2024	$ 4,547.36	$ 6,102.85	$ 1,555.49
2025	$ 4,557.82	$ 4,557.82	$ -
2026	$ 4,619.97	$ 4,619.97	$ -
2027	$ 4,683.69	$ 4,683.69	$ -
2028	$ 4,749.02	$ 4,749.02	$ -
2029	$ 4,946.06	$ 4,946.06	$ -
2030	$ 5,013.79	$ 5,013.79	$ -
2031	$ 5,084.18	$ 5,084.18	$ -
2032	$ 5,156.35	$ 5,156.35	$ -
2033	$ 5,230.33	$ 5,230.33	$ -

Total Portfolio Power Supply Costs

Year	Base Case: 2004 IRP ($ x 1,000)	Case #2 ($ x 1,000)	Difference (Case #2 - Base Case) ($ x 1,000)	Cummulative Present Value of Difference (Case #2 - Base Case) ($x 1,000)
2004	$ 320,365.28	$ 320,365.28	$ -	$ -
2005	$ 340,995.83	$ 346,864.24	$ 5,868.42	$ 5,239.36
2006	$ 372,843.63	$ 382,067.98	$ 9,224.36	$ 12,875.36
2007	$ 378,814.39	$ 392,762.79	$ 13,948.40	$ 23,581.32
2008	$ 504,644.26	$ 514,598.82	$ 9,954.56	$ 30,665.59
2009	$ 527,662.31	$ 536,326.08	$ 8,663.76	$ 36,382.37
2010	$ 532,307.42	$ 536,334.81	$ 4,027.39	$ 38,846.37
2011	$ 592,910.91	$ 596,500.64	$ 3,589.73	$ 40,882.71
2012	$ 601,139.57	$ 603,142.89	$ 2,003.31	$ 41,936.39
2013	$ 594,056.87	$ 593,057.92	$ (998.95)	$ 41,449.23
2014	$ 568,371.30	$ 567,258.49	$ (1,112.80)	$ 40,946.05
2015	$ 564,211.91	$ 550,814.93	$ (13,396.98)	$ 35,329.33
2016	$ 521,263.59	$ 503,255.14	$ (18,008.45)	$ 28,328.92
2017	$ 533,140.22	$ 517,156.23	$ (15,983.98)	$ 22,567.83
2018	$ 464,986.05	$ 452,326.13	$ (12,659.92)	$ 18,337.04
2019	$ 464,782.54	$ 448,898.76	$ (15,883.79)	$ 13,415.32
2020	$ 456,447.42	$ 436,760.42	$ (19,687.00)	$ 7,759.25
2021	$ 511,027.83	$ 491,848.34	$ (19,179.49)	$ 2,650.16
2022	$ 469,029.27	$ 446,748.34	$ (22,280.93)	$ (2,852.99)
2023	$ 506,779.14	$ 491,715.03	$ (15,064.11)	$ (6,302.79)
2024	$ 430,243.81	$ 409,889.60	$ (20,354.21)	$ (10,624.70)
2025	$ 424,472.71	$ 402,758.75	$ (21,713.96)	$ (14,899.67)
2026	$ 462,135.35	$ 441,974.68	$ (20,160.67)	$ (18,579.86)
2027	$ 552,289.39	$ 533,720.20	$ (18,569.19)	$ (21,722.76)
2028	$ 600,688.03	$ 591,747.43	$ (8,940.57)	$ (23,125.81)
2029	$ 606,250.35	$ 585,312.36	$ (20,938.00)	$ (26,172.41)
2030	$ 636,469.50	$ 612,690.30	$ (23,779.20)	$ (29,380.53)
2031	$ 652,560.84	$ 630,869.69	$ (21,691.15)	$ (32,093.88)
2032	$ 744,228.75	$ 726,082.82	$ (18,145.94)	$ (34,198.51)
2033	$ 930,248.18	$ 890,481.40	$ (19,766.78)	$ (36,324.22)
Discount Rate	7.8520%			
NPV	$ 5,760,081.71	$ 5,723,757.49	$ (36,324.22)	
Difference		$ (36,324.22)		
Levelized	$ 523,959.12	$ 520,654.93	$ (3,304.19)	
Difference		$ (3,304.19)		

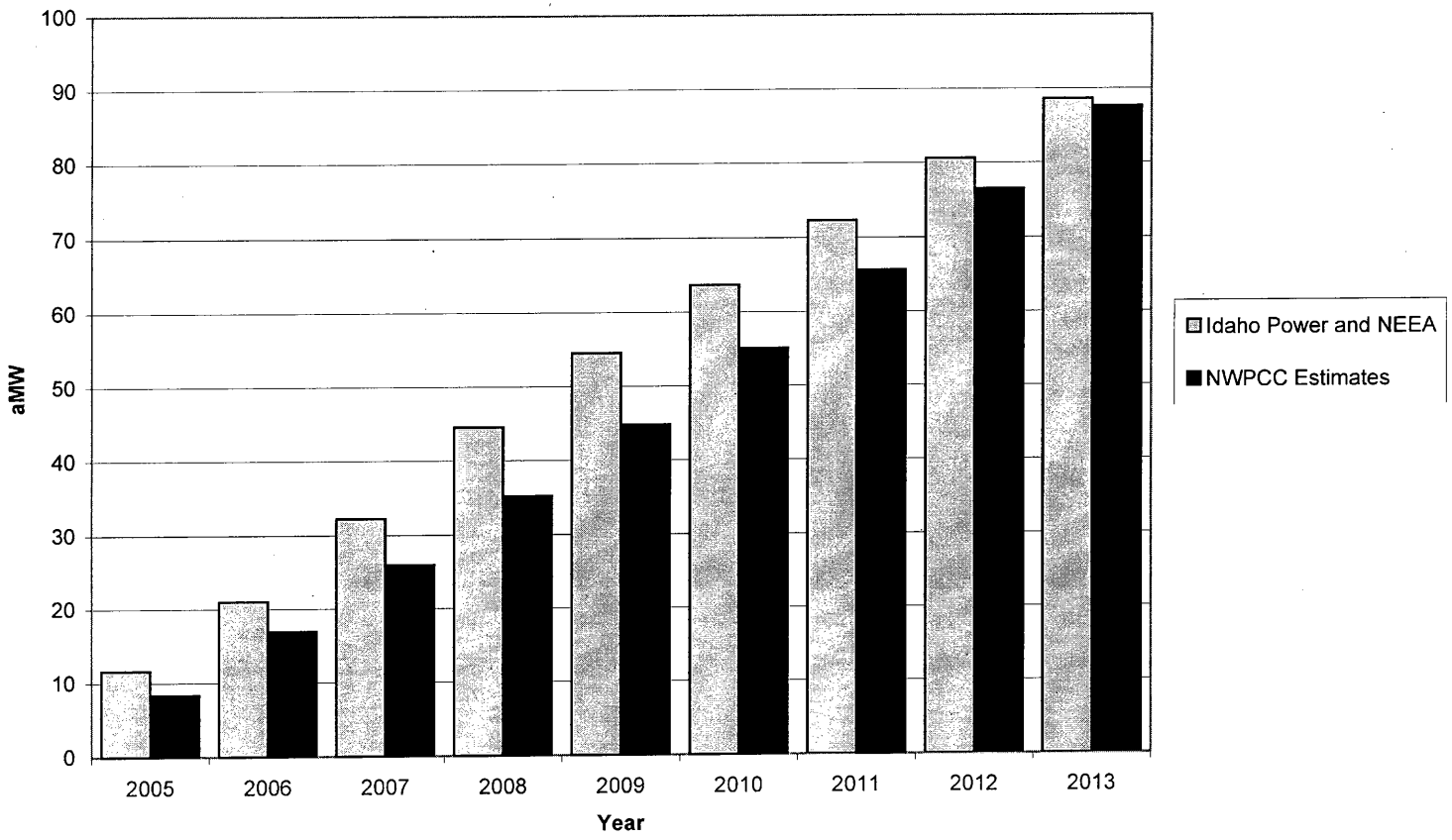
Notes: * All values averaged over all hours of simulation
Base case includes all existing and committed resources as of January 1, 2004.
Base case includes Portfolio II resources and DSM programs as outlined in IPC's 2004 Integrated Resource Plan (IRP).
All costs nominal.
IRP planning period is 2004 - 2013.
Additional resources have been added to the IPC portfolio to meet future loads.

Conditions: 70th percentile hydro conditions, 70th percentile loads as specified by 2004 IRP.
Simulation: Every 3rd hour, MWFSu, 1st & 3rd weeks, Jan. 2004 - Dec. 2033
Abbreviations: BC - Base case
IRP - Integrated Resource Plan
Version: AURORAxmp version 7.1.0.0
Revised: November 5, 2004

DSM Targets for 2013
within the Idaho Power Service Territory (aMW)

	Residential	Commercial	Irrigation	Industrial	Total
Idaho Power 2004 IRP	1.6	0.9	5.3	8.7	16.5
Idaho Power 2004 IRP with Increased DSM	15.3	13.9	5.3	8.7	43.2
Increase to 2004 IRP	13.7	13.0	-	-	26.7
NWPCC 5th Power Plan	32.3	29.4	5.8	20.2	87.6
IPCo Percentage of NWPCC	**47%**	**47%**	**93%**	**43%**	**49%**

Idaho Power DSM Including NEEA Compared to NWPCC Estimates



APPENDIX 13—FLIP CHART REGARDING TIM TATUM'S PRESENTATION

Δ Power Supply Costs from Increased Energy Conservation

(Excludes fixed costs, but includes higher levels of DSM—43% total)

1) Reduction in cost every year except year 7 (deferred CHP resource that year)
2) Fixed cost—increases except in 2 years of deferred resource (does not include DSM)
3) What does increasing level of DSM do to power supply costs?
   - By increasing DSM and deferring some CHP resources, shows reduction ($36 million) (now through 2033) in power supply costs. Net benefit does not occur until 2022—would require investment by company.

APPENDIX 14—FLIP CHARTS REGARDING COMMISSION REPORT

Commission Report

I. History of issue that generated work group—IPUC

II. What did work group do?
   - Studies –problems analysis, assumptions, why we did studies we did
   - What mechanisms explored
   - Results of investigation (possible solutions/details)

III. Conclusions and recommendations
   - Questions on wall

IV. Figures and tables, studies, workshop summaries

Report Review

Drafts circulated to all

Replies go to "report coordinator" from parties

- IPC
- NWEC
- Industry
- IPUC

APPENDIX 15—FLIP CHARTS REGARDING QUESTIONS TO ANSWER

Are there financial disincentives to energy conservation?

If there are financial disincentives, where are they (nature) and what is their extent?

What other information do we need?

Bin

1) Is the fixed cost recovery the issue or some other specific way to address DSM?
2) How much lost revenue (recovered) will cause company to do something otherwise?

Are there financial disincentives to energy conservation?

- IPUC—yes (loss of revenue associated with every kWh unsold)
- IPC
- ICIP
- NWEC

If there are financial disincentives, where are they (Nature), and what is their extent?

- In loss/fixed margin associated with unused kWh needed to recover fixed cost set in a rate case.
  - Magnitude of company energy efficiency effort
  - The more effective energy programs are, the less fixed cost lost margin
- Residential and small commercial ratepayers most affected. Rates would affect this.

How much lost revenue (recovered) will cause the company to do something otherwise?

- IPC
  - Re-energizing DSM program
  - Out-of-pocket expenses is bigger concern than lost revenue recovery at this time

Is fixed cost recovery the issue/best way to address DSM

[Cannot be answered at this time]

APPENDIX 16—FLIP CHARTS REGARDING NEXT MEETING AND ACTION ITEMS

What	Who	When
1) Check with commission regarding scope of PBR discussion (DSM related only)	Randy	
2) Talk with Bill about report coordination—reply to Susan to distribute to work group	Nancy	11/09
3) Coordinate timing for the draft report to work group for review/status report	Susan	Next meeting or e-mail
4) Develop PBR strawman well suited for Idaho, done elsewhere	IPUC	Next meeting
5) Complete Analysis For ○ PBR—IPC–Defer ○ Refined Cavanagh True-Up	IPUC	Next meeting
6) Refine Cavanagh true-up strawman	Ralph	Next meeting

December 1 meeting (9:30 to 3:30)

- Strawmen presentations
- Evaluation criteria
- Status update

December 13 (alternative or next date)

ASSESSING FINANCIAL DISINCENTIVES AND RESOLUTION OPPORTUNITIES, WORKSHOP #4

DECEMBER 1, 2004, 9:30 A.M. TO 3:00 P.M.
CONFERENCE ROOM 9 EAST, IDAHO POWER CORPORATE HEADQUARTERS, BOISE, ID

Facilitation Susan Hayman, North Country Resources, Inc.
Documentation Natalie Chavez, Chavez Writing & Editing, Inc.

WORKSHOP OBJECTIVES

1) Confirm criteria to evaluate the applicability and desirability of potential mechanisms to remove disincentives/provide incentives for utility investment in DSM programs
2) Review two potential mechanisms:
   a) Refined true-up mechanism
   b) Performance-based ratemaking mechanism
3) Confirm the type of report that will be submitted to the IPUC on December 15 and assignments for preparation and review

WORKSHOP DECISIONS AND OUTCOMES

Participants agreed to a set of evaluation criteria for potential disincentive/incentive mechanisms. The purpose of the evaluation would be to compare and contrast different mechanisms to determine their applicability and desirability.

Participants also decided to recommend a pilot of the performance-based mechanism proposed by IPUC staff for one program until the next rate case. They also want to simulate the true-up mechanism during the same period, based on real numbers, to consider it further and refine the mechanism. The next meeting is scheduled for December 13, 9:00 am to 12:00 pm at IPC to discuss the details of these recommendations. The final report and an application for the pilot program will be submitted to the IPUC some time in January (dates to be determined December 13).

ACTION ITEMS

	What?	Who?	When?
1)	Draft and distribute status report for review and comment	Susan Hayman and Scott Woodbury	December 3
2)	Prepare the outline and anything else necessary for developing the proposal for a pilot performance-based incentive mechanism; bring to the next meeting	IPC (Darlene Nemnich)	December 13
3)	Design the simulation for the true-up mechanism; bring to the next meeting	IPC (Mike Youngblood)	December 13

WORKSHOP INTRODUCTION

Susan Hayman, North Country Resources, welcomed participants (Appendix 1), reviewed workshop objectives (above), and then reviewed the agenda (Appendix 2). She also reviewed posters with the principles of meeting conduct, purpose and products of the workshop series, and important definitions.

MECHANISM EVALUATION CRITERIA

Hayman distributed a handout with potential mechanism evaluation criteria (Appendix 3). She compiled these criteria after telephone conversations with many of the participants prior to the November 8 workshop. Hayman said that the list served as a starting point for developing a final list of criteria against which to evaluate potential disincentive and incentive mechanisms. Participants first clarified their understanding of the criteria, and then revised criteria until they were acceptable to all. Appendix 4 includes flipchart notes taken during the discussion. However, most changes were captured on the wall poster of the preliminary criteria during group discussion. The final revised list is included in Appendix 5.

POTENTIAL MECHANISMS

Refined True-Up Mechanism

Ralph Cavanagh, Natural Resources Defense Council, spoke about the requested revision to the strawman proposal for an Idaho Power true-up mechanism (introduced at Workshop #2 on September 27, 2004). A handout summarized points of the original proposal as well as the proposed revisions (Appendix 6). These proposed revisions included true-up based on actual customer counts for residential and commercial customers (rather than on forecasted sales for all customer classes as originally proposed).

Cavanagh, in cooperation with Idaho Power staff, looked into how often a true-up tied to actual customer counts would have increased or reduced rates for the residential and commercial classes since 1990. For any year during which such a mechanism would have been in effect, rates would have gone down if the class's retail sales had grown more rapidly than the class's customer count, and vice versa. For the commercial sector, electricity use grew more rapidly than the customer count in 10 of the 14 years since 1990. For the residential sector, electricity use grew more rapidly than customer count in 2 of the 14 years, while rates of growth were essentially identical in 3 years (including 2003). These findings confirm the potential for rate decreases as well as increases for both classes under a true-up mechanism, although based on historical data, the likelihood of a rate decrease is substantially greater for the commercial sector than for the residential sector. Cavanagh emphasized that annual class-specific rate increases necessary to ensure recovery of the authorized fixed-cost revenue requirement would never have exceeded 2% under the true-up mechanism. In most years, for both classes, rates would have shifted up or down by 1% or less.

During his presentation, Cavanagh shared the following:

- A bar chart showed the net benefit of expanded energy-efficiency efforts for the Idaho system. The high case indicated the greatest net benefit to the system at just over a $100 million (Appendix 7). Given the net benefits, financial disincentives need to be removed so that Idaho Power is encouraged to promote energy efficiency through conservation programs.
- This true-up mechanism provides symmetry in that it addresses both lost revenues and found revenues. Therefore, it discourages "perverse incentives" and DSM programs that "look good on paper but aren't effective in practice."
- The revised strawman proposal avoids cross subsidies and is fundamentally fair to the customers.
- A second bar chart showed the annual household energy use (in kWh) for entertainment electronics that will likely be typical of households in about 10 years (Appendix7). It's expected that combined energy use for plasma TVs, DVD/VCRs, and set top box/satellite receivers will be about 1,200kWh annually, up from about 500 kWh now with analog TVs. Workshop participants were cautioned through this example that technological advances and changes in customer habits do not necessarily lead to reduced per-customer electricity usage. This underscores the importance of well-designed energy efficiency incentives, as well as and the merits of the revised NRDC true-up proposal (which ties any increases in fixed cost recovery for the residential and commercial classes to increases in the number of residential and commercial customers).
- A performance-based mechanism could be used in conjunction with the true-up mechanism.

Follow-up discussion among participants focused on how big the impacts of implementing a true-up mechanism would be to residential and commercial customers and how rate adjustments would be calculated. Flipchart notes made during this portion of the workshop are included in Appendix 8.

Performance-Based Ratemaking Mechanism

Lynn Anderson, IPUC, distributed a two-page strawman proposal for a performance-based mechanism (Appendix 9). Before talking about the proposal summarized on the second page, he asked that participants review the hypotheses included on the first page. Until he compiled this list, he had been unable to draft the proposed mechanism. The following issues were raised during discussion of hypotheses:

- Cavanagh questioned the exclusion of increased gas market share from fixed-cost losses in hypothesis #7. Idaho Power may be motivated to retain electric market share for water heaters if the company is unable to recover the fixed-cost revenue losses resulting from customers' conversion to more efficient gas water heaters. This approach seems to penalize the company for these conversions and encourage inefficiency. IPUC staff pointed out that Idaho Power could implement a DSM program that reimburses customers for converting to energy-efficient gas water heaters.
- Some workshop participants see some inconsistency in the IPUC's view on factors outside Idaho Power's control. For example, the strawman proposal disallows Idaho Power from collecting fixed-cost revenue losses unless incurred through DSM efforts. Yet reimbursement of fuel costs through the company's Power Cost Adjustment (PCA) mechanism does allow for factors outside the company's control.
- The means for verifying savings resulting from DSM programs are likely to be "complex, tedious, and expensive."

Following discussion of the hypotheses, Anderson explained the actual proposal, found on the second page of the handout. The IPUC staff's strawman proposal would implement a mechanism to remove financial disincentives by allowing specific fixed-cost revenue recovery for all verified DSM savings with a bonus financial incentive for exceeding cost-effective DSM targets. He pointed out that the financial incentives component of the proposal could also be implemented as a stand-alone approach or with a true-up mechanism. This mechanism, as proposed, would be implemented as a trial restricted to the Residential New Construction program. Residential energy rates have a relatively high fixed-cost recovery component, which means that Idaho Power's financial disincentive for DSM in this class may be higher than for other customer classes. It's also a relatively small program, so effects of any mistakes made in the trial would be minimized. The following points were made during discussion of the performance-based proposal:

- According to Darlene Nemnich, IPC, Idaho Power rewards customers $750 when they exceed building code on energy efficiency by 30% on new construction. Ideally, builders would want to make homes as energy efficient as possible, but they are unlikely to want to change codes. Therefore, code enforcement and training of code officials is important, and it is reasonable to credit utilities with work they do with code enforcement beyond typical DSM programs.
- Because of the trial nature of the mechanism, no penalties are included. Quality control is relatively straightforward, and the targeted customer group is narrow, but the potential for perverse incentives cannot be dismissed.

Flipchart notes pertaining to the performance-based mechanism are included in Appendix 10.

Additional Suggestion

David Hawk, J.R. Simplot Co., suggested that the group conduct an 18-month simulation of the two proposed mechanisms based on real numbers. He believed that all parties and participants had invested too much time discussing concerns with financial disincentives and potential corrective mechanisms for nothing to happen. Because participants may not be comfortable implementing one or both of the proposed mechanisms right now, an 18-month simulation would allow proposals to be studied further and problems worked out before the group forwarded a firm recommendation to the IPUC. The flipchart regarding Hawk's suggestion as well as other modeling options is included in Appendix 11.

NEXT STEPS

Mechanism Analysis/Evaluation

Ric Gale, IPC, requested that the interest groups (IPUC, Idaho Power, Northwest Energy Coalition, and Industrial Customers) caucus before presenting their views on each of the three proposals: true-up mechanism, performance-based pilot, and 18-month simulation of the two proposals. Hayman allotted 15 minutes for caucusing. Afterwards, she asked that group spokesmen share their groups' views on the three proposals and next steps. Industrial Customers felt that David Hawk's previous suggestion for a simulation adequately represented their view. Flipchart notes from the three interest reports are included in Appendix 12.

Idaho Power Company

Gale reported the following Idaho Power perspectives regarding the proposals:

- Idaho Power is concerned about disallowance of program costs. The company endeavors to manage program costs as effectively as possible. But disallowance of program costs and prudence reviews by the IPUC significantly deters DSM investment.
- In the intermediate or long term, the company may want to implement a true-up mechanism. In the next couple of years, Idaho Power wants to undertake the activities in the IRP but is probably unable to ramp up DSM any more than that. They are, however, amenable to simulating the true-up mechanism until the next rate case to at least identify unintended consequences. Gale isn't sure how much influence results of the simulation will have, but it could eliminate a degree of the uncertainties.
- The company is intrigued by IPUC staff's incentive mechanism and supports piloting it with one program until the next rate case and then evaluating its applicability to others.

Northwest Energy Coalition

Ralph Cavanagh shared the following viewpoints for Northwest Energy Coalition representatives:

- They are not convinced that a simulation will change people's minds. Therefore, the coalition isn't interested in pursuing a simulation unless the group is truly committed to moving forward, the simulation/test is credible, and the exercise establishes an architecture that can be used in the next rate case.
- The simulation may or may not be effective in evaluating how Idaho Power Company's appetite for conservation programs would change if a true-up were implemented. Rather, the simulation will give an indication of the rate impact of the true-up under hypothetical scenarios of conservation activity.
- Their commitment to the true-up mechanism hasn't diminished. Although they can forward the proposal directly to the IPUC, they prefer to continue working with this group. Gale commented that the simulation allows the group to refine the mechanism before the next rate case so that they can give the IPUC something feasible.

Idaho Public Utilities Commission

Randy Lobb reported the following points of view for IPUC representatives:

- They understand Idaho Power's concern about cost recovery and prudence reviews. But the IPUC will continue these reviews, and the company will likely continue to do a good job. They believe that, because of the Energy Efficiency Advisory Group (EEAG), the company is actually at less risk now regarding disallowances than it has been in the past.
- The IPUC is interested in piloting the performance-based mechanism on a single program. This pilot allows everyone to see whether the complexity can be worked out and the mechanism is feasible.
- The IPUC is also amenable to the 18-month simulation of the true-up mechanism if the other groups support it. The main purpose of the mechanism is to see how it changes company activities. A simulation may have some value. If nothing else, it keeps a mechanism that the IPUC staff is unlikely to suggest adopting at the moment on the table for future consideration. Working through it now may

provide the company information it needs when it starts making decisions for the next two-year IRP cycle.

Commission Reports and Timelines

Hayman directed participants to discuss the two reports—status and final—to the IPUC and timelines for continued activities. The following decisions were made:

- Scott Woodbury, IPUC, and Hayman will collaborate on the status report and send it out Friday, December 3, for review.
- This group will meet Monday, December 13, to discuss details of the pilot performance-based mechanism and simulation of the true-up mechanism.
- Idaho Power staff will prepare an outline for the pilot program and a design for the simulation for discussion and finalization at the December 13 meeting. The company would like to see the pilot start January 1 (or as soon as possible thereafter) when the DSM program begins. The pilot application does not have to be submitted with the final report, although the report will be supportive of the filing. The group agreed that the final report may precede the application filing unless they were submitted concurrently. The group decided to talk specifically about the timing of the filing and the report at the December 13 meeting.
- Bill Eddie, Advocates for the West, will coordinate the final report, which will likely be a recommendation to implement the pilot and simulation until the next rate case. The draft outline for the report was developed at the November 8 meeting.

WRAP-UP AND WORKSHOP EVALUATION

Hayman reviewed action items to be completed before the next workshop (Appendix 13). This workshop is scheduled for December 13, 2004, from 9:00 am to 12:00 pm. Mike Youngblood agreed to check on the availability of Conference Room 9 East for this workshop. During the workshop, participants will discuss details of the pilot performance-based mechanism and simulation of the true-up mechanism.

Hayman also requested that participants evaluate the workshop. She recorded positive items and possible changes on flipcharts (Appendix 14). Though feelings were mixed on preferable room size and temperature, for the most part, participants are pleased with the honest and frank discussion, facilitation and documentation, and refreshments.

APPENDIX 1—PARTICIPANTS

(Shading indicates work group participants unable to participate in person or by phone.)

Name and Affiliation	Name and Affiliation
Lynn Anderson, IPUC	Laura Nelson, IPUC
Maggie Brilz, Idaho Power	Darlene Nemnich, Idaho Power
Terri Carlock, IPUC	Peter Richardson, Industrial Customers of Idaho
Ralph Cavanagh, Natural Resources Defense Council	Brad Purdy, Community Action Partnership Association of Idaho
Bill Eddie, Advocates for the West	Don Reading, Ben Johnson Associates
Ric Gale, Idaho Power	Greg Said, IPC
David Hawk, J.R. Simplot Co.	David Schunke, IPUC
Nancy Hirsh, NW Energy Coalition	Tim Tatum, Idaho Power
Bart Kline, Idaho Power	Mike Youngblood, Idaho Power
Randy Lobb, IPUC	Scott Woodbury, IPUC

APPENDIX 2—AGENDA

ASSESSING FINANCIAL DISINCENTIVES AND RESOLUTION OPPORTUNITIES WORKSHOP #4

December 1, 2004
9:30am-3:00pm
Conference Room 9 East
Idaho Power Corporate Headquarters
Boise, Idaho

Objectives:

1) Confirm criteria to evaluate the applicability and desirability of potential mechanisms to remove disincentives/provide incentives for utility investment in DSM programs
2) Review two potential mechanisms:
   a. Refined true-up mechanism
   b. Performance-based ratemaking mechanism
3) Confirm the type of report that will be submitted to the IPUC on December 15, and assignments for preparation and review

Final Agenda
(breaks will be taken when most convenient for the group)

Time	Topic	Process
9:15am	*Coffee/Tea available in meeting room*	
9:30am	**Welcome/Introductions/Meeting Overview** – Susan Hayman	Information
9:45am	**Mechanism Evaluation Criteria** – Susan Hayman	Exercise / Discussion
10:30am	**Potential Mechanism** ▪ Refined true-up mechanism – Ralph Cavanagh	Presentation / Discussion
11:30pm	**Lunch** (on your own)	
12:30pm	**Potential Mechanism** ▪ Performance-based ratemaking mechanism – Lynn Anderson	Presentation / Discussion
1:30pm	**Next Steps** – Group ▪ Mechanism analysis/evaluation to be completed (using criteria, other?) ▪ Nature of the December 15 IPUC report ▪ Timelines	Discussion
2:45pm	**Wrap-up and Evaluation** – Susan Hayman	Discussion
3:00pm	**Adjourn**	

APPENDIX 3—POTENTIAL MECHANISM EVALUATION CRITERIA

Potential Mechanism Evaluation Criteria

1) Balanced (fair) allocation of program costs across shareholders and ratepayers
2) Cross-subsidization of program costs across ratepayer groups are minimized
3) Removes financial disincentives to the max
4) Positive financial benefit (at least less negative effect), measured over time
5) Ratepayers are better off than they would be without the mechanism
6) Promotes rate stability
7) Simple mechanism
8) Costs easily tractable
9) Mechanism adjustments are predictable and easily understood
10) Monitors short and long term effects to customers and company
11) Incentives to manipulate the mechanism are not present
12) Close link between mechanism and desired DSM outcomes
13) Provides adequate incentive for the acquisition of all cost-effective DSM

APPENDIX 4—FLIPCHARTS REGARDING EVALUATION CRITERIA

Criteria

#4 Needs clarification

- "Benefit to all stakeholders from where they would have been otherwise"
- Drop "less negative"—should be net benefit

#10 Process needs to monitor mechanism

"Ratepayers" are "customers" [change throughout]

#8 Tractable

- Want mechanism that is affordable
- Costs known and manageable, not subject to unexpected fluctuations
- not talking about program cost recovery

#5 Difficult to know benefits to all stakeholders until after the fact

- #5 is the bottom line

#11 Avoid "perverse" incentives

Stakeholder =

company and customers

includes everybody

APPENDIX 5—REVISED VERSION OF POTENTIAL MECHANISM EVALUATION CRITERIA

Potential Mechanism Evaluation Criteria

1) Stakeholders are better off than they would be without the mechanism
2) Minimize cross subsidies across customer classes
3) Removes financial disincentives
4) Optimizes the acquisition of all cost-effective DSM
5) Promotes rate stability
6) Simple mechanism
7) Administrative costs and impacts of the mechanism are known, manageable, and not subject to unexpected fluctuation
8) Monitors short and long term effects to customers and company
9) Avoids perverse incentives
10) Close link between mechanism and desired DSM

APPENDIX 6—REVISIONS TO THE STRAWMAN PROPOSAL FOR AN IDAHO POWER TRUE-UP MECHANISM

PROPOSED REVISIONS TO STRAWMAN PROPOSAL FOR AN IDAHO POWER TRUE-UP MECHANISM

Submitted by Ralph Cavanagh
For discussion at 12/1/04 workshop

I. ORIGINAL PROPOSAL, DISCUSSED AT 9/22/02 WORKSHOP

1. Starting point: fixed-cost revenue requirement and retail rates approved by Idaho PUC in latest Idaho Power rate case.

2. If, after initial year, changes in retail electricity use lead to under- or over-recovery of fixed cost revenue requirement, a rate true-up would occur in the following year on the same schedule as the Company's current Power Cost Adjustment.

3. Until reestablished in the next Idaho Power rate case, the currently approved fixed cost revenue requirement would be automatically adjusted annually to reflect the same rate of increase (or decrease) shown for retail electricity sales, net of any DSM programs, in Idaho Power's latest IRP. True ups would occur annually based on any divergence between the total fixed-cost revenue recovery that forecast sales would have delivered and the fixed-cost revenues actually recovered (so if, for example, sales were forecasted to increased by 2 percent and actually increased by a larger percentage, Idaho Power would refund the difference at the time of the next Power Cost Adjustment; if retail sales increased by a smaller percentage than forecast, Idaho Power would get back the lost revenues at the time of the next Power Cost Adjustment).

4. True-ups would occur by customer class based on divergence between actual and forecast sales to each customer class.

5. Idaho Power would continue to absorb the risk or benefits of purely weather-related effects on fixed-cost revenue recovery, as it does now. This would mean weather normalizing actual sales before making the annual true-up calculation.

MAXIMUM ANNUAL AVERAGE RATE IMPACT OF THE TRUE UP MECHANISM, UP OR DOWN, UNDER EXTREME CONDITIONS = 1.5 PERCENT.

II. PROPOSED REVISIONS AND ANSWERS TO SUBSEQUENT QUESTIONS

A. CHANGES IN CALCULATION OF ANNUAL FIXED COST RECOVERY: Without a true-up, fixed cost recoveries grow in direct proportion to growth in total retail sales, averaging

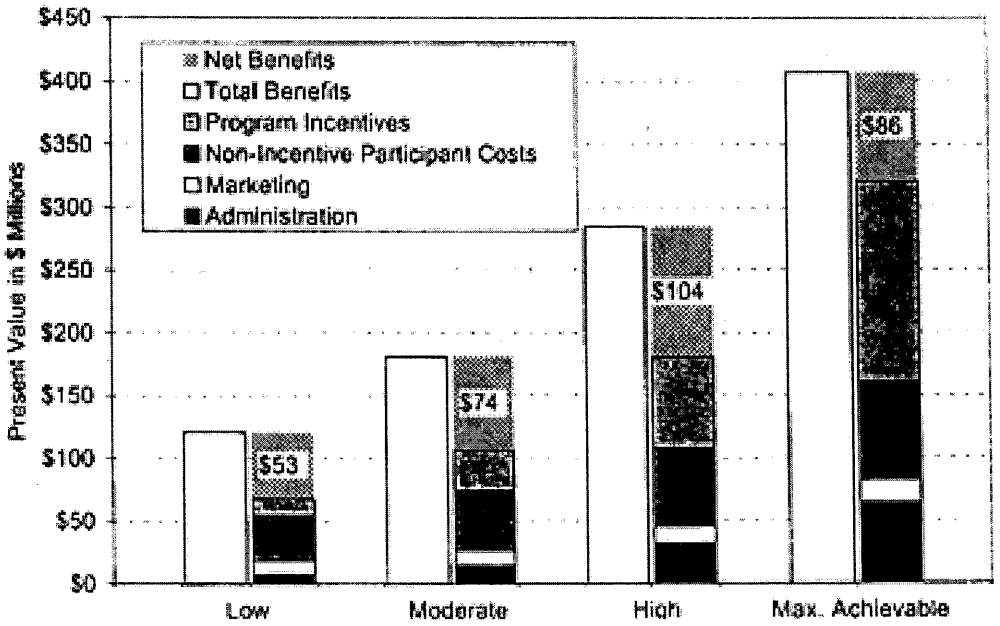
about 2 percent per year over the past decade. The initial proposal called for growth in fixed cost recovery to be tied to annual growth in the forecast of retail sales adopted in the Company's most recent IRP. Concerns were raised that, in the residential and commercial sectors particularly, growth in customer counts could substantially exceed growth in forecast sales, resulting in underrecovery of costs prudently incurred to serve new customers. PROPOSED SOLUTION: Tie growth in fixed cost recovery to actual measured changes in annual customer count for the residential and commercial sectors. This should allow a closer convergence between the fixed cost revenue requirement and actual costs of service.

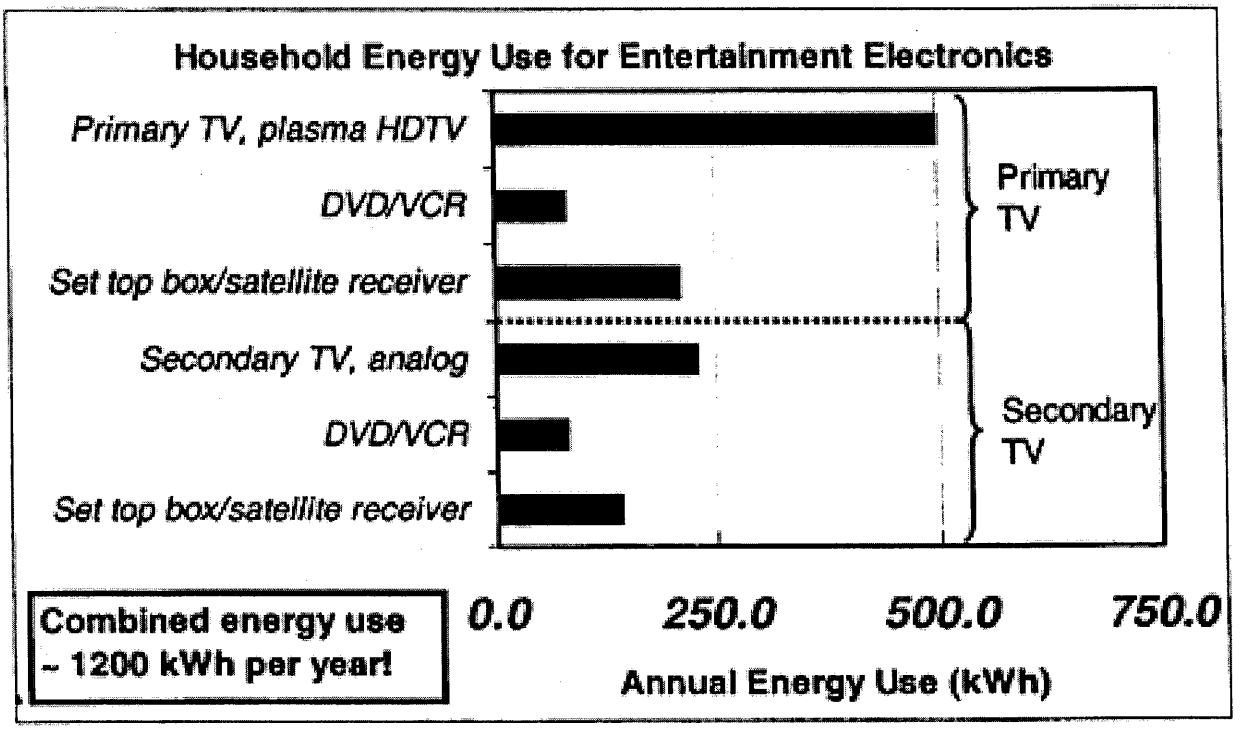
B. **RETROSPECTIVE ASSESSMENT:** In cooperation with the Company, I looked into how often a true-up tied to customer counts would have increased and reduced rates, respectively, for the residential and commercial classes since 1990 (concerns had been raised that rates would always go up under such a mechanism). For any year during which such a mechanism had been in effect, rates would have gone down if the class's retail sales had grown more rapidly than the class's customer count, and vice versa. So we looked at how often the residential and commercial customer counts increased more rapidly than class-wide electricity use in each year, starting in 1990. For the commercial sector, electricity use grew more rapidly than the customer count in ten of the fourteen years from 1990-2003. For the residential sector, electricity use grew more rapidly than customer count in two of the fourteen years, and the rates of growth were essentially identical in three other years (including 2003). This confirms the potential for rate decreases as well as increases for both classes under a true-up mechanism, although based on historical data the likelihood of a rate decrease is substantially greater for the commercial sector than the residential sector. Finally, it should be emphasized that annual class-specific rate increases needed to ensure recovery of the authorized fixed-cost revenue requirement would never have exceeded two percent under the true-up mechanism. In most years, for both classes rates would have shifted up or down by one percent or less.

APPENDIX 7—BAR CHARTS DISTRIBUTED BY CAVANAGH

Exhibit ES-5

Present Value Costs and Benefits - Achievable Potential Scenarios





APPENDIX 8—FLIPCHARTS REGARDING CAVANAGH'S REVISED STRAWMAN

Assumptions for True-Up

- Last year's consumption plus 2% to calculate the rate increase spread over kWh the next year.
- "Clear every year"—don't want to carry significant over/underages/year
- If kWh sales exceed customer count in a class, there would be a rate decrease.
- Question: How to resolve true-up within schedules for irrigators and industrial? [how to true-up with subclasses to the classes]
- Rate impacts could be more volatile under multiple true-up values

APPENDIX 9—PROPOSED STRAWMAN FOR A PERFORMANCE-BASED MECHANISM

Strawman Proposal for DSM Performance Incentive

For Discussion at IPC Decoupling Workshop, 12/01/04

Hypotheses:

1) The primary DSM financial disincentives in question are those that affect shareholders, rather than managers. These disincentives are primarily "fixed-cost" revenues that are not collected when electricity is not sold; i.e. those portions of energy and demand prices that are based upon utility costs that do not vary with energy usage in the short run.

2) Idaho Power will fail to maximize demand-side management (DSM) potential benefits for its customers unless the primary financial disincentive is removed through a regulatory mechanism.

3) Idaho Power's customers will be net beneficiaries if the company provides more cost-effective DSM as a result of customers paying to remove the primary financial disincentive.

4) Rate cases will occur too infrequently to sufficiently mitigate the primary financial disincentive.

5) The company is legitimately entitled to recover fixed-cost revenue losses caused by its DSM efforts regardless of the absence of rate case examination of overall costs and revenues.

6) Idaho Power is incurring new fixed costs due to customer growth and its incremental fixed costs exceed its incremental fixed-cost revenues. In other words, customer growth does not mitigate fixed-cost revenue losses.

7) It is unacceptable to the IPUC Staff to adopt a financial mechanism that would simply allow Idaho Power, without a rate case, to automatically collect <u>all</u> "fixed-cost losses" associated with <u>all</u> kWh per customer sales reductions, much of which is caused by factors not associated with the company's DSM, e.g. increased gas market share. The 10-year lapse between Idaho Power's last two rate cases, in spite of reduced sales per customer, is an indicator that profitability is largely independent of sales per customer.

8) It is unacceptable to Idaho Power to adopt a financial mechanism that considers only total sales; i.e. that does not account for growth in the number of customers.

9) Removing the primary financial disincentive for DSM can be reasonably accomplished through a mechanism that targets only DSM-caused sales reductions. There are two ways to do this: a) The financial disincentive could be removed by allowing specific fixed-cost revenue recovery for all verified DSM savings; b) The financial disincentive could be removed by providing other financial rewards for verified DSM accomplishments. Method b)'s financial rewards could be stand-alone or used in conjunction with method a) or with decoupling.

Strawman Trial Proposal

Unlike decoupling, both methods a) and b) above require precise measurement and verification of DSM program implementation details, baselines and DSM results, and, as such, are inherently complex, subject to measurement error, and require significant regulatory oversight. Thus, it is reasonable to implement either of these methods on a trial basis.

For a strawman trial, we have selected a proposal that combines methods a) and (b) above; i.e. recovery of DSM-caused fixed-cost revenue losses with a bonus financial incentive for exceeding cost-effective DSM targets. We suggest that the trial be restricted to the Residential New Construction program. Residential energy rates have a relatively high fixed-cost recovery component, which means that Idaho Power's financial disincentive for DSM for this class may be higher than for other customer classes. This is a comparatively small program, thus minimizing the effects of any mistakes made in the trial. Nevertheless, this program is projected to be very cost-effective for both energy and peak demand savings and "lost opportunity" will occur if it is not vigorously pursued.

The table below illustrates some of the projections for the Residential New Construction program as contained in the IRP. Also shown are discussion starting points for financially rewarding Idaho Power for significantly outperforming its projections. Whatever combination of indicators and incentives are used, the program must remain cost effective to customers.

Possible Indicators	Annual Targets	Fixed-Cost Rev. Recovery	e.g. Bonus Threshold	Bonus Financial Incentive (for illustration only)
MW reduction	0.19	n.a.	10% > target	20% of net $ savings
MWh reduction	1,661	actual MWh saved x $31.20	10% > target	10% of net $ savings
Idaho Power $/peak kW	5.30	n.a.	10% < target	5% of program costs
Idaho Power $/kWh	0.036	n.a.	10% < target	5% of program costs
Total Resource $/peak kW	8.50	n.a.	10% < target	5% of total costs
Total Resource $/kWh	0.058	n.a.	10% < target	5% of total costs
Participant Payback	6.5 yr.	n.a.	10% < target	5% of participants' costs
Number of Participants	?	n.a.	10% > target	5% of program costs
Market Transformation	?	n.a.	?	5% of program costs

APPENDIX 10—FLIPCHARTS REGARDING PERFORMANCE-BASED MECHANISM

PBR/Hypothesis Discussion

1) Managers = utility company managers
2) This proposal does not address "found" revenues and has a narrow view of "lost" revenues (DSM-related only)
3) #7 Concern about not linking advantages of true-up with issues about increased gas market share

   Staff wants fixed-cost recovery for DSM-related programs (utility co. control) → NOT consensus with group on this
4) Energy savings calculations would be difficult and problematic
5) Cost recovery may be a bigger issue than lost revenues
6) Proposal is for residential construction only (Energy Star program—exceeding building codes)
7) Some potential for perverse incentives—need to monitor closely

APPENDIX 11—ADDITIONAL SUGGESTIONS

Bin

1) 18-month financial simulation of proposals—real, documented numbers for FCR

Options

1) Model period of 10 years
   a) "Council level" of conservation against IPUC staff proposal
   b) True-up with "Council levels" of conservation

- Use maximum net benefit scenario:
  - rate impacts
  - IRP baseline

APPENDIX 12—INTEREST REPORTS

Interest Reports

IPC

1) Disallowance of program costs will kill DSM—first and foremost disincentive
2) Problem of lost revenues will have a...material impact on amount of load-reducing activities we undertake in short and long term
3) Next couple years, company will undertake DSM identified in IRP—can't take on any additional in this period (ramp-up ability limited)
4) 18-month simulation of T.U. mech. would help relieve uncertainties (unintended consequences) prior to next rate case
5) Intrigued with staff incentive mechanism, and piloting with one program then determining applicability to others

NWEC

1) Not convinced simulation will change minds—not interested in pursuing unless group is really committed to moving forward and simulation/test is credible with everyone and materially improve likelihood of approval by Commission
2) Retain right to bring proposal to Commission directly, but would rather work as a group

IPUC—Staff

1) Staff will continue cost-effectiveness/ prudence review
2) Interested in pilot incentive based program. Can work on measurement and evaluation to see if doable.
3) 18-month simulation—main impact of T.U. mechanism is to see how it changes company's behavior. Wouldn't oppose proceeding with this, though unsure of real value of simulation. May be best we can do now to keep alive without killing it.

APPENDIX 13—NEXT STEPS AND ACTION ITEMS

Next Steps

1) Status report on 15th
2) Flesh out concept of pilot and simulation on 13th (9:00–Noon)
3) Provide full report in January with recommendation, what we discussed and why we're proposing this approach. Decision at end point.
4) IPC would submit application for pilot to commission—projected date by end of January (simultaneous with filing or at least final report first)
5) Assuming model can be set up, could possibly start accounting after first of year (January 1 if possible)

Action Items

What	Who	When
1) Draft status report for review and comment	Scott and Susan	12/03/04
2) Bring what is necessary for pilot proposal—outline for filing	IPC (Darlene)	12/13/04
3) Bring simulation design	IPC (Mike)	12/13/04

APPENDIX 14—WORKSHOP EVALUATION COMMENTS

+	△
1) Good job!	1) Room is too small and too warm
2) Frankness of conversation useful & appreciated	
3) Like smaller room	
4) Like facilitating	
5) Like someone "ramrodding it"	
6) Appreciate deadlines and follow-up	
7) First class job	

+	△
8) Like smaller room	
9) Like fruit!	
10) Like summaries—timely and well-structured	
11) Nice to get prework discussion items ahead of time	
12) Very important that everyone is here—adds to the process	

+	△
13) Appreciate cheese and celery!	
14) Appreciate comprehensive summaries	
15) Enjoyed open and honest discussion, and movement in positions	
16) Like follow-up with meeting summary—that it is right	

ASSESSING FINANCIAL DISINCENTIVES AND RESOLUTION OPPORTUNITIES, WORKSHOP #5

DECEMBER 13, 2004, 9:00 A.M. TO 12:00 P.M.
CONFERENCE ROOM 6 EAST, IDAHO POWER CORPORATE HEADQUARTERS, BOISE, ID

Facilitation Susan Hayman, North Country Resources, Inc.
Documentation Natalie Chavez, Chavez Writing & Editing, Inc.

WORKSHOP OBJECTIVES

1) Review and finalize proposals for
   a) Refined true-up mechanism simulation
   b) Performance-based mechanism pilot program
2) Finalize the status report for submission to the IPUC by December 15, 2004
3) Determine the final report timelines and responsibilities

ACTION ITEMS

What?	Who?	When?
Prepare the application for the pilot project and circulate it to the work group for review and comment.	Lynn Anderson, IPUC, and Idaho Power	February 1
Refine the simulation proposal (and retrospective analysis) and circulate it to the work group for review and comment.	Mike Youngblood, Idaho Power; Bill Eddie, Advocates for the West; and Ralph Cavanagh, NRDC	January 14
Draft final report and circulate it to the work group for review and comment.	Bill Eddie, Advocates for the West	January 14
File pilot application with the IPUC	Idaho Power	Mid-February

WORKSHOP INTRODUCTION

Susan Hayman, North Country Resources, welcomed participants to Workshop #5 (Appendix 1), reviewed workshop objectives (above), and then reviewed the agenda (Appendix 2). Because Bill Eddie, Advocates for the West, was expected to be a little late, presentations for the true-up mechanism simulation and performance-based mechanism pilot were switched on the agenda.

Before participants moved on to the first presentation, David Hawk, J.R. Simplot Co., congratulated Ralph Cavanagh for being chosen to sit on the National Commission on Energy Policy. Hawk also shared that two natural gas utilities in the Pacific Northwest were looking into decoupling approaches, a situation that he found interesting given the context of these workshops.

PROPOSAL REVIEW

Performance-Based Mechanism Pilot

Susan Hayman distributed the draft proposal from Darlene Nemnich, Idaho Power, regarding the DSM fixed-cost revenue recovery and performance incentive pilot. Nemnich reviewed the document, which is

included as Appendix 3. Essentially, Idaho Power proposes to use the Energy Star Homes Northwest program for the pilot. This program, which is already included in the *Integrated Resource Plan*, will be implemented by three parties: the Northwest Energy Efficiency Alliance, Idaho Energy Division (a state office), and Idaho Power. Idaho Power provides an incentive to a builder for meeting a standard set at approximately 30% above existing Idaho residential building codes, IED qualifies that homes are built to the standard and conducts quality assurance, and NEEA provides the builder outreach and training components of the program. This program was started at a very small scale in 2003–2004 (30 to 40 homes), but this implementation of it is 10 times the size (430 homes).

Nemnich also reviewed how savings would be established and verified, how the fixed-cost revenue requirement would be calculated, and then how the DSM incentive would be calculated. Establishing and verifying savings would be a two-step process. At the beginning of the pilot, a review would look at assumptions and identify original savings estimates based on engineering estimates derived from a 2004 Idaho Power study by Ecotope. The review group would also determine any studies to be conducted to firm up uncertainty and get closer to validating savings by the end of the pilot. Evaluation costs would be included in program costs but would not exceed 5% of these costs. The second step would be to do any evaluations that the review group deemed necessary and determine the validated savings estimates. If the validated savings estimates differed from the original savings estimates, a new cost-effectiveness analysis would be completed and the program ended, modified, or extended. The validated savings estimates would feed into calculations of the fixed-cost revenue requirement. Then DSM incentives could be calculated. These incentives would be earned when at least 110% of the applicable DSM threshold was met. She showed three possibilities for thresholds. Nemnich proposed that the pilot be conducted for calendar year 2005. Validated energy savings and DSM incentives would be calculated by March 31, 2006, and submitted to the IPUC for review. Then the total fixed-cost revenue requirement and incentives could be collected from June 2006 through May 2007.

Following her explanation, she answered questions and addressed comments. Flipchart notes regarding the discussion are included in Appendix 4. The following issues were raised during the discussion:

- **Calculation of incentive**—The second threshold listed in the proposal should be "10% < target" rather than "10% > target." Participants preferred the option for MWh reduction, with the threshold being 10% greater than target and the incentive calculated as 10% of net annualized savings.
- **Persistence of the net benefit**—Cavanagh suggested an approach that would enable evaluation of the durability of savings. For example, Idaho Power could be paid 10% of the first year's annualized savings, with an additional incentive paid at year three to reflect the annualized net benefit for the additional 2 years of savings. It is important to verify that savings are ongoing and energy improvements are still in place.
- **Maximum incentive**—It may be beneficial to know the "maximum hit" and consider whether a cap is needed. The incentive is a percentage so it can increase with additional success.
- **Effect to other DMS programs**—The incentive might cause Idaho Power not to pursue other programs as aggressively as it could. On the other hand, incentives are designed to motivate. If this pilot works while other programs do not, it's safe to say that incentives work.
- **Basis for program budget**—Incentives were not originally calculated into the program budget since this program was already planned for implementation. Nemnich thought that the evaluation costs could remain roughly the same, at $25,000.
- **Adequacy of existing building codes**—To earn the $750 incentive, program participants have to show that the house meets the prescriptive building standard. These codes are relatively new and therefore hopefully adequate. However, enforcement is a problem, which is why utilities should be involved. Their involvement through DSM programs provides incentives for builders to meet or exceed code.
- **Inclusion of manufactured housing**—The program as is may favor higher income households. Inclusion of manufactured housing would likely broaden the economic scope of the program. Different building codes and standards apply to "stick built" homes than to manufactured homes. Nemnich commented that another DSM program was aimed at manufactured homes. She will look into combining the two programs for the pilot.

- **Collaboration between the IPUC and Idaho Power**—Much of the discussion focused on details that need to be worked out for filing regarding the pilot program. Ric Gale, Idaho Power, suggested that IPUC and Idaho Power staff collaborate on the filing, work out the details, and e-mail the proposal for review and comment.

True-Up Mechanism Simulation

Simulation Spreadsheet

Mike Youngblood distributed copies of two handouts: an Excel spreadsheet set up to simulate the fixed-cost recovery true-up mechanism and a table showing fixed-cost lost revenue per MWh by customer classes (Appendix 5). The first page of the Excel spreadsheet included those schedules of customer classes that would be trued up according to customer counts, while the second page included those customer classes trued up according to forecast sales in the IRP. On the first page, Youngblood had split large commercial and small commercial because the total fixed-cost loss per MWH differed for these two schedules (see the table in Appendix 5). Large commercial customers have demand meters in place and a demand component in their bills. So more of the fixed costs associated with these customers are captured somewhere besides variable costs. Cavanagh commented that Eddie's proposal trues up demand revenues as well as kWh revenues. Youngblood agreed to think more about the issue of truing up demand revenues.

Youngblood then explained how the simulation is set up, using residential customers on the first page and industrial on the second page as his examples. Blue zeroes will eventually be substituted with real numbers. On the first page, the actual customer count (column 2) is multiplied by $371.92 (fixed-cost recovery per customer) to calculate the authorized fixed-cost recovery (column 3). To calculate the actual fixed-cost revenue recovered (column 5), weather-normalized energy (column 4) is multiplied by $30.14 (fixed-cost recovery per MWh). Column 6 shows the difference between amounts in columns 3 and 5. This is the amount of true-up. Actual customer count may be year-end or average, depending on which approach was used in the rate case. Youngblood will look that up, although he used year-end customer count for this spreadsheet.

For industrial and irrigation customers, forecasted energy (column 2) is multiplied by $2.44 (the fixed-cost recovery per MWh) to calculate the allowed fixed-cost recovery. Once known, weather-normalized energy use (column 4) is multiplied by the same amount to calculate the actual fixed-cost revenue recovered. Again, the difference between columns 3 and 5 constitutes the amount of true-up needed. Although the simulation was originally intended for 2005, Youngblood included 2004 in the spreadsheet since those numbers will soon be available (March 2005). Per Bill Eddie's proposal, he will include 1994 to 2004 numbers to see what would have happened to customers' rates over the last 10 years with a true-up mechanism in place.

Simulation Proposal

Bill Eddie spoke about the proposal he had e-mailed to participants on behalf of the Northwest Energy Coalition. The proposal is included in Appendix 6, while flipchart notes regarding the simulation are included in Appendix 7.

The first page is a recap of information provided in earlier meetings. Cavanagh commented that truing up demand charges is not explicit on this page but should be. The second page spelled out details of the simulation. For item 2, they used the Northwest Power and Conservation Council number of about 0.5% sales annually for assumed level of efficiency savings. Although that number is not accurate for 1994, it is fairly close and can be applied retroactively. Item 4 identifies some parameters to analyze to illuminate results of the simulation. Eddie said that other parameters could be looked at as well if people had ideas. Items 5 and 6 are procedural in nature. He would like to see the retrospective analysis included in the final report in January. Eddie added that he'd like to see more frequent analysis of the true-up simulation, but given that only the year-end numbers would be "truth numbers," monthly checks may not be possible or informative.

Don Reading asked how the simulation would account for the state's efforts at buying water and retiring land. Eddie didn't believe that these actions would manifest during the simulation. The next IRP would

consider those activities in its forecasted sales. Anomalies will run through the system, and the simulation may show the effects of these anomalies.

Eddie, Youngblood, and Cavanagh will refine the simulation proposal, run the retrospective analysis, and send both out for review and comment in time for inclusion in the January report.

IPUC REPORTS

Status Report

Bart Kline, Idaho Power, provided copies of the redlined status report to the Idaho Public Utilities Commission (Appendix 8). He commented that a word in the first full paragraph of page 2 ("believes") will be changed to "stated." Hayman added that numbered agreements listed in the "Progress" section have been revised for wording only: the content is the same. Other changes include the following:

- In the list of participants, Greg Said's affiliation should be identified as "Idaho Power."
- Laura Nelson should be identified as "IPUC Advisor" or something rather than "IPUC Staff." The Commissioners know that she is coming to the meetings, but she would like it clarified that she is not entering into any agreements on behalf of the IPUC.

The document will be signed and ready for submission by Wednesday, December 15.

Final Report

At the December 1 workshop, Bill Eddie agreed to coordinate work on the final report. The deadline for submission is January 31, 2005. Eddie will e-mail the draft to participants two weeks in advance (January 14) for review and comment. Participants reviewed the outline developed at the November 8 workshop (see Appendix 9). IPUC staff will help with the first section (history of the issue). The third section (conclusions and recommendations) will have next steps and discuss the pilot and simulation. Summaries of the workshops will be included to support the report. The filing for the proposed pilot program will be submitted in mid-February, but the final report will "lay the groundwork" for the filing. Lobb agreed to see whether the Commissioners had any additional concerns that might need to be addressed in a presentation.

NEXT STEPS

Follow-Up Workshop

Participants decided that no follow-up workshop is necessary for January. However, they tentatively plan to meet again in midsummer to review the status of the pilot and simulation.

Monitoring Plan for Pilot and Simulation

Hayman asked that people forward ideas about evaluation and monitoring to those participants charged with developing the final documents. She also reminded them about the evaluation criteria that the group had developed at the December 1 workshop. For the simulation, monitoring means communicating results to work group members. Ultimate conclusions from the simulation will be worked out in the rate case.

WRAP-UP AND WORKSHOP EVALUATION

Hayman reviewed action items (Appendix 10). She also reviewed information in the bin: a couple of gas utilities in the Northwest looking at decoupling and a suggestion to poll customers for their "appetite" for conservation. Idaho Power is willing to let David Hawk provide details about such a poll.

Hayman also requested that participants evaluate the workshop series. She recorded what worked and what concerns still exist (Appendix 11). For the most part, participants felt that the process worked well,

members were open and honest, and more headway was made than people expected. People did feel that this series of workshops was just the beginning, and efforts needed to continue into the future.

APPENDIX 1—PARTICIPANTS

(Shading indicates work group participants unable to participate in person or by phone.)

Name and Affiliation	Name and Affiliation
Lynn Anderson, IPUC	Laura Nelson, IPUC
Maggie Brilz, Idaho Power	Darlene Nemnich, Idaho Power
Terri Carlock, IPUC	Peter Richardson, Industrial Customers of Idaho
Ralph Cavanagh, Natural Resources Defense Council	Brad Purdy, Community Action Partnership Association of Idaho
Bill Eddie, Advocates for the West	Don Reading, Ben Johnson Associates
Ric Gale, Idaho Power	Greg Said, Idaho Power
David Hawk, J.R. Simplot Co.	David Schunke, IPUC
Nancy Hirsh, NW Energy Coalition	Tim Tatum, Idaho Power
Alden Holm, IPUC	Mike Youngblood, Idaho Power
Bart Kline, Idaho Power	Scott Woodbury, IPUC
Randy Lobb, IPUC	

APPENDIX 2—AGENDA

ASSESSING FINANCIAL DISINCENTIVES AND RESOLUTION OPPORTUNITIES WORKSHOP #5

December 13, 2004
9:00am-12:00pm
Conference Room 6 East
Idaho Power Corporate Headquarters
Boise, Idaho

Objectives:

1) Review and finalize proposals for:
   a. Refined true-up mechanism simulation
   b. Performance-based mechanism pilot program
2) Finalize the status report for submission to the IPUC by December 15, 2004.
3) Determine the final report timelines and responsibilities

Final Agenda
(breaks will be taken when most convenient for the group)

Time	Topic	Process
8:45am	*Coffee/Tea available in meeting room*	
9:00am	**Welcome/Introductions/Meeting Overview** – Susan Hayman	Information
9:15am	**Proposal Review** ▪ True-up mechanism simulation – Mike Youngblood ▪ Performance-based mechanism pilot – Darlene Nemnich ▪ Timeline and process for submission to IPUC – Idaho Power	Presentation, Discussion & Decision
10:30am	**IPUC Reports** ▪ Update on the status report – Bart Kline ▪ Final report preparation – Bill Eddie o Timelines o Responsibilities	Discussion
11:00pm	**Next Steps** ▪ Follow-up workshop in January – Susan Hayman o Is it needed? ▪ Monitoring plan for pilot and simulation – Group o When should this be prepared? o Who should be assigned this task?	Discussion
11:45pm	**Wrap-up and Evaluation** – Susan Hayman	Discussion
12:00pm	**Adjourn**	

APPENDIX 3—DRAFT PILOT PROGRAM

DRAFT

Proposal for DSM Fixed-cost Revenue Recovery and Performance Incentive Pilot

12/13/04

Proposed Program for Pilot

The Energy Star Homes Northwest program is the program proposed to acquire the resources identified in the Residential New Construction Option in the 2004 IRP and is proposed as the program for this pilot. This program was developed by the EPA/DOE, the Northwest Energy Efficiency Alliance and PNW electric utilities. Idaho Power piloted this program with the Alliance in 2004. There are three implementation partners for this program in the Idaho Power service territory; the Alliance, Idaho Energy Division (IED) and Idaho Power.

The essential feature of this program is a prescriptive building standard, also called a builder option package or BOP, that is set at approximately 30% above existing Idaho residential building codes. Idaho Power provides an incentive to the builder for each home built to the standard and provides marketing for the program. IED qualifies that homes are built to the standard and conducts a quality assurance process. The Alliance provides the builder outreach and training components of the program.

- Idaho Power's program budget for 2005 is $502,400
- Estimated 2005 kWh savings is 1,070,000.
- 2005 participation estimated at approximately 430 homes.

Establishing and verifying savings

Original Savings Estimates

As close to the beginning of the pilot as possible, Idaho Power proposes to establish an Original Savings Estimate. This estimate, measured in kWh per month per qualified house, represents the estimated reduction in customer usage between a program house and a non-program house. This estimate will be determined through a collaborative, peer-review process. The Energy Efficiency Advisory Group or a sub-set of the EEAG could be used for this purpose. Engineering estimates will be the primary method for determining savings estimates. An engineering simulation study, conducted

for Idaho Power in early 2004 by Ecotope to estimate program savings in Idaho will be used as a basis for the collaborative review.

This review group will also determine what assumptions should be tested, if any, during or at the end of the pilot to validate the savings estimates. Cost-effectiveness of the program will be calculated using these estimates. Evaluation costs of the pilot program will be recovered by the DSM rider, will be included in the cost-effectiveness calculation and will not exceed 5% of total program costs.

Idaho Power will review the program costs with the review group. Program costs shall include the cost of planning, developing, implementing, monitoring and evaluating DSM programs.

Validated Savings Estimates

At the end of the pilot period the collaborative review group will review any evaluations compiled during or at the end of the pilot and determine a Validated Savings Estimate per home. Total program savings will be determined by multiplying Validated Savings Estimate per home by the actual program participation. If the Validated Savings Estimates are different than Original Savings Estimates, a new cost-effective analysis will be completed and the program may be ended, modified or extended.

Calculation of Fixed-cost Revenue Requirement

For the pilot period, the Validated Savings Estimates (in MWh) will be multiplied by the total fixed-cost per MWh for purposes of determining the total fixed-cost revenue requirement to be recovered. For this pilot the residential total fixed-cost per MWh is estimated at $30.14/MWh. Total fixed-cost revenue requirement will be calculated using the Validated Savings Estimates irrespective of whether program goals are met.

Calculation of DSM Incentive

DSM Incentives are earned by Idaho Power when at least 110% of the applicable DSM threshold is met. Energy savings thresholds are calculated by multiplying the

Original Savings Estimate by original participation goals in the calculation of an incentive. There are three possibilities for this program:

	Threshold	Incentive
-MWh reduction	10%>target	10% of net $ savings
-Idaho Power $/kWh	10%>target	5% of program costs
-Number of part.	10%>target	5% of program costs

The total fixed-cost revenue requirement and incentives will be quantified and submitted for Commission review in a time frame that allows for collection during a 12-month June 2006 through May 2007 timeframe.

Timeframe for Pilot

Idaho Power proposes the pilot timeframe be calendar year 2005. Determination of Original Savings Estimate will be determined soon after approval of this pilot by the Idaho PUC. Determination of Validated Energy Savings, fixed-cost revenue requirement and DSM Incentive will be calculated by March 31, 2006.

APPENDIX 4—FLIPCHARTS REGARDING THE PILOT PROGRAM

Pilot Program Discussion

1) What is expected payment and max payments?
2) How much incentive is paid, and how much fixed costs recovered. This is focus of pilot. Cost effective is considered too.
3) For pilot, incentive % is fixed, but payments based on total savings.
4) Incentives are included in program budget ($750/home)—much of program budget is devoted to builder incentives.

Refinements to Pilot Proposal

1) First incentive
   - Pay 10% of first year's annualized savings, then 3-year evaluation again to test persistence of program (2 payments in this scenario)

or

   - Base payment on a single point in time
   - 3-year period between rate cases could be used to true-up fixed cost recovery

Refinements to Pilot Proposal (cont.)

2) Include manufactured housing in with "stick built"—though codes not the same, still incent to build above code (look at 2 different validated estimates, etc.)
3) IPC-IPUC staff will work to refine incentives, and look at durability incentive—joint application

APPENDIX 5—DRAFT SIMULATION SPREADSHEET

Fixed Cost Lost Revenue per MWh by Customer Class

		Base Rate Components ($/MWh)				
		Residential	**Small Commercial***	**Large Commercial****	**Irrigation**	**Industrial*****
Total Base Energy Rate **(b+c+d+e)**	(a)	$51.90	$62.61	$26.38	$32.57	$21.45
Variable Cost - *Class*	(b)	$20.69	$21.05	$20.14	$23.53	$18.41
Variable Cost - *Subsidy*	(c)	$1.08	$1.25	$0.78	($5.72)	$0.60
Fixed Cost - *Class*	(d)	$28.76	$38.70	$4.48	$22.09	$1.67
Fixed Cost - *Subsidy*	(e)	$1.38	$1.61	$0.99	($7.33)	$0.77
Total Fixed Cost Loss/MWh **(d + e)**	(f)	$30.14	$40.31	$5.47	$14.76	$2.44

(*) Small Commercial rate is schedules 07
(**) Large Commercial rate is a wghtd. avg. of schedule 09 S, P & T based on energy use.
(***) Industrial rate is a wghtd. avg. of schedule 19 S, P & T based on energy use.

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

RESIDENTIAL

Rate Case Constants:

4,141,393 Energy
335,605 Customers
$124,816,934 Class Fixed Costs
$371.92 Fixed Cost Recovery per Customer
$30.14 Fixed Cost Recovery per MWH

Year	Actual Customer Count	Allowed Fixed Cost Recovery Based on Actual Customer Count	Weather Normalized Energy (MWH)	Actual Fixed Cost Revenue Recovered	Amount of True-Up
(1)	(2)	(3)	(4)	(5)	(6)
2003	**335,605**	**$124,816,934**	**4,141,393**	**$124,816,934**	**$0**
2004	**0**	**$0**	**0**	$0	$0
2005	**0**	**$0**	**0**	$0	$0

SMALL COMMERCIAL

Rate Case Constants:

265,336 Energy
32,316 Customers
$10,694,989 Class Fixed Costs
$330.95 Fixed Cost Recovery per Customer
$40.31 Fixed Cost Recovery per MWH

Year	Actual Customer Count	Allowed Fixed Cost Recovery Based on Actual Customer Count	Weather Normalized Energy (MWH)	Actual Fixed Cost Revenue Recovered	Amount of True-Up
(1)	(2)	(3)	(4)	(5)	(6)
2003	**32,316**	**$10,694,989**	**265,336**	**$10,694,989**	**$0**
2004	**0**	**$0**	**0**	$0	$0
2005	**0**	**$0**	**0**	$0	$0

LARGE COMMERCIAL

Rate Case Constants:

3,014,427 Energy
17,415 Customers
$16,499,592 Class Fixed Costs
$947.44 Fixed Cost Recovery per Customer
$5.47 Fixed Cost Recovery per MWH

Year	Actual Customer Count	Allowed Fixed Cost Recovery Based on Actual Customer Count	Weather Normalized Energy (MWH)	Actual Fixed Cost Revenue Recovered	Amount of True-Up
(1)	(2)	(3)	(4)	(5)	(6)
2003	**17,415**	**$16,499,592**	**3,014,427**	**$16,499,592**	**$0**
2004	**0**	**$0**	**0**	$0	$0
2005	**0**	**$0**	**0**	$0	$0

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

INDUSTRIAL

Rate Case Constants:

1,978,824	Energy
105	Customers
$4,821,154	Class Fixed Costs
$45,916	Fixed Cost Recovery per Customer
$2.44	Fixed Cost Recovery per MWH

Year	Forecasted Energy from 2004 IRP (MWH)	Allowed Fixed Cost Recovery Based on Forecasted Energy	Weather Normalized Energy (MWH)	Actual Fixed Cost Revenue Recovered	Amount of True-Up
(1)	(2)	(3)	(4)	(5)	(6)
2003	**1,978,824**	**$4,821,154**	**1,978,824**	**$4,821,154**	**$0**
2004	2,035,043	**$4,958,125**	**0**	$0	$4,958,125
2005	2,104,294	**$5,126,846**	**0**	$0	$5,126,846

IRRIGATION

Rate Case Constants:

1,620,931	Energy
13,517	Customers
$23,925,859	Class Fixed Costs
$1,770	Fixed Cost Recovery per Customer
$14.76	Fixed Cost Recovery per MWH

Year	Forecasted Energy from 2004 IRP (MWH)	Allowed Fixed Cost Recovery Based on Forecasted Energy	Weather Normalized Energy (MWH)	Actual Fixed Cost Revenue Recovered	Amount of True-Up
(1)	(2)	(3)	(4)	(5)	(6)
2003	**1,620,931**	**$23,925,859**	**1,620,931**	**$23,925,859**	**$0**
2004	1,670,717	**$24,660,729**	**0**	$0	$24,660,729
2005	1,677,923	**$24,767,100**	**0**	$0	$24,767,100

APPENDIX 6—DRAFT TRUE-UP SIMULATION PROPOSAL

PROPOSAL FOR SIMULATION OF AN IDAHO POWER TRUE-UP MECHANISM

Submitted by Bill Eddie, Ralph Cavanagh, Nancy Hirsh
For discussion at 12/13/04 workshop

Per the discussion at the December 1, 2004, workshop, NRDC and NWEC propose the following simulation to illuminate impacts of the revised true-up mechanism proposed by NRDC and NWEC.

Recap of true-up. The key points of the revised true-up mechanism proposal are:

1. Starting point is fixed-cost revenue requirement and retail rates approved by Idaho PUC in latest Idaho Power rate case.

2. For the Industrial and Agricultural sectors, until reestablished in the next Idaho Power rate case, the currently approved fixed cost revenue requirement would be automatically adjusted annually to reflect the same rate of increase (or decrease) shown for retail electricity sales, net of any DSM programs, in Idaho Power's latest IRP.

3. For the Residential and Commercial sectors, until reestablished in the next Idaho Power rate case, the currently approved fixed cost revenue requirement would be automatically adjusted annually to reflect the actual changes in annual customer count for the residential and commercial sectors (in other words, the fixed cost revenue requirement per customer would remain fixed until the next rate case).

4. True ups would occur annually by customer class based on any divergence between the total fixed-cost revenue recovery that forecast sales (for Agricultural and Industrial sectors) or actual customer growth (for Residential and Commercial) would have delivered versus the fixed-cost revenues actually recovered through actual sales.

5. Idaho Power would continue to absorb the risk or benefits of purely weather-related effects on fixed-cost revenue recovery, as it does now. This would mean weather normalizing actual sales before making the annual true-up calculation.

6. The maximum annual average rate impact of the true up mechanism for any customer class would be capped at 2% annually, with any additional amounts carried over to the next year's true up.

Proposed simulation. The proposed simulation would study this mechanism both retrospectively (1994-2004 rate case) and prospectively (2004-next rate case):

1. Starting points are the fixed-cost revenue requirement and retail rates approved in the 1994 and 2003-04 rate cases, including subsequent Commission-approved adjustments to such revenue requirements.

2. Apply an assumed level of efficiency savings of 0.5% annually (roughly equivalent to the level of savings achievable in Idaho Power's territory per the NW Power Planning Council's draft 5th Plan) each year starting in 1994 and 2004. For simplicity, efficiency savings can be zeroed-out after the 2003-04 rate case.

3. Load forecasts for agricultural and industrial sectors will change with each IRP issued throughout the simulation periods.

4. Simulation should calculate the true-up mechanism's impacts in the following aspects: (1) annual rate impact to each customer class for the true-up alone, and the true-up together with the PCA; (2) annual and total impact to average customer bill amounts (assuming the 0.5% annual efficiency savings and the annual net benefit estimates developed in the recent Quantum consulting energy efficiency assessment), (3) total impact to IdaCorp shareholders if true-up mechanism were not in place.

5. Idaho Power will provide the results of the retrospective simulation to the workshop participants so they may be included in the final report to the Commission regarding this workshop proceeding. Idaho Power will provide the results of the prospective simulation to workshop participants and the Commission contemporaneously with each annual PCA filing.

6. Idaho Power will work with workshop participants as they prepare their next rate case filing to analyze the results of the simulation and evaluate incorporation of a true-up mechanism into the rate filing.

APPENDIX 7—FLIPCHARTS REGARDING THE TRUE-UP SIMULATION

Simulation

1) Would use same method of determining customer counts as in the last rate case (residential and commercial)
2) Suggest including 2004 figures with 2005 figures in simulation
   - Both for actualized (IRP) and NWPPC projections
   - Also look at 1994–2004 period

3) NWEC proposal includes demand and kWh charges
4) Simulation will also test anomalies that occur in next year
5) Testing period
   - 1994–2000 (back)
   - 2004–next rate case (about 18 months) (forward)

APPENDIX 8—DRAFT STATUS REPORT

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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 INVESTIGATIVE WORKSHOP STATUS REPORT

BACKGROUND

On May 25, 2004, The Idaho Public Utilities Commission (Commission) in Order No. 29505 (Idaho Power Company general rate case No. IPC-E-03-13) determined that a separate "proceeding to assess financial disincentives inherent in Company-sponsored conservation programs is appropriate and should proceed by informal workshops." The Commission's Order provided in relevant part as follows:

> The Commission specifically directs the parties (Idaho Power, NW Energy Coalition, Industrial Customers of Idaho Power (ICIP) and Commission Staff) to address possible revenue adjustment when annual energy consumption is both above and below normal. The parties should also consider how much adjustment is necessary to remove DSM investment disincentives and whether (and to what extent) performance-based incentives such as revenue sharing could or should be incorporated into the resolution of this issue. The Commission is interested in proposals that could provide Idaho Power the opportunity to share and retain

> benefits gained from efficiencies, especially technologies... In short, the Commission believes opportunities exist for improvements in operating efficiency that would benefit the Company shareholders and its customers, and we encourage the parties to creatively consider the options for a performance-based mechanism to present to the Commission. *The parties to the agreement are directed to propose a workshop schedule and initiate a proceeding.* (emphasis added)

Order No. 29505 at pp. 68, 69.

As a follow up to the Commission's Order, the NW Energy Coalition on June 18, 2004 formally requested that a proceeding be initiated and that a workshop schedule be established. The Commission in Order No. 29558 established this docket to investigate the financial disincentives which hinder Idaho Power's investment in cost-effective energy efficiency resources. The Commission believes that the scope of the investigation should be focused on decoupling and performance based ratemaking. The Commission directed the participating parties to provide a written report to the Commission no later than December 15, 2004 to update the Commission on the status of the investigative workshops.

PROCESS

The parties have participated in five ~~four~~ workshops to date: August 24, September 27, November 8, ~~and~~ December 1, 2004, and December 13, 2004. These workshops have included presentations by participants, group discussion, and sensing for areas of agreement and disagreement. Workshops are designed and facilitated by Susan Hayman, North Country Resources, Inc., a Boise-based facilitation/mediation firm. Workshops are designed in cooperation with four designated workshop coordinators representing each of the four major interests at the table (Idaho Power Company, Idaho Public Utilities Commission Staff, Industrial Customers of Idaho Power, and Northwest Energy Coalition). Copies of all workshop summaries are provided as attachments to this Status Report.

PARTICIPANTS

The following people have attended one or more workshops, receive meeting materials and summaries, and are considered active workshop participants:

Name and Affiliation	Name and Affiliation
Lynn Anderson, IPUC Staff	Laura Nelson, IPUC Staff
Maggie Brilz, Idaho Power	Darlene Nemnich, Idaho Power
Terri Carlock, IPUC Staff	Peter Richardson, Industrial Customers of Idaho
Ralph Cavanagh, Natural Resources Defense Council	Brad Purdy, Community Action Partnership Association of Idaho
Bill Eddie, Advocates for the West	Don Reading, Ben Johnson Associates
Ric Gale, Idaho Power	Greg Said, IPC
David Hawk, J.R. Simplot Co.	David Schunke, IPUC Staff
Nancy Hirsh, NW Energy Coalition	Tim Tatum, Idaho Power
Bart Kline, Idaho Power	Mike Youngblood, Idaho Power
Randy Lobb, IPUC Staff	Scott Woodbury, IPUC Staff

PROGRESS

Since the inception of the workshops on August 24, participants have reached the following agreements:

1) Agreed on a set of operational principles that guide the workshops.
2) Clarified the nature and extent of financial disincentives to Idaho Power for investment in energy conservation through demand-side management programs (DSM).
3) Agreed that material financial disincentives do exist and will increase as DSM expenditures increase. ~~, though n~~Not all participants agree that restoration of lost fixed cost revenues would directly result in additional investment in DSM programs by Idaho Power.
4) Agreed on a set of evaluation criteria by which to compare and contrast potential mechanisms for removing financial disincentives and/or providing incentives for DSM programs.
5) Agreed to continue exploring two specifically proposed mechanisms: A true-up mechanism (referred to as a decoupling mechanism in early workshops) and a performance-based incentive mechanism.
6) Agreed to design a true-up mechanism simulation and a pilot program performance-based incentive mechanism to evaluate the effects of these two mechanisms. The

simulation and pilot program will be the subject of further review and discussion at the next workshop.

TIMELINE

Participants established the following timeline at the December 1 workshop:

1) Provide this ~~a~~ status report to the Commission on or before December 15, 2004, as specified in Order No. 29558.
2) Provide a full report to the Commission no later than January 31, 2005, including participant recommendations and rationale.

This Status Report to the Commission has been reviewed and approved by Idaho Power Company, Northwest Energy Coalition, the Commission Staff and the Industrial Customers of Idaho Power.

Date	Barton L. Kline Attorney for Idaho Power Company and on behalf of Northwest Energy Coalition, the Commission Staff and the Industrial Customers of Idaho Power

APPENDIX 9—FLIPCHARTS REGARDING THE FINAL REPORT

Commission Report

January 31 Deadline—Bill Eddie Lead

I. History of issue that generated work group (with help from IPUC staff)

II. What did the workgroup do?

- Studies undertaken
- Mechanisms proposed
- Results of investigation

III. Conclusions and recommendations

- Schedule/timeline for addressing pilot and simulation findings—final recommendations

IV. Figures and tables, studies, workshop summaries

APPENDIX 10—FLIPCHARTS REGARDING NEXT STEPS AND ACTION ITEMS

Next Steps

1) If Randy gets feedback from Commissioners that there is something of concern, Randy will let the workgroup know—could possibly meet with them as a group
2) Possible mid-summer workgroup check-in (TBD)

Bin

1) Gas utilities → decoupling mechanism
2) Still interested in evaluation customer "appetite" for conservation at higher levels. (David Hawk to bring proposal to IPC)

Action Items

What	Who	When
1) IPC-IPUC staff will prepare pilot application and circulate for review and comment (include monitoring mechanism)	Lynn–PC	February 1
2) IPC and NWEC refine simulation proposal (and retrospective analysis) for review and comment by workgroup (include monitoring mechanism for March)	Mike, Bill, Ralph	January 14

Action Items

What	Who	When
3) Draft final report to workgroup by mid-January for R&C	Bill	January 14
4) File pilot application with IPUC	IPC	Mid-February

APPENDIX 11—FLIPCHARTS REGARDING THE WORKSHOP SERIES

What's Worked	Outstanding Concerns
1) Open, honest discussion and bringing to table	1) Feels like we have just begun—need to take next steps seriously—need to accomplish something together
2) Quality of recording—capturing essence of meetings	2) Need to monitor and carefully evaluate results—issue is not dropped
3) Appreciate organization of meetings/tracking what happened, quality of info presented	
4) Very successful workshop	
5) Facilitation helpful	
6) Interchange forthright—advanced issue further than thought we would	

What's Worked	Outstanding Concerns
7) Pleased with results of workshop	3) Language in order about "PBR" that we didn't get to. Hope it meets needs of Commissioners
8) Good solution, reached fairly quickly with good deliberation	4) Easy to do pilots and simulation—hope we have enough information to make follow-up decisions
9) Appreciated everyone attending	5) Being able to capture how we really will evaluate these things as we go along—ability to modify evaluation criteria
10) Appreciated openness of everyone to hear other perspectives	
11) Always had goals in sight—felt movement and progress towards goals	
12) Impressed with us all! Came a long way.	

What's Worked	Outstanding Concerns
13) IPC participation and get numbers out that people could understand	6) What Commissioners will say about the group's work/ agreements (curious)
14) Not everyone got what they wanted, but lots accomplished	7) Establishing program evaluation criteria
15) Candid discussion	8) Proof is in the pudding
16) Appreciate IPC going along with this in a positive way	9) Building codes/ enforcement
17) Ralph and Bill's analysis and numbers	

What's Worked	Outstanding Concerns
18) Group has had form and substance	10) Asking IPC to do additional things to an already "full plate"
19) Frank and fair	11) Look for results to "sell" process
20) Possible solution to issue, and conservation as a way to get at issue	
21) IPC collaborative involvement	