DSM Program Development. The demand-side resource options were developed using a combination of internal engineering estimates and external consulting services. The residential and commercial program options were designed by Quantum Consulting of Berkeley, California, and Idaho Power's engineering staff developed the remaining programs. Each of the energy efficiency programs were designed to maximize the potential energy benefits of the resource while remaining cost-effective from a total resource perspective. The demand response options were designed to maximize the load impact achieved while remaining cost-effective from the utility's perspective. During this process, two to four program levels were developed to allow for the determination of the optimum program level to be included in the IRP.

The demand-side management options were all designed using similar cost components. The demand response options include some additional costs not contained in the energy options due to the need for ongoing operation of the programs by the utility. Each of the energy and demand response program options contain the following cost components:

- Administrative costs
- Marketing and advertising costs
- Incentive or rebate payments
- Participant costs

The demand response program cost structure contains the following additional costs not included in the energy program options:

- Capital costs
- Operating and maintenance costs
- Increased supply costs (resulting from the energy shifted from on-peak to off-peak periods)

Once the program design phase was completed, each new program was put through a series of static screening analysis prior to being included in the IRP dynamic portfolio analysis.

Screening Criteria. The DSM screening criteria were designed to assess a program's potential to maximize benefits at the lowest cost for all stakeholders.

There are four general categories of criteria taken into consideration when looking at selecting DSM programs.

- Programs will be **cost-effective**. From a total resource perspective, estimated program benefits must be greater than estimated program costs. As shown by the 2002 Idaho Power Integrated Resource Plan, programs that decrease summer peak demand will be valuable because they reduce the need for new peak resources. Programs that capture cost-effective, lost-opportunity DSM resources will be encouraged.

- Programs will be **customer-focused**. From the participants' perspective, programs will offer real benefits and value to customers. The Idaho Public Utilities Commission stated in Order No. 29026, "It is our hope that the programs created by the DSM rider will empower customers to exercise control over their energy consumption and reduce their bills."
- Programs will be **equitably distributed**. From the customers' perspective, programs will be selected to benefit all groups of customers. Over time, programs will be offered to customers in all sectors and in all regions of the company's service territory.
- Programs will be as close to **earnings-neutral** as possible. From the utility's perspective, programs will be selected to minimize the negative impact on shareowners.

These criteria are used as guidelines in selecting a new program or initiative. A program that doesn't meet all of these criteria is not excluded from consideration, but would have to be further evaluated for other valued characteristics. Ultimately, all programs must be cost-effective in order to be considered as ordered by the IPUC.[1]

Static Cost-Effectiveness Analysis: The cost-effectiveness analysis is the primary focus of the screening criteria. The static cost-effectiveness analysis of DSM programs at Idaho Power is performed using the methods described in the EPRI End-Use Technical Assessment Guide Manual as well as The California Standard Practices Manual: Economic Analysis of Demand-side Programs and Projects.[2] The proposed DSM programs considered for inclusion into the 2004 IRP are evaluated from Utility Cost Test and Total Resource Cost test perspectives.

- **Total Resource Cost Test (TRC)** [3]

The TRC test is a measure of the total net resource expenditures of a DSM program from the point of view of the utility and its ratepayers as a whole. Costs include changes in supply costs, utility costs, and participant costs. (Transfer payments between ratepayers and the utility are ignored).

The following are the calculations performed by this test:

- Net Present Value: A net present value of zero or greater indicates that the program is cost-effective from the total resource cost perspective.
- Benefits-Cost Ratio: A benefit-cost ratio of 1.0 or greater indicates the program is cost-effective from the total resource cost perspective.
- Levelized Cost: This measurement makes the evaluation of potential demand-side resources comparable to that of supply side resources. The cost stream of DSM resource (in this case, the stream of utility costs and participant costs) is

[1] IPUC Order No. 29026, May 20, 2002
[2] http://www.cpuc.ca.gov/static/industry/electric/energy+efficiency/rulemaking/resource5.doc
[3] EPRI End-Use Technical Assessment Guide (End-Use TAG), Volume 4: Fundamentals and Methods, Barakat and Chamberlin, Inc, April 1991

discounted and then divided by the stream of discounted kW or kWh that is expected from the program.

- **Utility Cost Test**[4]

The Utility Cost test is a measure of the total costs to the utility to implement a DSM program.

The following are the calculations performed by this test:

- Net Present Value: A net present value of zero or greater indicates that the program is cost-effective from the Utility Cost perspective.
- Benefits-Cost Ratio: A benefit-cost ratio of 1.0 or greater indicates the program is cost-effective from the Utility Cost perspective.
- Levelized Cost: This measurement attempts to put demand side resources on equal ground with supply-side resources. As with supply-side resources, the cost stream of DSM resource is discounted and then divided by the stream of kW and kWh that is expected from the program.

DSM Analysis Calculation Definitions: [4]

- Net Present Value: Calculated as the discounted stream of program benefits minus the discounted stream of program costs using the Company's weighted average cost of capital (WACC) for resource planning.

$$\sum_{T=1}^{N} \frac{\text{Program Benefits}}{(1+\text{WACC})^{t-1}} \quad \text{(minus)} \quad \sum_{T=1}^{N} \frac{\text{Program Costs}}{(1+\text{WACC})^{t-1}}$$

Where: N = the total number of years, t = the incremental year, and WACC = the Company's weighted average cost of capital.

- Benefits-Cost Ratio: Calculated as the discounted stream of program benefits divided by the discounted stream of program costs.

$$\sum_{t=1}^{N} \frac{\text{Program Benefits}}{(1+\text{WACC})^{t-1}} \div \sum_{t=1}^{N} \frac{\text{Program Costs}}{(1+\text{WACC})^{t-1}}$$

- Levelized Costs: The present value of total costs of the resource over the life of the program in the base year divided by the discounted stream of energy or demand savings, depending on how the resource size has been defined.

[4] EPRI End-Use Technical Assessment Guide (End-Use TAG), Volume 4: Fundamentals and Methods, Barakat and Chamberlin, Inc, April 1991

$$\sum_{T=1}^{N} \frac{\text{Program Costs}}{(1+\text{WACC})^{t-1}} \div \sum_{T=1}^{N} \frac{\text{Energy Savings}}{(1+\text{WACC})^{t-1}}$$

- Discounted Payback: Number of years from the initial program participation to the point at which the cumulative discounted benefits exceed the cumulative discounted costs for participants. (Usually calculated for an average customer who joins the program in its 1st year)
- Undiscounted Payback: Number of years from the initial program participation to the point at which the cumulative undiscounted benefits exceed the cumulative undiscounted costs for participants.
- Free riders: Program participants that would have implemented the energy efficiency measure without the program or incentive.
- Incremental Costs: The additional cost incurred by choosing to select one option over another.

Total Installed Cost of Energy Efficient Option
– Total Installed Cost of a Non-Energy Efficient Option
= Incremental Cost

To quantify the "benefit" portion of the calculation, five costing periods were created for the year that are consistent with the proposed industrial time-of-use rate pricing periods[5]. Each costing period contains a price that reflects the alternative cost of energy and capacity at the associated time period. The alternative cost represents the cost of energy resources that would most likely be the alternative at that time period. Each time segment has a different alternative cost associated with it depending on the expected price for that period.

The following is tables are illustrate the time of day and time of year costing period definitions used in the static program screening analysis:

[5] General Rate Case No. IPC-E-03-13.

June 01 – August 31

SOFP = Summer Off-Peak

SMP = Summer Mid-Peak

SONP = Summer On-Peak

SUMMER SEASON								
Hour	***Sunday***	***Monday***	***Tuesday***	***Wednesday***	***Thursday***	***Friday***	***Saturday***	***Holiday***
1	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
2	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
3	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
4	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
5	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
6	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
7	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
8	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
9	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
10	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
11	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
12	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
13	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
14	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
15	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
16	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
17	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
18	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
19	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
20	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
21	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
22	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
23	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
24	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP

September 01 - May31

NSOFP = Non-Summer Off-Peak
NSMP = Non-Summer Mid-Peak

NON-SUMMER SEASON								
Hour	*Sunday*	*Monday*	*Tuesday*	*Wednesday*	*Thursday*	*Friday*	*Saturday*	*Holiday*
1	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
2	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
3	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
4	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
5	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
6	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
7	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
8	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
9	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
10	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
11	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
12	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
13	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
14	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
15	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
16	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
17	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
18	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
19	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
20	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
21	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
22	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
23	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
24	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP

Forward market prices are used for the segmented alternative cost periods in all periods except in the “Summer On-peak” period. Forward market prices are forecasted in two categories, “heavy load” and “light load”. The heavy load and light load prices are forecasted by month for 10 years[6]. For measures with lives beyond ten years, the forecast is extended by escalating the final year of the forward market price schedule for the additional years needed for the analysis using the Company’s escalation rate for capital investments.

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[6] The forward price curve was taken from the 2002 Idaho Power Integrated Resource Plan.

The costing period prices are calculated using the following method:

- NSMP = Average of heavy load prices in Jan. – May. And Sept. – Dec.
- NSOFP = Average of light load prices in Jan. – May. And Sept. – Dec.
- SOFP = Average of light load prices in Jun. – Aug.
- SMP = Average of heavy load prices in Jun. – Aug.
- SONP = Idaho Powers variable energy cost of a 162 MW Simple Cycle Gas Turbine plus the marginal capacity cost of that Gas Turbine in $/kW/Year.

The benefit values for the A/C Demand Response and Irrigation Demand Response programs were calculated under the assumption that these programs will result in no energy savings. It was assumed that the energy saved during the down time would be shifted from the high price summer on-peak time period to the lower price summer mid-peak time period.

The following table shows the schedule of alternative costs used to calculate the benefit value of each program in the static analysis:

	Alternative Energy Cost ($/MWH)				
	IPCo Variable Energy Cost	**Market Price Forecast**			
Year	**SONP**	**SMP**	**SOFP**	**NSMP**	**NSOFP**
2004	$ 68.43	$ 35.61	$ 29.10	$ 34.76	$ 28.41
2005	$ 70.16	$ 36.37	$ 29.87	$ 35.51	$ 29.16
2006	$ 71.92	$ 37.39	$ 30.63	$ 36.50	$ 29.90
2007	$ 73.74	$ 68.28	$ 35.49	$ 37.74	$ 30.98
2008	$ 75.59	$ 73.32	$ 36.82	$ 40.34	$ 32.60
2009	$ 77.50	$ 76.79	$ 37.78	$ 40.10	$ 34.03
2010	$ 79.45	$ 79.25	$ 38.48	$ 42.83	$ 35.67
2011	$ 81.45	$ 82.13	$ 39.58	$ 45.89	$ 37.36
2012	$ 83.51	$ 84.20	$ 40.58	$ 47.05	$ 38.30
2013	$ 85.61	$ 86.32	$ 41.60	$ 48.23	$ 39.27
2014	$ 87.77	$ 88.50	$ 42.65	$ 49.45	$ 40.26
2015	$ 89.98	$ 90.73	$ 43.72	$ 50.70	$ 41.27
2016	$ 92.25	$ 93.02	$ 44.83	$ 51.97	$ 42.31
2017	$ 94.57	$ 95.36	$ 45.96	$ 53.28	$ 43.38
2018	$ 96.96	$ 97.76	$ 47.11	$ 54.63	$ 44.47
2019	$ 99.40	$ 100.23	$ 48.30	$ 56.00	$ 45.59
2020	$ 101.90	$ 102.75	$ 49.52	$ 57.41	$ 46.74
2021	$ 104.47	$ 105.34	$ 50.77	$ 58.86	$ 47.92
2022	$ 107.10	$ 108.00	$ 52.05	$ 60.34	$ 49.13
2023	$ 109.80	$ 110.72	$ 53.36	$ 61.87	$ 50.36

	Alternative Capacity Cost ($/kW/Yr)				
	162 MW Simple Cycle Gas Turbine				
Year	**SONP**	**SMP**	**SOFP**	**NSMP**	**NSOFP**
2004	$ 59.18	$0.00	$0.00	$0.00	$0.00
2005	$ 60.67	$0.00	$0.00	$0.00	$0.00
2006	$ 62.20	$0.00	$0.00	$0.00	$0.00
2007	$ 63.77	$0.00	$0.00	$0.00	$0.00
2008	$ 65.37	$0.00	$0.00	$0.00	$0.00
2009	$ 67.02	$0.00	$0.00	$0.00	$0.00
2010	$ 68.71	$0.00	$0.00	$0.00	$0.00
2011	$ 70.44	$0.00	$0.00	$0.00	$0.00
2012	$ 72.22	$0.00	$0.00	$0.00	$0.00
2013	$ 74.04	$0.00	$0.00	$0.00	$0.00
2014	$ 75.90	$0.00	$0.00	$0.00	$0.00
2015	$ 77.81	$0.00	$0.00	$0.00	$0.00
2016	$ 79.77	$0.00	$0.00	$0.00	$0.00
2017	$ 81.79	$0.00	$0.00	$0.00	$0.00
2018	$ 83.85	$0.00	$0.00	$0.00	$0.00
2019	$ 85.96	$0.00	$0.00	$0.00	$0.00
2020	$ 88.13	$0.00	$0.00	$0.00	$0.00
2021	$ 90.35	$0.00	$0.00	$0.00	$0.00
2022	$ 92.62	$0.00	$0.00	$0.00	$0.00
2023	$ 94.96	$0.00	$0.00	$0.00	$0.00

Notes:

1 IPCo Variable Energy Cost includes fuel and O&M for a 162MW Simple Cycle CT. (Calculated on "Gas Worksheet")

2 The Market Price Forecast includes capacity cost. (Refer to "Electric Prices" for detail)

3 Escalation rate is 2.52% as stated in the 2002 IRP.

4 Time of Day segments are defined on the "TOD Segments" worksheet.

For all energy programs it is assumed that the energy savings will continue beyond the measure life time period for each program participant. It was felt that it is reasonable to assume that once a person participates in the program, they will not revert back to a less efficient behavior after the measure life expires. As a result, the energy savings schedule for each program shows a ramp-up period followed by a sustained maximum level for the entire analysis period.

Dynamic Modeling. The programs that were determined to be cost effective using the static analysis were then put through the Aurora dynamic modeling process to determine the impacts to the overall resource portfolio. The hourly energy savings associated with each program was valued within the Aurora simulation model. The model output is the present value dollar impacts to the overall resource portfolio revenue requirement. If the present value reduction of overall revenue requirement exceeds the present value program costs, the program is determined to be cost effective.

The two demand response options were analyzed outside of the Aurora model due to the complexity of modeling the hourly load reduction of a time constrained resource. The two demand response programs were analyzed using the static analysis and shown to be cost-effective. These two programs were also compared against the other supply-side and demand-side options using a 30-year levelized cost measurement. The two programs were among the lowest levelized costs of all the portfolio resources and were selected based on those criteria.