



# **2013 Interim Avista Natural Gas Demand-Side Management Portfolio Business Plan**

**Avista Utilities  
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## **Introduction**

Avista's Interim Business Plan represents a commitment to documenting the outcome of an ongoing business planning effort that occurred between May 2012 and July 2013. The business planning effort was specifically designed to be responsive, in a timely manner, to a Washington Utilities and Transportation Commission directive to shift from the Company's optimization of the natural gas DSM portfolio around a net Total Resource Cost (TRC) test to the use of the gross Utility Cost Test (UCT). (The details of these tests and the implications upon the management of the portfolio will be elaborated upon later in this document).

The Company engages in ongoing business planning efforts in response to changes in markets, technologies and regulatory direction. In recent months, several changes to the demand side management (DSM) natural gas portfolio that the Company believes would lead to improved portfolio performance warranted a revision to tariff Schedule 190 "Natural Gas Efficiency Programs" and the need to make revisions prior to the completion of the full 2014 DSM Business Plan.

This Interim Business Plan will explain and document the planning effort that has been completed up to the initiation of the regularly scheduled comprehensive annual business planning process. The results of these planning efforts have moved seamlessly forward into the development of a 2014 DSM Business Plan. That planning effort is currently underway and scheduled for completion and filed on or before November 1, 2013.

## **Background**

Natural gas DSM programs have been difficult to deliver in a TRC effective manner. The elements of the total resource cost (summarized in the table below) are heavily reliant upon the customer incremental cost in comparison to the present value of the stream of avoided energy cost savings.

Table 1: Total Resource Cost (TRC) test benefits and costs

Benefits:

- Present value of the future stream of avoided cost of natural gas
- Present value of the future stream of avoided cost of electricity (positive or negative)
- Present value of the future stream of the benefits of non-utility energy

Costs:

- The customer incremental cost of the efficiency measure (using symmetric base case assumptions for the determination of both cost and savings)
- The non-incentive utility cost of the program

The TRC test defines the costs and benefits based upon the perspective of the customer population of a specific utility. Optimizing for the TRC test will minimize the customer populations total energy cost.

The relatively slow improvement in natural gas efficiency technologies and avoided costs that are less than 30% of their electric counterpart, (on an mmBTU basis) create inherent cost-effectiveness challenges for the delivery of natural gas DSM in comparison to electric DSM offerings.

Quantum leaps in the development of low-cost natural gas gathering technologies have led to yet further reductions in the market price of natural gas. The Company has been observing these drastic cost reductions in market prices over the past few years. Though the avoided cost is based upon the incremental, and not the average or market commodity cost, the two measures are tied closely enough that this market direction did indicate an impending decrease in avoided costs as well. Thus, it was anticipated that the 2012 Natural Gas Integrated Resource Plan (IRP) would lead to much lower avoided costs. This future challenge has been a topic of discussion for the Company's external energy efficiency technical committee as early as May 2011.

In May 2012, the first calculations of the avoided cost stream for the 2012 natural gas IRP were completed. The avoided cost stream actually fell by more than was previously anticipated. A review of the existing natural gas portfolio indicated that the portfolio would no longer be TRC cost-effective under the updated avoided costs.

Various optimization scenarios were performed to determine if a cost-effective portfolio could be developed. Unfortunately, there were very few programs that were incrementally cost-effective on an individual basis, even without consideration of relatively fixed infrastructure costs. Those few programs that were incrementally cost-effective were narrowly so, and had insufficient residual benefits to support any reasonable allocation of non-incentive utility costs. The most favorable scenarios yielded benefit-to-cost ratios of approximately 0.6 (a benefit-to-cost ratio below 1.0 indicates that the costs exceed the benefits and that the program is not cost-effective).

Given the Company's commitment to delivering a TRC cost-effective program, and the clear inability to do so under expected circumstances, the Company felt the obligation to file in a timely manner for the indefinite suspension of the natural gas DSM portfolio. The Company committed to evaluating the prospects for re-initiating the portfolio in the event that a cost-effective program could be delivered in the future. This commitment explicitly included frequent review of the impact of future natural gas avoided costs, the cost and efficacy of efficiency technologies or improvements in delivery technologies (including regional market transformation opportunities).

The timing of Avista's natural gas IRP, and the rapidity with which the Company responded to the changing market conditions, placed Avista's natural gas DSM conundrum into a policy discussion earlier than most other utilities.

A comprehensive discussion of the viability of the natural gas DSM portfolio ensued, including a discussion of the appropriate performance metrics and policies that should be applied to the decision to continue or suspend such programs. The discussion included consideration of alternative discount rates, increased avoided cost preferences, and the use of the utility cost test (UCT) in place of the TRC test as the key portfolio cost-effectiveness metric.

During the natural gas DSM in general discussion, there appeared to be a strong consensus that, regardless of the outcome, the natural gas component of the low-income program would not be impacted. The reasons cited for such a position was the heavy emphasis on non-resource acquisition attributes of this portfolio, as well as the individual assessment of each measure application by the community action agencies delivering these programs under annual funding

contracts with Avista. Thus, the low-income portion of the natural gas portfolio was excluded from planning efforts on the presumption that the existing annual contracts would go forward without revision.

Ultimately, the Washington Utilities and Transportation Commission provided the Company with the regulatory guidance to apply the UCT test in place of the TRC test for purposes of the natural gas DSM portfolio.

The UCT metric differs substantially from the TRC metric currently summarized. The benefits and costs of the UCT metric are as represented below:

Table 2: Utility Cost Test (UCT) benefits and costs

Benefits:

- Present value of the future stream of avoided cost of natural gas
- Present value of the future stream of avoided cost of electricity (positive or negative)

Costs:

- The incentive cost of the utility program
- The non-incentive utility cost of the program

The UCT test defines costs and benefits based upon the perspective of the utility and how the cost that the utility incurs will be passed on to their customers. Optimizing for the UCT test will minimize the customers utility bill.

The costs of the TRC and UCT metric differ in that the TRC test includes the customers full incremental cost of the measure prior to the receipt of any utility incentive. The UCT test replaces this incremental customer cost with the cost of the incentive only. Since the incentive cost is invariably well below the customers full incremental measure cost, the UCT is nearly guaranteed to be easier to pass than the TRC test. The TRC test does include the value of non-energy benefits; however these benefits are almost never sufficient to offset the TRC's much higher cost definition.

Additionally, the regulatory direction indicated that the UCT test was to be defined based upon all program participants. Previously the Company adjusted the calculation of the TRC test to measure the incremental cost and benefits of only of those customers who were determined to have adopted the measure only as a consequence of the utility program. This adjustment, termed a “net-to-gross” adjustment, is based upon a periodic evaluation of the programs within the portfolio.

Avista expressed concern, and the Commission concurred, that a narrowly focused optimization upon the UCT test could lead the Company to promote measures that did not necessarily pass an assessment of participant cost-effectiveness. To the extent that utility incentives could be considered an endorsement, the Company believes it is necessary to exercise a degree of caution to ensure that the spirit of the Commissions guidance is fully considered within the planning process.

### **Developing a Revised Natural Gas DSM Portfolio**

Upon the receipt of the above outlined regulatory guidance, the Company immediately re-opened the planning process with the intent to determine what, if any, revisions were necessary to optimize the portfolio based upon a gross UCT test metric.

An updated estimate of the portfolio performance on a gross UCT basis was projected to yield a benefit-to-cost ratio of 0.88. This is a moderately significant failure to reach cost-effectiveness even based upon the UCT metric (with its lower hurdle for cost-effectiveness). All three of the major components of the natural gas DSM portfolio (excluding the low-income portfolio) also individually failed to be cost-effective (residential prescriptive programs delivering a 0.85 benefit-to-cost ratio, non-residential prescriptive programs a 0.89 and the non-residential site-specific program being nearly cost-effective at a 0.96 benefit-to-cost ratio).

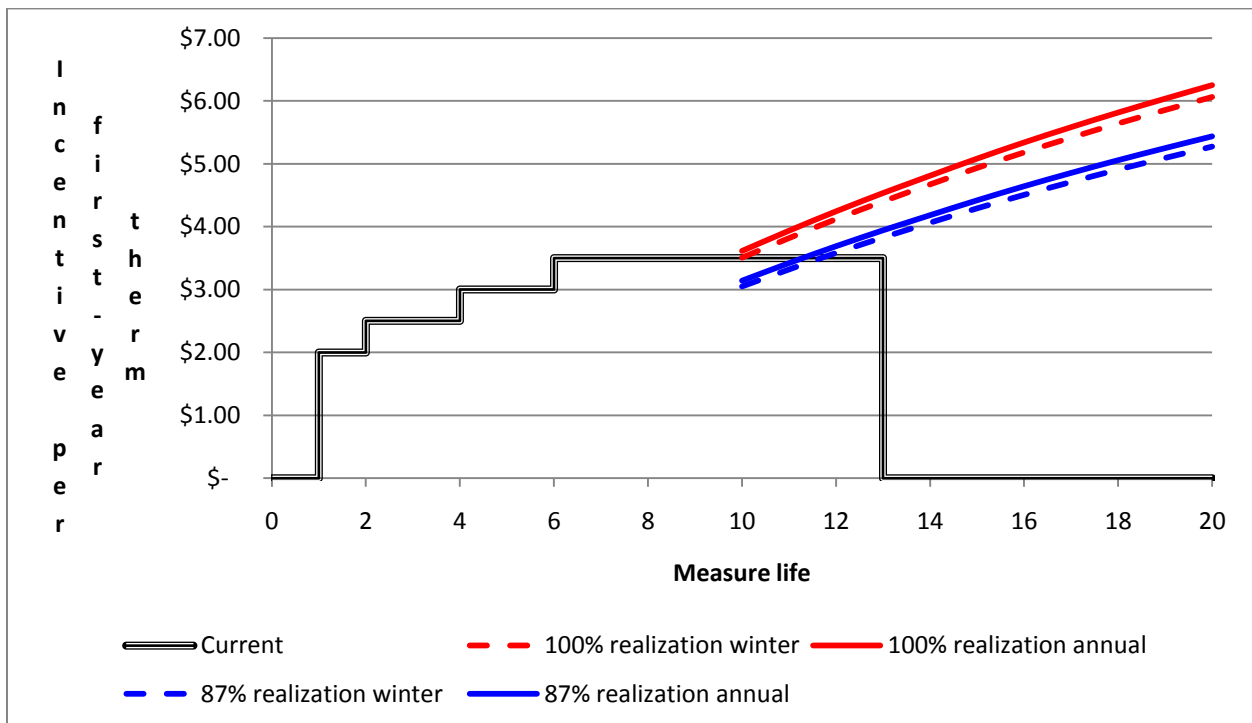
Direct financial utility incentives are by far the largest cost within the UCT test. Avista’s Schedule 190 tariff (governing the implementation of the natural gas DSM programs) defines a tiered incentive level structure for all measures with a life of ten years or greater. The tiers are established based upon the energy simple payback of the measure. The incentive level provided

(stated in terms of the incentive per first-year therm saved) increases as the simple payback increases, until a simple payback of 13 years is reached. Measures with a simple payback of over 13 years are not eligible for an incentive under the current tariff.

The substantial majority of the long simple payback (over 13 year) projects are TRC cost-ineffective due to high customer incremental costs. In previous years, when these projects were eligible for incentives, these long-payback projects have detracted (sometimes substantially) from the TRC cost-effectiveness of the portfolio. The current exclusion of projects with simple paybacks in excess of 13 years was driven by the need to deliver a TRC cost-effective portfolio.

It should be noted that the incentive levels defined within Avista’s current tariff came close to and under some unusual circumstances could exceed the comparable avoided cost, as illustrated below. The illustration also indicates the impact of a realization rate (the percentage of energy savings anticipated from the project at time the incentive was granted vs. the verified savings) upon the relationship between the incentive and the avoided cost value.

Illustration No. 1: Comparison of incentive levels and avoided cost values for winter and annual load shapes and 100% and 87% realization rates.



Since the avoided costs must not only be sufficient to allow for the recovery of the incentive costs but also the non-incentive cost related to the program, the above illustration indicates that projects with measure lives of between 10 and 13 years have insufficient residual value to allow for the recovery of the supporting utility infrastructure. Only when the incentive drops to zero (for projects with simple paybacks over 13 years) is there a substantial amount of residual benefit. Given that these “over 13 year” simple payback projects do not qualify for an incentive, they are not materially present in the portfolio.

A review of the portfolio diagnostics indicates three related issues in need of review as part of the gross UCT optimization of the natural gas portfolio:

1. The current incentive is too high to allow for sufficient residual benefits to cover non-incentive costs.
2. Projects with simple paybacks in excess of 13 years and possessing significant avoided cost value are being excluded from the portfolio based upon their generally unfavorable (now less relevant) TRC cost-ineffectiveness.
3. The minimum measure life of 10 years may be too short for the current incentive tier structure.

A fourth factor was identified as being inevitably part of the optimization discussion; that of the level of non-incentive utility costs. Reductions in non-incentive utility cost would benefit the UCT cost-effectiveness if they could be achieved without reducing the throughput of otherwise UCT cost-effective projects. Reductions in non-incentive utility cost may also adversely impact relatively non-quantifiable portfolio values such as customer education and awareness that may not create an immediate measureable impact upon the portfolio but could have long-term consequences.

Based upon the determination that these four factors would likely be the most important tools for use in optimizing the portfolio for the gross UCT test, the Company developed a planning model allowing for the adjustment of these factors and their consequential impact upon cost-effectiveness and other characteristics.

To maximize the clarity of the customer-facing elements of the portfolio, it was determined that the tier structure itself (the simple payback range associated with each tier) would not change given that this same structure was also used in the electric DSM portfolio. Additionally, it was



believed that any revision in the incentive level should be first evaluated as a proportionate reduction across all tiers.

One important characteristic of the portfolio, the projection of therm throughput, was likely to be impacted by any adjustment in the four previously mentioned portfolio management elements. The incentive level and the maximum permissible simple payback were likely to have a particular impact. The Company rarely has the opportunity to experiment with alternative incentive levels under circumstances when other factors are not also in flux. Previous tentative evaluations indicated an incentive elasticity of 25% (a doubling of the incentive would lead to 25% greater therm throughput). This evaluation is many years old and based upon an increase in the electric incentives and not a decrease in the natural gas incentives. Additionally, the impact of these revisions may be mitigated by the net-to-gross ratio of the portfolio.

It is recognized that some of the optimization scenarios may increase throughput (increasing the maximum energy simple payback) while others would reduce throughput (reducing incentives, reducing non-incentive utility cost or increasing the minimum measure life). Depending on the final adjustments made to the portfolio, it is possible that even the direction of the impact upon energy acquisition could be indeterminate.

To further define the objective function of the planning process, it has long been Avista's intent to maximize the residual benefits of the portfolio (benefits less costs) rather than the benefit-to-cost ratio. A narrow focus on maximizing the benefit-to-cost ratio could lead to a very cost-effective but small portfolio that excludes marginally cost-effective resource opportunities. Maximizing residual benefits encourages the adoption of any measure which is incrementally cost-effective and delivers higher net benefits to customers.

Applying all optimization factors with particular attention to the four identified above, the Company experimented with several scenarios with the objective to maximize the residual gross UCT benefits.

It was subjectively determined that reductions to the non-incentive utility cost would lead to an unacceptable compromise in the ability to recruit projects, inform customers of their alternatives and to efficiently implement and evaluate those projects. Based upon these conclusions no

adjustments to the non-incentive utility costs were assumed in the plan. A comprehensive review of the Avista DSM portfolio (included the shared electric and natural gas infrastructure) will be reviewed as part of the 2014 DSM Business Plan to be filed on or before November 1, 2013.

A review of the related opportunities to adjust the ten-year minimum measure life applicable to the tiered incentive structure was found to be unnecessary if the level of the incentive itself was revised downward. As various scenarios rapidly demonstrated such a downward modification in the incentive was necessary to optimize the UCT performance of the portfolio. This incentive adjustment would remove the need to modify the minimum measure life necessary to be eligible for the tariffs tiered incentive structure.

A series of experiments and calculations of alternative incentive levels based upon various assumptions regarding incentive elasticity and the net-to-gross ratio ensued. These calculations were performed with ample input from not only the analytical and planning staff but also from program managers, field engineers and account executives. This process concluded with a consensus for a 33% reduction in the incentive level (across all tiers) as the best compromise between cost-effectiveness, acquisition objectives, returning a reasonable percentage of utility cost to customers in the form of incentives and responsibly managing the net-to-gross relationship.

Various scenarios establishing different (higher) maximum simple paybacks for incentive eligibility were also evaluated. These long simple payback projects that are very likely to be cost-ineffective from a TRC standpoint do nevertheless contain an avoided cost value. When one disregards the incremental cost that the customer invests in the project (as is the case when the UCT test is applied) and substitutes the cost of the utility incentive it is possible to redefine these projects in a UCT cost-effective manner. Applying a 33% reduction to all incentive levels created an environment where these projects favorably contributed to the portfolio UCT cost-effectiveness. Lifting the maximum current energy simple payback criteria for incentive eligibility led to increased portfolio UCT cost-effectiveness while increasing therm acquisition and the number of customers served. It is likely that the favorable influence of eliminating the simple payback has been underestimated since these projects have not been marketed in the

recent past and may, therefore, be underrepresented within the updated portfolio mix. (“Legacy” projects eligible prior to the imposition of the simple payback maximum were retained in the portfolio mix used for purposes of this planning exercise).

Applying the consensus 33% reduction in the incentive tiers and the elimination of any simple payback maximum from the tariff requirements leads to the program revisions represented in the illustration below:

Illustration No. 2: Revisions to incentive levels and simple payback maximum tariff criteria

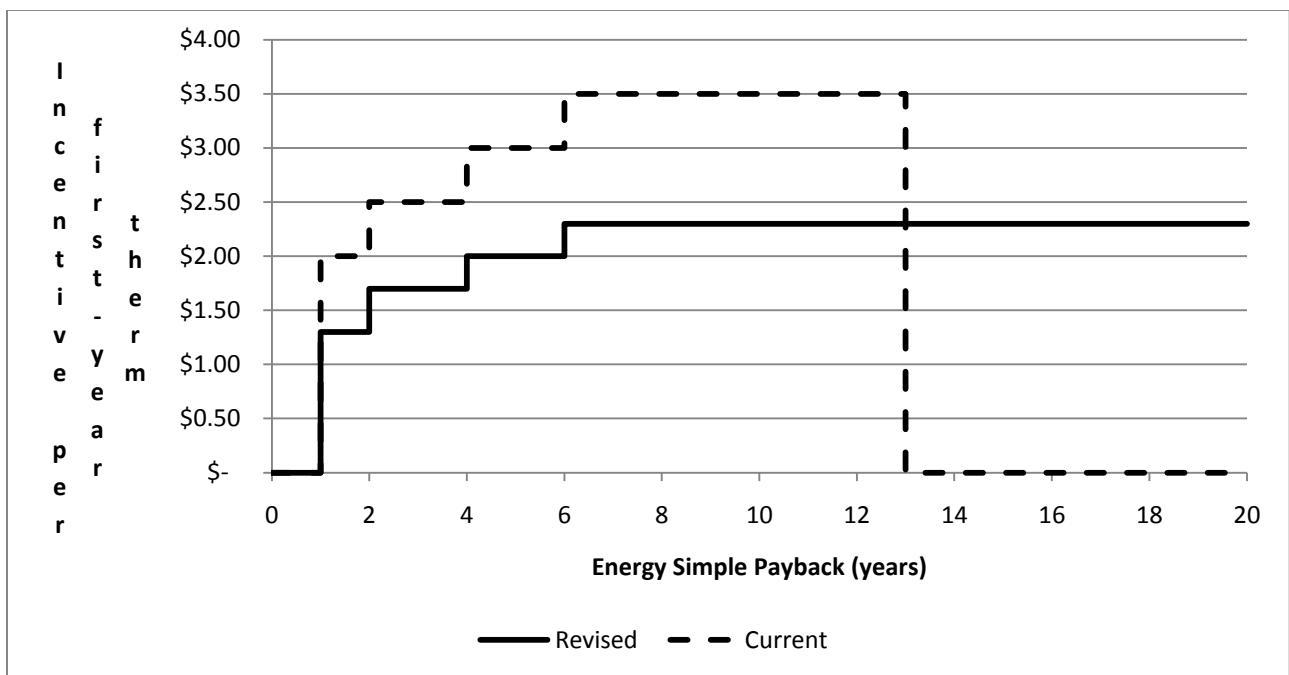


Table 3: Existing and proposed Schedule 190 incentive levels

Energy Simple Payback	Existing Sch 190	Proposed Sch 190	% change
Under 1 year	\$0.00	\$0.00	0%
1 to 2 years	\$2.00	\$1.30	-35%
2 to 4 years	\$2.50	\$1.70	-32%
4 to 6 years	\$3.00	\$2.00	-33%
6 to 13 years	\$3.50	\$2.30	-34%
Over 13 years	\$0.00	\$2.30	+ NA %

When translated to the actual tariffed incentives, each individual tier is reduced by between 32% and 35% of the previous levels (consistent with a 33% numerical reduction developed within the planning process).

Before finalizing the scenario above the prescriptive programs within the portfolio were reviewed in greater detail. No prescriptive programs with significant customer participation were found to individually fail the UCT cost-effectiveness test by a significant degree (recognizing that fixed non-incentive utility costs were not allocated to the individual measure and program review). Furthermore, continuation of any of these programs may misrepresent or mislead customer decisions when they are acting on their own best judgment as applied to their individual circumstances.

It is recognized that the 2014 DSM Business Plan will comprehensively review all electric and natural gas programs in less than three months after the requested effective date of the revision to the Schedule 190 tariff. It is also recognized that the adjustment, launch or termination of prescriptive programs must occur with a significant degree of notice given that the programs permit customers to apply for rebates up to 90 days after the purchase or installation of the measure. Typically, a longer transition period is necessary to accommodate the need to communicate with both customers and trade allies. Consequently, any change in the eligibility, the launch or termination, or the incentive levels of these programs have been deemed to be combined with adjustments that may occur as part of the 2014 DSM Business Plan. Customer-facing revisions to the program, including revisions to prescriptive incentive level, resulting from the adjustment to Schedule 190 incentive levels when and if proposed Schedule 190 tariff revisions are approved, are likely to take place in January of 2014.

This process led to the change of only two tariff factors; a 33% reduction in incentives and lifting the simple payback maximum. These adjustments should not overshadow a general discussion of targeting and future program development. The extended discussion, both externally and internally within Avista, of the relative merits of the TRC and UCT test have increased the fundamental understanding of how the change in cost-effectiveness tests impact the targeting of both site-specific and prescriptive programs. The portfolio has not been adjusted for any improvement in targeting, given that the impact upon near-term performance is speculative. It is

also likely that the greatest impact, particularly on site-specific projects with long sales cycles, will be more of a long-term situation.

### **Anticipated Portfolio Performance**

Based upon the adjustments previously cited, the planning model predicts an improvement in the gross UCT of the existing portfolio from 0.88 (moderately cost-ineffective) to 1.20 (moderately cost-effective) based upon a portfolio operating under revised tariff guidelines.

The revisions to the portfolio have decreased the TRC performance, as might be expected given that the very long simple payback projects are being returned to the portfolio. The TRC benefit-to-cost ratio decreases from 0.56 to a less favorable 0.44.

The major revisions to the portfolio consist of adjustments that will both increase (lifting the simple payback maximum) and decrease (reducing incentive levels) resource acquisition. Thus, within the ability to estimate such acquisition, the net impact is upon acquisition is indeterminate.

Generally, the actual portfolio performance can be improved when the degree of comprehensiveness of the portfolio is expanded. Thus, it is quite possible that a comprehensive review of the full portfolio within the 2014 DSM Business Plan may identify additional opportunities to improve portfolio performance. However, it was the consensus of all involved in the planning process that it was unnecessary and unwise to delay pursuing revisions to the tariff for the full comprehensive portfolio review. Revisions to Schedule 90 (governing the electric DSM portfolio) have been under discussion since early 2013 and the Company was similarly concerned that delaying the filing of these tariffs would deny the opportunity to reap the benefits as quickly as possible.