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VIA – Electronic Mail

February 20, 2015

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
Statehouse Mail
W. 472 Washington Street
Boise, Idaho 83720

RE: Addendum to Avista Utilities' 2015 Demand Side Management (DSM) Business Plan

Dear Ms. Jewell:

In compliance with Commission Order 33196 in Case No. AVU-G014-03, Avista Corporation's d/b/a Avista Utilities ("Avista" or "Company") respectfully submits its "Addendum" to its 2015 DSM Business Plan. Also, provided as an appendices to the plan is the Company's "Review of the Viability of a Natural Gas Demand-Side Management Portfolio in the Idaho Service Territory." If you have any questions regarding this information, please contact Dan Johnson at 509-495-2807 or myself at 509-495-4975.

Sincerely,

/s/Linda Gervais

Linda Gervais
Manager, Regulatory Policy
Avista Utilities
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Avista Utilities

Review of the Viability of a Natural Gas Demand-Side Management Portfolio in the Idaho Service Territory

December 31, 2014

Introduction

Avista Utilities completes an annual comprehensive demand-side management (DSM) business planning process intended to prepare for the following year and to estimate the results of the key metrics by which that portfolio will be judged. This 2015 DSM planning process was initiated in June of 2014, was completed at the end of October and focused upon the Washington electric and natural gas DSM portfolios and the Idaho electric DSM portfolio.

The aforementioned planning process explicitly excluded consideration of an Idaho natural gas DSM portfolio, which was and continues to be suspended due to the inability of the company to be able to project that such a portfolio would be cost-effective under the Total Resource Cost (TRC) test. Precipitous reductions in the twenty year projection of future avoided costs led the company conclude that it would not be possible to offer a fully cost-effective natural gas DSM portfolio. The company committed to tracking changes in the weighted average cost of gas (WACOG) as a proxy for the avoided cost of natural gas and, if significant upward movements in WACOG were to occur, to initiate a more detailed evaluation of the prospects for a DSM portfolio. More recently the company committed to performing a review of the viability of an Idaho natural gas DSM portfolio by building upon the recently completed 2015 DSM Business Planning document. This document summarizes the results of that analysis.

Due to the nature of Avista's low income program funding agreements this analysis excluded consideration of that program. The total funding for income qualified customers would not change as a result of re-opening the natural gas DSM portfolio; it would merely permit the funding to be used for both natural gas and electric efficiency measures. Therefore it isn't possible to do an analysis of the natural gas portion of the program in isolation without the consideration of the impact upon the electric portfolio. Since the low income portfolio is a small part of the overall DSM portfolio the exclusion will not materially change the analysis.

The analysis and conclusions of the viability review are documented within this report, along with recommendations for future analysis and opportunities.

Foundational data

The analysis has been largely built off of a review of the Washington natural gas DSM portfolio. The 2015 Washington portfolio was optimized against the Utility Cost Test (or UCT, also known as the program administrator cost test, or PACT). The UCT test incorporates only the utility cost associated with the measure and excludes any consideration of the incremental measure cost borne by the customer. Under Avista's current Washington incentive structure for natural gas DSM it is nearly certain that <u>any</u> natural gas efficiency option will be incrementally UCT cost-effective, assuming the absence of extraordinary incremental administrative costs specific to the measure. Thus the Washington natural gas DSM portfolio evaluated as part of the 2015 DSM Business Planning process conveniently identifies the universe of all potentially TRC cost-effective Idaho natural gas measures that the company believes that it can operationally deliver.

For purposes of this review the library of potential measures includes natural gas components of dual fuel efficiency measures, those measures simultaneously generating electric and natural gas savings.

Methodologies applied and Idaho scenarios tested

First optimization exercise: Aggregate sub-TRC cost-effective measures

Based upon the library of natural gas efficiency measures defined within the Washington DSM planning process it is possible to assess those measures for their ability to contribute towards the creation of a TRC cost-effective portfolio.

Avista's traditional methodology for optimizing portfolio performance for cost-effectiveness is to begin at the most granular level (the measure level) and calculate a "sub-TRC" value. A sub-TRC value is a cost-effectiveness evaluation based solely upon the benefits and costs that are incremental at that level of aggregation. Allocated infrastructure costs are not included as costs within Avista's sub-TRC test. This approach allows for measures which bring favorable value to the portfolio, but perhaps not enough value to fully offset allocated infrastructure cost burdens, to be incorporated into the optimized portfolio. In order to deliver a cost-effective program or portfolio the collective residual benefits (benefits less costs) of all measures included within the portfolio would need to outweigh the total infrastructure cost burden. Any portfolio component that is incrementally cost-effective at the sub-TRC level aids in the portfolios ability to bear those infrastructure costs. Due to the small size of the potential Idaho natural gas portfolio scenarios the analysis has omitted the program level of aggregation and instead created a portfolio out of an aggregation of measures.

This approach to portfolio optimization is consistent with Avista's objective of maximizing the TRC value of the portfolio to the customer base. It is distinctly different from either (a) seeking to maximize the benefit-to-cost ratio or (b) maximizing the size of the overall portfolio while simultaneously attempting to maintain a passing cost-effectiveness ratio. Both of these approaches are certain to lead to a lower TRC value for the customer base.

Screening the Washington natural gas DSM portfolio for sub-TRC cost-effective measures led to the identification of ten prescriptive measures for further study. Nine of these measures have been incorporated into the Washington portfolio and one (residential mail-by-request 2.00 GPM showerhead replacements) is not offered in consideration to the three other retail buy-down residential showerhead measures (which also passed the sub-TRC test). The site-specific program, the largest single program in Avista's Washington natural gas portfolio, was not sub-TRC cost-effective by a significant margin (achieving a sub-TRC benefit-to-cost ratio of only 0.64).

These measures and their summary cost-effectiveness characteristics are identified Table 1 below. The estimated Idaho therm acquisition is based upon an adjustment to the Washington natural gas DSM business plans projection of therm acquisition using Avista's traditional 70% Washington and 30% Idaho ratio.

Table 1: Compilation of all sub-TRC cost-effective natural gas efficiency measures

	Idaho therms	Residual sub-TRC benefits	Sub-TRC B/C ratio
Commercial 10 pan or larger steamer	2,608	$ 3,124	1.85
Comm. gas multi stage furnace <225 kBTU, 90%-95% AFUE	315	$ 545	1.74
Comm. gas multi stage furnace <225 kBTU, over 95% AFUE	1,899	$ 2,903	1.60
Comm. gas single stage furnace <225 kBTU, 90%-95% AFUE	3,444	$ 6,054	1.76
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Res. showerhead replacement, 2.00 GPM	2,864	$ 21	3.00
Res. Web-enabled thermostat, DIY installation	1,757	$ 882	1.71
Total sub-TRC cost-effective portfolio	18,535	$ 21,780	1.74

As illustrated, without consideration of non-incentive utility costs excluded from the measure-level analysis, the nine prescriptive measures create a sub-TRC cost-effective portfolio. But the analysis also shows that they can bear only $21,780 in non-incentive utility costs before the portfolio becomes cost-ineffective.

The table below demonstrates the impact of the estimated non-incentive utility costs upon portfolio cost-effectiveness.

Table 2: Impact of non-incentive utility cost upon the previously identified portfolio

	Idaho therms	Residual sub-TRC benefits	Sub-TRC B/C ratio
Total sub-TRC cost-effective portfolio	18,535	$ 21,780	1.74
Non-incentive utility cost		$ 34,932	
Total TRC cost-effectiveness calculation	18,535	$ (13,152)	0.80

Based upon the per BTU non-incentive utility cost estimate the non-incentive utility costs are about 60% higher than the level tolerable with this package of measures. The consequence is a TRC cost-ineffective portfolio (as reflected in the benefit-to-cost ratio of 0.80). Also of importance, the size of the portfolio is only 8% of the per customer therm acquisition that is obtained in the current Washington program. The very small size of the portfolio creates an additional viability concern in that such a small portfolio may not create a meaningful impact.

Testing a larger portfolio to include the site-specific program

It does not take additional analysis to conclude that incorporating the sub-TRC cost-ineffective site-specific program into the previously defined cost-ineffective portfolio of nine prescriptive measures will create an even more cost-ineffective portfolio. However since the previously defined portfolio failed to meet what many would consider to be the minimum threshold size for a viable portfolio it does provide additional policy information and creates additional options to project the performance of a larger portfolio.

The site-specific program was the most obvious omission from the previous list of sub-TRC cost-effective measures and programs. The site-specific program has traditionally been the largest single program in the Avista DSM portfolio. Extrapolating from Washington experience, the site-specific program would deliver about 93,000 therms in Idaho; five times larger than the total acquisition from all nine of the sub-TRC cost-effective prescriptive programs. With the addition of the site-specific program the Idaho portfolio would have 45% of the per customer therm impact of the existing Washington natural gas DSM program. This would be a significantly smaller portfolio, but potentially of sufficient size to merit incorporation into the larger Avista Washington / Idaho portfolio.

Table 3: Portfolio of site-specific and selected prescriptive measures

	Idaho therms	Residual sub-TRC benefits	Sub-TRC B/C ratio
Site-specific portfolio without non-incentive utility cost	92,823	$ (282,707)	0.64
Estimate site-specific non-incentive utility cost	-	$ -	0.00
Full cost-effectiveness of the site-specific program	92,823	$ (457,645)	0.52
Full cost-effectiveness of prescriptive measures	18,535	$ (13,152)	0.80
Total portfolio (site-specific and selected prescriptive measures)	111,358	$ (470,797)	0.54

The site-specific program has a sub-TRC cost-effectiveness (without non-incentive utility cost) of 0.64. When non-incentive utility costs are incorporated the cost-effectiveness falls to 0.52. Bringing the site-specific program into a portfolio that also includes the nine prescriptive measures described above reduces the TRC benefit-to-cost ratio from 0.80 to 0.54, but the therm acquisition of the portfolio does break out of its previous insignificance to a projected acquisition of 111,358 therms.

However, as the table above demonstrates, creating a portfolio that is larger and even more cost-ineffective works against the interest of the customer, as evidenced by the more negative residual TRC value. The residual benefits move from a value of negative $13,152 (harming the customer base in this amount) to a value of negative $470,797 (even greater harm to the customer base).

Incentive level scenarios

In optimizing the Washington natural gas DSM portfolio for the UCT test it was necessary to reduce the incentive level by approximately 1/3rd in order to have any prospect for achieving UCT cost-effectiveness. However, from the TRC test perspective utility incentives are not considered to be a cost. Thus increasing the incentive could lead to greater acquisition, an option not considered in the analysis above.

The nature of utility regulated DSM programs makes it difficult to perform the tests necessary to determine the sensitivity of portfolio acquisition to changes in incentives with all other factors held equal.

Two very limited calculations several years ago both yielded 25% incentive elasticity estimates (changing the incentive by 100% would lead to a change in throughput of 25%).

Based upon this incentive elasticity a hypothetical 50% increase in incentives would lead to a 12.5% increase in throughput. Thus for the two scenarios previously explained, the scenario consisting of the nine prescriptive measures would increase from 7.6% of the per customer acquisition of the current Washington natural gas DSM portfolio to 8.5% and the second scenario of nine prescriptive measures plus the site-specific program would increase from 45% to 51% of the per customer Washington DSM portfolio acquisition. Thus even aggressive changes in the incentive level would not yield significant changes in the size of the potential portfolio absent the inclusion of measures with exceptionally poor cost-effectiveness.

It is also likely that the incremental acquisition generated from higher incentives would be from projects that required the additional incentives to achieve a participant cost-effectiveness threshold. These more marginal projects would move the TRC cost-effectiveness to even lower levels of performance.

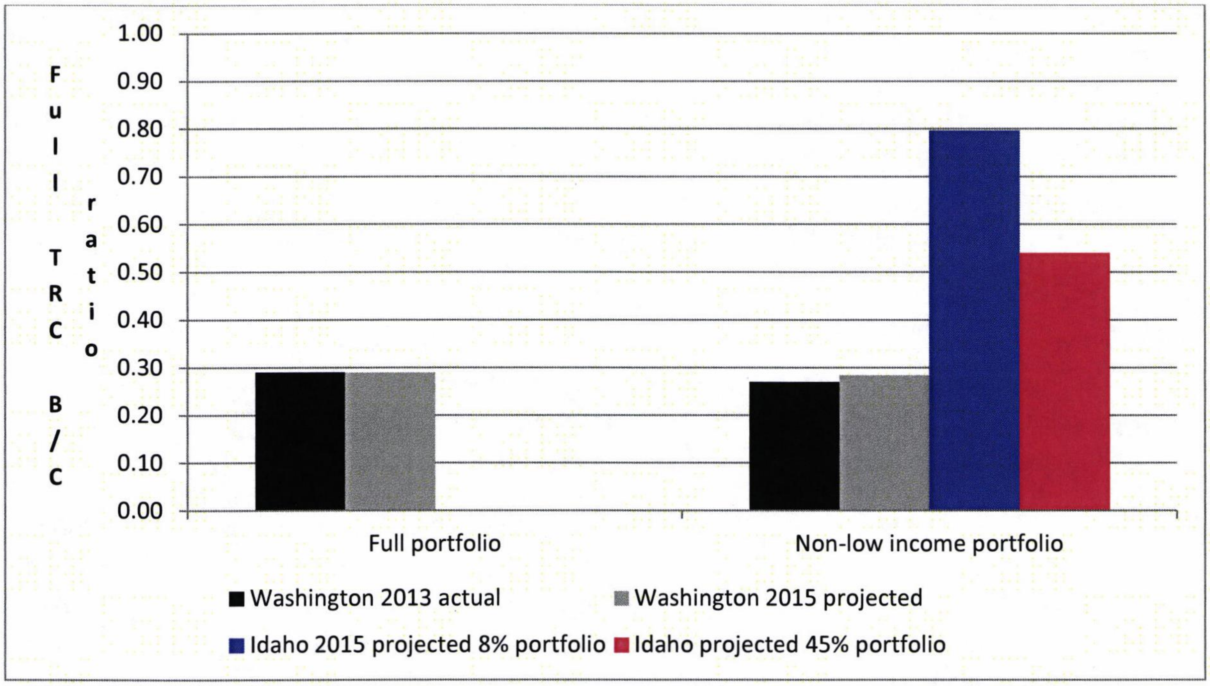
Perspective against historical results

The analytical conclusion that a TRC cost-effective Idaho natural gas DSM portfolio could offered is based upon extrapolating a projection of Idaho performance from a projection of Washington 2015 performance. Given that this is one projection layered upon another projection any conclusions should be tempered with a degree of doubt. To the extent possible these conclusions should also be tied back to actual performance to the extent possible.

The closest metric of actual performance comparable to a prospective Idaho natural gas DSM portfolio is the performance of the existing Washington natural gas DSM portfolio. It is Avista's intent to offer the same programs across both jurisdictions whenever feasible due to the closely linked nature of those markets. However, the Washington natural gas DSM portfolio has been optimized for UCT performance and not TRC performance. That said, Avista's 2013 Annual Report on 2013 operations (the last analysis performed on actual performance) found that the Washington natural gas portfolio achieved a TRC benefit-to-cost ratio of only 0.29 for the overall portfolio and 0.27 when the low income component of that portfolio was excluded.

The column chart below illustrates the actual and projected performance of the Washington portfolio against the two Idaho portfolios tested. The "8% portfolio" is the smaller portfolio of nine sub-TRC cost-effective prescriptive measures generating per customer savings of 8% of the existing Washington portfolio. The "45% portfolio" is with the addition of the site-specific program bringing the portfolio size to 45% of the per customer acquisition of the existing Washington portfolio.

Figure 1: Comparison of actual and prospective Washington natural gas DSM portfolio performance to the two Idaho scenarios tested.



Conclusions and recommendations for future analysis and strategies

Thus this exercise has led to the conclusion that the TRC performance of the portfolio can be improved above the UCT-optimized Washington actual portfolio, but not to a level that is reasonably close to being TRC cost-effective and not without reductions in the size of the portfolio ranging from substantial to extreme.

It should be noted that all of the aforementioned analysis and conclusions are based upon the pursuit of a local DSM portfolio in the manner in which Avista has historically constructed a local DSM portfolio. Under the current and future expected avoided costs the usefulness of that tool in delivering cost-effective outcomes is very limited.

Looking forward Avista and several other northwestern natural gas utilities and DSM program administrators are working together towards the funding of a regional gas market transformation portfolio to be administered through the Northwest Energy Efficiency Alliance (NEEA) that anticipates delivering efficiency resources at a TRC levelized cost of 28 cents per therm, in comparison to Avista's 20 year levelized avoided cost of 41 cents per therm.

Market transformation is a tool that is less adversely impacted by the falling avoided costs due to the strategic nature of the interventions. The intent is to identify markets that can be moved through carefully selected interventions that yield vastly disproportionate changes in markets and outcomes. By contrast purely local DSM portfolio is reliant upon a collection of individual touches that lead to a greater correlation between program costs incurred and efficiency gains realized, thus linking success more tightly to the prevailing avoided costs.

Successful regional market transformations may well lead to opportunities for leveraging those successes into cost-effective local enhancements to these regional programs. This may be as the result of market transformations bringing new cost-effective gas efficiency technologies towards commercialization or lower cost approaches to moving towards the adoption of fundamentally cost-effective technologies in regionally cooperative ways.

The proposed funding contract with NEEA commits to funding a natural gas market transformation organization for five years (coincident with the electric market transformation funding cycle) with all expenditures and the continuation of the overall effort contingent upon the NEEA Board of Directors approval and subject to the recommendations of a Natural Gas Advisory Committee that will be created.

An ongoing effort to assess the opportunities for local enhancement of regional efforts and a periodic comprehensive assessment of the viability of an Idaho natural gas DSM portfolio should be expected given these prospective changes in the market. It is unlikely that these events will trigger new market opportunities in the first few years of the existence of the regional organization, but it is also likely that there will be opportunities within the first five year funding cycle. Given the expectation that future avoided costs will not increase by the substantial degree necessary to make a purely local DSM portfolio cost-effective, the leveraging of regional market transformation activities is the most likely future for the a successful local DSM portfolio.

Idaho Addendum to 2015 Demand Side Management (DSM) Business Plan

Overview

Pursuant to the Idaho Public Utilities Commission (IPUC) Order No. 33196 in Case No. AVU-G-14-03 regarding the Commission's review of Avista's 2014 Natural Gas Integrated Resource Plan (IRP), the Company has completed additional analysis to project the conditions under which it would be feasible to offer a Total Resource Cost (TRC) cost-effective natural gas demand-side management (DSM) portfolio.

The Order specifically states:

> We also appreciate Staff s review of the IRP, and acknowledge Staff s concern that the Company's IRP and DSM Business Plan do not analyze when the Company might cost-effectively re-implement natural gas DSM programs in Idaho. We find it reasonable and in the public interest to direct the Company to file an addendum to the 2015 DSM Business Plan that analyzes the CPA results and comments on when it might be cost-effective for the Company to again offer natural gas DSM in Idaho. The Company shall file the addendum as soon as is practicable, but no later than 60 days from the service date of this Order.

Background

Avista filed for, and was granted a suspension of its Idaho natural gas DSM portfolio as a result of a large reduction in natural gas avoided costs as identified in the Company's 2012 Natural Gas IRP. The Company committed to tracking the weighted average cost of gas (WACOG) on a quarterly basis as a proxy for natural gas avoided costs. Moreover, the Company committed to complete a full analysis of the potential for a natural gas DSM portfolio if the WACOG was 50% or more in excess of that which was prevailing at the time that the previous IRP was completed. The WACOG was considered to be the best proxy for natural gas avoided costs between IRP's.

Subsequent to the suspension, an independent Conservation Potential Analysis (CPA) and Avista's 2014 Natural Gas IRP were completed. The CPA analysis identified cost-effective acquisition potential for natural gas DSM. Avista utilizes differing assumptions than those included in the CPA. The CPA bases customer adoption assumptions derived from the Northwest

Power and Conservation Council that are founded on the Hood River Conservation Project. There are critical differences between electric and natural gas customer adoption and assumes incentives of up to 100% of measure cost that has little in common with a permanently available natural gas DSM program.

The Conservation Potential Assessment (CPA) is a "top-down" view of resource potential performed by the Applied Energy Group (AEG). The process begins with typical regional-level information regarding the usage of energy within the home and, to the extent possible, customizes and indexes that information to utility specific forecasts, end-use saturations, weather and other factors to provide a compilation of how energy is used within the service territory. AEG also maintains a large library of alternative measures that can be applied to create different prospective service territory energy usage resulting from the adoption of efficiency measures. These measures are characterized by an expected cost and energy usage. Measure life assumptions determine the timing of future equipment replacement. Program delivery cost assumptions are specified as a percentage of the incremental measure cost and are assumed to be entirely variable.

The CPA process leads to the identification of a technical potential (the installation of the highest efficiency options without regard to cost-effectiveness). The economic potential is the subset of the technical potential which is cost-effective under the total resource cost test based upon utility specific avoided costs and discount rates. The achievable potential is the portion of the economic potential that is assumed to be acquirable through utility intervention over time. The timing of the acquisition is determined based upon the application of ramp rates moving towards an ultimate saturation level that is consistent with the Northwest Power and Conservation Council (NPCC) planning methodologies.

The business planning process is a "bottom-up" approach to planning for the acquisition of all cost-effective efficiency resources. It begins with the characterization of all plausibly cost-effective efficiency options utilizing input from the CPA as well as past Avista program experience, known new opportunities and opportunities that have been identified through regional and national experience. Information from previous impact evaluations of Avista programs and actual program cost and measure cost data are the preferred data source, whenever they are applicable. The measures and measure characteristics are defined based upon an operationally feasible customer-facing program definition consistent with how the measure would ultimately be offered as part of a DSM portfolio. Potential acquisition is based upon the program managers subjective assessment of reasonable participation in the operational programs to include the full array of customers participating in that program.

The business plan proceeds to aggregate measures into programs based upon actual expected program delivery. Programs are then aggregated into various definitions of portfolios (jurisdictional portfolios, electric or natural gas portfolios, regular and low income portfolios).

Program delivery costs are based upon the requirements for delivery of the overall DSM portfolio. It consists of labor and non-labor requirements and builds off of actual historical program delivery costs with modifications as necessary for revisions to the portfolio. The program delivery costs are a combination of assigned costs (those that can be identified to particular program components) and allocated costs (those expenses not tied to the delivery of a particular measure or program). The assigned program delivery costs are incorporated into the analysis at the level of aggregation at which they are considered to be incremental (generally at the program level of aggregation). All program delivery costs, both assigned and allocated, are fully incorporated within the overall portfolio. Allocated program costs are distributed based upon the energy savings of measures or programs, thus allocating those fixed costs to the portions of the portfolio where they are most capable of bearing the cost.

With these differences in mind, in October 2014, the Company completed its annual operational DSM Business Plan. The 2015 DSM Business Plan encompassed the existing Washington electric, Washington natural gas and Idaho electric DSM portfolios. An important distinction regarding the continuance of a Washington natural gas portfolio is that the Washington Utilities and Transportation Commission (UTC) adopted a cost-effectiveness policy in 2013 for natural gas measures based on the Utility Cost Test (UCT)[1]. Application of the UCT yields a portfolio that is cost-effective and different than the results of analyses using the Idaho standard of the Total Resource Cost (TRC) test.

The completion of an operational plan for the Washington natural gas DSM provides information necessary for analysis of the potential for an Idaho DSM portfolio. Consequently, the Company completed a "Review of the Viability of a Natural Gas Demand-Side Management Portfolio in the Idaho Service Territory" on December 31st, 2014 (and attached to this filing). This study indicated that there were nine measures within the Washington natural gas DSM portfolio that were cost-effective in the absence of delivery costs, see Table 1 below for these nine measures. If delivered in Idaho, these prescriptive measures would be expected to deliver approximately 18,535 first-year therms, or about 8%. There was one additional prescriptive measure that was cost-effective, however excluded in the Washington portfolio due to redundancy with other offered measures. This portfolio became cost-ineffective when delivery costs were included in the analysis.

Table 1:	Idaho therms	Residual sub-TRC benefits	Sub-TRC B/C ratio
Commercial 10 pan or larger steamer	2,608	$ 3,124	1.85
Comm. gas multi stage furnace <225 kBTU, 90%-95% AFUE	315	$ 545	1.74
Comm. gas multi stage furnace <225 kBTU, over 95% AFUE	1,899	$ 2,903	1.60
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Total sub-TRC cost-effective portfolio	18,535	$ 21,780	1.74

[1] UTC Docket No. UG-121207 - Policy Statement on the Evaluation of the Cost-Effectiveness of Natural Gas Conservation Programs

The largest single program in Avista's overall DSM portfolio, the site-specific program, was not cost-effective, even in the absence of delivery cost.

Response

The specific request stated in the Order was for an explanation of "...when it might be cost-effective for the Company to again offer natural gas DSM in Idaho." The Company has identified the following three significant factors that would have a significant impact upon the potential for developing a cost-effective portfolio:

Increased natural gas avoided costs

It was the fall in natural gas avoided cost that moved the DSM portfolio from being cost-effective to being non-cost-effective. The Company has returned to the previously-mentioned natural gas viability analysis to further refine the potential portfolio and to determine what avoided costs would be necessary, all else being equal, to make an Idaho portfolio cost-effective. Holding all other factors equal, a 77% increase in the present value of natural gas avoided costs would be necessary for the portfolio to achieve a cost-effective outcome. At present, the likelihood of an avoided cost increase of that magnitude seems unlikely. However, any increase in avoided costs, in conjunction with other events favoring a natural gas portfolio, would improve the ability to offer a cost-effective portfolio.

New cost-effective natural gas efficiency technologies

There is the potential for notable improvements in natural gas end-use efficiency technologies, though historically natural gas efficiency technologies have not progressed as rapidly as comparable electric end-use efficiency options. In the event that commercially available cost-effective natural gas technologies advance in the future, there is the opportunity to incorporate them into a natural gas DSM portfolio. In addition to the relatively slow pace of technology, there have also been difficulties in moving these technologies towards commercialization and widespread availability to customers.

Regional market transformation

In recognition of the aforementioned difficulties in moving cost-effective natural gas efficiency technologies towards commercialization and with recognition that the Northwest Energy Efficiency Alliance (NEEA), on the electric side, has proven that cooperative market transformation efforts can be very successful, several regional natural gas utilities have successfully constructed a companion regional natural gas effort.

At present, this effort is nearing the full-scale launch of a five-year business plan with funding of over $18 million. As with the electric component of NEEA, the expectation is that long-term funding will come in the form of successive renewals of funding following the same five year cycle that NEEA currently has in place. The NEEA effort is anticipated to deliver cost-effective (28 cents per therm levelized cost) natural gas efficiency acquisition by accelerating and/or enhancing the adoption of efficiency technologies and services through strategic interventions to transform the market. Though it is impossible to guarantee the success of any individual venture, this approach has proven to be successful in generating a reliably cost-effective portfolio of market transformation ventures. In addition to the opportunity to derive cost-effective acquisition from these regional efforts, there are often significant opportunities for local utilities to enhance these programs through coordinated traditional DSM programs. At present the most likely source for future cost-effective local DSM opportunities is through the leveraging of the future NEEA portfolio. The emergence of these local opportunities may take some years to present themselves and not every regional venture will present such opportunities, but in aggregate the prospects for the future are favorable.

Avista's Plan

Avista is committed to diligently monitoring opportunities for cost-effective natural gas efficiency measures and promptly proposing a local DSM portfolio if and when it can benefit customers. Towards that end, the Company intends to:

- Continue to monitor the WACOG as a proxy for the avoided cost and trigger a full analysis of the potential for a natural gas DSM portfolio if the WACOG is 50% above that which was in place at the time that the previous avoided costs were developed. This is in recognition that much can happen during the two year IRP cycle and that the WACOG is the closest approximation available for changing natural gas costs.

- Follow-up each DSM Annual Business Plan with additional analysis of the viability of a cost-effective Idaho natural gas DSM portfolio. That analysis can be structured so as to build off of all that was learned in developing a Washington natural gas DSM portfolio. Though the Washington portfolio is optimized against the Utility Cost Test (UCT), and thus performs poorly in a TRC sense, the use of the UCT will ensure that all measures that could contribute to a TRC cost-effective portfolio will be incorporated into the UCT-optimized portfolio.
- As NEEA builds the 2015-2019 (inclusive) natural gas DSM portfolio, Avista will:
    - Continue to play an active role in the management of that portfolio.
    - Work towards creating a portfolio and governance structure that will favor the success of the regional effort beyond the current five-year funding cycle.
    - Seek out opportunities for the cost-effective local enhancement to those regional ventures through local DSM efforts and, if beneficial to our customers, use them to establish a foundation for a larger local natural gas DSM portfolio.