Adventures in Tweaking the TRC: Experiences from British Columbia

Katherine Muncaster and Andrew Pape-Salmon, BC Ministry of Energy and Mines
Sarah Smith, FortisBC Energy Utilities
Mark Warren, FortisBC Inc.

ABSTRACT

British Columbia has made changes to the Total Resource Cost test used to evaluate cost-effectiveness of utility DSM proposals in order to address a number of problems. First, natural gas DSM opportunities were at risk of being rejected on the basis of the Total Resource Cost test due to low natural gas prices, in spite of being cost-effective from a broader emission-reduction perspective. Second, non-energy benefits were playing a significant role in consumer decisions for some programs and yet were being excluded in the TRC. Third, valuable market transformation programs were difficult to justify based on their TRCs alone. As a result of these concerns, BC has mandated use of a variant of the Societal Cost Test, called the "Modified TRC", which:

- indirectly places value on greenhouse gas emission reduction,
- includes non-energy benefits through a combination of a deemed adder and quantification, and
- allows utilities to claim a portion of savings from any code or standard towards which market transformation activities were targeted.

Use of a social discount rate was also explored but rejected.

The utility regulator has been empowered to use the Utility Cost Test as an optional backstop to maintain the utilities' focus on energy savings. A cap has also been placed on the impact of the modifications to portfolio expenditure.

Although the electric utilities' regulatory proceedings incorporating this new cost-effectiveness test are not complete, indications are that it will significantly increase natural gas portfolios, and have minimal effects on electric portfolios (due to BC's low-carbon electricity supply).

Introduction

Across North America, utilities and utility regulators use cost-effectiveness tests to determine what demand-side measures (DSM) to proceed with. The accuracy and appropriateness of these tests is therefore vital to achieving optimal levels of demand side management activity both for ratepayers and for societal objectives like energy security and environmental sustainability.

Among the five cost-effectiveness tests[1], the most common primary tests are the Total Resource Cost test (TRC) and its close relative, the Societal Cost Test (SCT). The TRC is an

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[1] Participant Cost Test (PCT), Utility Cost Test (UCT) also known as Program Administrator Cost Test (PACT), Ratepayer Impact Measure (RIM), Total Resource Cost Test (TRC) and Societal Cost Test (SCT)

economic test of a measure, program or portfolio's benefits and costs:[2] The benefits are the net present value of the avoided commodity costs (e.g. power purchase costs) plus deferred capital expenditures of the utility's infrastructure, over the effective measure life; the costs are the applicable measure costs, which are typically incremental in the case of new construction or full cost in the case of retrofit, plus the program administration cost. The incentive cost paid by the utility to the participant is classified as a transfer cost, and thus does not impact the TRC. The Societal Cost test is essentially the TRC with externalities such as environmental costs and non-energy benefits factored in, and with the use of a lower discount rate in the calculations.

In British Columbia, utilities and regulatory bodies have relied primarily on the Total Resource Cost test. However in recent years, three concerns have prompted a change in the primary test. First, the TRC does not reflect the societal value of emission reduction from DSM. This has been underscored by recent low natural gas prices which have hindered an expansion of DSM portfolios which are needed to help meet provincial emission reduction targets. Second, non-energy benefits can play a significant role in program participant decisions and yet are often excluded from the TRC. As a result, utilities have been under-investing in programs which are cost-effective to the utility. And third, the TRC does not value the key role that utility measures play in preparing markets for energy efficiency codes and standards. This has made it difficult for utilities to justify programs which have been developed in partnership with governments to help pave the way for planned building code changes and equipment standards.

As a result of these concerns, BC has mandated use of a variant of the SCT, called the "modified TRC", which:

- indirectly places value on greenhouse gas emission reduction,
- includes non-energy benefits through a combination of a deemed adder and quantification, and
- allows utilities to claim a portion of savings from any code or standard towards which market transformation activities were targeted.

A number of safeguards were also implemented, including use of the Utility Cost Test as a backstop, and a cap on the portfolio impact of the modified TRC.

This paper provides an overview of BC's process of development of the modified TRC, including options proposed, the end product, expected impacts on regulatory proceedings, and views of various stakeholders.

Background

British Columbia is dominated by three regulated utilities—a large government-owned electric utility (BC Hydro), a small investor-owned electric utility (FortisBC Inc, or FBCI) and a large investor-owned utility primarily providing natural gas[3] (FortisBC Energy Utilities, or FEU). Although DSM portfolio and other approvals are the responsibility of an arm's length regulator, the BC Utilities Commission (BCUC), the BC government can establish rules the BCUC must follow when assessing the adequacy and cost-effectiveness of proposed utility

[2] The TRC can be expressed either as a net present value (NPV), or more typically a ratio, of the measure benefits and costs. If a ratio is used, it must be greater than one to "pass" the TRC test.

[3] FortisBC Energy Utilities is increasingly providing other forms of thermal energy and services, such as biomethane, geoexchange and district energy services.

demand-side measure expenditures. This power was first used in 2008 to ensure special treatment of programs for low-income households, rental accommodations, schools, public awareness, community engagement, training, and technology innovation. It also established rules for attribution of savings from DSM that supports codes & standards (see below for more details).

In the spring of 2011, utilities approached the BC Ministry of Energy and Mines (the Ministry) with a request to amend regulations to help them maintain or increase their DSM portfolios. The Ministry took this as an opportunity to address its concerns with the basic cost-benefit framework. The amendments needed to be complete by fall in order to affect a number of upcoming regulatory proceedings—a fairly rapid timeline for such a major change to the TRC. FEU had already produced a consultant report which helped inform the Ministry regulation amendments. The Ministry put together a proposal and conducted confidential stakeholder consultations over late summer and fall. Stakeholders included utilities, the BCUC, industrial, commercial and low-income ratepayer groups, environmental NGOs, a consumer association, the clean energy producers' association, the energy service company association, several academics, and several community organizations. The final regulation was issued in December 2011 (BC 2011), in time for consideration in regulatory proceedings for all three utilities.

Key Amendments

A Ministry objective at the outset of the process was to introduce global policy signals which would influence the scale and selection of DSM, rather than "picking winners" that the BCUC would be required to approve. This was achieved with three key changes to the TRC: use of a zero-emission energy alternative, inclusion of non-energy benefits, and attribution of codes and standards savings. A fourth component, a social discount rate, was also considered but not included in the final regulation.

Zero-Emission Energy Alternative

BC has legislated targets to reduce greenhouse gas emissions by 33% below 2007 levels by 2020 and 80% by 2050. This was followed by the introduction of a revenue-neutral carbon tax[4] in 2008, currently valued at $30 per metric tonne of CO_{2equiv} (BC 2008), applied across all fuels at the point of consumption. In the electricity sector, BC has strong policies to ensure that all new electricity is zero-emission. As a result, the cost of BC Hydro's electricity DSM is typically compared against the cost of zero-emission energy sources—by using the long-run marginal cost of acquiring clean or renewable BC electricity (at the time, $112/MWh, or $25.18/GJ).

In contrast, the TRC for natural gas (gas) DSM uses the utility's marginal cost of natural gas, a carbon-based fuel (currently $6.66/GJ). Although BC has a carbon tax which is charged to the customer and included in TRC calculations, this $30/tonne CO_2 is much weaker than the implicit carbon price signal in other key provincial energy regulations, such as the BC Hydro requirement for clean and renewable electricity, and the Renewable and Low Carbon Fuels

[4] BC is unique in North America in having a carbon tax. There is no such carbon tax or carbon price at the federal level in Canada or the US. Alberta has an effective carbon price of $15/tonne. Some US utilities have carbon prices from state regulations or regional trading initiatives, such as New York's Regional Greenhouse Gas Trading Initiative, which has a current trading price range from $1.8 to $4.9/tonne.

Requirement Regulation. Gas DSM is thus primarily viewed as an opportunity for the gas utility to help customers to manage their energy bills rather than as a cost-effective means to reduce emissions. In fact, gas DSM is a zero-emission method of "meeting" demand. If the goal instead is to reduce energy emissions at the least cost, then the appropriate cost comparison for gas DSM is another zero-emission energy source. This idea was introduced by FEU in its consultant report (ICF Marbek, Habart & Associates, and Cadmus Group 2011).

In BC there are two primary zero-emission energy alternatives (ZEEAs): biomethane and BC Hydro electricity. FEU recently introduced a preliminary offering of 10% biomethane to its residential customers. The BCUC had approved a cost of biomethane of up to $15.28/GJ, a ceiling derived from BC Hydro's Tier 2 residential inclining block electricity price, adjusted to 90% to account for the typical efficiency difference between gas and electricity. This was the formulation suggested by FEU in its report and subsequent application.

In its stakeholder consultations, the Ministry instead proposed BC Hydro electricity as its preferred ZEEA. It observed that the long-term price of biomethane is uncertain due to an immature market. There is also no government requirement for utility acquisition of biomethane, whereas there is a government requirement for BC Hydro to acquire only clean or renewable electricity supply to meet new demand. The Ministry explored several options for the electricity price: setting it at the BC Hydro customer cost with an efficiency adjustment, and setting it at the latest published price of long-term clean electricity (at the time, $25.18/GJ) with an efficiency adjustment. It also explored the idea of allowing the BCUC to determine the most appropriate ZEEA.

The Ministry calculated the potential effect of a ZEEA on a number of proposed gas DSM programs and found it to be very large, but also variable. For one program it brought the TRC from 0.14 up to 1.87, for another is went from 0.56 to 0.90.

Stakeholder reaction to the ZEEA concept was mixed. Some stakeholders were strongly opposed to the notion of incorporating a societal value like emission reduction into the TRC and argued that emission-focused programs should be taxpayer- rather than ratepayer-funded; others found the objective worthwhile but the ZEEA to be nontransparent. One key ratepayer group supported the notion of the ZEEA but believed that the proposed value was unreasonably high, and that the BCUC should be tasked with setting a value that weighed ratepayer interests against the emission reduction objective. One stakeholder suggested reducing the $/GJ value by using a 50% efficiency adjustment factor (drawing on the comparison of a NG furnace to an electric heat pump) instead of 90% efficiency adjustment (which draws on the comparison of a NG furnace to electric baseboards).

In response, the Ministry canvassed internally a proposal to use a simpler, more transparent method—incorporating a higher dollar per tonne carbon value than the current carbon tax—but it was not accepted.

With regards to the actual ZEEA value, the Ministry decided to specify use of BC Hydro's "long-run marginal cost (LRMC) of acquiring electricity generated from clean or renewable resources in BC" for gas DSM. This would create a direct parallel with the government's clean electricity policy, and also allow the value to adjust with a changing LRMC.

The Ministry was sympathetic to concerns about ratepayer impacts but also felt that it would be unfair and risky to task the BCUC with weighing ratepayer interests against an emission reduction goal. So rather than asking the BCUC to make adjustments to the ZEEA, or manipulating the technical efficiency adjustment with a certain result in mind, the Ministry instead chose a policy-driven adjustment factor of 0.5. This adjustment factor value was chosen to align with the implicit carbon value of other government policies, particularly the low-carbon fuel standard[5]. It was also based on an analysis of the expected impact on rates, which was projected to be reasonable.

In addition to substituting the avoided cost of gas with the LRMC of clean BC electricity x 0.5, the Ministry also decided to state that electric DSM must use the electric utility's LRMC of clean BC electricity. Although this is current practice for BC Hydro, this ensures the practice will continue even in the face of intervener arguments or energy supply policy changes. For FBCI this would be a new practice, as it currently uses the weighted average of long-term clean and mixed spot market prices.

Social Discount Rate

In its DSM application to the BCUC, FEU proposed use of a social discount rate of 3%, rather than its weighted average cost of capital (7.15%) currently being used in the TRC. The use of a social discount rate is provided for in the California Standard Practice guidelines in the application of the Societal Cost Test. A social discount rate is intended to capture broader benefits including the intergenerational benefits associated with avoiding carbon emissions today. Both electric and gas utilities have been placing increased emphasis on DSM with longer term energy savings—such as building envelope retrofits and new home construction. The net present value of measure benefits for these programs are severely reduced by discounting—for example, a 50-year measure with $5,000 of benefits undiscounted would have $2,600 with a 3% discount rate and only $1,400 with a 7% discount rate. This places a strong bias against actions with long-term emission reductions. Social discount rates are used by a number of jurisdictions including Iowa, Maine, Massachusetts, Minnesota, Montana, Oregon, Vermont and Wisconsin.

The Ministry included the concept in its consultation, as either an addition or an alternative to the ZEEA concept. Use of a social discount rate would serve to boost all of the societal benefits associated with DSM—emission reduction (for gas DSM), land and water impact reductions, and social benefits such as improved human health. It would boost the TRC on a similar scale to the ZEEA, but would not discriminate between gas and electric DSM.

The stakeholder reactions were surprisingly dissimilar to those for the ZEEA. Interveners solely concerned with rate impacts were similarly opposed. But one intervener group that supported the ZEEA believed an SDR to be inappropriately broad. In contrast, another intervener which had accused the ZEEA of being "irrational" and of watering down the TRC, supported an SDR as a method of encouraging long-term emission reductions. A third stakeholder supported an SDR because it has been adopted in other jurisdictions, whereas the ZEEA has no precedent.

The Ministry felt that adoption of both a ZEEA and a social discount rate would be too much. Although the Ministry received more support for a social discount rate than the ZEEA, it decided that the ZEEA achieved its objectives better. A series of events in 2011 highlighted upcoming steep increases in electricity rates, and reducing electricity rate increases became a government priority. Incorporating the ZEEA into the TRC would allow the Ministry to target emission reductions through gas DSM without substantially affecting electricity DSM, which in BC has only negligible emission reduction benefits. As such, the Ministry's proposal to adopt a social discount rate was dropped.

[5] The Renewable and Low Carbon Fuels Requirement Regulation has a noncompliance penalty of $200/tonne.

Private Non-Energy Benefits

In their 2010 paper, Nemes and Kusher argue that exclusion of non-energy benefits from the TRC is problematic. In theory the TRC should include only the incremental costs for the energy efficiency aspect of a measure (for example, the extra cost of efficient furnace in comparison with a standard furnace), and weigh these against only the energy benefits. But in practice, the energy efficiency features are inextricable from other features. For example, new efficient windows inherently improve comfort and aesthetics, while daylighting in commercial buildings improves employee productivity. These are major factors in a consumer's decision to undertake an energy efficiency action. As a result, full program costs are weighed against only partial program benefits, resulting in low-than-appropriate TRCs and underinvestment in DSM.

Amann (2006 and 2007) summarizes the variety of methods to address this issue, including subtracting the value of NEBs from program cost, adding NEBs into benefits, and discounting participant costs by a percentage that would reflect the ratio of energy benefits to non-energy benefits. Nemes and Kusher argue that a simpler solution is to switch to the Utility Cost Test, which solves the problem by removing all participant costs and benefits from the equation. The Ministry presented a variety of options in its consultation.

One option presented was to allow inclusion of non-energy benefits in the TRC. In practice BC Hydro has already included them where they are readily quantifiable—such as maintenance savings from CFLs in hotels. Unfortunately, most NEBs—such as comfort, aesthetics, and green status—are notoriously difficult to quantify. Allowing inclusion of quantified NEBs would create greater regulatory certainty for utilities. However, FEU argued that that one of the major challenges with quantifying is the time, expense and difficulty of doing so, and this would not be solved by simply "allowing" NEBs.

A second option was to switch to the Utility Cost Test. Preliminary analysis revealed very high UCT scores for a variety of electric and gas DSM in BC. However the idea of switching to a UCT instead of a TRC was not well received by the utilities, for three reasons. First, they have invested significant resources into evaluating DSM using the TRC. Second, they argued that the test must include customer costs in order to fairly compare the costs of DSM against supply. And third, they pointed out that this would move the test in the opposite direction from the notion of including societal benefits like emission reduction.

A third option was to avoid quantification by using a uniform deemed value intended to represent an average NEB value at the portfolio level. This approach has been used in several jurisdictions, including Iowa and Colorado. BC has already employed a 30% adder on all low-income programs. Overall, a deemed approach is consistent with the portfolio-level evaluation of TRC that utilities prefer, but does not acknowledge that NEBs may play a more significant role in some programs with TRCs low enough to be left out of the portfolio. The Ministry was concerned that a deemed approach would prevent the utility from proving higher NEB values for such programs.

A fourth option involved a simplified quantification approach developed by the Ministry. In this method, NEBs would be estimated using only the results of the Participant Test (although it is only valid for programs with a PCT<1). In this "inferred NEB methodology", customers are assumed to be competent decision-makers that only engage in a program if it has a net benefit to them, either in energy or non-energy benefits. Non-energy benefits are included in the PCT equation until the PCT = 1. This NEB value would then be used in the TRC. The advantage of this approach is its ease. However it was not generally well received by stakeholders. Some stakeholder were intrigued by the method but believed it was too new and untested to implement at this time, or believed it might be kept as an option rather than a required methodology. One believed it brought a false sense of precision, and was concerned that it only works for programs with a PCT<1. The majority of stakeholders that supported inclusion of NEBs preferred use of a deemed adder.

The Ministry decided to take a hybrid approach. In the final regulation, utilities may include quantified NEBs for some programs and use a deemed adder for all other DSM. The deemed adder is set at a value such that the overall portfolio non-energy benefits do not exceed 15% of the value of the portfolio energy benefits. If no quantification is undertaken, the deemed adder will be 15% per measure (see Table 1). The larger the quantified NEBs, the smaller the deemed adder for the remaining measures (see Table 2). If quantified NEBs are smaller than 15%, the deemed adder will exceed 15% per measure. Quantified NEBs on their own may increase *portfolio* benefits by 15% or more; However if that is the case then then there will be no deemed adder (see Table 3).

Table 1 shows a fictional case in which the utility does not propose any quantified NEBs. As a result, all programs are assigned a deemed NEB adder of 15%.

Table 1. Example: No Quantified NEBs

Measure	Benefits	Non-Energy Benefits	% Increase	New Total Benefits
Program A	$100,000	$15,000	15%	$115,000
Program B	$50,000	$7,500	15%	$57,500
Program C	$75,000	$11,250	15%	$86,250
Program D	$10,000	$1,500	15%	$11,500
Program E	$20,000	$3,000	15%	$23,000
TOTAL	**$255,000**	**$38,250**	**15%**	**$293,250**

Table 2 shows a case in which there are quantified NEBs for programs A and D that on their own do not increase portfolio benefits by 15% or more. Remaining measures are assigned a deemed NEB adder of 9% which results in a 15% increase in portfolio benefits.

Table 2. Example: Quantified NEBs are less than 15% of pre-NEB portfolio benefits

Measure	Benefits	Non-Energy Benefits	% Increase	New Total Benefits
Program A	$100,000	$20,000	20%	$120,000
Program B	$50,000	$4,569	9%	$54,569
Program C	$75,000	$6,853	9%	$81,854
Program D	$10,000	$5,000	50%	$15,001
Program E	$20,000	$1,828	9%	$21,828
TOTAL	**$255,000**	**$38,250**	**15%**	**$293,250**

Table 3 shows a case in which there are quantified NEBs for programs A and D that on their own increase portfolio benefits by 15% or more. As a result, remaining programs are not given a deemed NEB adder.

Table 3. Example: Quantified NEBs exceed 15% of pre-NEB portfolio benefits

Measure	Benefits	Non-Energy Benefits	% Increase	New Total Benefits
Program A	$100,000	$30,000	30%	$130,000
Program B	$50,000	-	-	$50,000
Program C	$75,000	-	-	$75,000
Program D	$10,000	$30,000	300%	$40,000
Program E	$20,000	-	-	$20,000
TOTAL	**$255,000**	**$60,000**	**24%**	**$315,000**

Attribution of Codes and Standards Savings

Across North America, some utilities are aligning their DSM programs with energy efficiency codes for buildings and standards for appliances and equipment, including established initiatives in California, the Pacific Northwest and Arizona, along with emerging initiatives in Ohio, Massachusetts and Rhode Island (Drexler 2012). In a conventional framework, codes and standards (C&S) shift efficiency baselines higher and erode utility DSM savings. In a market transformation framework, utility DSM supports the savings that arise through codes & standards. The California Energy Commission (CEC) evaluation highlighted three broad categories of DSM that support advancement of C&S (KEMA et.al. 2011):

- development of analytic techniques such as compliance verification tools
- development of technical, scientific, and economic information in support of the standard, and development of code language, and
- feasibility demonstration–addressing barriers such as product availability through education, training and incentive programs.

A key challenge for approval of costs for utility C&S support is the attribution of savings to DSM programs, or the share of savings that is credited to a utility for getting a new code adopted or improving compliance rates of existing codes. KEMA et.al. estimated the effect of utility programs on a variety of California codes & standards, and found attributable savings to be 59% and 45% for annual electricity and natural gas savings respectively (KEMA 2011, 27). Similarly, the Salt River Project in Arizona is allowed to claim up to 50 percent of savings from new building codes and appliance standards (Drexler 2012, 3).

In the new BC regulation savings can be claimed for programs that are run after a standard is announced or enacted, but before it comes into effect. The BCUC is tasked with approving the attribution rate. Attribution of savings from codes and standards is considered a part of the TRC rather than modified TRC (MTRC), since it is concerned with energy benefits rather than non-energy or societal benefits.

Eligible standards include BC and national equipment regulations, building energy codes, and municipal and First Nation laws pertaining to energy efficiency, including site designs. For example, in spring 2012, the Ministry of Energy and Mines announced four proposed regulatory standards for set-top boxes, general service fluorescent lighting, geoexchange heat pumps and natural gas boilers, with effective dates ranging from 2012 to 2014. The act of publishing the regulatory impact statement for those proposed regulations enabled utilities to launch support programs and attribute savings from standards.

This provision was surprisingly uncontroversial among stakeholders. No concerns were raised. However, to date no BC utility has made use of this provision in the determination of program-specific or portfolio-wide TRCs or MTRCs. On the other hand, BC Hydro currently counts 100% of C&S savings toward its overall energy efficiency target under the *Clean Energy Act*, but does not attribute those savings toward the costs of utility spending on DSM, approved by the BCUC.

General Concerns about Modifying the TRC

A number of general concerns arose during the consultation. First, some stakeholders felt that the proposed changes to the TRC would result in most proposed measures passing the test, thus removing the BCUC's primary evaluation tool. They argued that fear of failing the TRC encourages utilities to be fiscally disciplined in their program design. However, in the Ministry's view the TRC is not the best measure of fiscal discipline, since a high-cost program might be well managed yet fail the TRC, while a low-cost program may pass the TRC yet not be fiscally well managed. Since the utility regulator already has the legal power to reject programs even if they pass the TRC, no change was made.

Second, some stakeholders felt that changing the TRC would harm the BCUC's ability to evaluate DSM by using other jurisdictions' TRC values as a benchmark. The Ministry was skeptical of the value of benchmarking in practice, since every jurisdiction has dramatically different inputs to a TRC (energy prices, program costs, customer uptake). Nevertheless, the Ministry tried to address this concern by requiring reporting of both the TRC and the MTRC.

Third, the possibility was raised that the portfolio could be become dominated by emission reduction and non-energy benefits to participants, resulting in programs with little value to the utility. This concern was addressed by giving the BCUC the discretion to reject DSM (with some exceptions) on the basis of the utility cost test (UCT), even if the measure passed the modified TRC. The Ministry estimated that this would put a few programs at risk, but felt that utilities could effectively argue to keep them as long as they didn't dominate the portfolio.

Fourth, stakeholders were concerned that the ultimate impact of the TRC modifications was unknown. The Ministry calculated that the TRC changes, if applied without restraint, would result in a rate impact of 2% amortized over 10 years for gas, and a negligible rate impact on electricity rates. However, utilities could in future introduce currently unanticipated new programs that would pass the MTRC, and the rate impact of these was unknown. To address these concerns, the Ministry put a cap on the percentage of portfolio spending which could be on measures that pass the MTRC but fail the TRC. The cap was set at 33% for gas DSM and 10% for electricity DSM. These were expected to limit the rate impact to a maximum of 0.8% over ten years for gas, and 0.3% over ten years for electricity.

Lastly, stakeholders pointed to the potential for the regulation amendment to have unanticipated consequences, and suggested a one-year review. The Ministry noted that several years would need to pass for the full impact on regulatory proceedings and DSM portfolios to be evaluated, and agreed to a 3-year review of the regulation amendment.

Expected Impact

Although no electric utilities' regulatory proceedings have concluded since the regulation amendment, a decision has been made on gas DSM. In its 2012-2013 spending proposal FortisBC Energy Utilities (FEU) chose to simply adopt the 15% deemed NEB adder for all programs, rather than quantify NEBs. It also incorporated, as required, the new ZEEA, which among the Ministry's regulation changes had the largest impact on the cost-effectiveness test scores.

Table 4 below shows spending and cost-effectiveness for those proposed FEU programs that are significantly affected by the Ministry's changes to the test. These account for 56% of the proposed $64.5 million per year gas DSM portfolio.

Table 4. Proposed FEU Gas Programs Significantly Affected by TRC Changes

#	Program Name	Program Area	Avg Annual 2012-2013 budget ($000's)	TRC	MTRC*	UCT	PCT	RIM
	Accepted Programs							
#1	ENERGY STAR® Domestic Hot Water "DHW" Technologies	Residential	1,786	0.50	1.13	1.23	1.06	0.49
#2	ENERGY STAR® Washers and Other Measures for DHW Conservation	Residential	525	0.94	2.03	4.44	1.49	0.68
#3	Customer Engagement Tool for Conservation Behaviours	Residential	775	0.69	1.67	0.69		0.37
#4	New Construction – EGH 80 & Beyond and EE Appliances	Residential	945	0.45	1.01	1.89	0.92	0.52
#5	Energy Conservation Assistance Program (ECAP)	Low Income	4,450	0.38	**0.75**	0.28	1.61	0.21
#6	Continuous Optimization Program	Commercial	2,437	0.98	2.24	3.17	2.25	0.46
#7	Catalytic Radiant Burner Technology	Innovative Technology	183	0.79	1.78	1.36	1.71	0.52
#8	Furnace Scrap-It Program	Residential	10,000	0.59	0.95	0.82	0.70	0.47
	TOTAL		**21,100**					
	Rejected Programs							
#9	Solar Thermal	Residential/ Commercial	4,000	0.19	**0.42**	0.21	0.95	0.51
#10	Thermal Energy for Schools	Commercial	11,000	0.16	1.52	5.75	0.62	1.24
	TOTAL		**15,000**					

** Modified Total Resource Cost Test. See footnote 1 for other cost-effectiveness test acronyms*

The effect is most pronounced on the residential sector including the low-income residential sector. It should be noted that although the low-income program (#5 of Table 4) still does not pass the MTRC, FEU obtained approval as it offers significant benefit to an underserved customer population, and because the BCUC has allowed the FEU to take a "portfolio level" approach to cost-effectiveness analysis. Two programs (#9 and #10) were rejected on the basis of insufficient information and overlap with a parallel regulatory proceeding on alternative energy; one of these failed the MTRC while the other clearly passed. Even with these and other variations from FEU's proposal, approved spending on the programs shown in Table 4 will likely account for over 30% of portfolio spending.

The regulation changes are not expected to have an immediate impact on planned spending for either electric utility, although inclusion of NEBs will boost TRC scores. The regulation has had some unintended consequences on a FortisBC Inc. DSM application currently in process. An interpretation of the legal wording in the regulation has resulted in use of a *lower* avoided cost for parts of the portfolio (the Ministry is considering a clarification in the regulation as a result). A number of proposed measures did not pass either the TRC or the MTRC and so will continue to rely on the BCUC's acceptance of a portfolio-level approach in order to be approved.

The Ministry expects that over time the TRC changes will lead to more diversified portfolios that respond to longer term opportunities – weathering short-term energy commodity price fluctuations and other factors. Utilities are expected to align information and incentive DSM with proposed future codes and standards due to provisions allowing attribution of a portion of energy savings from regulation toward pre-regulatory programs. For example, it will facilitate a new energy-efficient home program to improve consumer awareness, acceptance by builders, and trades training—critical elements for a successful building code regulation.

Conclusion

The results of cost-effectiveness tests are the primary determinant of the type and quantity of DSM being carried out in most jurisdictions in North America, and it is important that these tests reflect policy priorities. By tweaking the TRC, the BC government hopes to achieve a positive outcome for its emission reduction and energy savings targets, while avoiding the trap of favoring specific utility programs.

In spite of a tight timeline for making changes to the TRC, the Ministry made an effort to meaningfully engage stakeholders throughout the process, and made substantive changes to both the concepts and the draft legal text in response to stakeholder concerns. Although the staunchest opponents to the TRC modifications remained opposed in spite of these changes, several stakeholder groups expressed that most of their concerns were addressed in the final version. Some of the resulting revisions, such as the portfolio expenditure impact cap, will ensure more predictable outcomes from the regulation.

Unfortunately, the complexity of the topic, and the revisions resulting from stakeholder input—such as the enhanced use of the UCT, and adoption of a hybrid approach to NEBs—have resulted in a very complex regulation. This complexity has increased the likelihood of interpretation errors and unintended consequences. This is already apparent in current regulatory proceedings, and it is likely that clarifying amendments will be required from time to time.

Overall, however, indications to date suggest success in achieving outcomes, particularly for natural gas DSM (which is where emission reduction opportunities are concentrated in BC). This process of modifying the TRC to help achieve specific objectives may be of some relevance to other jurisdictions with similar policy objectives and utility regulation challenges.

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