Section 5
BC Transmission Inquiry

Comments on Scenarios
to BCTC

by: ESVI, OEIA, ITO and ROMS BC

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Date: Aug 12, 2009
For: ESVI, OEIA, ITO and ROMS BC

On August 5, 2009, BCTC held a Scenario workshop for the Long Term Electricity Transmission Inquiry. Participants were given the opportunity to provide written comments by August 12, 2009 for BCTC's consideration in its September 18 filings.

The following document contains the written comments on behalf of Energy Solutions for Vancouver Island Society (ESVI), Okanagan Environmental Industry Alliance (OEIA), IslandTransformations.Org (ITO) and Rental Owners and Managers Society of BC (ROMS BC).

In order to reduce the size of the attachments, web-site links are provided for the larger documents – we would be pleased to send any document files that might be required, or a complete package of attachments if it is helpful.

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P.S. Please note our Errata on the next page noting a few section number corrections.

Errata (from Version .008)

Section 2.2.1: Should read: "*Beyond the suggestion for more DSM as noted in Section **2.1.3**. . .*"
Section 4: A few sections have been renumbered within this section.
Footnote 219: Should read: "*See Section **2.2.1***"
Footnote 228: Should read: "*See Section **2.2.1***"
Footnote 229: Should read: "*See Section **2.2.2***"

Summary

The following is a brief summary of the sections of our submission – for specific and full recommendations, please refer to the text within the document.

Section 1:

We suggest that the "*Non-Wires*" Initial Scenario proposed by BCTC should be renamed "*Integrated Non-Wires*" and should be defined as:

> Energy policy in BC focuses on encouraging integrated non-wire regional solutions (e.g. DSM, strategic IPP generation placement, conservation rates) and development of local and distributed generation to limit transmission development.

Section 2.1:

In response to restrictions placed on the use of the LTAP in the Transmission Inquiry, we suggest clarification. We also suggest higher levels of DSM in the "*Current Practice*" due to the LTAP Decision.

Section 2.2.1:

We suggest an Initial Scenario should include higher levels of DSM.

Section 2.2.2:

We suggest an Initial Scenario should include Electric Vehicles.

Section 3:

We suggest clarifications on building up the Scenarios, including the proposed definitions of the Drivers for Scenarios (e.g. economy, technology, policy decisions and environmental developments).

Section 4.1:

We suggest an Initial Scenario should accommodate a wider range of climate and climate-related events.

Section 4.2

We suggest an Initial Scenario should have more aggressive pricing approach for the future price of carbon.

Section 5

We suggest an Initial Scenario should incorporate Feed-In Tariffs and Distributed Generation.

Section 6

We suggest an Initial Scenario should include Solar technology.

Section 7

We suggest an Initial Scenario should include Ocean technology.

Section 8

We suggest a new Initial Scenario, “Expanded Integrated Non-Wires”. Each driver is discussed in detail: economy, technology, policy decisions, and environmental developments.

1.0 Non Wires Initial Scenario:

1.1 Non-Wires

1.1.1 "Non-Wires" in BCTC Scenario Workshop Presentation

The BCUC Scoping Document[1] describes a significant feature of scenarios:

> "*Agreement or Panel direction on a manageable number of demand scenarios, which are* ***meaningfully different*** *from each other, is vital to the Panel delivering useful determinations*"[2]. [***emphasis added***]

In the "*Development of Initial Scenarios*" section[3] of the BCTC Scenario workshop, seven potential scenarios were presented[4].

A "*current practice*" scenario (e.g. "business as usual") was presented as:

> "*The world looks similar in 2040 as it does today; no major changes in demand or resource availability*"[5]

Five other scenarios (#2 to #6) were presented using the adjectives: "*low*", "*high*", "*moderate*" or "*aggressive*"[6]. The seventh scenario, "*non-wires*", is presented without an adjective. The implication here seems to be that scenarios #2 to #6 point to the main attributes which are significantly different (lower, higher etc) from the "*current practice*", whereas the characteristics of scenario #7 are implied within the name "*non-wires*" and therefore implied to be significantly different than "*current practice*".

The "*non-wires*" scenario in the BCTC scenario workshop presentation by Dr. Ren Orans is described as:

> "*North America agrees to cut emissions by half relative to today; restrictions on the development of new, large power plants and transmission require a focus on development of local and distributed generation*"[7]

1.1.2 "Non-Wires" in the Electric Utility Industry

In 2001, the Bonneville Power Administration was faced with $775 million of transmission infrastructure improvements after having "*added virtually no circuit*

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[1] BCUC Order G-86-09, Appendix A, Attachment A, Page 3 of 7
[2] BCUC Order G-86-09, Appendix A, Attachment A, Page 3 of 7
[3] BCTC Scenario Workshop presentation, Aug 5, 2009, slides 20 to 27
[4] BCTC Scenario Workshop presentation, Aug 5, 2009, slide 22
[5] BCTC Scenario Workshop presentation, Aug 5, 2009, slide 23
[6] "***Low*** *economic growth*", "***High*** *economic growth*", "***High*** *renewable targets in USA*", "***Moderate*** *GHG reductions*", "***Aggressive*** *GHG reductions*"
[7] BCTC Scenario Workshop presentation, Aug 5, 2009, slide 24

miles in the transmission system since the late 1980's"[8]. "*Before proceeding with the construction of transmission projects, BPA wants to ensure that there is a clear and compelling demonstration of project need and that it is providing the most cost-effective solution to the region's transmission problems from an engineering, economic and environmental standpoint. As part of its evaluation, BPA must consider whether non-transmission options can be employed as viable alternatives to transmission expansion. Non-transmission solutions can include pricing strategies, demand reducing strategies, and strategic placement of generators.*"[9]

BPA recognizes that "*In many respects these nonwire activities have been outside the TBL's [Transmission Business Line] purview and TBL has had to be passive with respect to them*"[10].

In reviewing the existing Transmission Business Line (TBL) planning process[11], BPA recognized that "*it identifies transmission needs on a schedule that is too late for implementation of nonwires alternatives*"[12]. "*A longer term, system-wide planning process is needed as a supplement to the existing process*" [13].

As noted in an E3 report (authored in part by Dr. Ren Orans) it states that problems with traditional planning is that there is "*insufficient time to consider non-wires alternatives*"[14] and "*insufficient time to engage other stakeholders*"[15].

BPA suggests that a multiple screening process be implemented which includes "*non-wires solutions*"[16] which makes the process "*more proactive and expansive*"[17].

BPA noted categories of potential transmission and nonwire activities to include[18] transmission expansion, merchant transmission, wholesale and retail pricing, demand management (including energy efficiency programs and load shifting programs)), and strategically placed generation plants.

The process would add two new functions, a 10 year system-wide report and a two-part screening process[19], plus provide opportunities for stakeholder

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[8] Appendix A, BPA "Expansion of BPA Transmission Planning Capabilities", Page 1
[9] Appendix A, BPA "Expansion of BPA Transmission Planning Capabilities", Page 1
[10] Appendix A, BPA "Expansion of BPA Transmission Planning Capabilities", Page 1
[11] Appendix A, BPA "Expansion of BPA Transmission Planning Capabilities", Page 8, Figure 1
[12] Appendix A, BPA "Expansion of BPA Transmission Planning Capabilities", Page 8
[13] Appendix A, BPA "Expansion of BPA Transmission Planning Capabilities", Page 8
[14] Appendix B, E3 "Expansion of BPA Transmission Planning Capabilities", Page 4
[15] Appendix B, E3 "Expansion of BPA Transmission Planning Capabilities", Page 4
[16] Appendix A, BPA "Expansion of BPA Transmission Planning Capabilities", Page 11, Figure 2 and Appendix B, E3 "Expansion of BPA Transmission Planning Capabilities", Page 8
[17] Appendix A, BPA "Expansion of BPA Transmission Planning Capabilities", Page 7
[18] Appendix A, BPA "Expansion of BPA Transmission Planning Capabilities", Page 9
[19] Appendix A, BPA "*Expansion of BPA Transmission Planning Capabilities*", Page 7

involvement in the form of two workshops[20] well in advance of the project need.

The implementation of the new process would mean that "*every potential transmission project would appear on the market participants' radar screen at least ten years before the project need date*"[21].

"*BPA cites two past successful demand response projects that justify its current efforts at finding additional non-wires solutions. Traditional conservation measures lowered peak loads on Orcas Island for several years while an underwater cable was replaced. The Puget Reinforcement Project used conservation programs to help[~~ed~~] avoid voltage collapse in the Puget Sound area and delayed construction of additional transmission lines crossing the Cascade mountains for ten years.*"[22]

"*Subsequently, BPA formed a Non-Wires Solutions Round Table to obtain opinions from diverse set of stakeholders within the region*".[23] It was recommended that a expected load project on the Olympic Peninsula be taken through the non-wires screening process[24], including avoided cost analysis.

An example of benefit/cost ratios and assumptions for non-wire alternatives are shown in the Appendix 1[25], which was implemented in BC by the E3 group[26].

In the "*Worldwide Survey of Network-driven Demand-side Management Projects*"[27], the Olympic Peninsula project is listed as one of eight "*Integrated DSM Projects*", and the only one listed in North America. It is described as "*several pilot projects to determine whether it is possible to use non-wire solutions to defer a transmission line construction project*"[28].

In Vermont, "*prior to the adoption of any transmission system plan, a utility preparing a plan shall host at least two public meetings at which it shall present a draft of the plan and facilitate a public discussion to identify and evaluate*

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[20] Appendix A, BPA "*Expansion of BPA Transmission Planning Capabilities*", Page 4

[21] Appendix A, BPA "*Expansion of BPA Transmission Planning Capabilities*", Page 10

[22] www.ferc.gov/legal/staff-reports/demand-response.pdf, Federal Energy Regulatory Commission, "*Assessment of Demand Response & Advanced Metering*", August 2006, Page 106

[23] www.ferc.gov/legal/staff-reports/demand-response.pdf, Federal Energy Regulatory Commission, "*Assessment of Demand Response & Advanced Metering*", August 2006, Page 106 - 107

[24] Appendix A, BPA "*Expansion of BPA Transmission Planning Capabilities*", Pages 5, 17 to 23

[25] Appendix A, BPA "*Expansion of BPA Transmission Planning Capabilities*", Appendix 1

[26] Appendix A, BPA "*Expansion of BPA Transmission Planning Capabilities*", Page 10, Footnote 6

[27] www.google.com/search?q=Worldwide+Survey+of+Network-driven+Demand-side+Management+Projects&rls=com.microsoft:en-US:&ie=UTF-8&oe=UTF-8&sourceid=ie7&rlz=1I7ADBR, International Energy Agency "*Worldwide Survey of Network-driven Demand-side Management Projects*"

[28] www.google.com/search?q=Worldwide+Survey+of+Network-driven+Demand-side+Management+Projects&rls=com.microsoft:en-US:&ie=UTF-8&oe=UTF-8&sourceid=ie7&rlz=1I7ADBR, International Energy Agency "*Worldwide Survey of Network-driven Demand-side Management Projects*", Page 11 and Page 95 to 103

nontransmission alternatives."[29]

We suggest that the use of "*Non-Wires*" in this Inquiry is exemplified by the information referenced above.

1.1.3 Current "Non-Wires" Practice for BCTC

This section is intended to describe the current practice for BCTC regarding "*Non-Wires*".

In the F2006 to F2015 Transmission System Capital Plan, BCTC noted from the previous Capital Plan that "*the Commission Panel also noted that, 'DSM solutions to transmission issues may be in the public interest and the role of BC Hydro and BCTC regarding the DSM solutions to transmission issues remains an outstanding issue'. BCTC has considered this issue further as a result of the Commission's statement. BCTC has indicated that it is prepared to consider DSM opportunities as 'bridging' resources while longer-term solutions are being put in place. BCTC also contracts for 'non-wires' solutions as part of various Remedial Action Schemes. BCTC is in the process of reassessing its role in evaluating and contracting to avoid or delay 'wires' solutions in light of the Commission's comments.*"[30]

In the decision for the capital plan "*the Commission Panel therefore directs BCTC, if it has not already done so, to initiate discussions with customers (including BC Hydro) on potential customer-provided solutions to transmission constraints, and to report to the Commission on the outcome those discussion in its next capital plan. Without limiting the scope of the discussions, the Commission Panel expects BCTC will examine the following in conjunction with BC Hydro:*

- *options for general (i.e. system- or area-wide) demand reductions, to the extent they are not already covered by existing DSM initiatives such as PowerSmart;*
- *options for location- or area-specific demand reductions, either planned or in response to system events (e.g., by arming customer-specific remedial action schemes);*
- *demand reduction timing requirements (e.g. all hours, peak months or hours, or only when armed);*
- *mechanisms for compensating customers, such as reduced rates, direct payments through commercial contracts, or investment deferral credits;*
- *options for customer-supplied transmission services, such as reactive power or reliability must-run generation.*

[29] Appendix C, The Vermont Statues Online, Title 30, Public Service, Chapter 5, Section 281c, d(2), Page 2

[30] BCTC F2006 to F2015 Transmission System Capital Plan, March 23, 2005, Page 4

The Commission Panel further notes that, as the entity responsible for developing solutions to transmission constraints, BCTC is in the best position to identify the extent to which customer- or third-party-provided solutions could defer or eliminate the need for Growth Capital investments. Without pre-judging whether BCTC or BC Hydro (or both) should ultimately contract for non-wires solutions, the Commission Panel expects that BCTC will identify non-wires solutions in future studies and capital plan applications."[31]

BCTC reported on non-wires in its OATT Rate Design Report on December 20, 2006[32].

In the F2008-F2017 Capital Plan, BCTC reported that many of its substations and transformers that "*non-wires options which were deemed not feasible in the absence of new generation or IPP development prospects in the area*"[33].

In the F2009-F2018 Capital Plan, BCTC reported in relation to various projects: "*the magnitude of the likely achievable DSM effects would be insufficient to address the need*", "*this is a significant reduction in use and unlikely to be achieved from residential and commercial DSM programs*", "*there is insufficient time available to implement either a DSM project or to construct generation and meet the in-service date . . .*" and "*there isn't sufficient load . . . to implement an effective DSM project*"[34].

In the F2010/F2011 Capital Plan, added a new section, "*Projects with Non-Wires Solutions"*[35]. "*BCTC examines whether or not non-wires alternatives exist in the planning analysis that leads to the selection of preferred alternatives. None of the projects in this TSCP, for which BCTC is seeking approval to install or expand facilities, have practical non wires alternatives. Demand side management targets are already built in to the load forecast that drives these projects and there are no generation resources in the vicinity of the projects that could offset the growing load.*" [36]

"*As outlined in the F2009 TSCP, non wires alternatives such as the integration of generation interconnection in the . . . valley are being considered. BCTC is examining the dependable capacity of the run of river projects that exist and/or are being proposed, and the possibility of higher dependable capacity thermal*

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[31] BCUC BCTC F2006 to F2015 Transmission System Capital Plan Decision, Sep 23, 2005, Pages 19 to 20

[32] BCTC OATT Compliance Filing – Rate Design Report, Dec 20, 2006, Appendix B

[33] BCTC F2008 to F2017 Transmission System Capital Plan, Dec 21, 2006

[34] BCTC F2009 to F2018 Transmission System Capital Plan, Dec 21, 2007

[35] BCTC F2010/F2011 Transmission System Capital Plan, Nov 21, 2008, Page 5-124 to 5-125

[36] BCTC F2010/F2011 Transmission System Capital Plan, Nov 21, 2008, Page 5-124

generation projects in this region. To maintain the ability to supply the . . . area until a suitable solution can be put in place, BCTC and BC Hydro are engaged in discussions with a customer in the . . . area to explore load curtailment measures." [37]

"*. . . significant wind resources exist in the . . . area that may contribute to the solution for reinforcing this region. While some transmission reinforcement may be required to integrate this wind, the same reinforcements may be used to supply load, and some of the capacity from the wind generation may serve to offset some of the transmission capacity that would otherwise have been required to meet incremental load.*" [38]

A recent specific project can be used as an example to help understand how BCTC currently handles the "*Non-Wires*" approach. In the December 10, 2008 BCUC decision on the Central Vancouver Island Transmission Project a series of "*non-wire*" alternatives were discussed[39]: DSM, load generation, remedial action schemes, and curtailment.

BCTC notes that "*. . . any new generation project that may be announced would not likely be in service by October 2010, to meet the required ISD for the proposed solution to the capacity constraints in CVI . . .*" [40]

"*BCTC does not address curtailment in its Application. However, BCTC addressed the Customer Capacity Curtailment Contracts entered into by BC Hydro and certain of its customers . . .* "[41].

BCTC's approach for Non-Wires is being recognized in the utility industry – for example, a report from New Zealand lists BCTC as one four approaches world-wide: "*BCTC has recently (2006) undertaken to evaluate non-wires transmission alternatives where such alternatives have the potential to avoid or delay wires solutions.* "[42]

However, the report summarized the success, "*BCTC recently assessed opportunities for non-wire transmission alternatives – but failed to identify any.*" [43]

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[37] BCTC F2010/F2011 Transmission System Capital Plan, Nov 21, 2008, Page 5-124
[38] BCTC F2010/F2011 Transmission System Capital Plan, Nov 21, 2008, Page 5-125
[39] Appendix F, BCUC Decision of the Central Vancouver Island Transmission Project, Dec 10, 2008
[40] Appendix F, BCUC Decision of the Central Vancouver Island Transmission Project, Dec 10, 2008, Page 19
[41] Appendix F, BCUC Decision of the Central Vancouver Island Transmission Project, Dec 10, 2008, Page 20
[42] Appendix D, Transpower New Zealand, Selected pages of "*Grid Support Contracts*", Nov 2008, Page 16
[43] Appendix D, Transpower New Zealand, Selected Pages of "*Grid Support Contracts*", Nov 2008, Page 16

Although BCTC is using the "*Non-Wires*" approach, we suggest that the current practice of BCTC is of an early form, more of a "*passive*" approach – no detailed analysis are done, there is often not adequate notice to consider other approaches, and there are typically no formal meetings or workshops to draw out other solutions from stakeholders before application.

1.1.4 Our Assessment of "Non-Wires" for the Transmission Inquiry

We suggest that the title "*Non-Wires*" on its own for the scenario in the Transmission Inquiry is not satisfactory. As evidence in section 1.1.3, BCTC is already committed to and using a "*Non-Wires*" approach. As stated previously, one of the goals of the Transmission Inquiry is to ensure that the scenarios are "*meaningfully different*" from each other. A scenario of "*Non-Wire*s" would not be "*meaningfully different*" than the "*current practice*" and therefore would not be appropriate.

The fact that BCTC is already moving in this direction is helpful. As shown in section 1.1.3, from the introduction of the "*Non-Wires*" approach in the F2006 Capital Plan, BCTC has progressively endorsed and placed greater focus on this area.

However, for the Transmission Inquiry, to differentiate from the current practice and test further analysis through non-wire approaches, it is suggested that the scenario be renamed to "*Integrated Non-Wires*". It is suggest that this "*Integrated Non-Wires*" scenario move to the more advanced levels of the "*Non-Wires*" approach in the future than as with "business as usual" - for example, adding new concepts from the Olympia Peninsula project, and similar projects.

A presentation on the International Energy Agency DSM Program highlights "*a number of key areas in which changes could be made to enable increased use of demand-side resources as alternatives to network augmentation and to support electricity networks.*"[44]

- Forecasting future electricity demand[45]
- Communicating information about network constraints[46]
- Developing options for relieving network constraints[47]
- Establishing policy and regulatory regimes for network planning[48]

This scenario assumes that BC would endorse an integrated non-wire policy environment and would address the key areas as listed above, plus in "*Non-*

[44] Appendix E, International Energy Agency, IEA DSM Programme, Page 25
[45] Appendix E, International Energy Agency, IEA DSM Programme, Page 27
[46] Appendix E, International Energy Agency, IEA DSM Programme, Page 28
[47] Appendix E, International Energy Agency, IEA DSM Programme, Page 29
[48] Appendix E, International Energy Agency, IEA DSM Programme, Page 30

Wire" processes described in section 1.1.2. For example, it would be assumed that the recommended process as suggested for BPA[49] would be implemented - this includes a 10 year-ahead planning report, workshops, analysis and screening processes.

A key principle is to ensure the process is integrated between transmission, generation and demand. This allows non-wire solutions, such as DSM or strategic local renewable generation, to have a reasonable lead-time in order to be fairly considered and encouraged over potential transmission infrastructure enhancements.

This approach would also allow BCTC to support the DSM, conservation, energy efficiency goals in the 2007 Energy Plan at the same time ensuring that the overall lowest cost solutions are found for the overall BC electrical system – e.g. BC Hydro, Fortis BC and BCTC combined.

It is suggested the wording for this scenario[50] state:

Integrated Non-Wires

Energy policy in BC focuses on encouraging integrated non-wire regional solutions (e.g. DSM, strategic IPP generation placement, conservation rates) and development of local and distributed generation to limit transmission development as illustrated in ESVI et al's comment submission.

2.0 BC Hydro's 2008 LTAP, Demand & DSM:

2.1 BC Hydro's 2008 LTAP

2.1.1 Transmission Inquiry treatment of 2008 LTAP

The Terms of Reference of the Transmission Inquiry issued by the Government of BC notes that the Commission must have regard for "*the load-serving utilities' long-term resource plans filed under section 44.1 of the Act, including their most recently filed and relevant contingency resource plans as accepted by the Commission*"[51].

The Terms of Reference also note: "*In addition to any other evidence and submissions relevant to the inquiry that the load-serving utilities may wish to provide, if not adequately addressed in their most recently approved long-term*

[49] Appendix A, BPA "Expansion of BPA Transmission Planning Capabilities"
[50] BCTC Scenario Workshop presentation, Aug 5, 2009, Slide 24
[51] Government of BC, Terms of Reference, Dec 17, 2008, Page 3 of 7, section 7(a)

resource plans, the Commission must allow the load-serving utilities to provide evidence and submissions regarding their electrical energy and capacity requirements for the Determination Period . . ."[52].

In its Decision on Scope, the Panel Inquiry clarifies that "*BC Hydro's and FortisBC's long term resource plans, including their recently filed and relevant contingency resource plans as accepted by the Commission are in scope*"[53].

The Inquiry Panel in its Scoping Decision states: "*In addition, scenarios may need to be developed to reflect future outcomes that were not adequately addressed in the [2008] LTAP.*"[54]

In its Scoping Decision it is also stated in regards to items "*Not in Scope*": "*The Panel interprets the direction provided in the Terms of Reference with regard to the utilities' most recently approved long-term resource plans to mean that the Inquiry is not intended to be a forum for revisiting BC Hydro's June 2008 LTAP after the Commission LTAP Panel has issued its Decision on it. Thus the Panel does not consider that revisiting any load forecast or DSM forecast methodology that has been approved by the Commission in its forthcoming decision on BC Hydro's LTAP to be in scope.*"[55]

2.1.2 Outcome of BC Hydro's 2008 LTAP

On July 27, 2009, BCUC issued its decision on BC Hydro's 2008 LTAP[56].

One of the BCUC Directives states: "*The Commission Panel has concluded that BC Hydro has not met the statutory burden it acknowledged the Act requires. Accordingly, the Commission Panel finds that it is unable to determine the DSM Plan as proposed by BC Hydro complies with section 44.1 of the Act.*"[57]

Some of the Commission's Determinations in support of this Directive include:

> "*The Commission Panel does not accept BC Hydro's assertion that by meeting more than its load growth with DSM it would impose a cost on its ratepayers, since the portfolio analysis prepared by BC Hydro in Figure 5-14 of Exhibit B-1 only showed that this might happen in extremely remote circumstances.*"[58]
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> "*As noted in Section 1.2 of this Decision, BC Hydro provided its interpretation of*

[52] Government of BC, Terms of Reference, Dec 17, 2008, Page 6 of 7, section 8(a)
[53] Exhibit A-18, Appendix A, Attachment A, Page 3 of 7
[54] Exhibit A-18, Appendix A, Attachment A, Page 3 of 7
[55] Exhibit A-18, Appendix A, Attachment A, Page 4 of 7
[56] BCUC Decision on BC Hydro's 2008 LTAP, July 27, 2008
[57] BCUC Decision on BC Hydro's 2008 LTAP, July 27, 2008, Page 181, Directive 12
[58] BCUC Decision on BC Hydro's 2008 LTAP, July 27, 2008, Page 84

the relevant framework as" 'Pursuant to subsection 44.1(2)(b), [BC Hydro] must pursue all cost-effective DSM prior to pursuing any supply-side options, [and] pursuant to subsection 44.1(2)(f), BC Hydro must prove why it cannot fill its entire load/resource gap with DSM only.'"[59]

Another BCUC Directives states: "*Inasmuch as BC Hydro has effectively chosen to truncate its DSM programs in F2020 by letting the impact of those programs progressively decay, the Commission Panel find that BC Hydro's DSM Plan is deficient.*"[60]

In support of this Directive, BCUC states "*The Commission Panel agrees with CEC and ESVI that BC Hydro's 20-year plan does not reflect the fact that there will be more cost-effective DSM available than is planned for in Adjusted Option A.*"[61]

Another BCUC Directives states: "*The Commission Panel believes that parts of the LTAP it has rejected represent a level of individual and collective materiality that removes the underpinnings of the entire 2008 LTAP. Accordingly the Commission Panel finds that BC Hydro's LTAP is not in the public interest and rejects it.*"[62]

In support of this Directive, BCUC states "*Among other things, the Commission Panel has rejected or found deficient the following parts of the 2008 LTAP: . . . DSM Plan – BC Hydro allowed its programs to progressively decay over the relevant period . . .'*[63]

2.1.3 Our Assessment of 2008 LTAP DSM for the Transmission Inquiry

Given the uncertainty around whether to use BC Hydro's rejected 2008 LTAP or accepted 2006 IEP/LTAP for the Transmission Inquiry, we suggest that it is more appropriate to use the 2008 LTAP with appropriate compensation, as the 2008 LTAP reflects the understanding of the 2007 BC Energy Plan and the 2006 IEP/LTAP does not reflect the 2007 BC Energy Plan.

We suggest that because the DSM plan of BC Hydro's LTAP was found "*deficient*" and does not comply with the Act, plus that the decay of the DSM plan was noted as a reason for rejecting of the entire LTAP, that the calculations for the BC Hydro domestic electricity demand should be lowered to compensate for the increased DSM before incorporating it into the Transmission Inquiry and before extending the

[59] BCUC Decision on BC Hydro's 2008 LTAP, July 27, 2008, Page 85
[60] BCUC Decision on BC Hydro's 2008 LTAP, July 27, 2008, Page 181, Directive 13
[61] BCUC Decision on BC Hydro's 2008 LTAP, July 27, 2008, Page 86
[62] BCUC Decision on BC Hydro's 2008 LTAP, July 27, 2008, Page 182, Directive 22
[63] BCUC Decision on BC Hydro's 2008 LTAP, July 27, 2008, Page 131

study period[64]. It is suggested that the calculations and assumptions be clearly shown.

As noted above, the Panel discussed items not in scope: "*the Inquiry is not intended to be a forum for* ***revisiting*** *BC Hydro's June 2008 LTAP after the Commission LTAP Panel has issued its Decision on it.*"[65] [***emphasis added***] This statement revolves around the meaning of the word "*revisit*". We suggest that the appropriate use of the word "*revisit*" is contained in the YourDictionary.com, whose definition is: "*to reconsider or reevaluate*"[66]

We suggest that these restrictions of using the LTAP in Transmission Inquiry were developed to cover the case where the intent is to reconsider decisions made in the LTAP, in order to attempt to change such decisions. We suggest that these restrictions were not developed to cover other purposes of using the LTAP, including looking at the LTAP (and its Decision) in order to understand what the ramifications might be nor how the Decisions of the LTAP might affect the market.

2.2 Further Comments about Demand & DSM

2.2.1 Higher levels of DSM

Beyond the suggestion for more DSM as noted in Section 2.1.3 above[67] for the "*current practice*" "correction", we suggest that it would be appropriate to have an Initial Scenario that includes significantly more DSM than the "*current practice*" using techniques (if they are not already considered in the "current practices") such as rates linked to energy efficiency of homes and lower greenhouse house emissions, other advanced conservation (e.g. dividend) rates, advanced communicating appliances, smart meters, advanced demand responses including critical peak pricing, time of use rates, community distributed generation, load shedding, curtailment, rental/landlord DSM etc.

It is suggested the following documents be reviewed for potential new DSM techniques and appropriate methods and suggest it be included in this Initial Scenario: BC Hydro's latest BC Hydro's Conservation Potential Review, the Vancouver Island study by Rocky Mountain Institute[68], and notes/minutes from BC Hydro's Rates Working Group, notes/minutes from BC Hydro's Energy Conservation & Efficiency Advisory Committee and notes/minutes from

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[64] "*Because the Inquiry study period is longer than the LTAP period, the LTAP forecasts will need to be extended.*": Exhibit A-18, Appendix A, Attachment A, Page 3 of 7

[65] Exhibit A-18, Appendix A, Attachment A, Page 4 of 7

[66] www.yourdictionary.com/revisit

[67] that "*the BC Hydro domestic electricity demand should be lowered to compensate for the increased DSM before incorporating into the Transmission Inquiry and before extending the study period*"

[68] Appendix R, Rocky Mountain Institute, "*Exploring Vancouver Island's Energy Future – A Workshop by BC Hydro & Rocky Mountain Institute*", Sept 29, 2003,

FortisBC's DSM Advisory Committee.

2.2.2 Electric Vehicles

Electric vehicles treatment in the Transmission Inquiry

The BCUC scoping document states: "*The Independent Power Producers Association of British Columbia (" IPPBC") submitted that the following matters should be within scope: . . . technologies that can be used to store electricity such as batteries in hybrid electric vehicles. . .* ***The Panel agrees that all of these issues are in scope.***"[69]

> "*CPC also encouraged the Panel to look at how broad deployment of electric plug-in vehicles within the study period would affect transmission requirements and operations.* ***This is a scenario that has been suggested by several participants and the Panel considers such a scenario to be within the scope of the Inquiry.***"[70]
>
> "*The Panel considers the following issues to be in scope and consistent with the Terms of Reference. . . . Investigation of whether or not electricity storage options such as batteries in hybrid electric vehicles . . . are available as a means of meeting capacity requirements and whether it is cost competitive with other alternatives;*"[71]
>
> In scope topics for Assessment of Domestic Electric Demand include: "*New technologies such as electric vehicles . . . may increase demand . . .*"[72]

Recent electric vehicles activity

An August 11, 2009 news release from GM states adds to volume of evidence in considering electric vehicles for the Initial Scenarios in the Transmission Inquiry:

> "*The Chevrolet Volt extended-range electric vehicle is expected to achieve city fuel economy of at least 230 miles per gallon, based on development testing using a draft EPA federal fuel economy methodology for labeling for plug-in electric vehicles.*
>
> *The Volt, which is scheduled to start production in late 2010 as a 2011*

[69] Exhibit A-18, Appendix A, Page 5 of 13
[70] Exhibit A-18, Appendix A, Page 7 of 13
[71] Exhibit A-18, Appendix A, Attachment A, Page 1 & 2 of 7
[72] Exhibit A-18, Appendix A, Attachment A, Page 4 of 7

model, is expected to travel up to 40 miles on electricity from a single battery charge . . .

The Chevrolet Volt uses grid electricity as its primary source of energy to propel the car."[73]

Discussion of Electric Vehicles

We suggest that the fact that electric vehicles are now being scheduled by America manufacturers for mass production in 2010 shows a clear need for the electrical infrastructure to accommodate the demand and the storage capability of electric vehicles.

Therefore, we suggest that there is sufficient evidence that it is reasonable and plausible to anticipate that Electric Vehicle technology will need to be accommodated by the BC system. It is anticipated that handling electric vehicles will require smart meter and smart grid technology.

Further, we suggest that this situation is one which will further enhance the Transmission Inquiry to "*represent a range of possible futures*"[74]. Therefore, we suggest that at least one of the Initial Scenarios should include Electric Vehicle Technology.

3 Scenario Development:

3.1 Definition of Scenarios for Domestic Electricity Demand in the Transmission Inquiry

In clarifying "*scenarios*" for Provincial Generation Potential, the Inquiry Panel notes: "*BCTC highlighted the difference between scenarios and forecasts, describing a scenario as a construct that will '. . . provide a broad view of the future that may be influenced by a variety of factors (both controllable and non-controllable) including the economy, technology, policy decisions and environmental developments. A particular scenario would not necessarily represent the most likely case, but rather a set of scenarios would represent a range of possible futures. In this context a forecast would describe the load or generation associated with a particular scenario.*"[75]

In clarifying "scenarios" for Assessment of Domestic Electricity Demand, the Inquiry Panel notes: "*BCTC provided a description of scenarios which has been*

[73] Appendix Q, General Motors, "*Chevrolet Volt Expects 230 mpg in City Driving*", August 11, 2009
[74] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7
[75] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7

quoted above in the context of assessment of generation. The same description of a scenario could be applied to future demand."[76]

"*The Panel concurs with the comments in the Staff Paper that a limited number of scenarios be used to group factors that influence demand in order to produce a viable number of options.*"[77]

3.2 Treatment of Scenarios for Domestic Electricity Demand in the Scenario Workshop

On August 5, 2009, BCTC presented a number of slides regarding Scenario Development[78].

Kip Morison presented an overview slide which listed inputs of "*Drivers*" and outputs for each Scenario "*Provincial Potential*", "*Generation Resources*", "*Provincial Load Growth*" and "*Trade*"[79].

Dr. Ren Orans presented a number of slides on the "*Development of Initial Scenarios*"[80].

To identify potential futures, one slide presented in a prescribed order the following[81]:

Range of Potential Futures
Range of Drivers
Range of Outcomes

Seven initial scenarios were presented[82], their descriptions provided[83] and Key Drivers listed[84]. For demand scenarios, three drivers were listed[85]:

Economic growth and regional expansion
Energy efficiency
Electrification: conversion of gas and fossil fuels to electricity

[76] Exhibit A-18, Appendix A, Attachment A, Page 4 of 7
[77] Exhibit A-18, Appendix A, Attachment A, Page 4 of 7
[78] BCTC Scenario Workshop presentation, Aug 5, 2009, Slides 13 to 27
[79] BCTC Scenario Workshop presentation, Aug 5, 2009, Slides 14
[80] BCTC Scenario Workshop presentation, Aug 5, 2009, Slides 20 to 27
[81] BCTC Scenario Workshop presentation, Aug 5, 2009, Slide 21
[82] BCTC Scenario Workshop presentation, Aug 5, 2009, Slide 22
[83] BCTC Scenario Workshop presentation, Aug 5, 2009, Slide 23 & 24
[84] BCTC Scenario Workshop presentation, Aug 5, 2009, Slide 25
[85] BCTC Scenario Workshop presentation, Aug 5, 2009, Slide 25

On the workshop slide labeled "*Build Scenarios: Demand Range*"[86] four rows were included in a table:

Economic Growth
GHG Target
Energy Efficiency
Electrification

3.3 Our Assessment of Scenarios for Domestic Electricity Demand

3.3.1 Assumptions of workshop presentation

We feel that some clarification surrounding these slides would be useful.

First, we assumed that the outputs for each Scenario of "*Provincial Potential*", "*Generation Resources*", "*Provincial Load Growth*" and "*Trade*"[87] in the Overview Scenario slide are examples of specific forecasts as discussed in the Scoping decision[88].

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We also assumed that the discussions in the Initial Scenario slides[89] revolved around the Drivers[90] and the definition of "*scenarios*" but not intended to address those forecasts[91].

Although not labeled, we assumed that the "*Build Scenarios: Demand Range*" slide[92] listed are intended to be the "Drivers".

[86] BCTC Scenario Workshop presentation, Aug 5, 2009, Slide 26
[87] BCTC Scenario Workshop presentation, Aug 5, 2009, Slides 14
[88] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7
[89] BCTC Scenario Workshop presentation, Aug 5, 2009, Slides 20 to 27
[90] Drivers, as in slide #14
[91] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7
[92] BCTC Scenario Workshop presentation, Aug 5, 2009, Slide 26

3.3.2 Discussion of Drivers for Demand Scenarios

We note that the Demand "Drivers" presented in the workshop slides did not align with the list provided in the Scoping document:

Scoping Document Demand Drivers	Initial Scenario Slides Demand Drivers
- Economy	- Economic growth and regional expansion
- Technology	- Electrification: conversion of gas and fossil fuels to electricity
- Policy decisions	
- Environmental developments	- Energy Efficiency - GHG (added in table, not in "Key Drivers" slide)

While understanding the need for brevity in a presentation and the challenges it entails, it is not clear of the reasons or intentions for the differences between the Scoping Document and the Initial Scenarios. It is suggested that the next Scenario document clearly establish the link between the Scoping Document Drivers and those used within the Initial Scenarios.

This opens up a myriad of questions: Was it decided that only the most important aspects of the drivers be those listed in the Initial Scenarios? Is it not as important to consider "Policy decisions"? What about other aspects of technology besides "Electrification"? Has all Scoping Document Demand Drivers been considered in the establishment of the Initial Scenarios? Why weren't the Scoping Document Demand Drivers used in the Initial Scenarios? What is lost or gained by changing the list?

It is also suggested that a full description (including assumptions) be included for each Demand Driver – e.g. what is meant by each driver. It is suggested, where appropriate, that a time line of changes within the drivers be discussed as well. We also suggest that a glossary and definition of terms be added, and that this would be a good place to put the driver descriptions.

Here is a starting point for the Driver descriptions (and assumed for use within this document):

Economy: the overall North American economic situation. Unless otherwise stated, it is assumed that the BC economic situation will be in concert with the rest of North America. The economic situation could have normal, higher growth, slowdown, or remain steady. Any abnormality of important segments of the market growing faster or slower than the overall market is

to be noted.

Technology: how technology is used to deal with demand side solutions. The demand side technology is described in both the scale of introduction (how wide spread), and the maturity of the technology (including cost). It is assumed that technology throughout North America, including BC, is roughly at the same level, unless specifically noted.

Policy Decisions: policies which relate to and affect the electrical energy industry. These policies could come in the form of energy plans, provincial laws and acts/statues, regulatory directives & decisions, and similar mechanisms which point the direction of the utilities. It is assumed that each jurisdiction will have its own set of policies, progress at its own timing, and could very well vary between jurisdictions. Therefore, it is important to distinguish whether the policies being discussed are BC policies or from other jurisdictions. As noted in the "Environmental Developments" section below, it is recommended that policies that are driven primarily from an "environmental" point of view, be only discussed within that "Environmental Developments" section.

Environmental Developments: developments addressing a range of issues relating to the environment, energy efficiency, climate change, and pollution. These developments include the energy plans, provincial laws and acts/statues, regulatory directives & decisions, and similar mechanisms relating to these "range of issues", plus the general public's reactions to these "range of issues" which may not be directly due to policies, but instead due to their interest in helping to solve the issues. For consistency, it is recommended that all Environmental Developments, whether policy or not, be discussed within this section. Because of the importance of the 2007 BC Energy Plan and general focus on the environment, we suggest that even though there is some overlap, that the "Environmental Developments" remain as a separate Driver.

We also found the distinction of "*futures*", "*drivers*" and "*outcomes*" blurred and not clear.

We suggest there should be a table which includes at least the four noted Scoping Document Demand Drivers (and the list should be labeled as "Drivers")[93]:

Economy
Technology
Policy decisions
Environmental developments

[93] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7

We understand that the list may expand, but we suggest it should contain at least those Drivers noted above.

By including such a table, it helps ensure that the intentions of the Scoping Document are carried through (e.g. considering all factors), clarifies the connection between the Scoping Document and Initial Scenarios and clarifies the terminology of "*Drivers*".

A more specific table (such as in slide #26[94]) could also be included, but if so, it is suggested that it include a clear description of the particular assumptions or considerations taken into account.

While the one sentence descriptions of the Initial Scenarios already used in the Workshop Presentation are useful[95], we suggest that it is also important that a more rigid and structured definition of the Initial Scenarios be also included. We suggest each Scenario should include a clear and detailed definition of at least each of the Scoping Document Drivers noted[96] (economy, technology, policy decisions and environmental developments). All Scenarios other than "Current Practice" should include how they differ (or not) from the "Current Practice" considering that particular Driver. Refer to Section 8 of this document as an example of how we suggest describing a particular Scenario.

The Inquiry Panel suggests that: "*the same description of a [provincial generation] scenario* ***could*** *be applied to future demand.*"[97] [***emphasis added]*** We note that it is not automatic that the demand and generation scenarios would be the same, however, we suggest that the scenarios be the same, as it is less confusing in describing situations in which both generation and demand are to be considered, and is easier for an Integrated approach to be developed.

We have similar suggestions for the Drivers of the Generation Scenarios than we have for the Drivers of Demand Scenarios.

4 Climate Change:

4.1 Climate Change Impacts

[94] BCTC Scenario Workshop presentation, Aug 5, 2009, Slide 16
[95] BCTC Scenario Workshop presentation, Aug 5, 2009, Slide 23 & 24
[96] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7
[97] Exhibit A-18, Appendix A, Attachment A, Page 4 of 7

Climate Change Impacts refers to the efforts to respond to the impacts of climate changes, rather than providing methods to mitigate climate change.

4.1.1 Climate Change Impacts addressed in the Scoping Document

The Inquiry Panel Scoping document discusses the climate change impacts that are considered in scope: "*The Ocean Renewable Energy Group . . . notes that climate change impact mitigation was not addressed in the Staff Paper. The BC Sustainable Energy Association et al ("BCSEA") and Energy Solutions for Vancouver Island et al ("ESVI") made similar requests. The Panel . . . accepts that climate change impacts may be considered as alternative scenarios or sensitivity tests around future forecasts of hydro generation associated with both reduced inflows and higher demand for low-carbon electricity.*"[98]

4.1.2 Studies on Climate Change Impacts

4.1.2.1 California Climate Change Impact Study

Dealing with the impacts of climate changes (versus trying to mitigate its effect) is a new strategy which is gaining credibility. On August 3, 2009, the state of California "*released a comprehensive plan to guide adaptation to climate change, becoming the first [US] state to develop such a strategy*"[99].

> "*As the climate changes, so must California.*"[100]
>
> "*Adaptation is a relatively new concept in California policy. The term generally refers to efforts to respond to the impacts of climate change – adjustments in natural or human systems to actual or expected climate changes to minimize harm or take advantage of beneficial opportunities.*"[101]
>
> "*Finally, California's hydroelectricity production relies on predictable water reserves. In 2007, nearly 12 percent of California's electricity was produced from large hydroelectric power plants, presently the state's largest source of renewable energy. With snow falling at higher elevations, creating less snowpack, and melting earlier in the year less water is available for this source of power generation when it is needed, during the warmer summer months. When several dry years create drought conditions, reservoir levels can be reduced to levels lower than*

[98] Exhibit A-18, Appendix A, Page 3 of 13
[99] Appendix G, California Resources Agency, Climate Change Strategy Released, Aug 3, 2009
[100] Appendix H, California Resources Agency, "*2009 California Climate Adaptation Strategy Executive Summary*", Aug 3, 2009, Page 5
[101] Appendix H, California Resources Agency, "*2009 California Climate Adaptation Strategy Executive Summary*", Aug 3, 2009, Page 5

those required for hydroelectric power generation."[102]

"*Potential reductions on precipitation levels could significantly reduce hydropower production which currently accounts for up to 20 percent of the state's electricity supply.*"[103]

"*Fluctuations, and possible total reductions, in California's precipitation patterns will impact several key energy and transportation infrastructure components; primarily hydropower production . . .*"[104]

It is recognized that the climate change impacts have large regional variations, and that the effect on BC may vary significantly from California, but it was felt the California report is relevant to the BC Transmission Inquiry, as there are few if any other reports containing the detail of the California report. Also, the very recent release (August 3, 2009) provides up-to-date information and the discussions on Hydropower is very relevant to BC.

4.1.2.2 British Columbia Climate Change Impact Study

A relevant study for Canada was produced by Natural Resources Canada and involved dozens of experts: *"From Impacts to Adaptation: Canada in a Changing Climate 2007 reflects the advances made in understanding Canada's vulnerability to climate change during the past decade."*[105]

One of the chapters deal specifically with British Columbia[106]. The conclusion contains a discussion of key messages and themes:

"***Climate change impacts and the costs of extreme events are increasingly evident but responses and adaptation measures remain reactive.***"[107]

"*Most of BC's alpine glaciers are retreating rapidly and many may*

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[102] www.energy.ca.gov/2009publications/CNRA-1000-2009-027/CNRA-1000-2009-027-D.PDF, California Resources Agency, "*2009 California Climate Adaptation Strategy Executive Summary*", Aug 3, 2009, Page 81

[103] www.energy.ca.gov/2009publications/CNRA-1000-2009-027/CNRA-1000-2009-027-D.PDF, California Resources Agency, "*2009 California Climate Adaptation Strategy Executive Summary*", Aug 3, 2009, Page 119

[104] www.energy.ca.gov/2009publications/CNRA-1000-2009-027/CNRA-1000-2009-027-D.PDF, California Resources Agency, "*2009 California Climate Adaptation Strategy Executive Summary*", Aug 3, 2009, Page 122

[105] Appendix I, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Summary from Website

[106] http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia

[107] http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia, Page 373

disappear in the next 100 years (see Box 1). Coupled with reduced snowpack and warmer spring temperatures, this will result in earlier spring freshets, warmer river temperatures, declining summer river flows and increasing peak flows for many of BC's watersheds (Section 2.4). Impacts on current and future water supplies, hydroelectric power generation, fisheries and river ecosystem integrity are significant concerns for BC."[108]

"***Management of increasingly frequent and severe water shortages will entail complex trade-offs and require improved consideration of climate change.*** "[109]

"*British Columbia's hydroelectric power generation capacity is currently vulnerable to declining water supply and changing river flow patterns, most notably in the Columbia River basin, where more than half of the province's hydroelectricity originates.*"[110]

"*The connection between climate change and water will be an increasingly important consideration in planning to meet many of the key energy production and mitigation strategies outlined in the plan.*"[111]

"***British Columbia's critical infrastructure faces immediate challenges and long-term threats from climate variability and change.***"[112]

"*Extreme weather and associated natural hazards currently present challenges to British Columbia's critical infrastructure, and these impacts are projected to increase as a result of continued climate change. In many places, critical infrastructure, including pipelines, power and telecommunication transmission lines, and transportation networks, are geographically confined to narrow valleys and coastal stretches, and therefore vulnerable to disruption from natural hazards, such as landslides, coastal storms and surges, flooding and forest fires. Research on the impacts of climate change on BC's critical infrastructure systems remains limited, while insurance and costs for*

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108 http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia, Page 373

109 http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia, Page 374

110 http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia, Page 374

111 http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia, Page 374

112 http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia, Page 374

emergency response and recovery are rising (Section 3.8)."[113]

"*Life-cycle cost analysis, return period statistics for extreme events and engineering standards all influence management decisions on how or when to maintain or replace infrastructure. Updating these analyses, statistics and design standards so that they consider climate change impacts and trends will enable managers to better plan for future changes. Institutional constraints remain, however, as many standards and policies that guide infrastructure decisions rely only on past climate statistics.*"[114]

"***Integrating climate change adaptation into decision-making is an opportunity to reduce long-term costs and impacts on British Columbia's communities and economy.***"[115]

A statement with the "Energy" section of the report summarizes: "*In British Columbia, where 89% of the province's electricity is hydro generated (BC Hydro, 2006), the energy sector is highly sensitive to the impacts of climate change on water resources . . .*"[116]

One of the key findings of the report: "*Small hydro and 'run of river' alternatives can increase capacity but are more vulnerable to variable river flows than are facilities with large storage reservoirs. Alternative 'clean' sources of energy, such as wind power, will help meet increasing energy demands in the future, but are currently only a small contributor to BC's power supply.*"[117]

4.1.2.3 Assessment of Climate Change Impacts

Analyzing the impacts of climate change highlights the vulnerability of BC having such a high concentration of one type of power generation – based on hydro.

We suggest that there is sufficient evidence that it is reasonable and

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[113] http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia, Page 374 & 375

[114] http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia, Page 375

[115] http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia, Page 376

[116] http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia, Page 352

[117] http://adaptation.nrcan.gc.ca/assess/2007/bcb/index_e.php, Natural Resources Canada, "*From Impacts to Adaptation: Canada in a Changing Climate 2007*" Chapter 8, British Columbia, Page 352

plausible to anticipate that BC may in the future recognize that the BC electrical infrastructure needs to be made more reliable in accommodating a wider range of climate and climate-related events. BC would realize a need to diversify the generation mix, and reduce the reliance on hydro. Consequently, BC would provide policies to support regional and local distributed generation, and where larger generation systems are needed, such systems as ocean power or solar farms that do not rely on hydro.

Further, we suggest that this situation is one which will further enhance the Transmission Inquiry to "*represent a range of possible futures*"[118]. Therefore, we suggest that at least one of the Initial Scenarios should include the accommodation of Climate Change Impacts as described within this section[119].

4.2 Future price of carbon

4.2.1 Several future price predictions of carbon

The future price of carbon is a complex subject, and could occupy volumes on its own. It is an important subject, as it affects the costs and therefore the types of generation in the future, but time does not permit a comprehensive study.

In order to get a snapshot and a view of the subject, we have compiled a number of carbon pricing studies together[120].

Referencing the pages on the lower right hand side of the package . . .

Appendix J, Page 1: BC's Carbon Tax

Appendix J, Page 2: Various carbon pricing scenarios presented by BC Hydro in the 2008 LTAP up to 2030

Appendix J, Page 3: Table showing BC Hydro's pricing scenario in the 2008 LTAP out to 2050

Appendix J, Page 4: Table showing US pricing as presented by BC Hydro in the 2008 LTAP

Appendix J, Page 5, 6: Table showing most likely scenarios by BC Hydro in the 2008 LTAP

[118] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7
[119] Section 4.1 and subsections of this document
[120] Appendix J, compilation of various carbon pricing predictions

Appendix J, Page 7: Evidence provided by Dr. Mark Jaccard for IPPBC in the 2008 LTAP

Appendix J, Page 8, 9, 10: Charts developed by National Round Table on the Environment and the Economy

Appendix J, Page 11: David Suzuki report

It should be cautioned that the full content of each table or chart needs to be taken into account, but the compilation does present a viewpoint on the subject.

4.2.2 Discussion on future price predictions of carbon

Essentially, the graph on Page 2 of the carbon pricing Appendix J[121] shows the "*Current Practice*" for BC, as these are the pricing scenarios that BC Hydro has considered for the 2008 LTAP.

We suggest that there is sufficient evidence that it is reasonable and plausible to anticipate that BC may in the future move towards policies supporting and encouraging a more aggressive pricing approach for the future price of carbon as demonstrated in Pages 7 to 11 of Appendix J[122].

Further, we suggest that this situation is one which will further enhance the Transmission Inquiry to "*represent a range of possible futures*"[123]. Therefore, we suggest that at least one of the Initial Scenarios should deal with more aggressive pricing for the future price of carbon.

5 <u>Feed-In Tariffs and Distributed Generation:</u>

5.1 Status of Feed-In Tariffs & Distributed Generation in BC

The 2007 BC Energy Plan clearly includes small distributed generation as an appropriate technique to help achieve its 50% conservation target.

<u>Policy #1:</u>

"***Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.***"[124]

[121] Appendix J, Page 2
[122] Appendix J, Pages 7 to 11
[123] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7
[124] 2007 BC Energy Plan, Policy #1

"*This may include energy efficiency, conservation, and other demand reduction measures like load displacement, fuel switching (e.g. solar hot water heating) and* ***small distributed generation*** *(e.g. net metering.)"*[125] *[**emphasis added**]*

While energy efficiency and conservation have support funding for incentives in the utilities plans, a July 30, 2009 BCUC Decision for the FortisBC Net Metering application addresses why small distributed generation does not have such incentives for the utilities:

"*The Commission Panel is not persuaded by the Alliance arguments that the payback period should be lessened by incentive pricing. The Province has yet to give direction to the Commission requiring net metering programs to contain incentive pricing. Consistent with the recent Commission decision on the BC Hydro net metering program, an incentive price component is not required as a condition of approval at this time:*

The Province has not yet issued a directive to the Commission with respect to incentive pricing and the specific role of the Net Metering program in achieving conservation objectives. Until the time that such a directive is issued, the Commission cannot presume the details of potential Government policy. The Commission is therefore not persuaded that it should order BC Hydro to include an incentive component into the Net Metering price at this time. (Commission Order G-4-09)"[126]

In the Transmission Inquiry Scoping Document the following points were made in regards to Feed-In Tariffs and Distributed Generation:

"*CPC submitted that distributed generation will play an important role in BC's electricity system, and encouraged the Panel to consider the impact of distributed generation over the 30-year study period and to make recommendations for appropriate development and implementation. ESVI also suggested that 'Feed-in Tariffs' and distributed generation should be within scope for the inquiry.*

The Panel considers the potential impact of distributed generation on the transmission system to be within scope, but recommendations for development and implementation of specific generation to be out of scope. Moreover, the Panel accepts that the potential impact of Feed-In Tariffs is within scope, but if and how the impact of Feed-In Tariffs are incorporated into the analysis depends on the availability of evidence on the issue. The acceptance of the potential impact of Feed-In Tariffs as an in scope issue the

[125] 2007 BC Energy Plan, Policy #1

[126] Appendix K, BCUC Decision on FortisBC Net Metering, July 30, 2009, Appendix A, Page 4 of 6

Inquiry should not be taken as a signal that the Panel will ask BC Hydro or FortisBC to undertake a price elasticity or other new study to provide a detailed estimate of the distributed generation that might be provided at various price levels."[127]

A workshop run by BC Hydro and Rocky Mountain Institute discussed a number of potential solutions relating to Distributed Generation for Vancouver Island[128].

5.2 Studies and Reports on the Status of Feed-In Tariffs & Distributed Generation world-wide

In order to properly assess whether or not to include Feed-In Tariffs or Distributed Generation should be included into the Initial Scenarios, we felt it appropriate to include some evidence (a snapshot) highlighting the implementation throughout the world. This is particularly true of these topics, since there is very little evidence throughout the BCUC filings to determine whether or not it is appropriate for consideration in the Initial Scenarios.

The report, "*PV Status Report 2008 - Research, Solar Cell Production and Market Implementation of Photovoltaics*"[129], written for the Joint Research Centre of the European Commission, provides a table of Feed-In Tariffs and other support mechanisms in Europe[130].

"*Distributed generation of renewables can help to reduce investment in transmission costs. Therefore, there is a unique opportunity at the moment to use the need for an infrastructure overhaul to change to a transmission and distribution systems which will be capable of absorbing the large new quantities of different renewable energy sources, centralised and decentralised all over Europe and the neighbouring countries.*"[131]

Appendix L: *Frequently Asked Questions about Feed-in Tariffs, Advanced Renewable Tariffs, Renewable Tariffs, and Renewable Energy Producer Payments*[132] by Paul Gipe of Wind-works.org, Dec 6, 2008

[127] Exhibit A-18, Appendix A, Page 4 of 13
[128] Appendix R, Rocky Mountain Institute, "*Exploring Vancouver Island's Energy Future – A Workshop by BC Hydro & Rocky Mountain Institute*", Sept 29, 2003,
[129] http://re.jrc.ec.europa.eu/refsys/pdf/PV%20Report%202008.pdf
[130] http://re.jrc.ec.europa.eu/refsys/pdf/PV%20Report%202008.pdf, Pages 95 to 100
[131] http://re.jrc.ec.europa.eu/refsys/pdf/PV%20Report%202008.pdf, Page 124
[132] Appendix L, Paul Gipe, Wind-works.org, Dec 6, 2008, "*Frequently Asked Questions about Feed-in Tariffs, Advanced Renewable Tariffs, Renewable Tariffs, and Renewable Energy Producer Payments*"

"Systems of feed-in tariffs have been highly successful at developing large amounts of geographically dispersed renewable sources of generation quickly, at low cost and with minimal administration."[133]

"*Feed-in tariffs are simply payments for generation. They have nothing to do with taxes or subsidies. Thus, feed-in tariffs are more egalitarian because they allow everyone to be paid for their electricity even those who do not pay a lot in taxes."*[134]

"*In Germany in 2007, the average household paid outright less than $50 per year for the world's largest concentration of wind turbines, solar panels, and biomass plants, and the 250,000 new jobs these industries have created."*[135]

"*While feed-in tariffs are also used to develop centralized renewable sources of generation, they are best known for increasing the role of distributed renewable resources."*[136]

Appendix M: *Feed-In Tariffs in America*[137] by Paul Gipe of Wind-works.org, Dec 6, 2008

A summary historical background on Feed-In Tariffs in Denmark[138] and Germany[139] is provided. The rest of the report discusses the applicability of Feed-In Tariffs for the USA.

In conclusion, the report states:

> "*The United States would benefit from a change in renewable energy policy to a feed-in tariff. The lesson from Europe is clear: Americans can continue to debate 'market-based' ideas and tax credits or they can jump to the solutions that work.*
>
> *In addition to turbocharging renewable energy development, a feed-in tariff unlocks the potential of dispersed generation and community ownership. Compared to the byzantine array of incentives and rules facing renewable energy producers, a feed-in tariff decreases the economic and legal costs of doing business and increases the social*

[133] Appendix L, Paul Gipe, Wind-works.org, Dec 6, 2008, "*Frequently Asked Questions*", Page 1
[134] Appendix L, Paul Gipe, Wind-works.org, Dec 6, 2008, "*Frequently Asked Questions*", Page 2
[135] Appendix L, Paul Gipe, Wind-works.org, Dec 6, 2008, "*Frequently Asked Questions*", Page 3
[136] Appendix L, Paul Gipe, Wind-works.org, Dec 6, 2008, "*Frequently Asked Questions*", Page 3
[137] Appendix M, John Farrell, New Rules Project, "*Feed-In Tariffs in America*", April 2009
[138] Appendix M, John Farrell, New Rules Project, "*Feed-In Tariffs in America*", April 2009, Pages 8 to 10
[139] Appendix M, John Farrell, New Rules Project, "*Feed-In Tariffs in America*", April 2009, Pages 11 to 12

and economic benefits."[140]

***State Clean Energy Policies Analysis (SCEPA) Project: An Analysis of Renewable Energy Feed-in Tariffs in the United States*[141] for the National Renewable Energy Laboratory by Toby Couture (E3 Analytics) and Karlynn Cory (National Renewable Energy Laboratory), June, 2009**

"*Well-designed FIT policies offer a cost-efficient method for fostering rapid development of RE resources, thereby benefiting ratepayers, RE developers, and society at large.*"[142]

A map of USA shows the introduction of Feed-In Tariffs[143]. Each of the US programs are discussed, with comparisons to the European programs[144].

"*As of March 2009, state representatives have proposed FIT policies in a wide range of U.S. states, including Arkansas, California, Florida, Hawaii, Illinois, Indiana, Michigan, Minnesota, New York, Oregon, Rhode Island, Vermont, Washington, and Wisconsin. California and Washington are examining the possibility of expanding their existing FIT policies (IEPR 2008 and HB 1086, respectively) and Hawaii saw a number of solar FIT proposals in its legislature in 2007. Throughout this flurry of legislative activity, a trend toward designing FIT policies similarly to those found in Europe can be seen. Many jurisdictions that already have either state- or utility-based FIT policies are exploring ways of improving them, and this could help increase the success of FIT policies in the United States in the future.*

In addition to state legislative proposals, governors are also proposing FIT policies. Hawaii, for example, has included a more comprehensive FIT policy within its most recent energy plan (FIT-Hawaii 2009). As part of the Hawaii Clean Energy Initiative, Hawaii identifies reaching 40% of the state's electricity from renewable sources by 2030 as one if its objectives, with the long-term goal of supplying 70% of the state's energy needs with clean energy sources (FIT-Hawaii 2009).

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[140] Appendix M, John Farrell, New Rules Project, "*Feed-In Tariffs in America*", April 2009, Page 30

[141] www.nrel.gov/applying_technologies/pdfs/45551.pdf, for National Renewable Energy Laboratory, "*An Analysis of Renewable Energy Feed-In Tariffs in United States*", June 2009

[142] www.nrel.gov/applying_technologies/pdfs/45551.pdf, for National Renewable Energy Laboratory, "*An Analysis of Renewable Energy Feed-In Tariffs in United States*", June 2009, Page v

[143] www.nrel.gov/applying_technologies/pdfs/45551.pdf, for National Renewable Energy Laboratory, "*An Analysis of Renewable Energy Feed-In Tariffs in United States*", June 2009, Page 8

[144] www.nrel.gov/applying_technologies/pdfs/45551.pdf, for National Renewable Energy Laboratory, "*An Analysis of Renewable Energy Feed-In Tariffs in United States*", June 2009, Pages 8 to 16

State energy offices are also proposing FIT policies. Florida, Ohio, and Maine are considering FIT policies at the state-level (Gipe 2009b), and California recently held hearings at the CEC to examine different policy options for an expanded FIT policy, with the aim of replicating the success of its European counterparts by improving the policy design (CEC 2008).

Finally, the municipalities of Palm Desert, Santa Monica, and Los Angeles in California have also recently proposed FIT policies; however, none were implemented as of April 2009 (Gipe 2009b; Ferguson 2009)."[145]

"*Interest in FIT policies in the United States is expected to continue to grow in coming years. In Europe, the policy has successfully helped deploy significant amounts of RE capacity, across a wide variety of technologies, in a relatively short period of time.*"[146]

The support of Feed-In Tariffs for encouraging distributed generation is highlighted:

"*The United States has a number of utility-based FIT policies which differ considerably in design and effectiveness. They are generally put forth by utilities to help meet utility-specific goals, which may range from meeting RPS targets to encouraging distributed generation.*"[147]

A table listing how the states can achieve their goals through the use of Feed-In Tariffs[148]. It is reproduced on the following page:

[145] www.nrel.gov/applying_technologies/pdfs/45551.pdf, for National Renewable Energy Laboratory, "*An Analysis of Renewable Energy Feed-In Tariffs in United States*", June 2009, Page 16

[146] www.nrel.gov/applying_technologies/pdfs/45551.pdf, for National Renewable Energy Laboratory, "*An Analysis of Renewable Energy Feed-In Tariffs in United States*", June 2009, Page 31

[147] www.nrel.gov/applying_technologies/pdfs/45551.pdf, for National Renewable Energy Laboratory, "*An Analysis of Renewable Energy Feed-In Tariffs in United States*", June 2009, Page 7

[148] www.nrel.gov/applying_technologies/pdfs/45551.pdf, for National Renewable Energy Laboratory, "*An Analysis of Renewable Energy Feed-In Tariffs in United States*", June 2009, Page 20

Kirschen 2008). More distributed supply sources can also help reduce line losses while deferring the need for grid upgrades (Bouffard et al. 2008).

Table 3 outlines various policy goals that a FIT policy could help a state achieve.

Table 3. State Policy Drivers

State Policy Drivers	Specific State Policy Objectives	FIT Policy Impacts	Notes
Economic Objectives	Job creation	High	• Due to the guaranteed terms and low barriers to entry offered by FIT policies, they have been highly successful at driving economic development and job creation • Fixed prices for renewable energy sources can also help stabilize electricity rates
	Economic development	High	
	Economic transformation	High	
	Stabilize electricity prices	Moderate	
	Lower long-term electricity prices[12]	Low/Moderate	
	Grow the state economy	High	
	Revitalize rural areas	High	
	Attract new investment	High	
	Develop community ownership[13]	High	
	Develop future export opportunities	High	
Environmental Objectives	Clean air benefits (Mercury, particulates, etc.)	Moderate	• The rapid RE development seen in jurisdictions with FIT policies has helped reduce the environmental impacts of electricity generation, while providing valuable air quality and other environmental benefits. • Differentiating FIT payments by resource type can also target various biomass waste streams.
	Greenhouse gas emissions reduction	Moderate	
	Preserve environmentally sensitive areas	Low	
	Minimize human impacts of energy development	Moderate	
	Manage waste streams (biogas, landfill gas, biomass, agricultural wastes, forestry wastes, etc.)	High	
	Reduce exposure to carbon legislation	Moderate	
Energy Security Objectives	Secure abundant future energy supply	High	• Well-designed FIT policies can improve overall energy security by helping diversify energy supply and helping domestic energy resources be more widely harnessed.
	Reduce long-term price volatility	High	
	Reduce dependence on natural gas[14]	Low/Moderate	
	Promote a more resilient electricity system[15]	Moderate	
Renewable Energy Objectives	Rapid RE deployment	High	• By creating favorable conditions for RE market growth, FIT policies can help jurisdictions meet RE targets. • FIT policies have also helped countries move toward a green energy economy.
	Technological innovation	High	
	Drive RE cost reductions	High	
	Meet RPS targets	High	
	Reduce fossil fuel consumption	Moderate	
	Provide base-load generation	Low/Moderate	
	Stimulate green energy economy	Low/Moderate	
	Reduce barriers to RE development	Moderate/High	

[12] Cost reduction is more likely to be ensured if lower cost RE resources like wind and biogas are included.
[13] Community ownership will depend on how high the payment levels are set, and whether or not communities are able to participate.
[14] Dependence on natural gas will be reduced primarily in areas where natural gas is the marginal supply.
[15] Greater grid resilience will be fostered if more distributed resources are encouraged, and particularly if they are sited in highly congested areas.

Appendix N: *Britain To Launch Innovative Feed-In Tariff Program in 2010*[149] for the National Renewable Energy Laboratory by Toby Couture (E3 Analytics) and Karlynn Cory (National Renewable Energy Laboratory), June, 2009

The ramifications of Britain's Feed-In Tariff introduction in 2010 is perhaps best stated in the following:

> "*The move {Britain introducing a Feed-In Tariff] has potentially far reaching ramifications in the English speaking world where there has been reluctance to use full-fledged systems of feed-in tariffs, sometimes on ideological grounds. Now that Britain, Ontario, and South Africa, two of Britain's former colonies, have definitively moved toward implementing sophisticated feed-in tariff programs, there may be less reticence to do so elsewhere in the Anglophone world.*"[150]

Appendix O: *Ontario Unveils North America's First Feed-In Tariff*[151] by the Ontario Power Authority, March 12, 2009

Feed-In Tariffs are also provided in Canada, where Ontario is in the process of updating their Feed-In Tariff program:

> "*The proposed feed-in tariff program would help spark new investment in renewable energy generation and create a new generation of green jobs, " said George Smitherman, Deputy Premier and Minister of Energy and Infrastructure. "It would give communities and homeowners the power and tools they need to participate in the energy business in the new green economy.*"[152]

Appendix P: *Proposed Feed-In Tariff Prices for Renewable Energy Projects in Ontario*[153] by the Ontario Power Authority, July 8, 2009

On July 8, the latest updated pricing for the Feed-In Tariffs were adjusted from its March 12 announcement, and included Aboriginal (First Nations) and Community price adders.

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149 Appendix N, Paul Gipe, "*Britain to Launch Innovative Feed-In Tariff Program in 2010*", July 23, 2009

150 Appendix N, Paul Gipe, "*Britain to Launch Innovative Feed-In Tariff Program in 2010*", July 23, 2009

151 Appendix O, Ontario Power Authority, "*Ontario to Unveils North America's First Feed-In Tariff*", March 12, 2009

152 Appendix O, Ontario Power Authority, "*Ontario to Unveils North America's First Feed-In Tariff*", March 12, 2009

153 Appendix P, Ontario Power Authority, "*Proposed Feed-In Tariff Prices for Renewable Energy Projects in Ontario*", July 8, 2009

Premier's Technology Council 10th Report[154] **for the Premier's Technology Council, September, 2007**

Based on the 2007 BC Energy Plan, the BC Technology Council, chaired by the Premier Gordon Campbell and supported by a large group of respected individuals[155] discussed and recommended Feed-In Tariffs and Distributed Generation in its report.

One of its recommendations specifically addressed Feed-In Tariffs. Find the recommendation listed below (***in bold***) with supporting statements following that recommendation:

> "***That government support the development of appropriate feed-in tariffs that decline over time to assist the commercialisation of emerging, renewable energy sources and their associated technologies.***"[156]
>
> > "*To drive the development of alternative, renewable, cost-effective energy technology and meet the goals of the Energy Plan, BC Hydro must make some changes in the way it purchases electricity, in particular green power.*"[157]
> >
> > "*More aggressive options need to be considered such as a feed-in tariff system that varies by the source of renewable energy and the maturity of the technology. These kinds of tariffs are being successfully deployed in Europe and elsewhere.*"[158]
> >
> > "*It is important to take a long-term view of supply, and while certain power supply technologies will not be commercial for some time – such as ocean energy from waves or tides – they will eventually be needed, and BC is in a good position to develop an industry around these technologies. Appropriate feed-in tariffs can be a powerful stimulus to the industry.*"[159]

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154 Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007

155 Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Pages 124 to 127

156 Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Page 49, Recommendation 10.21

157 Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Pages 47

158 Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Pages 48

159 Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Pages 48

"*Legislation that governs the energy system mandates that higher rates be paid for power supplied by deploying emerging technologies.*"[160]

A number of other recommendations are related to distributed generation:

"***That government continue to pursue its goal of self-sufficiency by 2016.***"[161]

"*At the same time, such a firm target could act as an incentive to address other challenges facing the renewable energy industry. It would demand a build-out of advanced infrastructure, in particular transmission lines and a 'smart' grid to allow for distributed generation and technology-driven conservation.*"[162]

"***That government direct BCUC to consider the broader goals of government in its monitoring role, in particular the objectives of the Energy Plan. Examples of specific measures that need to be considered are:***

Investment in infrastructure, including smart grid technologies, to allow access to more supplies and enable system efficiencies; . . "[163]

"*First, the utility will need to make large investments in infrastructure to build a grid system that can support both conservation and distributed generation.*"[164]

"***That government direct BCUC to consider government policies for conservation and renewable energy when reviewing the long-term strategic plans of the utilities to invest in a 'smart grid' digital power infrastructure.***"[165]

"*Still more projects might be small-scale, such as photovoltaic*

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[160] Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Pages 48

[161] Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Page 32, Recommendation 10.9

[162] Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Page 31

[163] Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Page 33, Recommendation 10.11

[164] Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Page 32

[165] Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Page 36, Recommendation 10.13

panels on a building. Such 'distributed generation' calls for careful micromanagement of data and electricity flows, and possibly net metering on facilities that will sometimes draw from the grid and sometimes feed into it. Currently, the system is not sophisticated enough to manage these required elements of the Energy Plan."[166]

"***That government continue to advance the Green Cities Project and the Green Building Code, through the mandating of green targets and promoting the use of green technologies.***"[167]

"*All three options should exist, but the third option is particularly critical as performance based compliance paths provide the most opportunity to incorporate advanced technologies such as distributed (co)generation, solar thermal and geo-exchange into building design.*"[168]

5.3 Discussion on Feed-In Tariffs and Distributed Generation

As described within this section of the document[169], Feed-In Tariffs and Distributed Generation are gaining support in various parts of the world (of particular interest to BC, the USA and Ontario). There are many benefits, including the benefits as shown in "State Policy Drivers" table[170]. In addition, the Premier's own Technology Council has recommended Feed-In Tariffs and Distributed Generation[171], and it seems only a matter of time before Distributed Generation include incentives like energy efficiency and conservation in order to help achieve the conservation targets of the BC Energy Plan.

Therefore, we suggest that there is sufficient evidence that it is reasonable and plausible to anticipate that BC may in the future move towards policies supporting and encouraging Feed-In Tariffs and Distributed Generation.

Further, we suggest that this situation is one which will further enhance the Transmission Inquiry to "*represent a range of possible futures*"[172]. Therefore, we suggest that at least one of the Initial Scenarios should include Feed-In Tariffs

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166 Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Page 35

167 Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Page 44, Recommendation 10.16

168 Appendix P, Premier's Technology Council, "*Premier's Technology Council 10th Report*", September, 2007, Page 43

169 Section 5.0 of this document and all subsections

170 www.nrel.gov/applying_technologies/pdfs/45551.pdf, for National Renewable Energy Laboratory, "*An Analysis of Renewable Energy Feed-In Tariffs in United States*", June 2009, Pages 20

171 Discussion of the "Premier's Technology Council 10th report" (Appendix U) within Section 5.2 of this document

172 Exhibit A-18, Appendix A, Attachment A, Page 2 of 7

and Distributed Generation.

6 Solar:

6.1 Solar as discussed in the Transmission Inquiry Scoping Document

In the Transmission Inquiry Scoping Document[173], the Inquiry Panel notes:

> "*ESVI also suggested that 'the regional aspect for wind be expanded to include the regional considerations for solar'. The Panel understands the examples in the Staff Paper to be illustrative and that the cost estimates for various generations resources (especially developing technologies, including both wind and solar) will have regional considerations.*"[174]
>
> "*The Panel considers the following issues to be in scope and consistent with the Terms of Reference . . .*
>
> > *Developing technologies and their impacts on the economics of generation may be considered, especially as this may affect renewable generation such as wind, solar, wood waste, other bioenergy, geothermal, ocean (wave, tidal and in-stream current), or other such renewable generation resource that is anticipated to be commercial or near commercial*"[175]
>
> "*Similarly, scenarios could be developed with assumptions favourable to run-of-river generation, to ocean (wave, tidal and in-stream current) generation, to solar generation, or to coal generation with carbon capture and storage, and such scenarios would tend to increase or decrease the generation forecasts in various regions depending on the supply resource options in each region.*"[176]

[173] Exhibit A-18
[174] Exhibit A-18, Appendix A, Page 5 of 13
[175] Exhibit A-18, Appendix A, Attachment A, Page 1 of 7
[176] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7

6.2 Reports and Papers addressing Solar generation

In order to properly assess whether or not to include Solar generation should be included into the Initial Scenarios, we felt it appropriate to include some evidence (a snapshot) highlighting the aspects important for such considerations: the predicted future of solar technology and its costs. There is very little solar generation in BC at present, yet that situation is bound to change in the future as the technology improves and costs fall.

6.2.1 Solar-related activities in the United States – Department of Energy

While there are many efforts around the world working at enhancing the solar technologies, a view of the US Department of Energy (DOE) activities could serve as an appropriate example of those world-wide efforts.

DOE has a multi-prong approach for solar technologies.

There are a number of early commercialization programs which DOE provides millions of dollars in funding to help foster the developments.

Next Generation Photovoltiac:

"*The Next Generation Photovoltaic (PV) Devices and Processes projects represent innovative, revolutionary, and highly disruptive next-generation PV technologies. These PV research and development (R&D) activities within the Solar Energy Technologies Program are expected to produce prototype PV cells and/or processes by 2015, with full commercialization by 2020-2030.*"[177]

Photovoltaic Pre-Incubator:

"*The Photovoltaic (PV) Technology Pre-Incubator project helps small solar businesses transition from concept verification of a solar PV technology to the development of a commercially viable PV prototype by 2012.*

The goals of the project include promoting grid parity for PV technologies, transitioning innovative PV technologies into the prototype stage, and developing prototype PV concepts with manufacturing costs of less than $1/watt."[178]

Photovoltaic Incubator:

"*The PV Incubator awards target research and development of PV systems and component prototypes with full functionality, produced in*

[177] www1.eere.energy.gov/solar/next_generation_pv.html
[178] www1.eere.energy.gov/solar/pv_preincubator.html

pilot-scale operations."[179]

There are also programs in which the technologies are close to mass production, including the Technology Pathway Partnerships (TPP) [180] program:

The objectives of the TPP Program include:

"*Accelerate development of U.S.-produced PV systems so that PV-produced electricity reaches parity with the cost of electricity in grid-tied markets across the nation by 2015.*"[181]

"*Research toward lowering the cost of electricity from PV to $0.05 - $0.10 per kWh by 2015 –a price that is competitive in markets nationwide. [Range given because of various applications (i.e., residential, commercial, utility)]*"[182]

Thirteen technology programs, including their cost projections, are listed in the TPP presentation[183]. Cost projections for each technology in 2015 are shown in one graph on Slide #14[184] (note that not all companies have listed their expected manufacturing volumes).

A graph of the range of historical and predicted costs of solar technology compared to utility costs is included on Slide #2[185] of the TPP presentation.

6.2.2 World wide solar developments

The report, "*PV Status Report 2008 - Research, Solar Cell Production and Market Implementation of Photovoltaics*"[186], written for the Joint Research Centre of the European Commission, provides a world wide view of the solar technologies.

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[179] www1.eere.energy.gov/solar/pv_incubator.html

[180] www1.eere.energy.gov/solar/pdfs/tpp_project_prospectus.pdf, Department of Energy, "*Overview of Technology Pathway Partnerships*", Mar 8-9, 2007

[181] www1.eere.energy.gov/solar/pdfs/tpp_project_prospectus.pdf, Department of Energy, "*Overview of Technology Pathway Partnerships*", Mar 8-9, 2007, Slide #3

[182] www1.eere.energy.gov/solar/pdfs/tpp_project_prospectus.pdf, Department of Energy, "*Overview of Technology Pathway Partnerships*", Mar 8-9, 2007, Slide #5

[183] www1.eere.energy.gov/solar/pdfs/tpp_project_prospectus.pdf, Department of Energy, "*Overview of Technology Pathway Partnerships*", Mar 8-9, 2007, Slides #16 to #28

[184] www1.eere.energy.gov/solar/pdfs/tpp_project_prospectus.pdf, Department of Energy, "*Overview of Technology Pathway Partnerships*", Mar 8-9, 2007, Slide #14

[185] www1.eere.energy.gov/solar/pdfs/tpp_project_prospectus.pdf, Department of Energy, "*Overview of Technology Pathway Partnerships*", Mar 8-9, 2007, Slide #2

[186] http://re.jrc.ec.europa.eu/refsys/pdf/PV%20Report%202008.pdf

The world-wide production of PV cells and modules from 1990 to 2007 shows a dramatic increase, with an estimated 4 GW world-wide production in 2007[187]. By 2012, this volume is expected to increase ten-fold to over 42 GW[188].

Numerous solar technologies developments in Japan, People's Republic of China, Taiwan, the United States and the European Union are described in the report[189].

A study called "*Scoping Study on Financial Risk Management Instruments for Renewable Energy Projects*"[190] written for the United Nations Environment Programme under the Sustainable Energy Finance Initiative shows a table with projected future costs of a range of technologies – with Solar technologies beyond 2020 projected to drop to 5 to 8 cents/kwh[191].

6.2.3 Solar in Canada

A key issue, which will be dealt with in more detail within the Resource Options work for the Transmission Inquiry to be done by BC Hydro (deadline August 14), is the suitability of solar for BC – solar thermal energy, in commercial form, is already competitive in price to other energy forms in BC. This will include among other aspects, the resource characterization and the analysis of the "Potential Solar Insolation" provided by BC Hydro in the Resource Options workshop.

We suggest that BCTC in developing its Initial Scenarios take into account the information and comments provided to BC Hydro on its Resources Options work (not only for solar, but also for all other areas).

6.3 Discussion on Solar Generation

We suggest that the US DOE developments show numerous technology developments in which the solar pricing projections are expected to come close to compete to utility energy costs by 2015[192]. In addition, there are even larger world-wide initiatives outside the US, which could have lower costs yet.

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[187] http://re.jrc.ec.europa.eu/refsys/pdf/PV%20Report%202008.pdf, Page 5
[188] http://re.jrc.ec.europa.eu/refsys/pdf/PV%20Report%202008.pdf, Page 11
[189] http://re.jrc.ec.europa.eu/refsys/pdf/PV%20Report%202008.pdf, Pages 18 to 121
[190] http://www.uneptie.org/energy/activities/frm/pdf/Scoping_study.pdf
[191] http://www.uneptie.org/energy/activities/frm/pdf/Scoping_study.pdf, Page 52, Table 8, "Grid connected photovoltaic", 1000 and 1500 kWh/m^2
[192] Section 6.2.1 of this document

Therefore, we suggest that there is sufficient evidence that it is reasonable and plausible to anticipate that solar technology may have an increasing role for BC.

Further, we suggest that this situation is one which will further enhance the Transmission Inquiry to "*represent a range of possible futures*"[193]. Therefore, we suggest that at least one of the Initial Scenarios should include Solar Technology generation.

7 Ocean Generation:

7.1 Ocean Generation as discussed in the Transmission Inquiry Scoping Document

In the Transmission Inquiry Scoping Document[194], the Inquiry Panel notes:

> "*The Ocean Renewable Energy Group suggested broadening the term 'Ocean (wave and/or tidal current)' as used in the Staff Paper to 'Ocean (wave, tidal and in-stream current)' . . . The BC Sustainable Energy Association et al. ('BCSEA') and Energy Solutions for Vancouver Island et al. ('ESVI') made similar requests. The Panel agrees to the use of the broadened description as suggested . . .*"[195]

> "*The Panel considers the following issues to be in scope and consistent with the Terms of Reference . . .*

> > *Developing technologies and their impacts on the economics of generation may be considered, especially as this may affect renewable generation such as wind, solar, wood waste, other bioenergy, geothermal, ocean (wave, tidal and in-stream current), or other such renewable generation resource that is anticipated to be commercial or near commercial*"[196]

> "*Similarly, scenarios could be developed with assumptions favourable to run-of-river generation, to ocean (wave, tidal and in-stream current) generation, to solar generation, or to coal generation with carbon capture and storage, and such scenarios would tend to increase or decrease the generation forecasts in various regions depending on the supply resource options in each region.*"[197]

[193] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7
[194] Exhibit A-18
[195] Exhibit A-18, Appendix A, Page 3 of 13
[196] Exhibit A-18, Appendix A, Attachment A, Page 1 of 7
[197] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7

7.2 Ocean generation technology

We note that BC Hydro will be developing the "*Resources Options*" portion of the Transmission Inquiry and gathering input from Intervenors regarding this aspect. We suggest that the evaluation of Ocean generation for use in the Initial Scenarios is particularly difficult to pursue without the full input from the "Resource Options" section due to its location-specific characteristics and information expected to be contained in the "Resource Options" section.

We suggest that BCTC in developing its Initial Scenarios take into account the information and comments provided to BC Hydro on its Resources Options work (not only for ocean, but also for all other areas).

In spite of this situation, we will present our comments within this document, our comments on Scenarios.

In order to properly assess whether or not to include Ocean generation should be included into the Initial Scenarios, we felt it appropriate to include some evidence (a snapshot) highlighting the aspects important for such considerations: the various potential ocean technology techniques and its costs.

A report called "*Inventory of Canada's Marine Renewable Energy Resources*"[198] for the Canadian Hydraulics Centre of National Resource Council Canada and written by A. Cornett provides useful information Ocean Technology.

> Examples of the various types of technologies are shown on pages 3 to 5 of the report[199].
>
> The annual and monthly mean wave power is shown for 30 stations along the west coast of BC[200]. It shows particularly large numbers in winter, which is the traditional high demand time of the BC system. For example, six stations have higher than 70 kw/m for the months of November to February and eleven stations higher than 70 kw/m in January. A graph shows the normalized seasonal variation[201]. Maps show the mean wave power along the west coast of BC, including summer and winter[202].
>
> Tables show the tidal potential in BC, regions of BC, and stations[203] with also with map locations[204].

[198] www.oreg.ca/docs/Atlas/CHC-TR-041.pdf
[199] www.oreg.ca/docs/Atlas/CHC-TR-041.pdf, Pages 3 to 5
[200] www.oreg.ca/docs/Atlas/CHC-TR-041.pdf, Page 20
[201] www.oreg.ca/docs/Atlas/CHC-TR-041.pdf, Page 23, Figure 13
[202] www.oreg.ca/docs/Atlas/CHC-TR-041.pdf, Page 31, Figure 18 & Page 32, Figure 19
[203] www.oreg.ca/docs/Atlas/CHC-TR-041.pdf, Pages 83 to 87
[204] www.oreg.ca/docs/Atlas/CHC-TR-041.pdf, Pages 95

A study called "*Scoping Study on Financial Risk Management Instruments for Renewable Energy Projects*"[205] written for the United Nations Environment Programme under the Sustainable Energy Finance Initiative shows a table with projected future costs of a range of technologies – with Ocean technologies beyond 2020 projected to drop to 5 to 15 cents/kwh[206].

The dropping costs of wave power[207] and tidal stream[208] are presented by the Carbon Trust in a study called "*Future Marine Energy*"[209].

A report on a workshop done by BC Hydro and the Rocky Mountain Institute states:

> "*Tidal power is an enormous resource around Vancouver Island, which has some of the best sites worldwide. Most of BC's tidal resource is located near the Queen Charlotte Islands and around V.I. Based on the study performed by Triton Consultants the total resource on VI exceeds 2 GW. The study assumed an average 3.5 m/s tide velocity and estimated a cost of 11c/kWh. However, Amory Lovins suggested that if the top seven sites were developed (2/3 of the ~2GW potential) the cost would be closer to 5 c/kWh (power increases by the cube of tidal velocity). The tides at some top sites, however, are so strong that existing turbine technology would be unable to withstand the forces generated. This is a technical barrier that can eventually be overcome.*"[210]
>
> "*Wave power is related to tidal power and also is a large resource around Vancouver Island. Wave power is predictable a few days ahead, although energy performance is very site dependent. The technology is expected to be cost effective in the kind of wave regime that exists off VI.*"[211]
>
> "*As in the case of tidal power, BC could develop an entire industry around wave power technology, integrating the technology with hydrogen and other renewable technologies.*"[212]

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[205] http://www.uneptie.org/energy/activities/frm/pdf/Scoping_study.pdf

[206] http://www.uneptie.org/energy/activities/frm/pdf/Scoping_study.pdf, Page 52, Table 8, "Marine Energy"

[207] http://www.oceanrenewable.com/wp-content/uploads/2007/03/futuremarineenergy.pdf, Carbon Trust, "Future Marine Energy", Pages 19 & 20

[208] http://www.oceanrenewable.com/wp-content/uploads/2007/03/futuremarineenergy.pdf, Carbon Trust, "Future Marine Energy", Pages 21 & 22

[209] http://www.oceanrenewable.com/wp-content/uploads/2007/03/futuremarineenergy.pdf, Carbon Trust, "Future Marine Energy"

[210] Appendix Z, Rocky Mountain Institute, "*Exploring Vancouver Island's Energy Future – A Workshop by BC Hydro & Rocky Mountain Institute*", Sept 29, 2003, Page 37

[211] Appendix Z, Rocky Mountain Institute, "*Exploring Vancouver Island's Energy Future – A Workshop by BC Hydro & Rocky Mountain Institute*", Sept 29, 2003, Page 38

[212] Appendix Z, Rocky Mountain Institute, "*Exploring Vancouver Island's Energy Future – A Workshop by BC Hydro & Rocky Mountain Institute*", Sept 29, 2003, Page 38

7.3 Discussion on Ocean Generation

We suggest that there is a wide range of Ocean technologies that could be adapted to the BC coast[213]. We suggest that there is a large energy potential, and that it is particularly favourable to generation in the peak demand requirement times of the BC system load – in winter[214]. We suggest that Ocean technology supports higher system reliability through diversity (allows for adapting to climate change[215]) and supports the BC economy.

Therefore, we suggest that there is sufficient evidence that it is reasonable and plausible to anticipate that ocean technology may have an increasing role for BC.

Further, we suggest that this situation is one which will further enhance the Transmission Inquiry to "*represent a range of possible futures*"[216]. Therefore, we suggest that at least one of the Initial Scenarios should include Ocean Technology generation.

8 <u>Suggested Initial Scenario:</u>

8.1 Description of Suggested Initial Scenario

In response to the request for comments from the Scenario Workshop, we will describe within this section a scenario that we believe to be appropriate. It is based upon the background provided in Section 3 "*Scenario Development*"[217] and is in essence an expanded version of the "Integrated Non-Wires" Scenario, discussed in Section 1, let's call it "Expanded Integrated Non-Wires".

"**Expanded Integrated Non-Wires**" Scenario:

Economy: The value of encouraging and enhancing the BC clean energy and regional economy is recognized. Appropriate mechanisms and policies are implemented to ensure that such a long term sustainable green economy is developed in BC[218].

Technology: The technologies for sophisticated demand side management

[213] www.oreg.ca/docs/Atlas/CHC-TR-041.pdf, Pages 3 to 5
[214] Discussed in Section 7.2 of this document
[215] Discussed in Section 4.1 and its subsections of this document
[216] Exhibit A-18, Appendix A, Attachment A, Page 2 of 7
[217] See Section 3.0 "*Scenario Development*" and its subsections of this document
[218] "*create economic opportunities in British Columbia*": Terms of Reference, Page 5 of 7, Item 8(b)(vi)

result in higher levels of conservation and costs are reduced[219]. Distributed[220], Solar[221] and Ocean[222] generation costs drop significantly, and these technologies become more prevalent.

Policy Decisions: For this scenario, it is assumed that the high cost and uncertainty of land issues relating to new transmission lines has encouraged BC to adopt a fully integrated "*Non-Wires*" solution approach (look proactively at solutions other than transmission lines, such DSM and strategic renewable generation placement) similar to those outlined with the Bonneville Power Administration as described with Section 1.0 of this document[223].

BC policies are incorporated to place higher emphasis on regional solutions and appropriately consider seasonal characteristics of generation.

BC policies, such as those supporting Feed-in Tariffs and Distributed Generation[224], are implemented to encourage higher reliability and security of the transmission system through diversity of generation location (distributed generation[225]) and technology selection.

Environmental Developments: In the early years of the 30-year study period, it becomes clear that the projected cost of carbon and greenhouse gas emissions will rise significantly in future years as described in Section 4.2 of this document[226], and therefore BC policies are implemented to anticipate these upcoming costs, and further encourage low-carbon or no-carbon solutions. In later years of the study period, the projected high costs come to fruition.

In the early years of the study period, it is recognized that the looming climate change crisis and climate change science hit a critical point such that climate change impacts need to be considered to ensure BC continues to have a reliable electrical transmission system even if the climate changes, and weather conditions are extreme as described in Section 4.1 of this document[227]. BC policies are implemented to ensure that DSM is further encouraged[228], electric vehicles prevalent with

[219] See Section 2.2.1
[220] See Section 5.0 "*Feed-In Tariffs and Distributed Generation*" and its subsections of this document
[221] See Section 6.0 and its subsections in this document
[222] See Section 7.0 and its subsections in this document
[223] See Section 1.0 "*Non-Wires Initial Scenario*" and its subsections of this document
[224] See Section 5.0 "*Feed-In Tariffs and Distributed Generation*" and its subsections of this document
[225] See Section 5.0 and its subsections in this document
[226] See Section 4.2 "*Future price of Carbon*" and its subsections of this document
[227] See Section 4.1 "*Climate Change Impacts*" and its subsections of this document
[228] See Section 2.2.1

appropriate rate structures[229] (drawing on the grid and acting as storage for the grid), and that the supply/generation of the BC electrical system is diverse in technology and does not so heavily rely on large hydro – instead distributed generation[230], solar[231] and ocean[232] generation are encouraged.

[229] See Section 2.2.2
[230] See Section 5.0 and its subsections in this document
[231] See Section 6.0 and its subsections in this document
[232] See Section 7.0 and its subsections in this document

APPENDICES

Expansion of BPA Transmission Planning Capabilities

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Appendix A

Table of Contents

Appendix A

List of Tables

List of Figures

Appendix A

Executive Summary

Transmission Planning and Expansion Framework

Bonneville Power Administration's (BPA) Transmission Power Line (TBL) has proposed transmission infrastructure investments totaling $775 million above previously planned capital expenditures. Should TBL choose to move forward with any or all of these additions, it will have to take them through the National Environmental Policy Act (NEPA) process. In that process, TBL will need to determine how these projects affect the environment relative to alternative actions it could take, and it will have to justify these transmission additions to a variety of stakeholders.

TBL has added virtually no circuit miles to its transmission system since the late 1980s. During this lengthy period, however, electrical demand in the Pacific Northwest has continued to grow (BPA has experienced a 1.8% annual growth in demand over the past 15 years). Equally important, the increasingly competitive nature of wholesale electricity markets is leading to energy transactions and power flows that differ substantially, both in magnitude and directions, from historical practice. Transmission planning has to evolve to keep up with this changing environment.

The future promises more changes in utility practice and transmission planning with the introduction of RTOs. In October 2001, FERC held a series of workshops (called "RTO Week") to discuss electricity market design and structure. From the panel discussion on transmission planning and expansion the following points of consensus were identified:[1]

> A regional transmission plan with representation from all stakeholders is the best way to perform transmission planning and expansion.
>
> Market driven solutions [to transmission problems] are best.

Before proceeding with the construction of transmission projects, BPA wants to ensure that there is a clear and compelling demonstration of project need and that it is providing the most cost-effective solution to the region's transmission problems from an engineering, economic and environmental standpoint. As part of its evaluation, BPA must consider whether non-transmission options can be employed as viable alternatives to transmission expansion. Non-transmission solutions can include pricing strategies, demand reducing strategies, and strategic placement of generators.

In many respects these nonwires activities have been outside of TBL's purview and TBL has had to be passive with respect to them. If they happen, TBL can account for them, but it cannot make them happen. Other regional stakeholders that control nonwires activities and, in so doing, affect system costs and topology, include BPA's Power Business Line (PBL), other regional utilities, merchant generators, state regulatory commissions, loads, and possibly others. This separation of

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[1] FERC Docket No. RM01-12-000

responsibilities, without coordination, has made it difficult to develop a bulk power system that in its entirety, from generation to retail-customer loads, provides the lowest-cost electricity and delivery system to retail consumers in the region.

If TBL and other regional players acted in concert, it is much more likely that they could create a system that is lower-cost and more reliable than would be the case if each acted alone. It may be possible to achieve these goals through market discipline when RTO West is operational. However, an operating RTO may be several years away, and we believe that the following recommendations apply both to BPA today and to RTO West in the future.

Summary of Conclusions

We recommend that TBL engage regional stakeholders in its planning process with the goal of sharing information that would lead to a more efficient region-wide system. The report suggests an approach for BPA to provide these stakeholders with the information they need to identify and construct potentially lower-cost and reliable alternatives to transmission expansion. In addition, TBL could employ transmission-pricing strategies that encourage economically efficient behavior, including the suitable location of new generating units and the timing of electricity use.[2]

Proposed Planning Process and Its Implementation

In Sections 1 and 2 of this report, we recommend that TBL adopt two new elements to its already comprehensive planning process (Fig. ES-1):

1) The production of a biennial system-wide report that describes the expected use of BPA's transmission facilities over the following 10 years. The report will be used to produce the information required for long-term transmission-price signals and to educate BPA's transmission customers on the transmission costs and benefits of different actions that market participants might take that would affect the need for transmission expansion, such as building new generation in certain locations.

2) The refinement and implementation of TBL's existing planning process to screen specific proposed transmission projects against the costs of various forms of suitably located and operated generation, load management, and transmission pricing.

These steps are included in Figure ES-1, which depicts the entire planning process.

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[2] Implementing non-postage-stamp transmission-pricing strategies now could provide a good test for RTO West of the efficacy of its contemplated locational pricing scheme, and would help to make the RTO a more effective steward of the transmission system.

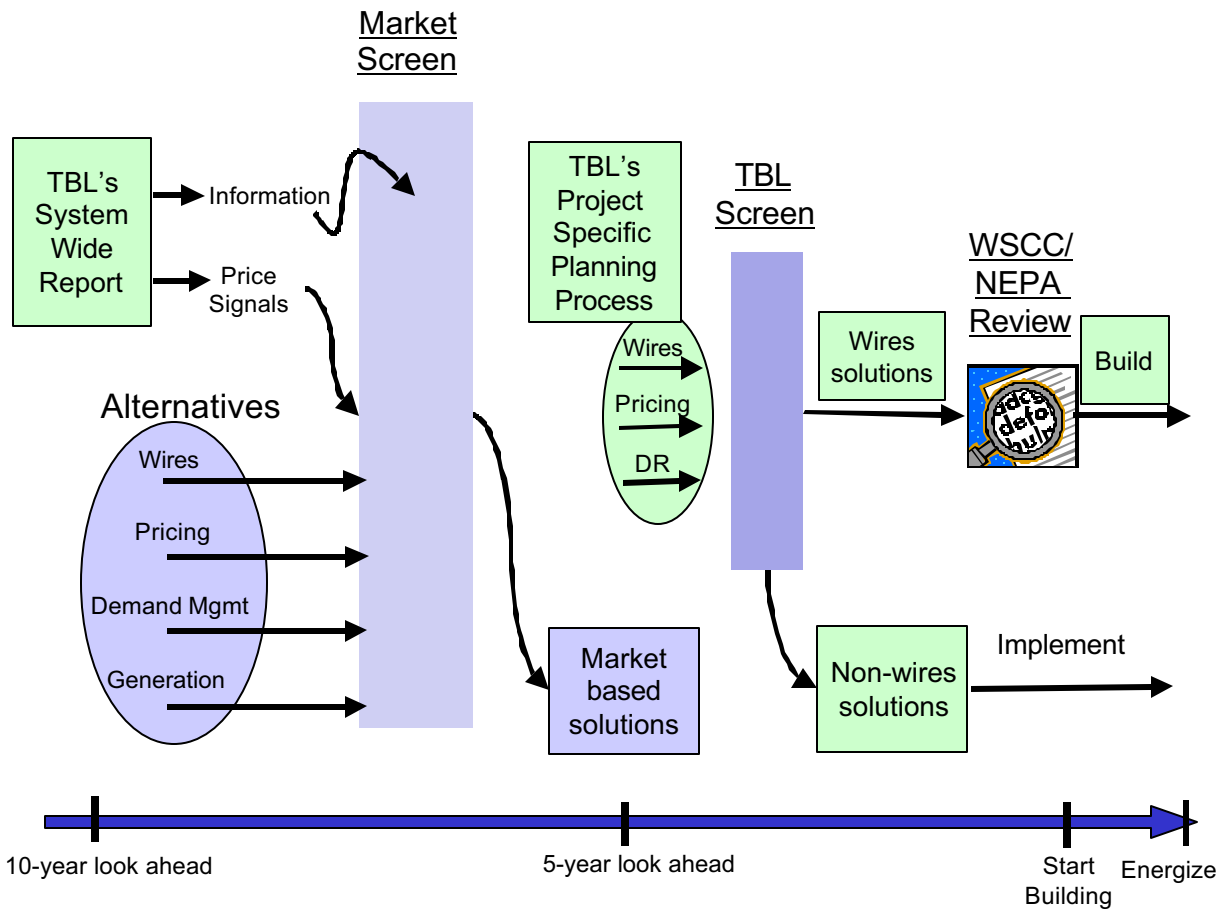

Figure ES-1: The Multiple Screening Process

Specific Recommendations

TBL can take the lead in developing a regional transmission plan, but both development and implementation of the plan should be a regional effort involving many interested and affected players. Ultimately, these regional choices should be made in concert with other Northwest interests. We suggest a detailed approach to coordinated decision making, throughout the planning process, moving from longer-term region-wide perspective to a shorter-term project-specific screening process as the time for action nears.

Revised Transmission Planning: Region-Wide Perspective.

TBL can be the catalyst that brings regional decision makers together to educate each other about the ramifications of their individual actions on the actions of others and the cost that everyone pays for delivered power. A proposed set of steps follows:

1. TBL should produce a long-term view of the transmission plan that includes expected congestion points, and the associated long-run differential costs of delivering power to various points on the grid. (See Section 2 for a detailed discussion of the long-run incremental costs of transmission expansion.) At this stage, TBL could raise the idea and

the possible range of differential transmission rates that could be proposed in its next transmission rate case.

2. TBL should conduct a scoping workshop with interested parties to display and discuss the results of Step 1. In the workshop, TBL might also find that it has additional information that would be helpful to others. In order to ensure a complete picture of the Northwest grid, the potential reinforcement plans identified by other parties should be incorporated into the long-term view. This might be done through regional planning coordination forums such as the NWPP.

3. Ask interested parties to analyze the results of the workshop, and be prepared to enter into detailed discussions of alternative cost-effective and reliable nonwires actions that they could take individually and collectively.

4. Conduct a second workshop wherein all regional stakeholders can discuss options within their jurisdiction that can help to alleviate the problems identified in TBL's initial long-term view. An important part of this workshop will be a continuing discussion about the uncertainties of acquisition and reliability in operation of all proposed alternatives to wires and of their cost effectiveness. These uncertainties are a consequence of factors such as fuel prices, load growth, federal and state regulation of the electricity industry, wholesale market structure, and market design.

5. TBL will have a number of options available to it at this point, as follows:

    a. It may conclude that there are no economic and reliable options to wires, in which case planning for grid expansion continues through the project-specific screening process proposed herein. As suggested in Figure ES-1, there is still opportunity at this stage to discover previously unrecognized alternatives, although they are fewer, due to the short time left to implement a solution.

    b. It may decide to issue RFPs for wires or nonwires solutions that can be implemented at lower cost by others.

    c. It may decide that locational and time-sensitive pricing of transmission can defer construction of new transmission and propose them in its next rate case.

    d. It may want to discuss with and lobby its customer utilities and state regulators to implement retail-pricing options that will decrease the need for transmission expansion.

    e. It might consider a broad package of alternatives that includes all of the activities listed above as well as other ideas that surface during the planning process.

Revised Transmission Planning: Project Specific Perspective

We identified a need to broaden TBL's consideration of nonwires alternatives. As the need for investment in specific wires or nonwires solutions nears, *the project-specific screening process* should be implemented. To refine this process, we recommend taking two of the currently

proposed G-20 projects through this screening process. (The screening process is discussed in Section 2.) The two projects would be put through all steps of the screening process in concert with TBL staff. This effort would refine the proposed screening process and help decide whether economic and reliable alternatives exist to delay transmission construction of either or both projects.

The first stage of the project-specific screening process identifies those projects that cannot be solved by nonwires alternatives and those that have viable alternatives. (See the discussion screening projects into "buckets" in Section 2.) Many of the projects included in TBL's proposed projects are driven by the need to interconnect new generators or are too far along in the process to identify suitable alternatives to them.

Of the remaining G-20 projects, we identified two for detailed projected specific screening that will address different issues that arise with respect to transmission expansion.

- G-8 is a project that crosses sensitive environmental areas, and the decision to construct is far enough out in time to provide a potential benefit from a search for alternatives. That is, if alternatives exist, there is a possibility that they can be implemented in time to delay the October 2003 decision date to proceed with grid expansion. The primary drivers for G-8 is the Canadian Entitlement return and load service within the Puget Sound.

- G-12 is proposed to serve expected load growth on the Olympic Peninsula. We recommend that G-12 be the other project that is put through the full screening process, again, in concert with TBL staff.

In summary, this project reviewed BPA's current transmission-planning process and identified potential additions to that process to strengthen its relevance to expanding wholesale power markets in the Northwest. Our recommendations focus on nonwires solutions to transmission problems, with suggestions on how to consider such alternatives to traditional "wire in the air" projects in both long-term and project-specific planning.

List Of Acronyms

BPA	Bonneville Power Administration
DG	Distributed generation
DSM	Demand-side management
EUE	Expected unserved energy
FERC	Federal Energy Regulatory Commission
ISO	Independent system operator
LICR	Long-run incremental cost
NEPA	National Environmental Policy Act
NWPP	Northwest Power Pool
PBL	Power Business Line
RTO	Regional transmission operator
TBL	Transmission Business Line
VOS	Value of service
WSCC	Western Systems Coordinating Council

Section 1: Proposed Planning Process

1.0. Introduction

The purpose of the suggested changes to TBL's transmission planning process is to make the process more proactive and expansive in identifying and resolving transmission problems at the lowest cost to the transmission system, thereby improving TBL's ability to meet the needs of its customers. This process could be implemented over the next three years, in time for full implementation for projects with start dates in 2004. The recommended process includes the addition of two new functions and the modification of several others.

The two new functions are:

1. The production of a biennial system-wide report that describes the expected use of TBL's transmission facilities over the following 10 years. The report will be used to produce the information required for long-term transmission-price signals and to educate TBL's transmission customers on the transmission costs and benefits of different actions that market participants might take that would affect the need for transmission expansion, such as the location of new generation plants.

2. A two-part screening process for TBL's transmission projects to identify those projects that have viable nonwires alternatives. This can be viewed as a "backstop" project-specific screen performed by TBL to find nonwires alternatives that may have been missed in the system-wide market process initiated by the biennial report described above as function 1.
   a. The first is a high level screen to identify transmission problems that cannot be solved by nonwires alternatives. These are transmission projects that do not have viable alternatives because of generation interconnection, contract, or safety obligations.
   b. The remaining transmission projects, for which viable alternatives might exist, will be screened against the costs of strategically located and operated generation, demand management, and transmission-pricing programs.

For all planned investments with start dates before 2004, we propose an interim screening approach that includes the high level screen described above in 2a, and also identifies transmission projects that do not have viable alternatives because they require immediate solutions. The application of this interim screening process is described in Section 2.1 and the process is applied to the TBL planned projects G1 through G20.

1.1. Existing Transmission Planning Process

Figure 1 shows a simplified version of TBL's existing transmission planning process. While designed to meet the anticipated needs of its transmission customers, the process is reactive in that it is almost always driven by events external to TBL. These events are called project drivers and include requests for generation or customer interconnection, or the need to comply with

legal, regulatory, safety or reliability requirements.[3] These drivers then lead to screening, evaluation, development of options, selection of the preferred plan, various reviews to ensure compliance with NERC and WSCC reliability requirements, regional planning processes under WSCC and NWPP and with the National Environmental Policy Act, and finally an implementation process that includes construction and rate-making[4].

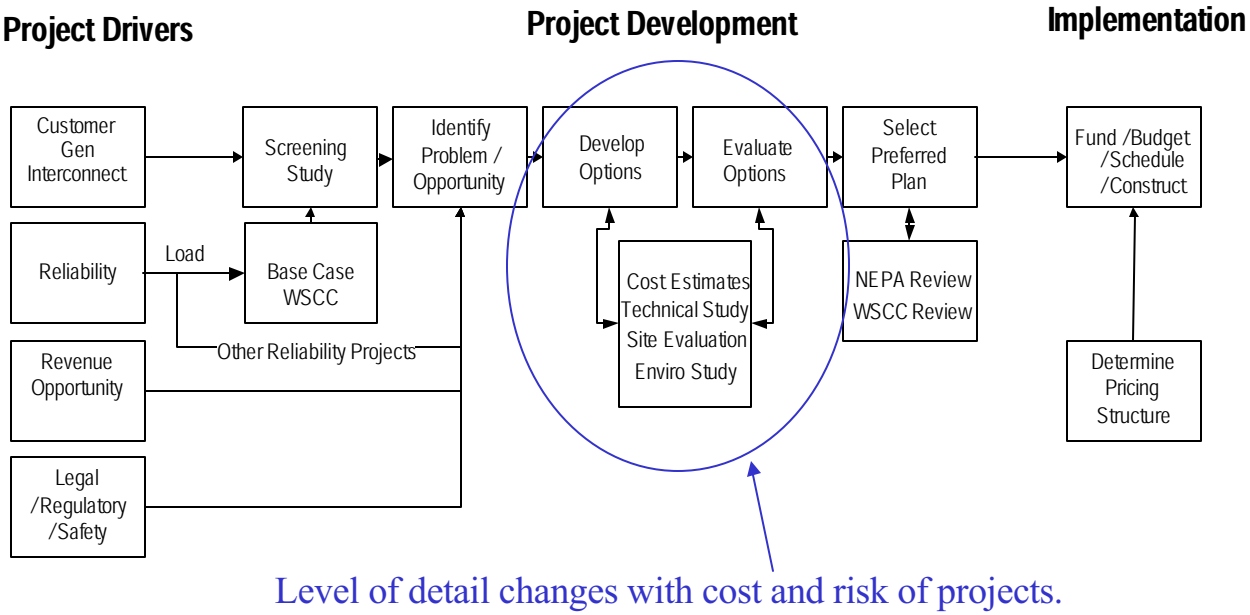

Figure 1: Simplified Existing TBL Planning Process

Although the existing TBL planning process is consistent with best practice industry standards, it identifies transmission needs on a schedule that is too late for implementation of nonwires alternatives. For example, a TBL-funded load-reduction program, designed to solve one of its transmission constraints and replace a wires expansion project, would have to be put in place long before the project's in-service date. The in-service dates for the current set of G1-G9 projects are four years or less in the future, whereas a coordinated demand reduction project may take five years to fully implement and therefore may be a nonviable alternative.

Reactive transmission planning processes are not conducive to finding cost-effective and feasible nonwires alternatives. A longer term, system-wide planning process is needed as a supplement to the existing process.

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[3] In a few cases new revenue opportunities may drive the need for new construction.

[4] See, for example, the BPA Infrastructure Addition Summary at: http://www.transmission.bpa.gov/tbllib/Publications/Infrastructure/defaultfiles/slide0001.htm

1.2. Creating a 10-Year Planning Study

The goal of the suggested system-wide transmission planning study is to identify future problems and requirements on the transmission system in sufficient time to solicit market-based solutions that are less expensive than transmission expansion. These market-based solutions will be funded by private investors who accept all risks for the project's success. That is, the returns on the investment will not be determined or guaranteed by a government regulator, but rather by competitive markets. The system-wide transmission planning study should look out over a 10-year horizon and be updated on a regular basis, i.e., biennially. This will allow sufficient time for market response and for the implementation of long-lead-time projects, such as the construction of large generation facilities.

The study should develop a broad consensus on new transmission and/or nonwires projects that are needed and that get built in a timely and cost-effective fashion. The categories of potential transmission and nonwires activities include the following:

1. Transmission expansion that is built within rate base for a FERC-regulated entity (or the equivalent) with regulated transmission rates;
2. Merchant transmission financed through market-based revenues;
3. Wholesale and retail pricing strategies for energy and transmission that reflect temporal and locational variations in costs;
4. Demand Management:
    a. Energy efficiency programs
    b. Load-shifting programs,
        i. Reliability management (energy and ancillary services),
        ii. Economics (price) based
5. Strategically placed generation plants within the transmission grid or underlying distribution system, including distributed generation.

The goal is to rely primarily on market-based solutions to transmission problems that are engendered by information from TBL that informs expectations of prices. However, BPA transmission operators should continue the existing TBL project planning process. This on-going process will be used to manage transmission problems that are serious and persistent, do not have a market based solution, and require a timely intervention and resolution.

We understand that TBL already has plans to resurrect its long-term planning process to produce better market information. The system-wide study we are proposing should be a natural extension of that effort.

Under this proposed process, once every other year TBL will produce a System-Wide Planning Study. The study will consist of the following steps:

1. Describe the current electricity situation, covering bulk-power operations, wholesale markets, and transmission pricing. Include transmission projects to which commitment has already been made.

2. Perform a 10-year load forecast that produces a range of plausible load scenarios. (Refer to Section 1.3 for recommendations on conducting a load growth forecast.)

3. Identify existing and potential problems (e.g., reliability, congestion, losses, generator market power) that are caused by the current and anticipated limitations of the transmission system. Report on the conditions under which the problems appear (e.g., certain hours, seasons, weather conditions, load forecasts, etc.).

4. Determine if the problems identified in Step 3 are chronic, and whether they are expected to persist without transmission upgrades or expansions, or without the implementation of nonwires solutions.

5. Based on steps 1 through 4, construct a set of alternative TBL expansion plans over the ensuing 10 years, under different scenarios of loads, generation development, transfers, regional power-flow patterns, etc.

6. Translate base-case expansion plans into expected long-run incremental costs (LRIC) of transmission expansion by zone or across major flowpaths. (See Section 2 for an explanation of the LRIC estimation.)

7. Identify feasible ways to provide efficient transmission-price signals (including charges for access, congestion, and losses) and conduct an aggressive public outreach to ensure as broad an understanding[5] as possible. Potential methods for pricing include cooperative programs with BPA's customers and structural pricing solutions.[6]

The implementation of this seven-step process would result in the following time line. Every potential transmission project would appear on the market participants' radar screens at least ten years before the project need date. The information would be updated on a biennial basis. TBL would develop a variety of incentives to encourage efficient behavior for the period running up to the project need date.

At least five years prior to the projected need date, TBL would run its project specific planning process. Closer to an expansion need date, TBL would produce more refined forecasts of load growth and other requirements on the transmission system, and would screen for smaller scale generation resources and other nonwires solutions in addition to transmission construction. A transmission project would undergo regional and NEPA reviews only after it has been exposed to (a) market forces to identify and encourage market solutions and (b) TBL's supplemental programs and screening processes. This multiple screening process is depicted in Figure 2.

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[5] This transmission-planning information should help market participants understand how the actions that they might take (e.g., build a new generating unit or implement a voluntary demand exchange) affect their transmission costs.

[6] See Appendix 1 for a description of one structural pricing program that Energy and Environmental Economics, Inc. implemented in British Columbia, Canada.

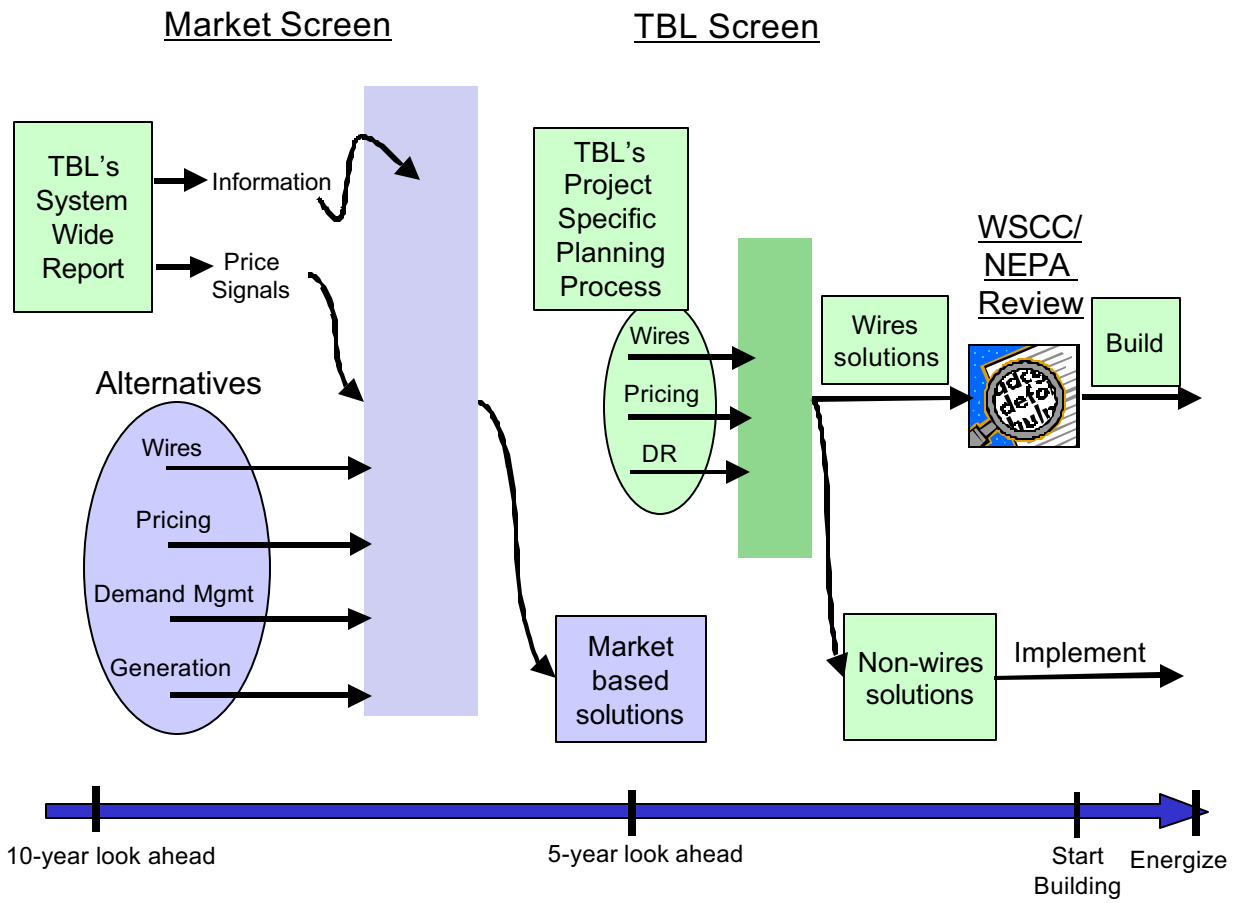

Figure 2: The Multiple Screening Process

1.3. Project-Specific Planning Process

In addition to the on-going proactive work in the longer-term planning horizon, we recommend that TBL supplement its existing project-specific planning process. In particular, TBL should develop the capability to screen transmission projects against the costs of strategically placed and operated generation resources and other nonwires solutions. Initially BPA would screen larger projects (e.g., more than $10 million in capital investment), and progressively include smaller projects as experience is gained. This supplemental task would require modifications to the current planning process that would:

1) Improve load forecasts for the biennial report and the project-specific planning process. The current process for forecasting the capacity requirements for the transmission system combines a BPA forecast for full-requirement customers (municipalities, PUDs, REAs, and cooperatives) with a growth projection provided by seven investor-owned utilities, and 14 public utilities with significant generation. The BPA forecast covers only 25% of the winter peak load, with forecasts provided by others making up the remaining 75%. Since these load forecasts drive the need for investments, their accuracy and consistency are extremely important. The recommended changes to the process include:

a) Remove the incentive for the utilities that submit their forecast to over-estimate their peak load requirement.[7] A comparison of past forecasts and loads could determine if there is a systematic bias in the forecasts that are submitted.

b) Analyze a range of high, base-case, and low peak loads in the forecasting process. This will allow for a meaningful analysis of alternative investment approaches. If a low forecast has a reasonable probability of occurring, a smaller, incremental investment approach may be cost-effective because it allows TBL to install capacity and observe the loads before committing to a large project.[8]

c) While transmission problems may be identified based on annual or seasonal peaks, as proscribed in NERC and WSCC criteria, analysis of nonwires alternatives should be based on hourly load-duration curves, rather than only on the annual peak. The load duration curve is important when evaluating alternative solutions because TBL will need to know when and how often generation or load reduction is required to solve the capacity problem. This is not typically part of traditional transmission planning since transmission lines provide capacity continuously once constructed.

2) Quantify the cost and reliability consequences of not building suggested projects. An important question in any review of a transmission plan is what will happen if the project is not built. The TBL planning process should address this by explicitly quantifying the degradation in reliability of the system, the number and types of customers that would be affected, and the potential economic impact on customers. Many projects are built to comply with the WSCC planning criteria. The quantification of the 'do-nothing' case should describe how far short a system will be of these criteria without the project. Depending on the type of customers, there are a number of ways to estimate the economic impact of not building a project. These include estimating the expected unserved energy (EUE) and value of service (VOS), and estimates of market power impacts on prices, and lost sales opportunities for generators[9].

3) Evaluate alternatives such as demand management, distributed generation (DG), interruptible/curtailable rates, and transmission pricing solutions to transmission problems. Are any nonwires alternatives more cost-effective than the proposed transmission project? In the project-specific planning process, we recommend that TBL perform a high-level

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[7] The incentive to submit high forecasts is caused by the payment structure for transmission. The payments are not linked to the load forecasts, but are based on actual metered usage. Therefore, a high forecast ensures excess capacity at no additional cost.

[8] On the other hand, there are large economies of scale in transmission construction that argue for overbuilding ahead of need.

[9] For further discussion on EUE and VOS refer to 'How Much Do Electric Customers Want to Pay for Reliability? New Evidence on an Old Controversy', Energy Systems and Policy, Volume 15, pp. 145-159 1991 by Woo, C.K, Pupp, R.L, Flaim, T. and Mango, R. and 'Costs of Service Disruptions to Electricity Consumers', Energy Vol. 17, No. 2, pp. 109-126, 1992 by Woo, C.K., and Pupp, R.L..

economic screening of a wide range of alternative solutions. This screening approach would start with a simple evaluation using optimistic assumptions about the cost-effectiveness of these nonwires options to allow TBL to look at as wide a set of alternatives as possible. For those measures that have some potential, more time can be devoted to refining the input assumptions and making a more detailed analysis of potential program designs. Section 2 presents an example of an easily implementable high-level economic screen for four different types of nonwires options.

4) Evaluate potential market impacts of new transmission investments. Beyond improving the reliability of the transmission system, many projects are built to allow increased trade and generation interconnection, and to improve market efficiency. In order to describe the complete benefits of a new transmission project, particularly those that are proposed for market reasons, TBL should estimate the effect on the regional energy markets. For example, adding new capacity into an existing load pocket could eliminate the need for standing contracts (such as Reliability Must Run contracts) with generators inside the load pocket and provide regional economic benefits. Because of the market power issues seen in the last few years, several jurisdictions including the California ISO and ISO New England have begun to look at transmission investments with respect to mitigation of market power and reduction of market prices.

5) Implement the modifications suggested by BPA to the scoring and selection of preferred transmission plans. TBL's current investment decision process (called "Matrix") ranks and prioritizes projects for consideration in the capital budgeting process. A number of improvements have been suggested that will significantly improve this process. The most important improvements are developing more specific financial and performance metrics to compare plans, and ranking projects with other projects in the same general category. This approach will make the budgeting process easier to explain since explicit criteria have been used to select projects for funding. Some of the other suggested modifications will provide additional criteria such as EUE, VOS, and impact on market power to supplement existing financial and reliability metrics that are already evaluated in the existing process.

Collectively, these new functions fit directly into the existing process as shown in Figure 3.

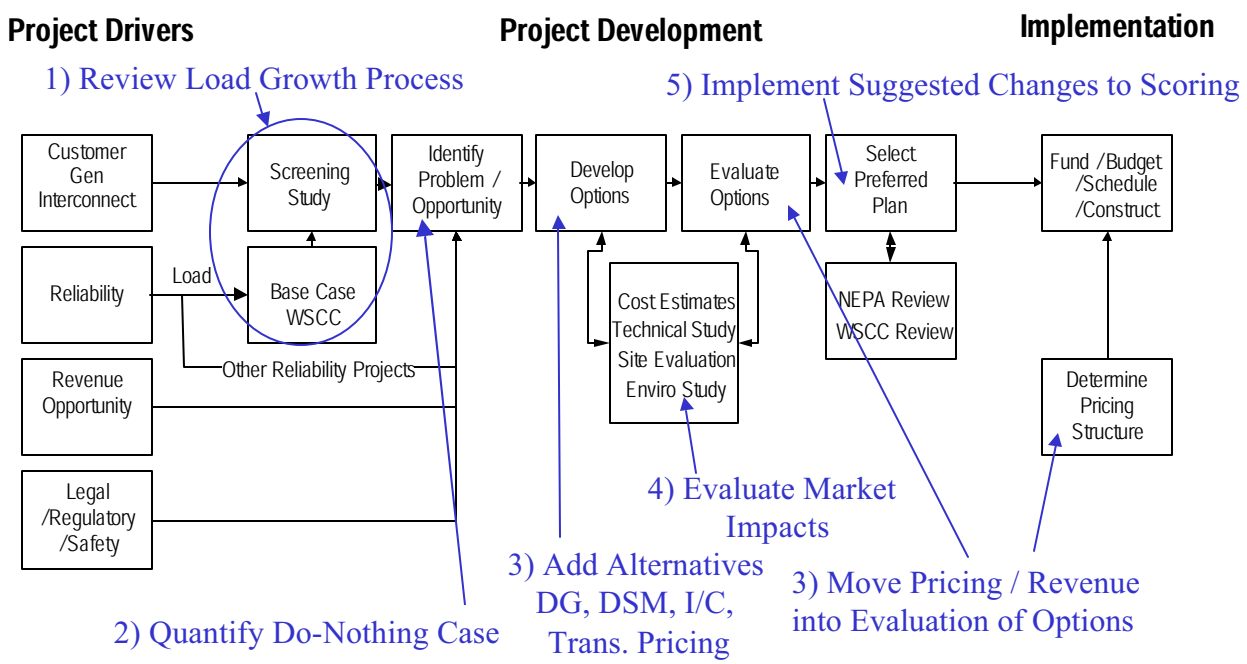


Figure 3: Suggested Modification to TBL's Planning Process

If market constraints or reliability problems are serious, persistent, and do not have a market solution, TBL's on-going project-specific planning process will identify suitable transmission projects to correct the problem. Because this initiates a centralized (rather than market) fix to the problem, the amount of accountability is now greater than if market solutions provided the fixes. TBL's recommended plan should include discussion of the following issues:

1) What is the existing transmission need?

2) Is the proposed project the lowest cost transmission investment to meet that need?

3) Is the recommendation based on realistic assumptions about the future? That is, have the various uncertainties about the input assumptions been adequately considered in assessing alternative solutions to transmission problems?

4) Based on the costs of nonwires alternatives is the plan the least cost alternative? This type of "backstop" screening requires that TBL produce a cost-effectiveness study of every large project that has the potential to be replaced by a nonwires alternative. While this may sound like an unneeded and onerous process, our experience with other utilities indicates that it will not be difficult to implement. If the long-term process is effective, most of the plans should be either the only option left or the most cost effective by the time it shows up on the project-specific planning process radar screen. Moreover, the screening process can be readily automated with relatively simple software and screening processes.

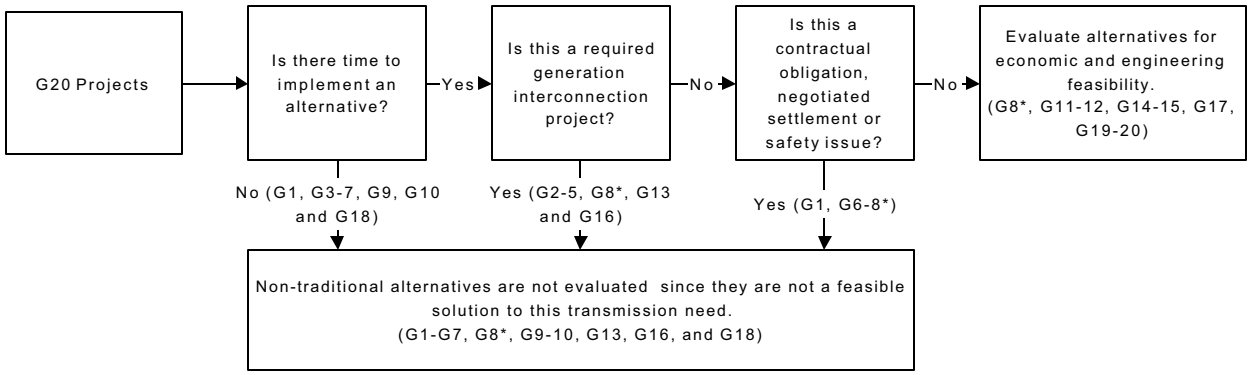
Section 2: Review of Existing Plans

2.1. Initial Screen of the G20 Projects for Evaluation of Alternatives

This section reviews the transmission projects that TBL currently has planned to estimate the potential for nonwires alternatives. Each of the G20 projects has its own particular considerations, and for some projects there has been significant engineering and economic analysis, public workshops and forums, and other work completed. The projects can generally be divided into four categories that are useful to assess whether non-traditional alternatives are a viable solution.

There are three general categories of TBL's transmission needs that non-traditional alternatives will not solve. These are: (1) problems that require an immediate solution; (2) generation interconnection: and (3) contract, negotiated settlement, or safety obligations. Each of these categories is described in more detail below, along with the list of projects for which it applies. All told, 11 of the G20 projects fall into one or more of these three categories. The remaining projects fall into the fourth category: (4) further analysis of the economic and engineering feasibility of alternatives should be conducted. The following diagram illustrates this high-level screening process.

Initial Screen of G20 Projects



* G8; The primary driver for this project is the Canadian Entitlement return, and service of loads to the Puget Sound area. If the Canadian Entitlement return is purchased within the US, non-traditional alternatives may effect this plan.

The following sections describe each of these categories in more detail.

2.1.1. Timing of the Project

Since transmission planning at TBL is an on-going effort, there are a number of projects whose decision date is very near, and it would be impossible to replace the project with a non-

traditional alternative and not violate WSCC reliability criteria. The timing of the decision dates, and in-service dates is included in Table 1 below.

Table 1: TBL Transmission Projects - Updated Schedule (9/26/01)[a]

	Project	Type	Decision	Energization
G1	Kangley - Echo Lake 500 kV line	EIS	Jan-02	Nov-02
G2	Schultz - Black Rock 500 kV line	EIS	Jan-03	Oct-04
G3	McNary - John Day 500 kV line	EIS	Sep-02	Oct-04
G4	Lo Monumental – Starbuck 500 kV line	EIS	Sep-02	Oct-04
G5	Smiths Harbor - McNary 500 kV line	EIS	Sep-02	Oct-04
G6	Schultz series capacitors	CX	Oct-01	Nov-03
G7	Celilo Modernization	CX	Oct-01	Dec-02
G8	Monroe - Echo Lake 500 kV line	EIS	Oct-03	Oct-05
G9	Bell – Coulee 500 kV line	EIS	Nov-02	Oct-04
G10	Pearl Transformer	CX	Apr-02	Oct-03
G11	South Seattle Transformer	CX	TBD	Oct-05
G12	Shelton Transformer and line addition	EIS	Oct-03	Oct-05
G13	Paul – Troutdale 500 kV line	EIS	Oct-04	Apr-06
G14	Hanford – Ostrander loop-in	CX	Apr-04	Apr-06
G15	Libby – Bonners Ferry rebuild	EIS	Oct-04	Oct-06
G16	McNary tap to Ashe - Marion 500 kV line	EIS	Oct-03	Apr-06
G17	Little Goose – Starbuck 500 kV line	EIS	Oct-04	Oct-06
G18	Hatwai – Lolo 230 kV line	EIS	Oct-02	Apr-05
G19	McNary – Brownlee 230 kV line	EIS	Oct-03	Jun-05
G20	Libby – Bell 230 kV line	EIS	Oct-04	Oct-06

[a]The shaded projects have decision dates before January 2003.

As a practical matter, those projects that must be committed to by the end of 2002 to avoid reliability problems are so near-term that it is not feasible to replace them with nonwires alternatives. The decision date is the critical date since even though it is possible to cancel at any point up until the project is in service, there will be a significant amount of money and staff time invested in the project.

The projects that fall into the near-term are G1, G3-7, G9-10, and G18. The rest are far enough in the future that there is time to consider nonwires approaches.

Generation Interconnection and Transmission Service

There is a second group of projects that are necessary to provide transmission network capacity to new generation that is being interconnected at customer request. These types of projects will not generally be able to be avoided by load reduction or distributed generation, since TBL must have enough capacity for these customers once they decide to interconnect and request long-term transmission service. These generation interconnection projects include G2-G5, G8 (although G8 is primarily driven by other factors), G13, and G16.

Negotiated Settlement, Contractual Obligation, Safety

Finally, a third category of transmission investment is necessary because of prior contractual obligations, such as the Canadian Entitlement return, negotiated settlement, or safety. A good example of a negotiated settlement project is G7. This project would upgrade the north terminal of the HVDC line to Southern California and is the result of extensive public collaboration.

The Canadian Entitlement return is the commitment made by the US government as part of the Columbia River Treaty of 1964 to return power to Canada. This agreement was made when Canada built three large storage dams that increase the output of dams in the US. The return of power back to Canada began in 1998, and will increase through 2003. The Canadians may decide to take delivery of the power within the US, thereby reducing the need to deliver power to the Canadian boarder, but under the current agreement a number of new lines would be required. The projects that are at least in part influenced by the Canadian Entitlement return are G1, G6, and G8. Because of its timing, the G8 project is the only one of these that might be avoidable by a future agreement with Canada and/or non-traditional alternatives.

Economic / Reliability

After examining the G20 projects using the three considerations described above the remaining projects have potential for non-traditional alternatives, no explicit legal requirement to build if a reliable alternative exists, and time to complete the analysis before a decision is made on the final project. The candidate projects include G8, G11-G12, G14-15, and G17-G20 (9 of the 20 projects).

2.2. Economic Screening of G12 Olympic Peninsula Additions

In this section we present an illustrative analysis of the avoided costs that appropriately located load reduction or generation could provide to the BPA transmission system. The example is based on the G12 transmission investments for the Olympic Peninsula that was placed in the economic screening 'bucket' from the previous analysis. While we have incorporated the available data as much as possible, this is an illustrative example only and we have simplified the data to better explain the underlying screening process.

The basic calculation behind the economic screening is the change in BPA-TBL revenue requirement that can be achieved by the deferral of a wires investment. If a deferral of a wires

investment lowers[10] the revenue requirement then this potential "savings" can be used to "buy" a nonwires alternative. The cost of the alternative should not exceed the savings achieved from the deferral of the wires project.[11] Estimation of avoided transmission costs would be performed by TBL and included in its 10-year planning document (and perhaps implemented with a new pricing mechanism).

The avoided transmission cost is just one component of the total system benefits of implementing an alternative solution. The backstop screening analysis of nonwires alternatives to a transmission investment, proposed for TBL's project-specific planning process and discussed in Section 1, should also include the avoided generation capacity and energy costs, and distribution avoided costs. While TBL could pay no more than its avoided transmission costs for a nonwires solution, an economic screen needs to incorporate all avoided costs that can be achieved by a nonwires project. [12]

This section focuses on the calculation of the transmission avoided cost component, however the method is similar for the other components of avoided cost[13].

2.2.1. Transmission Avoided Costs

Step 1: Estimate the revenue requirement and timing of the planned transmission investment.

Table 2 shows the revenue requirements for the planned G12 project. This project increases capacity for service to the Olympic Peninsula and is comprised of a conductor upgrade in 2005 and capacitor additions in each of the years 2011 through 2015. The costs are shown at revenue requirement levels (direct investment dollars have been scaled up to account for administrative and general costs, debt repayment, tax effects, and operations and maintenance expenses) so that the economic savings to the BPA ratebase can be estimated.[14] The revenue-requirement amounts shown in column C for the capacitors in years 2011 through 2014 are in 2001 dollars. These are

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[10] A deferral of a wires investment that resulted in increased O&M costs could potentially increase the revenue requirement.

[11] All other things being equal, e.g., reliability, environmental externalities, etc.

[12] For example, a load reduction program planned in a specific area to reduce loading on a transmission line would also reduce loads on the local distribution system and generation market. If the total incentive paid to the customer were based on transmission avoided costs it may not be attractive to the customer nor would the payment reflect all of the benefits of the load reduction. However, by adding any offset wholesale power purchases, and adding local distribution company incentives based on distribution avoided costs, the backstop screen may find the program cost-effective.

[13] For more detail, see *Costing Methodology for Electric Distribution System Planning*, prepared by E3 and Fred Gordon of Pacific Energy Associates for the Energy Foundation.

[14] The cost numbers listed here include an increase of 30% to account for indirect costs and overhead (provided by BPA), and an additional increase of 10% for allowance of funds used during construction.

inflated using the assumed annual inflation rate of 2.7% to get the nominal revenue requirements dollars shown in column E.

The approach described here has been used in dozens of case studies including those referenced earlier. This method of calculating the long run incremental costs is also referred to as the 'differential revenue requirement' method because it is based on the difference in revenue requirements before and after deferral of the transmission project.

Table 2: Revenue Requirement of Planned Expenditures

A	B	C	D	E
Year	Investment	Constant Base Year Dollars ($1000s)	Base Year	Revenue Requirement in Nominal Dollars ($1000s)
Investment data from BPA				
2005	G12 project			40,908
2011	capacitors	1,300	2001	1,697
2012	capacitors	1,300	2001	1,743
2013	capacitors	1,300	2001	1,790
2014	capacitors	1,300	2001	1,838

Step 2: Evaluate the load reduction on the transmission path that would be required to delay the project.

Table 3 shows the load growth forecast in the area affected by G12. The project has been planned to meet the expected load in the winter of 2004/2005, so if the load is kept at or below 2004/2005 levels the transmission project can be delayed. Column B gives the forecasted load projection. The highlighted numbers (2004 to 2009) in column B were provided by TBL, and the remaining peak load numbers were projected by E3 using an assumption of 2% growth rate. The load growth per year is shown in column C.

Table 3: Load Growth Estimate for G12

A	*B*	*C*
Year	Peak Load (MW) Escalated 2%	Total Growth (MW) *Col B - Col*
2002	1,367	
2003	1,394	27.34
2004	1,422	27.88
2005	1,451	29.00
2006	1,480	29.00
2007	1,509	29.00
2008	1,540	31.00
2009	1,571	31.00
2010	1,602	31.42
2011	1,634	32.05
2012	1,667	32.69
2013	1,701	33.34
2014	1,735	34.01
2015	1,769	34.69
2016	1,805	35.38
2017	1,841	36.09
2018	1,877	36.81
2019	1,915	37.55
2020	1,953	38.30
2021	1,992	39.07
2022	2,032	39.85
2023	2,073	40.65
2024	2,114	41.46
2025	2,157	42.29
2026	2,200	43.13
2027	2,244	44.00
2028	2,289	44.88

Step 3: Calculate the change in revenue requirement per kW of load reduction based on the deferral value.

Table 4 calculates the reduction in revenue requirement for the G12 project due to a load reduction.[15] Column A shows the revenue requirement of the expenditures (from Table 2). Column B is the projected annual growth from the load forecast in Table 3. Column C shows the assumed amount of load reduction, which has been set to equal the growth from 2004/5 to 2005/6, i.e. one year of load growth.

[15] This load reduction could be due to distributed generation, curtailable load, DSM or other strategy.

In this example, we assumed a sustained reduction of 29 MW of load through the planning horizon, which would be achievable with a long-life measure such as installation of wall and ceiling insulation in a building that is expected to remain in use for many years. However, only load reductions in years with expenditures affect the revenue requirement, i.e., the 29-MW load reduction will delay the $41 million investment in 2005 until 2006, with a deferral value of over $2 million, but there are no further expenditures planned until 2011 so the deferral value is zero in 2006-2010. If we were evaluating a short–term load reduction measure, such as a three-year curtailable rate option, then this measure would not be credited with the deferral values in years 2011 through 2014.

The assumption on the amount of load reduction is important but subtle. We are estimating the incremental value of load reduction on the constrained path for a **meaningful** increment of load[16]. Column D shows the deferral length in years achieved by the load reductions in column C and this value varies by year depending on the load growth that year. Column E shows the deferral value of the load reduction for each year. The deferral value is calculated as the difference in the present value of revenue requirement before and after the investment is deferred. [17]

This method for calculating the deferral value is based on the concept that the value of a load change is equal to the difference between the present value of the original investment plan and the present value of the deferred plan. [18] A deferred investment is increased by the inflation rate, but the costs are discounted an additional year. Since the discount rate is higher than the inflation rate, this results in a net savings:

Deferral Value = Nominal Cost in Year(i) × (1 – ((1+*Inflation Rate*)/(1+*Discount Rate*))^Δt)

Where Δt is the deferral length in years.

For example, the 29 MW of load reduction prior to 2005 results in a savings of $2.364 million dollars of revenue requirement. Column F divides this total value by the amount of load reduction required to get the value per kW of load reduction, giving a marginal cost of $81.53/kW in 2005. This means that each kW of the 29 MW of total reduction in 2005 is worth $81.53/kW[19] because of the value of deferring the expenditures in that year.

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[16] For systems that have a radial configuration, the amount of load reduction on the constrained path will be the same as the total resource that is implemented (adjusted for losses). In network systems, flow distribution factors can be used to estimate load reduction achieved on the constrained path from a reduction at a particular point on the system.

[17] The inflation rate and weighted average cost of capital (WACC) used in the calculation of Column E are 2.7% and 9%, respectively.

[18] See Area Specific Marginal Costing for Electric Utilities: "A Case Study of Transmission and Distribution Costs", R. Orans Ph.D. Dissertation, 1989.

[19] Note that the $81.53/kW value only holds if the full 29 MW of load reduction can be achieved.

Table 4: Calculation of Transmission Deferral Value

	A	B	C	D	E	F
Year	Scaled Nominal Cost ($000)	Load Growth (MW)	Load Reduction (MW)	Deferral Length (yrs)	Deferral Value ($000)	Marginal Cost ($/kW)
	(see prior table)			*(Col C / Col B)*	*(A * (1-((1+inflation)/(1+WACC))^D))*	*(Col E / Col D)*
2003	0	27.3	29.0	1.06	0	0.00
2004	0	27.9	29.0	1.04	0	0.00
2005	40,908	29.0	29.0	1.00	2,364	81.53
2006	0	29.0	29.0	1.00	0	0.00
2007	0	29.0	29.0	1.00	0	0.00
2008	0	31.0	29.0	0.94	0	0.00
2009	0	31.0	29.0	0.94	0	0.00
2010	0	31.4	29.0	0.92	0	0.00
2011	1,697	32.0	29.0	0.90	89	3.07
2012	1,743	32.7	29.0	0.89	90	3.09
2013	1,790	33.3	29.0	0.87	90	3.11
2014	1,838	34.0	29.0	0.85	91	3.14
2015	0	34.7	29.0	0.84	0	0.00
2016	0	35.4	29.0	0.82	0	0.00
2017	0	36.1	29.0	0.80	0	0.00
2018	0	36.8	29.0	0.79	0	0.00
2019	0	37.5	29.0	0.77	0	0.00
2020	0	38.3	29.0	0.76	0	0.00
2021	0	39.1	29.0	0.74	0	0.00
2022	0	39.8	29.0	0.73	0	0.00
2023	0	40.6	29.0	0.71	0	0.00
2024	0	41.5	29.0	0.70	0	0.00
2025	0	42.3	29.0	0.69	0	0.00
2026	0	43.1	29.0	0.67	0	0.00
2027	0	44.0	29.0	0.66	0	0.00
2028	0	44.9	29.0	0.65	0	0.00

Step 4: Calculate the total transmission avoided cost.

Table 5 shows the calculation of the total avoided costs of deferral of the G12 project over the life of the load reduction that achieves the deferral. Column B shows the marginal cost in $/kW from Table 4. Columns C, D, E and F show the avoided costs for load reduction measures that last for 3, 5, 10 and 15 years respectively. Row 14 calculates the net present value of the avoided cost stream, which is equivalent to the total avoided cost per kW over the horizon of 3, 5, 10 and 15 years respectively. For example, a load reduction of 29 MW for 3 years is worth $68.62 per kW, which is the sum of the marginal values in years 2003, 2004 and 2005 discounted by the weighted average cost of capital (WACC). The value for a 5-year reduction is the same as the 3-year reduction because there are no further avoided costs in the years 2006 and 2007. The

longer-term measures of 10 and 15 years have higher values as they are capturing the value of avoided cost in years 2011 through 2014.

Table 5: Calculation of the Total Marginal Cost Over the Life of the Load Reduction

	A	B	C	D	E	F	G
Row			Measure Duration in Years				
1	Year	Marginal Cost ($Nominal/kW) *From Col H*	3	5	10	15	Comment
2	2003	0.00	0.00	0.00	0.00	0.00	*Marginal Costs included match the*
3	2004	0.00	0.00	0.00	0.00	0.00	*duration of the measure indicated in*
4	2005	81.53	81.53	81.53	81.53	81.53	*Row 1*
5	2006	0.00		0.00	0.00	0.00	
6	2007	0.00		0.00	0.00	0.00	
7	2008	0.00			0.00	0.00	
8	2009	0.00			0.00	0.00	
9	2010	0.00			0.00	0.00	
10	2011	3.07			3.07	3.07	
11	2012	3.09			3.09	3.09	
12	2013	3.11				3.11	
13	2014	3.14				3.14	
14	Total Marginal Cost (NPV$/kW)		$68.62	$68.62	$71.59	$74.12	*NPV(WACC,Rows 2 to 11)*(1+WACC)*

These calculations suggest that TBL could pay up to $74.12/kW for a program that cut demand by 29 MW in 2003 and maintained that reduction for 15 years. If TBL can acquire such load reductions for a lower price, it should do so and defer the transmission project. If not, it should go ahead and build the G12 project. Programs lasting 3, 5, or 10 years should be evaluated on the same principle.

2.2.2. Application to Screening Non-Wires Alternatives

After calculating the avoided costs achievable by a load reduction, TBL should perform an economic screening analysis on a wide-range of nonwires alternatives to the transmission project. This screening process will help determine if a program to encourage nonwires alternatives warrants consideration, or if the economics make such projects clearly non cost-effective. Using optimistic assumptions for the nonwires alternatives, measures that are not cost-effective in this broad level screen will not warrant closer examination in a detailed screening study. The goal of the screening level analysis is to allow consideration of a broad set of options without requiring intensive analysis. For options that look promising after a screening study has been completed, a more refined analysis can be conducted. Appendix 1 provides an example of this screening analysis, calculating the lifecycle costs and benefits of a number of different alternatives including demand side management (DSM), DG, Fuel Switching, and Curtailable Programs in comparison to the G12 transmission project.

Benefit/Cost Perspectives

Suggesting that a measure is "cost-effective" immediately raises the question, "cost effective to whom?" The cost-effectiveness of a potential measure is evaluated from a number of different perspectives, which are described briefly below.

Ratepayer Impact Measure (RIM) - Transmission Company

This benefit/cost test measures the impacts on TBL's rates. The benefits included for this test are the transmission avoided costs, and the costs included are the incentive payments paid by TBL to the providers of the nonwires solution(s) to the transmission problem, TBL's administrative costs and TBL's lost revenues due to reduced sales. If the program benefit/cost ratio is less than one, this program would tend to increase the per unit rates that TBL charges to meet its revenue requirement. Measures that significantly reduce sales, such as conservation, generally appear not cost-effective from the RIM perspective.

Utility Cost Test - Transmission Company

This test measures the impacts on TBL's revenue requirement. The benefits included for this test are the transmission avoided costs, and the costs included are the incentive payments and administrative costs. If the program benefit/cost ratio is less than one, the program will increase the revenue requirement. This test is different than the RIM test because the lost sales due to any measures that reduce TBL sales do not affect the revenue requirement; this depends, of course, on the transmission rate design.

Total Resource Cost Test (TRC)

The TRC test measures the costs and benefits from a broader perspective and includes all of the direct cash costs due to the measure. The benefits include the transmission, distribution, generation capacity and energy avoided costs, and the costs included are the lifecycle costs of the measure and administrative costs. Transfers such as incentive payments between TBL and its customers, as well as bill savings are not included from this perspective since the net cost between TBL and customers is zero.

Societal Cost Test

The societal cost test includes the broadest set of costs and benefits due to a measure. In addition to the direct cash costs accounted for in the TRC test, any environmental externalities such as reduced air emissions are included as a benefit.

Participant Cost Test

The participant cost test measures the lifecycle net benefits for the participant. The participant is the customer that is installing the DSM, curtailing their load, or who owns the DG. The benefits included for this test are the incentives paid to the customer and the customer's bill savings due to the measure, and the costs included are the life-cycle costs to the participant of the measure. This cost test is a good indicator of how acceptable a program will be to a customer.

Each of these tests has value to some market participants. An interesting, but not yet resolved issue, concerns the appropriate tests to use in RTO-dominated competitive wholesale electricity markets.

Program Design Issues

The value of load reduction will be the economic basis of any incentives that TBL would use to encourage alternative solutions in the market place. The design of the program will depend on the type of alternative to the transmission project, and will have the following considerations in mind;

- Payments made by TBL for the program should reflect the value of load reduction with the objective of minimizing overall transmission costs for TBL customers.
- Level and timing of payments made by TBL should reflect TBL's confidence that the required level of load reduction will be achieved.
- Programs are designed to attract participants.

Incentive Payments

The transmission-avoided cost based on revenue requirement savings as calculated in Section 2.2.1 represents the total value of load reduction or generation. An assessment must be made on how to share these benefits between the participants and non-participants in the program. If the entire avoided costs are paid to the participants (for example to get a higher penetration level) then the revenue requirement remains unchanged, and transmission users in general do not share any of the benefits of the deferral. While paying the maximum incentive may maximize uptake of alternative solutions, the objective of the program is to minimize transmission costs. Therefore TBL wants to pay the lowest incentive that is required to induce an alternative solution. The typical starting point for this analysis is an incentive level set at 50% of the avoided cost, which represents an equal sharing between participants and non-participants.

Locational Nature of the Avoided Costs

The example shown in this section calculates only the transmission avoided costs of a specific investment in the G12 Olympic Peninsula Additions. Therefore, the value is only meaningful for load reductions or generation that reduce loads on the constrained path that is the target of the load reduction.

Required Amount of Load Reduction

This example is based on an incremental amount (29 MW) of load reduction. Investments are built to meet the forecasted peak loads, so typically a deferral is only meaningful if it is in one-year steps. For example, rather than an in-service date of fall 2005, the project is moved to an in-service date of Fall 2006. Therefore, if less than the amount required for a one year deferral is achieved, and the project must still be energized according to the original schedule, and there is no deferral benefit to the load reduction.

It is questionable if a project delay of less than a year has any meaningful value. Experience shows that projects are almost always scheduled to be energized in the season prior to the forecasted peak, which for most of BPA is the winter season (hence the schedule to energize in the fall). If the load reduction falls short of what is required to lower the peak load for that winter then the project still needs to be energized in the fall. Energizing in the spring will be too late, if TBL has gone through the winter it might as well wait until the following fall to energize.

Appendix A

Section 3: Implementation of Planning Process

3.1. Long-Term Transmission Planning

TBL can take the lead in developing a long-term transmission plan, but both development and implementation of the plan should be a regional effort involving all interested players. The options open to TBL cover a wide range of possibilities. Ultimately, the path chosen should be done in concert with other Northwest interests.

At one end of the spectrum, TBL could simply publish information about the transmission grid today and the expected conditions in the future. Developing this option would require TBL to identify the kinds of information about the grid that would be useful to market participants. At the other end of the spectrum, TBL could actually run demand-side programs and build generating units to solve transmission problems. This second option seems extremely unlikely because it is so antithetical to the creation, design, and operation of competitive wholesale markets and, therefore, will not be discussed further. However, TBL could achieve the objective of solving transmission problems at least cost in other ways, for example, by issuing RFPs for nonwires and merchant-transmission solutions to transmission problems.

From the spectrum discussed above, TBL should develop the details necessary to implement two options: 1) provision of information useful to market participants; and 2) acquisition from the market of least-cost solutions to transmission problems.

For the first option, TBL should identify the specific data elements and forms of presentation needed by generating companies, power marketers and brokers, load-serving entities, transmission owners, representatives of consumer and environmental groups to make informed decisions on generation and demand-management programs. The range of information TBL could provide encompasses simple maps showing the desirable and undesirable locations for new generation from the perspective of the transmission system to detailed results from load-flow studies (voltages, real- and reactive-power flows, and phase angles) and real-time operating data.

For the second option, TBL should review the experience that other utilities and ISOs have had with the acquisition of nonwires solutions to transmission problems. For example, all the existing U.S. ISOs operate demand-management programs intended to provide reliability resources and to reduce wholesale-power costs. This review will form the basis of TBL's decision on whether and, if so, how to proceed with potential acquisition from market participants of transmission solutions.

3.1.1. Recommendation.

TBL can be the catalyst that brings together regional decision-makers to educate each other about the ramifications of their individual actions on the actions of others and the cost that everyone pays for delivered power. Recommended steps include:

1. TBL should produce a long-term view of the transmission system that includes expected congestion points, and the associated long-run differential costs of delivering power to

various points on the grid. At this stage, TBL could raise the idea and the possible range of differential transmission rates that could be proposed in its next transmission rate case.

2. TBL should conduct a scoping workshop with interested parties to display and discuss the results of Step 1. In the workshop, TBL might also find that it has additional information that would be helpful to others. In order to ensure a complete picture of the Northwest grid, the potential reinforcement plans identified by other parties should be incorporated into the long-term view. This might be done through regional planning coordination forums such as the NWPP.

3. Ask interested parties to analyze the results of the workshop, and be prepared to enter into a detailed discussion of alternative cost-effective and reliable nonwires actions that they could take individually and collectively.

4. Conduct a second workshop wherein all regional stakeholders can discuss options within their jurisdiction that can help to alleviate problem areas identified in TBL's initial long-term view. An important part of this workshop will be a continuing discussion about the uncertainties of acquisition and reliability in operation of all proposed alternatives to wires and of their cost-effectiveness. These uncertainties are a consequence of factors such as fuel prices, load growth, federal and state regulation of the electricity industry, wholesale market structure, and market design. In order to stimulate ideas among stakeholders and provide for more productive workshops, industry professionals experienced with the economics and feasibility of wires and nonwires options should be invited to participate.

5. TBL will have a number of options available to it at this point, as follows:

    a. It may conclude that there are no economic and reliable options to wires, in which case planning for grid expansion continues through the short-term screening process proposed herein. As suggested in Figure 2, there is still opportunity at this stage to discover previously unrecognized alternatives, although they are fewer, due to the short time left to implement a solution.

    b. It may decide to issue RFPs for wires or nonwires solutions that can be implemented at lower cost by others.

    c. It may decide that locational and time sensitive pricing of transmission can defer construction of new transmission and propose them in its next rate case.

    d. It may want to discuss with and lobby its customer utilities and state regulators to implement retail-pricing options that will decrease the need for transmission expansion.

    e. It might consider a broad package of alternatives that includes all of the activities listed above as well as other ideas that surface during the planning process.

3.2. Project-Specific Screening.

We recommend taking two of the G-20 projects through the project-specific screening process described in Section 2 of this paper. Each of the projects would be put through all of the steps of the screening process in concert with TBL staff. Through this process, TBL will refine the screening process, and will determine if economic and reliable alternatives exist to delay transmission construction of either or both projects.

Because different issues arise with respect to transmission expansion driven by generation interconnection requests versus other reasons, we propose that TBL run two of the G-20 projects through the project-specific planning process (e.g., G-8 and G-12). G-8 is a project that crosses sensitive environmental areas, and the decision to construct it is far enough out to potentially benefit from a search for alternatives. That is, if alternatives exist, there is a possibility that they can be implemented in time to delay the October 2003 decision date to proceed with grid expansion. The primary drivers for G-8 is the Canadian Entitlement return and load service within the Puget Sound area.

Another good candidate is G-12. A brief example of how the marginal cost on a per kW-year basis would be calculated for G-12 is contained in Section 2.

3.3 Future Uncertainties

Finally, given all the uncertainties about the future of the electricity industry, we recommend that TBL develop, test, and deploy methods for dealing with these uncertainties in its planning and decision-making concerning new long-lived transmission projects. The focus should be both on the analytical process TBL might use to assess uncertainties and on presentation methods to aid interested stakeholders in understanding the implications of uncertainties related to load growth, fuel prices, new generation, demand management programs, industry restructuring, RTO formation, and government regulation.

Appendix A

Appendix 1: Sample Screen of Non-Traditional Alternatives

This Appendix shows how to derive the benefit/cost ratios of four nonwires alternatives to transmission projects: fuel switching, DG, DSM and interruptible/curtailable load programs. Please note that these examples are illustrative only and do not relate to any specific TBL projects.

Summary of Cost-Effectiveness

The alternatives for delaying the G12 transmission project are evaluated from each of the cost-effectiveness perspectives described in section 2.2.2. The measures evaluated include;

- Customer-owned distributed generation; generation that is not metered by BPA. This could be generation located at an end-users site, or within a local distribution utility. Assumed installed cost is $600/kW with a heat rate of 10,000 MMBtu/kWh and annual load factor of 10%.

- Merchant plant distributed generation; generation located on BPA's transmission that injects power and is subject to the TBL transmission tariff. Assumed installed cost is $600/kW with a heat rate of 10,000 MMBtu/kWh and annual load factor of 10%.

- Conservation DSM; based on a general mix of commercial energy conservation measures. The assumed cost is $3 million per average MW conserved (8760MWh per year).

- Fuel-switching DSM; based on switching from electric heating to natural gas heating for residential end-users. The assumed energy savings is 2500kWh per year, with a winter peak load reduction of 2kW.

- Curtailable Load; based on a three-year curtailable program. Each participant is assumed to be interrupted 30 hours per year with an incentive payment of $100/MWh.

Table 6, below, summarizes the benefit/cost ratio for each of these measures. The relationship of the benefit/cost ratios for each of the measures is typical. From the RIM perspective, any measures that significantly reduce sales such as DSM, fuel switching, or behind the meter generation are not cost-effective because of the lost sales component. The DG merchant plant and curtailable load program are cost effective from RIM because they do not result in significant revenue losses and the incentives are paid based on a percentage (approximately 50%) of the deferral value. For these two measures the RIM results are very similar to the utility cost test (UCT), since the only difference between the tests is the lost sales component. On the other hand, the customer DG bypass and fuel switching look much better from a UCT perspective than RIM.

The Total Resource Cost (TRC) test is the usual test of cost-effectiveness from a traditional least-cost planning perspective. If the TRC benefit/cost ratio is greater than one, incentive payments, public purpose charges, and other mechanisms can potentially be designed to make all other perspectives cost-effective. Fuel switching, and curtailable programs are the only cost-effective measures from the TRC perspective. The societal cost test is an extension of the TRC,

which includes additional non-cash benefits. Similar to the TRC, if public purpose charges are levied on the same group that accrue the non-tangible benefits, all perspectives can be made cost-effective if the societal cost test benefit/cost ratio is greater than one.

The participant cost test is critical because it indicates whether a measure is likely to be acceptable to the participants. If the benefit/cost ratio is lower than one, participants are worse off after having implemented the measure and therefore they are unlikely to adopt it. The fuel switching, conservation, and curtailable programs are cost-effective to the participant given the input assumptions of costs and incentive levels made to develop this example.

Table 6: Summary of Cost-Effectiveness

Benefit Cost Ratios	DG Customer Bypass (includes revenue loss)	DG Merchant Plant (no revenue loss)	Residential Switch to Natural Gas Heating	Generic Conservation Measure (Office Lighting, Shell Retrofit, etc.)	1kW of Curtailable Load (Demand Exchange Program)
RIM Test Transmission Company	1.31	2.05	0.45	0.02	5.17
Utility Cost Test Transmission Company	2.05	2.05	1.85	0.02	5.17
TRC Cost Test	0.42	0.42	1.22	0.25	7.25
Societal Cost Test	0.42	0.42	1.35	0.30	7.28
Participant Cost Test	0.52	0.03	1.19	1.06	1.16

Of the five measures evaluated, only the curtailable load program is cost-effective from every perspective. The measure is clearly 'cost-effective' from the broadest definition. Other programs are less clear. For example, the fuel switching to natural gas heating is cost-effective from all but the RIM test. Under traditional least cost planning, this measure might be pursued with the loss in revenue made up with a public benefits charge assessed to all customers.

The examples for all four alternatives use the same set of basic assumptions. These assumptions are outlined in Table 7 below. The transmission lifecycle avoided costs are from row 14 of Table 5, above.

Table 7: General Assumptions

Input Variable	Value
Utility Discount Rate	9.00%
Financing Rate of Generator (DG)	12%
	Annual Value ($/yr)
Generation Capacity $/kW-yr	0
Local Distribution Company $/kW-yr	20
Energy (Mid-C) $/MWh	30
Environmental Adder $/MWh	6
Total Average Rate $/kWh	$0.0800
Transmission Average Rate $/kW-month	$2.5600

Transmission Lifecycle Avoided Cost$/kW				
Measure Life (Years)	3	5	10	15
Transmission Lifecycle Avoided Cost $/kW	$68.62	$68.62	$71.59	$74.12

The following four tables present the detailed calculations of the five cost tests for various non-traditional alternative scenarios. The first half of each table contains the inputs and intermediate calculations that are used in the calculation of the cost tests in the second half of the table. Input variables not included in Table 7 are highlighted, and calculated values are left clear. Where necessary, the derivation of the inputs is explained in parentheses, with items referenced by row numbers.

Table 8: Cost Tests of Distributed Generation

		DG Customer Bypass (includes revenue loss)	DG Merchant Plant (no revenue loss)
1	DG Device	Gas Turbine Peaker	Gas Turbine Peaker
2	Utility Incentive Cost $/kW	$30.00	$30.00
3	Generator Life (Years)	10	10
	Generator Cost Assumptions		
4	Fuel Cost $/MMBtu	$5.00	$5.00
5	Heat Rate Btu/kWh	10,000	10,000
6	Fuel Cost $/kWh ($/MMBtu [4] * Heat Rate [5] / 10^6)	$0.05	$0.05
7	Capital Cost $/kW	$500.00	$500.00
8	Install Cost $/kW	$100.00	$100.00
9	Fixed O&M $/kW-yr	$10.00	$10.00
10	Variable O&M $/kWh	$0.005	$0.005
11	Annual Fuel and O&M Costs $/kW ({fuel cost [6] + var. O&M [10]} * annual load factor [14] * 8760 hrs in a yr + fixed O&M [9])	$58.18	$58.18
12	Environmental Externality Benefit? 1= yes, 2=no	0	0
	Generator Operating Assumptions		
13	Peak Period kW Savings	1.00	1.00
14	Annual Load Factor	10%	10%
15	Monthly Peak Demand Reduction (kW) (for billing determinants)	1.00	1.00
	Lifecycle Generator Costs		
16	Lifecycle Capital Cost ($/kW) (cap. cost [7] + install cost [8])	$600.00	$600.00
17	Lifecycle Fuel and O&M Cost ($/kW) (Discounted at Generator WACC)	$328.73	$328.73
18	Total Lifecycle Cost ($/kW)	$928.73	$928.73
	Per Unit Lifecycle Avoided Costs		
19	Generation Capacity $/kW	$0.00	$0.00
20	Transmission $/kW (total 10-year trans. marginal cost discounted at utility discount rate)	$71.59	$71.59
21	Local Distribution Company $/kW (local distr. marginal cost accruing over 10 years, discounted at utility discount rate)	$139.90	$139.90
22	Energy $/kWh ($MWh marg. cost accruing over 10 yrs discounted at utility disc. rate / 1000)	$0.21	$0.21
23	Energy + Environmental Adder (If Clean Generation) $/kWh (energy per unit cost [22] + {$MWh env. adder cost accruing over 10 yrs discounted at utility disc. rate} / 1000)	$0.21	$0.21
	Rates and Lost Revenue		
24	Total Average Rate $/kWh	$0.0800	$0.0000
25	Transmission Average Rate $/kW-year	$2.5600	$0.0000
26	Total Electricity Revenue Loss $/year (total avg rate [24] * annual load factor [14] * 8760 hrs in a yr)	$70.08	$0.00
27	Transmission Revenue Loss $/year (trans. avg. rate [25] * monthly peak demand reduction [15] * annual load factor [14] * 12 months)	$3.07	$0.00

Appendix A

	Lifecycle Avoided Costs per kW, Revenue per kW, Incentive per kW		
28	Generation Avoided Cost (gen. capacity per unit cost [19] * peak period kW savings [13])	$0.00	$0.00
29	Transmission Avoided Cost (trans. per unit cost [20] * peak period kW savings [13])	$71.59	$71.59
30	Local Distribution Company (local distr. per unit cost [21] * peak period kW savings [13])	$139.90	$139.90
31	Energy (energy per unit cost [22] * annual load factor [14] * 8760 hrs in a yr)	$183.84	$183.84
32	Energy w/ Environment (energy & env. adder per unit cost [23] * annual load factor [14] * 8760 hrs in a yr)	$183.84	$183.84
33	Total Electricity Revenue Loss (total annual loss [26] accruing over 10 years, discounted at utility discount rate)	$449.75	$0.00
34	Transmission Revenue Loss (total annual loss [27] accruing over 10 years, discounted at utility discount rate)	$19.72	$0.00
35	Lifecycle Incentive Payment	$30.00	$30.00
36	Lifecycle Admin Cost	$5.00	$5.00

		DG Customer Bypass (includes revenue loss)	DG Merchant Plant (no revenue loss)
	RIM Test - Transmission Delivery Company		
37	Program Cost (Incentive+T Rev. Loss+Admin)	$54.72	$35.00
38	Program Benefit (T Savings)	$71.59	$71.59
39	Net Savings	$16.87	$36.59
40	BC Ratio	1.31	2.05
	Utility Cost Test - Transmission Delivery Company		
41	Program Cost (Incentive + Admin)	$35.00	$35.00
42	Program Benefit (T Savings)	$71.59	$71.59
43	Net Savings	$36.59	$36.59
44	BC Ratio	2.05	2.05
	TRC Cost Test		
45	Program Cost (DG Cost+ Admin)	$933.73	$933.73
46	Program Benefit (Gen Savings + T Savings + D Savings)	$395.33	$395.33
47	Net Savings	($538.40)	($538.40)
48	BC Ratio	0.42	0.42
	Societal Cost Test		
49	Program Cost (DG Cost + Admin)	$933.73	$933.73
50	Program Benefit (Gen Savings + T Savings + D Savings + Environment)	$395.33	$395.33
51	Net Savings	($538.40)	($538.40)
52	BC Ratio	0.42	0.42
	Participant Cost Test		
53	Program Cost (DG Costs)	$928.73	$928.73
54	Program Benefit (Incentive + Electricity Bill Reduction)	$479.75	$30.00
55	Net Savings	($448.98)	($898.73)
56	BC Ratio	0.52	0.03

Appendix A

Table 9: Cost Tests of Fuel Switching

		Residential Switch to Natural Gas Heating
1	Cost of Original Device	$300.00
2	Replacement Device	$500.00
3	Utility Incentive Cost $/measure	$30.00
4	Measure Life (Years)	15
	Annual Demand and Energy Impacts	
5	Peak Period kW Savings	2.00
6	Annual kWh/measure	2500.00
7	Monthly Peak Demand Reduction (kW) (for billing determinants)	1.00
	Lifecycle Avoided Costs per kW or kWh	
8	Generation Capacity $/kW	$0.00
9	Transmission $/kW (total 15-year trans. marginal cost discounted at utility discount rate)	$74.12
10	Local Distribution Company $/kW (local distr. marginal cost accruing over 15 years, discounted at utility discount rate)	$175.72
11	Energy $/kWh ($MWh marg. cost accruing over 15 yrs discounted at utility disc. rate / 1000)	$0.26
12	Energy + Environmental Adder $/kWh (energy per unit cost [11] + {$MWh env. adder cost accruing over 15 yrs discounted at utility disc. rate} / 1000)	$0.32
	Rates, Administration Costs, and Lost Revenue	
13	Total Average Rate $/kWh	$0.0800
14	Transmission Average Rate $/kW-year	$2.5600
15	Alternative Fuel Rate ($/Replaced kWh)	$0.0500
16	Alternative Fuel Cost ($/Replaced kWh)	$0.0200
17	Alternative Fuel Bill ($/measure per year) (alt. fuel rate [15] * annual kWh/measure [6])	$125.00
18	Alternative Fuel Cost ($/measure per year) (alt. fuel cost [16] * annual kWh/measure [6])	$50.00
19	Admin Cost $/measure one time cost	$50.00
20	Total Electricity Revenue Loss $/year (total avg rate [13] * annual kWh/measure [6])	$200.00
21	Transmission Revenue Loss $/year (trans avg rate [14] * monthly peak demand reduction [7] * 12 months)	$30.72
	Lifecycle Avoided Costs, Revenue, Incentive per measure	
22	Generation Avoided Cost (gen. capacity per unit cost [8] * peak period kW savings [5])	$0.00
23	Transmission Avoided Cost (trans. per unit cost [9] * peak period kW savings [5])	$148.24
24	Local Distribution Company (local distr. per unit cost [10] * peak period kW savings [5])	$351.45
25	Energy (energy per unit cost [11] * annual kWh/measure [6])	$658.96
26	Energy w/ Environment (energy & env. adder per unit cost [12] * annual kWh/measure [6])	$790.75
27	Alternative Fuel Bill $/measure	$1.007.59
28	Alternative Fuel Cost $/measure	$403.03
29	Total Electricity Revenue Loss	$1.612.14
30	Transmission Revenue Loss	$247.62
31	Lifecycle Incentive Payment	$30.00
32	Lifecycle Admin Cost	$50.00

		Residential Switch to Natural Gas Heating
	RIM Test - Delivery and Alternative fuel Company	
33	Program Cost (Incentive+Trans. Rev. Loss+ Admin)	$327.62
34	Program Benefit (Trans Savings)	$148.24
35	Net Savings (Max. Incentive)	($179.38)
36	BC Ratio	0.45
	Utility Cost Test - Delivery	
37	Program Cost (Incentive + Admin)	$80.00
38	Program Benefit (Trans Savings)	$148.24
39	Net Savings (Max. Incentive)	$68.24
40	BC Ratio	1.85
	TRC Cost Test	
41	Program Cost (Measure Cost + Alternative Fuel Cost + Admin)	$953.03
42	Program Benefit (Gen Savings + T Savings + D Savings)	$1,158.65
43	Net Savings (Max. Incentive)	$205.61
44	BC Ratio	1.22
	Societal Cost Test	
45	Program Cost (Measure Cost + Alternative Fuel Cost + Admin)	$953.03
46	Program Benefit (Electric Gen Savings + Trans Savings + Environment)	$1,290.44
47	Net Savings (Max. Incentive)	$337.41
48	BC Ratio	1.35
	Participant Cost Test	
49	Program Cost (Buy Device + Alternative Fuel Bill)	$1,507.59
50		$1,792.14
	Program Benefit (Incentive + Electricity Bill Reduction+ Replace Conv. Device)	
51	Net Savings (Max. Incentive)	$284.55
52	BC Ratio	1.19

Table 10: Cost Tests of DSM

		Generic Conservation Measure (Office Lighting, Shell Retrofit, etc.)
1	Cost of Original Device	$2,000,000.00
2	Replacement Device	$8,000,000.00
3	Utility Incentive Cost $/measure	$3,000,000.00
4	Measure Life (Years)	10
	Annual Demand and Energy Impacts	
5	Peak Period kW Savings (for T&D capacity savings)	1,000
6	Annual kWh/measure	8,760,000
7	Monthly Peak Demand Reduction (kW) (for billing determinants)	1,000
	Lifecycle Avoided Costs per kW or kWh	
8	Generation Capacity $/kW	$0.00
9	Transmission $/kW (total 10-yr marginal cost discounted at utility discount rate)	$71.59
10	Local Distribution Company $/kW (local distr. marginal cost accruing over 10 years, discounted at utility discount rate)	$139.90
11	Energy $/kWh ($MWh marg. cost accruing over 10 yrs discounted at utility disc. rate / 1000)	$0.21
12	Energy + Environmental Adder $/kWh (energy per unit cost [11] + {$MWh env. adder cost accruing over 10 yrs discounted at utility disc. rate} / 1000)	$0.25
	Rates, Administration Costs, and Lost Revenue	
13	Total Average Rate $/kWh	$0.0800
14	Transmission Average Rate $/kW-year	$2.5600
15	Admin Cost $/measure one time cost	$50,000.00
16	Total Electricity Revenue Loss $/year (total avg rate [13] * annual kWh/measure [6])	$700,800.00
17	Transmission Revenue Loss $/year (trans avg rate [14] * monthly peak demand reduction [7] * 12 months)	$30,720.00
	Lifecycle Avoided Costs, Revenue, Incentive per measure	
18	Generation Avoided Cost (gen. capacity per unit cost [8] * peak period kW savings [5])	$0.00
19	Transmission Avoided Cost (trans. per unit cost [9] * peak period kW savings [5])	$71,590.00
20	Local Distribution Company (local distr. per unit cost [10] * peak period kW savings [5])	$139,904.94
21	Energy (energy per unit cost [11] * annual kWh/measure [6])	$1,838,350.88
22	Energy w/ Environment (energy & env. adder per unit cost [12] * annual kWh/measure [6])	$2,206,021.06
23	Total Electricity Revenue Loss	$4,497,494.52
24	Transmission Revenue Loss	$197,150.44
25	Lifecycle Incentive Payment	$3,000,000.00
26	Lifecycle Admin Cost	$50,000.00

		Generic Conservation Measure (Office Lighting, Shell Retrofit. etc.)
	RIM Test - Delivery Company	
27	Program Cost (Incentive+Trans. Rev. Loss+ Admin)	$3,247,150.44
28	Program Benefit (Trans Savings)	$71,590.00
29	Net Savings (Max. Incentive)	($3,175,560.44)
30	BC Ratio	0.02
	Utility Cost Test - Delivery	
31	Program Cost (Incentive + Admin)	$3,050,000.00
32	Program Benefit (Trans Savings)	$71,590.00
33	Net Savings (Max. Incentive)	($2,978,410.00)
34	BC Ratio	0.02
	TRC Cost Test	
35	Program Cost (Measure Cost + Admin)	$8,050,000.00
36	Program Benefit (Gen Savings + T Savings + D Savings)	$2,049,845.82
37	Net Savings (Max. Incentive)	($6,000,154.18)
38	BC Ratio	0.25
	Societal Cost Test	
39	Program Cost (Measure Cost + Admin)	$8,050,000.00
40	Program Benefit (Electric Gen Savings + Trans Savings + Environment)	$2,417,516.00
41	Net Savings (Max. Incentive)	($5,632,484.00)
42	BC Ratio	0.30
	Participant Cost Test	
43	Program Cost (Buy Device)	$8,000,000.00
44	Program Benefit (Incentive + Electricity Bill Reduction+ Replace Conv. Device)	$8,497,494.52
45	Net Savings (Max. Incentive)	$497,494.52
46	BC Ratio	1.06

Appendix A

Table 11: Cost Tests of I/C Programs

		1kW of Curtailable Load (Demand Exchange Program)
1	Customer Cost of Dropped Load ($/kWh) (Lost Productivity)	$0.15
2	Customer Cost of Dropped Load ($/kW lifecycle) ([1] accruing over 3 yrs)	$12.42
3	Utility Incentive Cost $/MWh	$100.00
4	Utility Incentive Cost $/kW lifecycle ([3] accruing over 3 yrs, discounted at utility discount rate)	$8.28
5	Measure Life (Years)	3
	Annual Demand and Energy Impacts	
6	Peak Period kW Savings (for T&D capacity savings)	1.00
7	Annual kWh/measure (Number of hours per year)	30
8	Monthly Peak Demand Reduction (kW) (for billing determinants)	0.00
9	Months in Peak Load Season for Curtailment	4
	Lifecycle Avoided Costs per kW or kWh	
10	Generation Capacity $/kW	$0.00
11	Transmission $/kW (total 3-year marginal cost discounted at utility discount rate)	$68.62
12	Local Distribution Company $/kW (local distr. marginal cost accruing over 3 years, discounted at utility discount rate)	$55.18
13	Energy $/kWh ($MWh wholesale energy cost accruing over 3 yrs discounted at utility disc. rate / 1000)	$0.08
14	Energy + Environmental Adder $/kWh (energy per unit cost [13] + {$MWh env. adder cost accruing over 3 yrs discounted at utility disc. rate} / 1000)	$0.10
	Rates, Administration Costs, and Lost Revenue	
15	Total Average Rate $/kWh	$0.0800
16	Transmission Average Rate $/kW-month	$2.5600
17	Admin Cost $/measure one time cost	$5.00
18	Total Electricity Revenue Loss $/year (total avg rate [15] * annual kWh/measure [7])	$2.40
19	Transmission Revenue Loss $/year (trans avg rate [16] * monthly peak demand reduction [8] * months in peak load season [9])	$0.00
	Lifecycle Avoided Costs, Revenue, Incentive per measure	
20	Generation Avoided Cost (gen. capacity per unit cost [10] * peak period kW savings [6])	$0.00
21	Transmission Avoided Cost (trans. per unit cost [11] * peak period kW savings [6])	$68.62
22	Local Distribution Company (local distr. per unit cost [12] * peak period kW savings [6])	$55.18
23	Energy (energy per unit cost [13] * annual kWh/measure [7])	$2.48
24	Energy w/ Environment (energy & env. adder per unit cost [14] * annual kWh/measure [7])	$2.98
25	Total Electricity Revenue Loss	$6.08
26	Transmission Revenue Loss	$0.00
27	Lifecycle Incentive Payment	$8.28
28	Lifecycle Admin Cost	$5.00

		1kW of Curtailable Load (Demand Exchange Program)
	RIM Test - BPA TBL	
29	Program Cost (Incentive+Trans. Rev. Loss+ Admin)	$13.28
30	Program Benefit (Trans Savings)	$68.62
31	Net Savings (Max. Incentive)	$55.34
32	BC Ratio	5.17
	Utility Cost Test - BPA TBL	
33	Program Cost (Incentive + Admin)	$13.28
34	Program Benefit (Trans Savings)	$68.62
35	Net Savings (Max. Incentive)	$55.34
36	BC Ratio	5.17
	TRC Cost Test	
37	Program Cost (Cost of Dropped Load+ Admin)	$17.42
38	Program Benefit (Gen Savings + T Savings + D Savings)	$126.29
39	Net Savings (Max. Incentive)	$108.87
40	BC Ratio	7.25
	Societal Cost Test	
41	Program Cost (Cost of Dropped Load + Admin)	$17.42
42	Program Benefit (Gen Savings + Trans Savings + Environment)	$126.78
43	Net Savings (Max. Incentive)	$109.37
44	BC Ratio	7.28
	Participant Cost Test	
45	Program Cost (Cost of Dropped Load)	$12.42
46	Program Benefit (Incentive + Electricity Bill Reduction)	$14.35
47	Net Savings (Max. Incentive)	$1.94
48	BC Ratio	1.16

Appendix A

Expansion of TBL Transmission Planning Capabilities

Prepared for BPA TBL by:

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Summary of Recommendations

- Engage regional stakeholders in TBL's planning process
  - Goal is to **share information** that would lead to a more efficient region-wide system
- Biennial system-wide report
  - **Describes the expected use** of BPA's transmission facilities over the following 10 years
- Refinement of existing planning process
  - **Screen transmission projects** against the costs of various forms of suitably located and operated generation, load management, and transmission pricing

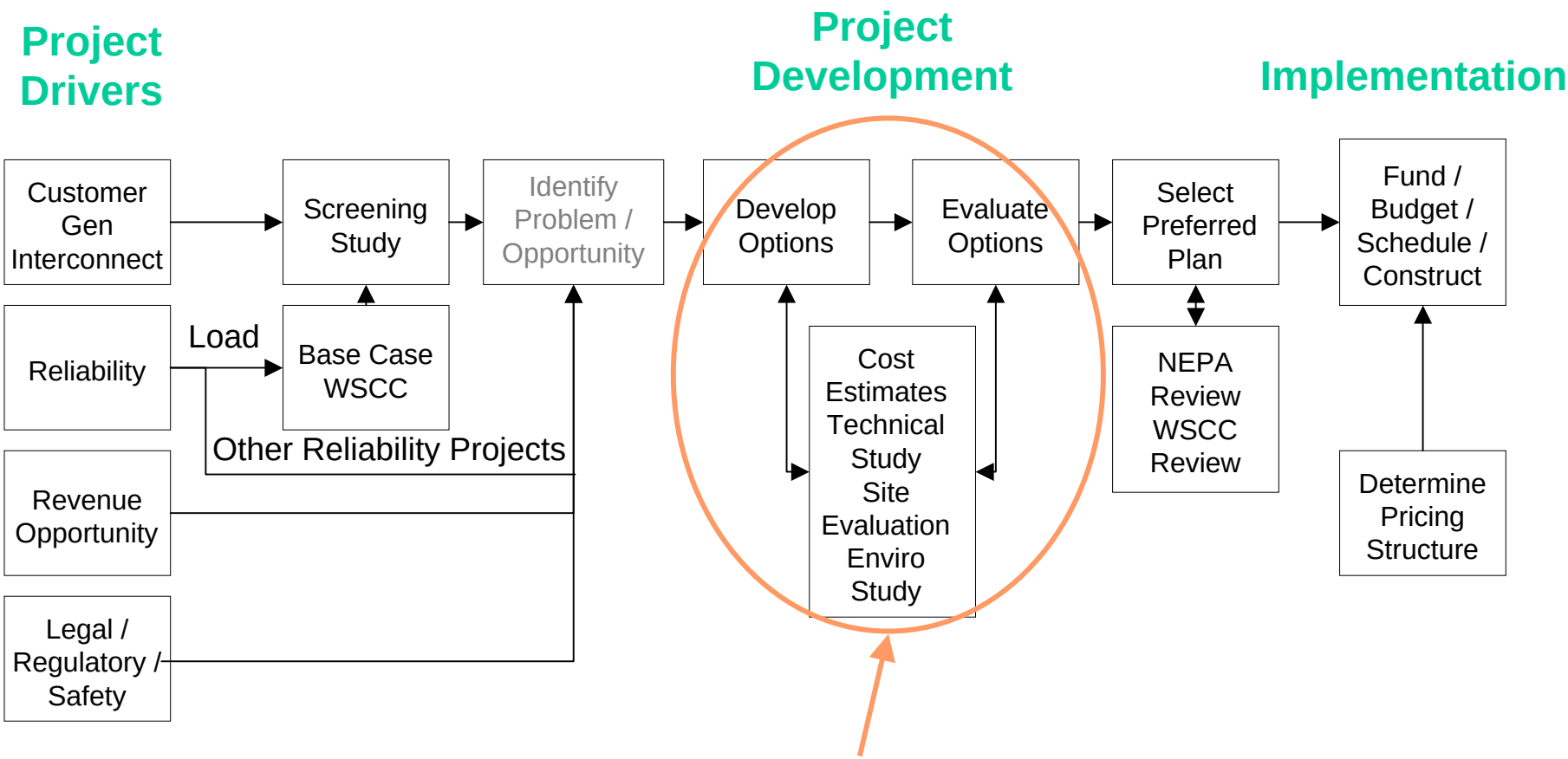
Existing TBL Planning Process

- Designed to **meet anticipated customer needs**
- **Reactive** -- driven by events external to TBL

Problems with Traditional Planning

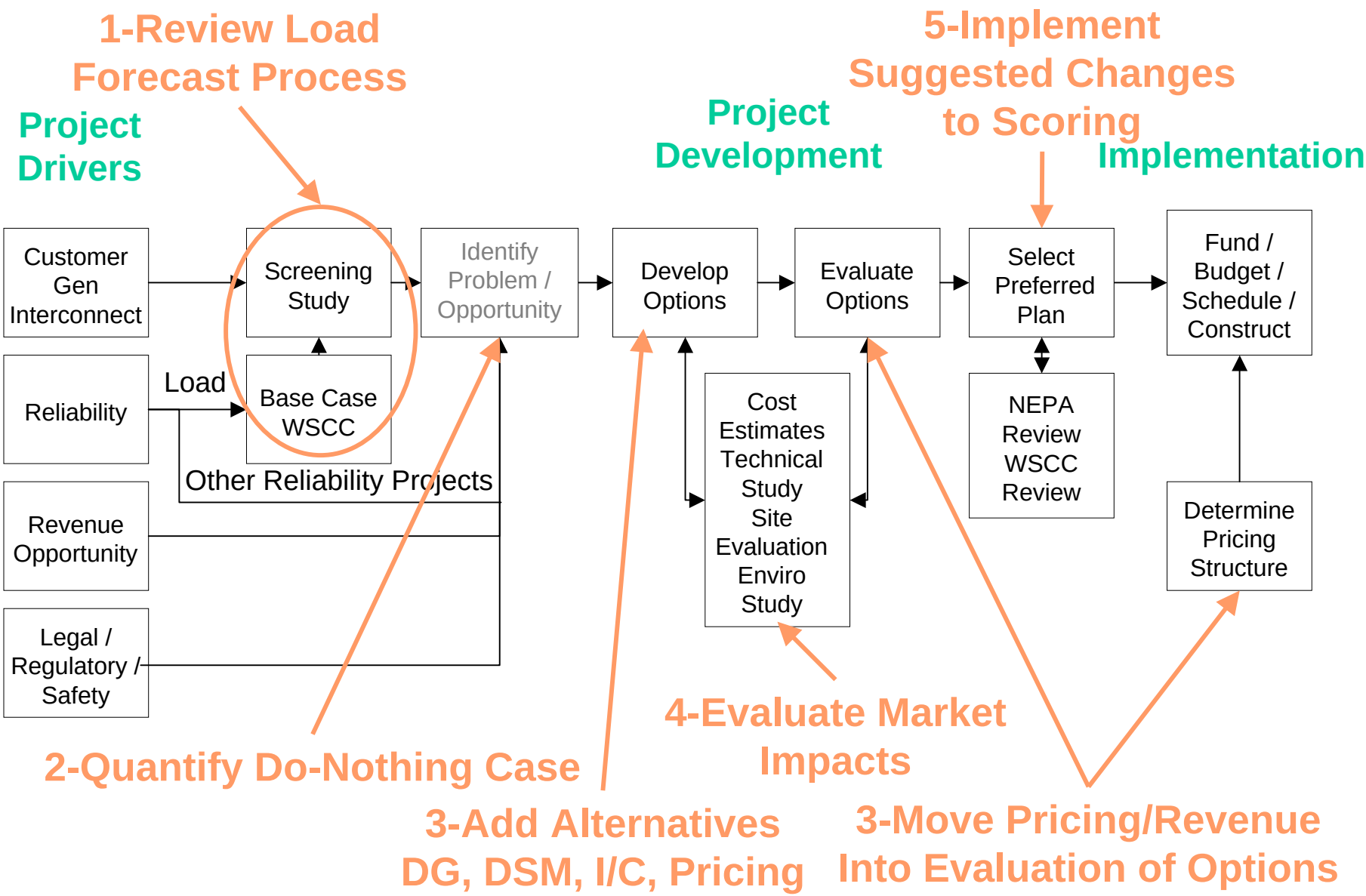
- **Reactive** -- driven by events external to TBL
- Insufficient time to consider non-wires alternatives
- Insufficient time to engage other stakeholders

Overview of Existing Process



Level of detail changes with cost and risk of projects

Suggested Modifications

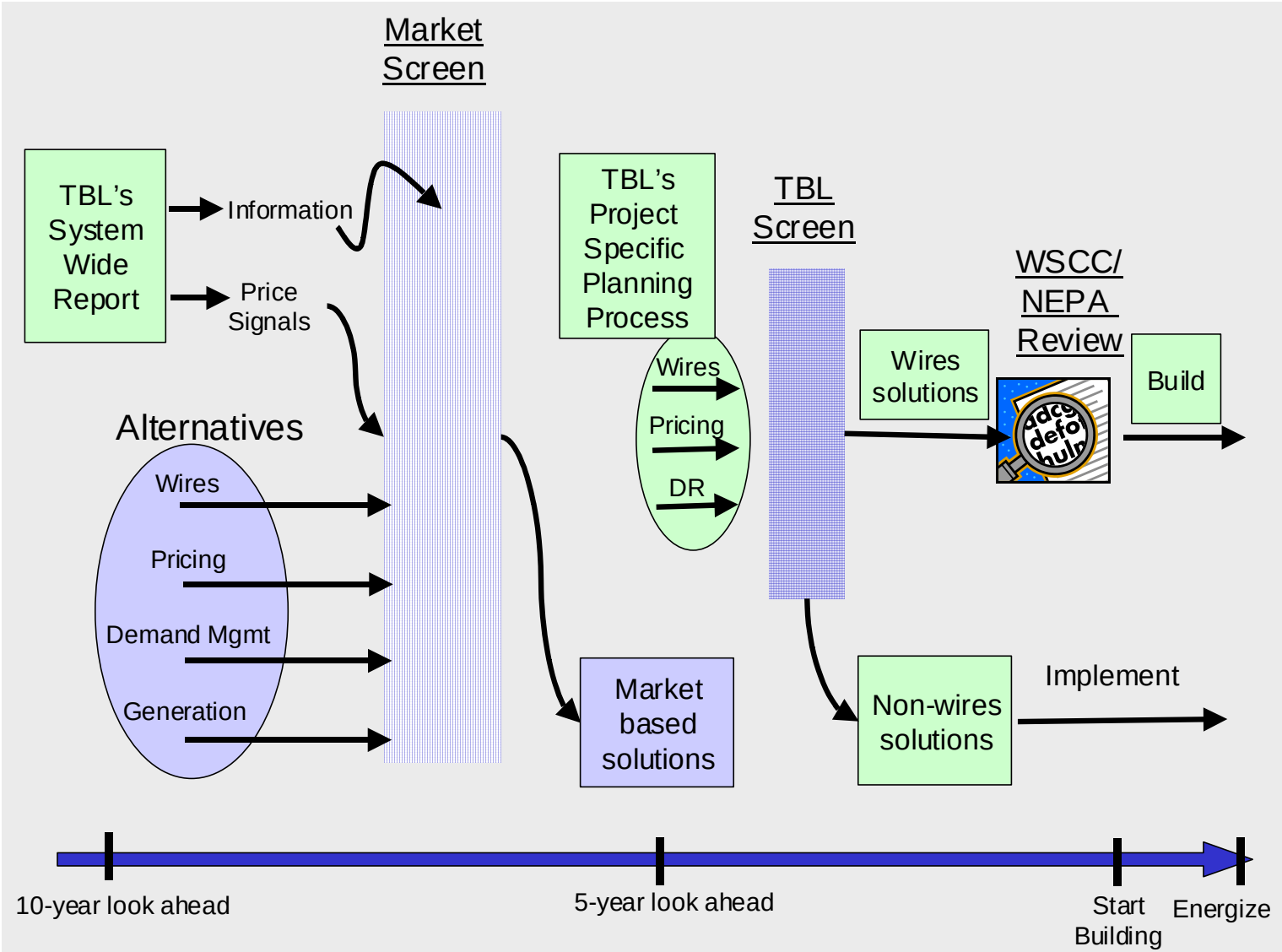


Extending the Existing Process

- A first screen to identify transmission problems that cannot be solved by non-wires alternatives.
- A second screen (for remaining transmission projects) against the costs of strategically located and operated generation, demand management, and transmission-pricing programs.

The TBL Backstop Screen

The Multiple Screening Process



Transmission Planning During Transition to Fully Functioning Markets

- Transparent planning in lieu of being able to set prices or to do least-cost planning.
- Coordination with affected parties

Engage Regional Stakeholders

Share information that will lead to more efficient region-wide system

Workshops for Stakeholders

❶ Conduct scoping workshop with interested and affected parties

❷ Discuss findings in biennial report and identify potential non-wires solutions to transmission needs identified.

❸ In second workshop ask for specific actions that can be taken by regional parties, and that would be as reliable and as cost-effective as wires upgrades.

The Vermont Statutes Online

Title 30: Public Service

Chapter 5: Powers and Duties of Department of Public Service

218c. Least cost integrated planning

§ 218c. Least cost integrated planning

(a)(1) A "least cost integrated plan" for a regulated electric or gas utility is a plan for meeting the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs. Economic costs shall be determined with due regard to:

(A) the greenhouse gas inventory developed under the provisions of 10 V.S.A. § 582;

(B) the state's progress in meeting its greenhouse gas reduction goals; and

(C) the value of the financial risks associated with greenhouse gas emissions from various power sources.

(2) "Comprehensive energy efficiency programs" shall mean a coordinated set of investments or program expenditures made by a regulated electric or gas utility or other entity as approved by the board pursuant to subsection 209(d) of this title to meet the public's need for energy services through efficiency, conservation or load management in all customer classes and areas of opportunity which is designed to acquire the full amount of cost effective savings from such investments or programs.

(b) Each regulated electric or gas company shall prepare and implement a least cost integrated plan for the provision of energy services to its Vermont customers. Proposed plans shall be submitted to the department of public service and the public service board. The board, after notice and opportunity for hearing, may approve a company's least cost integrated plan if it determines that the company's plan complies

Appendix C

with the requirements of subdivision (a)(1) of this section.

(c) [Deleted.]

(d)(1) Least cost transmission services shall be provided in accordance with this subsection. Not later than July 1, 2006, any electric company that does not have a designated retail service territory and that owns or operates electric transmission facilities within the state of Vermont, in conjunction with any other electric companies that own or operate these facilities, jointly shall prepare and file with the department of public service and the public service board a transmission system plan that looks forward for a period of at least 10 years. A copy of the plan shall be filed with each of the following: the house committees on commerce and on natural resources and energy and the senate committees on finance and on natural resources and energy. The objective of the plan shall be to identify the potential need for transmission system improvements as early as possible, in order to allow sufficient time to plan and implement more cost-effective nontransmission alternatives to meet

reliability needs, wherever feasible. The plan shall:

(A) identify existing and potential transmission system reliability deficiencies by location within Vermont;

(B) estimate the date, and identify the local or regional load levels and other likely system conditions at which these reliability deficiencies, in the absence of further action, would likely occur;

(C) describe the likely manner of resolving the identified deficiencies through transmission system improvements;

(D) estimate the likely costs of these improvements;

(E) identify potential obstacles to the realization of these improvements; and

(F) identify the demand or supply parameters that generation, demand response, energy efficiency or other nontransmission strategies would need to address to resolve the reliability deficiencies identified.

(2) Prior to the adoption of any transmission system plan, a utility preparing a plan shall host at least two public meetings at which it shall present a draft of the plan and facilitate a public discussion to identify and evaluate nontransmission alternatives. The meetings shall be at separate locations within the state, in proximity to the transmission facilities involved or as otherwise required by the board, and each shall be noticed by

Appendix C

at least two advertisements, each occurring between one and three weeks prior to the meetings, in newspapers having general circulation within the state and within the municipalities in which the meetings are to be held. Copies of the notices shall be provided to the public service board, the department of public service, any entity appointed by the public service board pursuant to subdivision 209(d)(2) of this title, the agency of natural resources, the division for historic preservation, the department of health, the scenery preservation

council, the agency of transportation, the attorney general, the chair of each regional planning commission, each retail electricity provider within the state, and any public interest group that requests, or has made a standing request for, a copy of the notice. A verbatim transcript of the meetings shall be prepared by the utility preparing the plan, shall be filed with the public service board and the department of public service, and shall be provided at cost to any person requesting it. The plan shall contain a discussion of the principal contentions made at the meetings by members of the public, by any state agency, and by any utility.

(3) Prior to the issuance of the transmission plan or any revision of the plan, the utility preparing the plan shall offer to meet with each retail electricity provider within the state, with any entity appointed by the public service board pursuant to subdivision 209(d)(2) of this title, and with the department of public service, for the purpose of exchanging information that may be relevant to the development of the plan.

(4)(A) A transmission system plan shall be revised:

(i) within nine months of a request to do so made by either the public service board or the department of public service; and

(ii) in any case, at intervals of not more than three years.

(B) If more than 18 months shall have elapsed between the adoption of any version of the plan and the next revision of the plan, or since the last public hearing to address a proposed revision of the plan and facilitate a public discussion that identifies and evaluates nontransmission alternatives, the utility preparing the plan, prior to issuing the next revision, shall host public meetings as provided in subdivision (2) of this subsection, and the revision shall contain a discussion of the principal contentions made at the meetings by members of the public, by any state agency, and by any retail electricity provider.

(5) On the basis of information contained in a transmission system plan, obtained through meetings held pursuant to subdivision (2) of this subsection, or obtained

Appendix C

otherwise, the public service board and the department of public service shall use their powers under this title to encourage and facilitate the resolution of reliability deficiencies through nontransmission alternatives, where those alternatives would better serve the public good. The public service board, upon such notice and hearings as are otherwise required under this title, may enter such orders as it deems necessary to encourage, facilitate or require the resolution of reliability deficiencies in a manner that it determines will best promote the public good.

(6) The retail electricity providers in affected areas shall incorporate the most recently filed transmission plan in their individual least cost integrated planning processes, and shall cooperate as necessary to develop and implement joint least cost solutions to address the reliability deficiencies identified in the transmission plan.

(7) Before the department of public service takes a position before the board concerning the construction of new transmission or a transmission upgrade with significant land use ramifications, the department shall hold one or more public meetings with the legislative bodies or their designees of each town, village, or city that the transmission lines cross, and shall engage in a discussion with the members of those bodies or their designees and the interested public as to the department's role as public advocate. (Added 1991, No. 99, § 2; amended 1999, No. 60, § 2, eff. June 1, 1999; 1999, No. 157 (Adj. Sess.), § 7; 2005, No. 61, § 9; 2007, No. 209 (Adj. Sess.), § 13.)

Appendix C

TRANSPOWER

Grid Support Contracts

Discussion Paper

November 2008

Appendix D

Contents

Appendix D

Glossary

Item	Description
3G	GRS, GEIP and GIT
Additionality	A term to describe whether the DSP called for was truly additional to whatever would have happened in the absence of the call
Aggregate	Assemble a number of DSP sources for the purpose of offering them to Transpower
APR	Annual Planning Report, a Transpower publication
AUFLS	Automatic Under-frequency Load Shedding – shedding load when the system frequency drops significantly
Block	A defined amount (MW) of DSP or non-market generation capacity, that can be called individually by Transpower
Call	A call by Transpower for delivery of DSP Deliver Provide DSP when called. The provider reduces demand or provides generation thus delivering DSP
DSP	Demand-side participation
EC	Electricity Commission
EGRs	Electricity Governance Regulations and Rules 2003
GEIP	Good electricity industry practice
GIT	Grid investment test
GRS	Grid reliability standards
GSC	Grid support contract
GUIRP	Grid upgrade investment and review process
GUP	Grid Upgrade Plan
IL	Interruptible load, being one form of Instantaneous Reserve
LF	Load forecaster: the model used by the System Operator in creating the Schedule of Dispatch Prices and Quantities (SDPQ)
LRMC	Long run marginal cost
RFI	Request for information
RFP	Request for proposals
RMA	Resource Management Act
SOO	Statement of Opportunities, an EC publication
SSF	System Security Forecast, a Transpower System Operator publication
TPM	Transmission pricing methodology, defined in Schedule F5 of Part F of the EGRs
USI	Upper South Island, being the region covered by Transpower's DSP Trial
VOLL	Value of lost load

Executive summary

Transpower has identified the need and opportunity to introduce grid support contracts (GSCs) that will – in certain specific circumstances – enable it to contract with non-transmission options to augment or substitute for grid capacity.

Transpower has developed a strawman design of how GSCs might be used for risk management or transmission deferral.

The overall parameters of Transpower's 2008 strawman GSC product would be:

- Specific to transmission capacity problems, and hence offered only for specific regions and periods when these are occurring, or are forecast to occur. GSCs will not be offered to address generation adequacy problems.
- Transpower would not pick winners or pick losers: Transpower would identify a need, a potential provider would propose a commercial solution to the need, and Transpower would decide whether or not to offer a GSC for that proposal.
- To encourage innovation in non-transmission solutions, GSCs will be open to all non-transmission options, but with clear qualification and evaluation criteria to ensure reliability.
- To encourage competition in procurement, GSCs will be offered to successful tenders through an RFI and RFP process: qualification and evaluation criteria would be applied.
- GSCs will be contract for services, not for Transpower ownership. Transpower would be offering them in its capacity as grid owner. For those GSCs that require to be called or dispatch, this will be done by the System Operator on behalf of the grid owner.
- Cost recovery will be through the transmission pricing methodology (TPM), for which approval will be required through Part F of the EGRs. GSCs would only be offered as part of a reliability investment proposal for assets on the interconnected grid: they wil not be offered for connection asset issues or for economic investments.

GSCs as a risk management tool

Transpower has significant concerns over the risk to reliability of supply that might arise in the foreseeable future from insufficient transmission capacity resulting from:

- Delayed build of new transmission assets - whether for reasons of regulatory approval, obtaining consents under the RMA, acquiring property, or due to competition in world markets for transmission assets and expertise;
- Higher demand growth than was forecast at the time of investment decision, which would bring forward the need date; or
- Major asset failure - which is a growing concern given the age of Transpower's asset base.

GSCs could provide a useful product as part of a toolbox of approaches to managing such these risks.

GSCs as a transmission deferral tool

Another purpose that has been mooted for GSCs is the deferral of transmission investments. Given the tightness of the system currently and the urgent need for increased transmission capacity, Transpower does not consider that, overall, deferring transmission investment would be a good outcome for New Zealand. However there may be cases where the there is genuine option value in deferring an investment decision, so it does need to be considered on a case-by-case basis.

Where such option values do not exist, Transpower would not propose to use GSCs to push investment to the very edge of modelled 'just in time' limits. There are huge asymmetries of risk, with transmission 'better a year early than a day late'. Critically, to

plan to use GSCs for deferring an investment in this way would remove its advantage as the insurance instrument against the risks outlined above. As any GSCs for transmission deferral would be used at the very end of the project, in the year or years immediately prior to commissioning, they would be better left as the Plan B.

Reliability

Historically, the transmission grid was developed to link previously unconnected regions to provide greater levels of reliability through access to more generation resources. While initially undertaken for energy transport reasons, more recently investment has been for market efficiency too.

Using GSCs to maintain reliability therefore requires the GSCs to be highly reliable.

It is unrealistic to expect local generation or demand-side response to be able to achieve transmission levels of reliability. Rather, a reliability level of around 99% to 99.9% may be achievable. Even using these options it must be appreciated that reliability will decline, but they could still add value as a risk management tool. Lower levels of reliability would in Transpower's view not be acceptable.

A key issue in GSC design and operation would therefore be in ensuring that appropriate reliability criteria are set for proponents wishing to enter into GSCs.

Market distortion

A significant issue for our GSC design process is to what extent the use of GSCs could distort existing markets, in particular the wholesale generation investment and operations market. The wholesale electricity market is a multi-billion dollar per annum market, whereas the GSC market is likely to be in the order of some tens of millions per annum. In Transpower's view the wholesale electricity market has performed admirably over its ten years of operation (noting the industry stakeholder concerns over generation capacity investment and inter-seasonal fuel management with regard to dry years), enabling significant productive, allocative and investment efficiencies. Designing and operating GSCs to minimise interference in the wholesale market is essential.

Forms of GSC

DSP including non-market generation. Transpower has trialled small aggregated DSP in its 2007 Pilot and 2008 Trial. These demonstrated that, under certain conditions, blocks of aggregated small DSP sources can be made reliable. Significant issues arose in forecasting the time and size of need accurately enough at the time of call: Transpower is investigating these. This form of GSC would include, in addition to aggregated blocks, blocks made up of single large load (or in principle, but unlikely in practice, large non-market generation sources). Blocks would be called individually by the System Operator in accordance with instructions from Transpower as grid owner reflecting the contract terms. Blocks would be expected to deliver the contracted capacity: their reliability would be a paramount consideration in the design, procurement and operation of this form of GSC. Blocks would either be called ahead of time using a GENCO terminal, or be operated automatically post-contingent.

Voltage support. Transpower would use GSCs for contracting for voltage support over medium to long term planning horizons. They would in effect replace the voltage support ancillary service contracts over these timeframes. This will provide improved integration in grid planning, as the grid planner can better 'co-optimise' real and reactive power issues, and transmission and non-transmission reactive support options, over planning horizons from a technical, good electricity industry practice, and economic perspectives. In particular, the grid planner can test and contract for the availability and cost of future voltage support, rather than simply assume that this will be the eventual outcome of ancillary service voltage support contracts. Cost allocation would change from zonal under Part C to national under Part F transmission pricing methodology, aligning cost allocation for transmission and non-transmission reactive support solutions. The System Operator would still procure contracts of a short-term nature to cover for unanticipated reactive power

Market generation For market generation, avoiding interference in the operational market is paramount. GSCs would not be offered to define how generators would offer real power into the market, whether in time, quantity or price. Rather, GSCs would be limited to contributions to capital or other fixed 'up front' costs. In effect, GSCs would be used to buy certainty over a particular generator's development path – be it for example in time, equipment or location – to allow transmission to be safely designed around it. Proponents would be required to demonstrate that they are sufficiently committed to be able to deliver, and that their contract price is a fair and reasonable reflection of actual cost.

GSC design proposal

Transpower in this consultation document discusses issues in GSC design and operation and presents for feedback key features of a strawman design.

The discussion document includes the key features of Transpower's 2008 strawman design, for feedback from the industry and other interested parties.

Consultation feedback

Transpower is the transmission owner and System Operator for New Zealand. In undertaking these roles, Transpower has gained extensive experience in maintaining and enhancing transmission system reliability, and in operating the grid and the system. Transpower is however not an expert in demand-side participation, nor in the full range of commercial issues and incentives around generation investment and operation.

Transpower has concerns about some specific issues around GSC design and operation, and intends to offer a GSC product that minimises these risks. Transpower's main concern is how to obtain the benefits possible from GSCs without:

- compromising reliability;
- significant interference in the wholesale electricity market;
- significant distortions in electricity generation investment; or
- Transpower becoming relied on for energy as well as transmission capacity provision.

Transpower is considering the use of GSCs over the long term, recognising that they can introduce significant risk if not managed carefully. Transpower's preferred approach to introducing GSC is to start with tried and tested sources and gradually increase the number of sources in contracts over time. Transpower believes that taking a cautious approach initially rather than casting the net too wide and contracting with untried and untested sources is the prudent path at this time. This would avoid a situation developing where GSC performance requires Transpower to decrease the range of situations where GSCs would be considered, thereby limiting, due to initial unsuccessful security products, the potential benefits to the electricity market of GSCs.

Transpower is considering the use of GSCs over the long term, recognising that they can introduce significant risk if not managed carefully. Transpower's preferred approach to introducing GSC would be to start with tried and tested sources and gradually increase the number of sources in contracts over time. Transpower believes that taking a cautious approach initially rather than casting the net too wide and contracting with untried and untested sources is the prudent path forward at this time.

Transpower has, following a two year demand-side participation trial and consideration of the many complex issues and trade-offs involved, developed a 'strawman' GSC product design. This '2008 strawman' is explained and described in this paper to provide a starting point for your feedback. Specifically, Transpower requests that you consider the issues raised, and the extensive and complex interdependencies between them, and comment on the 2008 strawman GSC design features that are described throughout this document in blue boxes.

Transpower welcomes your feedback to assist us to offer a GSC product that provides an appropriate balance between capturing the possible benefits while minimising the potential downsides.

Submissions are sought by the end of January 2009: the process is explained in section 12.

3 GSC experience in New Zealand and overseas

3.1 International practice

Transpower engaged SAHA International an update and analysis of the use of grid support contracts internationally. In a previous report prepared for Transpower by PWC in 2006, it was concluded that:

> *"Of the jurisdictions reviewed, Australia appears to be the most progressive jurisdiction in deferring investment using generation contracts, with examples of such contracts being used in practice for some years. As such, the Australian experience may offer reasonable guidance on possible approaches and regimes for the use of network generation contracts in New Zealand, notwithstanding the regulatory differences between the jurisdictions."*

The process described above has been developed with regard to the regulatory and governance regimes in New Zealand, incorporating learnings from the Australian experience.

Since the PWC report was completed, the key international developments have included a growing recognition that:

- GSCs may be used to manage delays in transmission augmentation.
- Impacts on the wholesale market need to be minimised (unless they are mitigating existing anomalies in the market).

In broad terms, a GSC is a contractual arrangement facilitating a non-network alternative to a network augmentation required to meet mandated reliability obligations. A GSC may be entered into with any party who is capable, and prepared, to provide network support in lieu of a physical augmentation to the network. For example, this may be in the form of additional generation, a change in the pattern of operation of existing generation, or demand side management.[4]

Internationally, it would appear that reducing the locational market power of generators (to maintain the integrity of competitive wholesale markets) is the predominant reason for GSCs to be used. Under this paradigm, transmission constraints are seen as barriers to competition, and GSCs are used to avoid inefficient market outcomes. Avoiding transmission investment would appear to be a secondary – but perhaps an increasingly important – purpose. For instance:

- in California, reliability-must-run contracts (RMR) were developed to mitigate the special form of local market power that must-run generation could dictate. In particular, where the market price was insufficient to compensate the 'downstream[5]' generator for its operating costs, the RMR provided additional compensation in a way that did not affect market clearing prices.
- in Alberta, the long standing policy position was that transmission-must-run contracts (TMR) must not be used as a long-term substitute for transmission investment as transmission is *the agent of reliability and the facilitator of the competitive market*[6], and TMR can distort market outcomes. However, more recently (2005) this policy position has been moderated to allow TMR as a longer term solution if it is a cost effective alternative to transmission investment.

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[4] *Adapted from the definition of a Network Support Agreement (NSA) in Australia – see* Powerlink; "Response to AEMC Issues Paper – Congestion Management Review"; 13 April 2006; p2

[5] *i.e.* downstream *of the constraint. Similarly an 'upstream' generator is* upstream *of the constraint.*

[6] *see Alberta Department of Energy; "Alberta's Electricity Policy Framework"; 6 June 2005*

- in British Columbia (Canada), BCTC has recently (2006) undertaken to evaluate *non-wires* transmission alternatives where such alternatives have the potential to avoid or delay wires solutions. This stance was supported by the British Columbia Utilities Commission (BCUC) which directed BCTC to, *inter alia*, examine options for customer supplied transmission services, such as reactive power or RMR generation.[7]
- in Australia, the current definition of NSCSs[8] is that they are transmission network services that are critical to the maintenance of secure and reliable operation of the power system, by providing the capability to control the real or reactive power flow into or out of a transmission network in order to: (a) maintain the transmission network within its current, voltage or stability limits following a credible contingency event; or (b) enhance the value of spot market trading in conjunction with the central dispatch process. The value of spot market trading may be enhanced by increasing the *transfer capability* of the transmission network (within its secure operating limits).

Summarised by types of use of GSCs overseas:

Risk management

In the USA, GSCs have been relied on to provide capacity during contingencies, and have complemented transmission construction. However, more recently FERC has expressed frustration with such contracts and has called for them to be replaced by "market-based" solutions to the problem of compensating locally constrained units.

In Alberta, GSCs are seen as a stop-gap measure (e.g. to manage delays in transmission augmentation).

Transmission deferral

In Queensland, Powerlink have relied on GSCs to avoid 'more costly' transmission augmentations (per Regulatory Test). However, having avoided augmentation for several years, Powerlink are now building transmission to remove constraints.

In Alberta, GSCs are not allowed as a (long-term) substitute for transmission.

In British Columbia, BCTC recently assessed opportunities for non-wire transmission alternatives – but failed to identify any.

Reliability

In most jurisdictions examined (particularly the USA and Queensland), GSCs have been used to improve the reliability of the system.

Wholesale market impacts

In Australia, NSA is cited as helping to mitigate potential 'mispricing' problems in the NEM.

In Alberta, by way of contrast, the use of GSCs was seen to depress the wholesale market price, and a solution to this has not yet been identified.

A more detailed review of GSCs in other jurisdictions is set out in Appendix B.

3.2 Transpower's demand-side participation (DSP) Trial

As Transpower began to investigate the development of a GSC product, it became apparent that:

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[7] *British Columbia Utilities Commission in the Matter of British Columbia Transmission Corporation Transmission System Capital Plan 2006 to 2015 Application Decision; September 23, 2005*

[8] *GSCs are commonly referred to as Network Support Agreements (NSA) in the NEM. NSAs are a category of contract that NEMMCO (and others) more broadly refer to as Network Support and Control Services (NSCS).*

Appendix E

IEA DSM Programme
Task XV: Network Driven DSM

Dr David Crossley
Managing Director
Energy Futures Australia Pty Ltd

Workshop on Network Driven DSM
Auckland, 23 November 2007

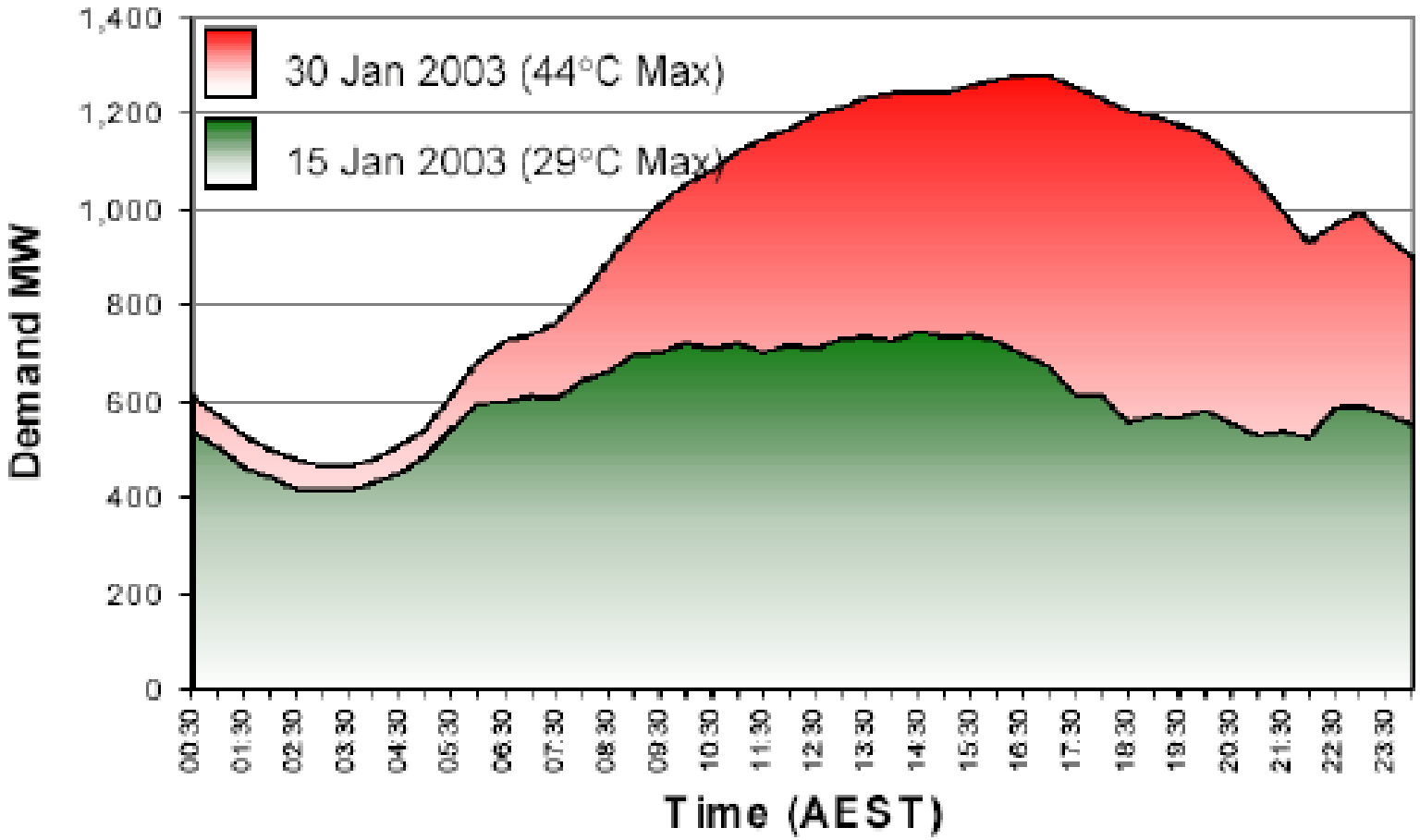
Presentation Topics

- Using DSM to support electricity networks
- Motivation, objectives and work plan for Task XV
- Task XV results so far
- Selected case studies
- Conclusions
- Information resources

Using DSM to Support Electricity Networks

Why Use DSM? (1)

Sydney West Bulk Supply Point Load Profile

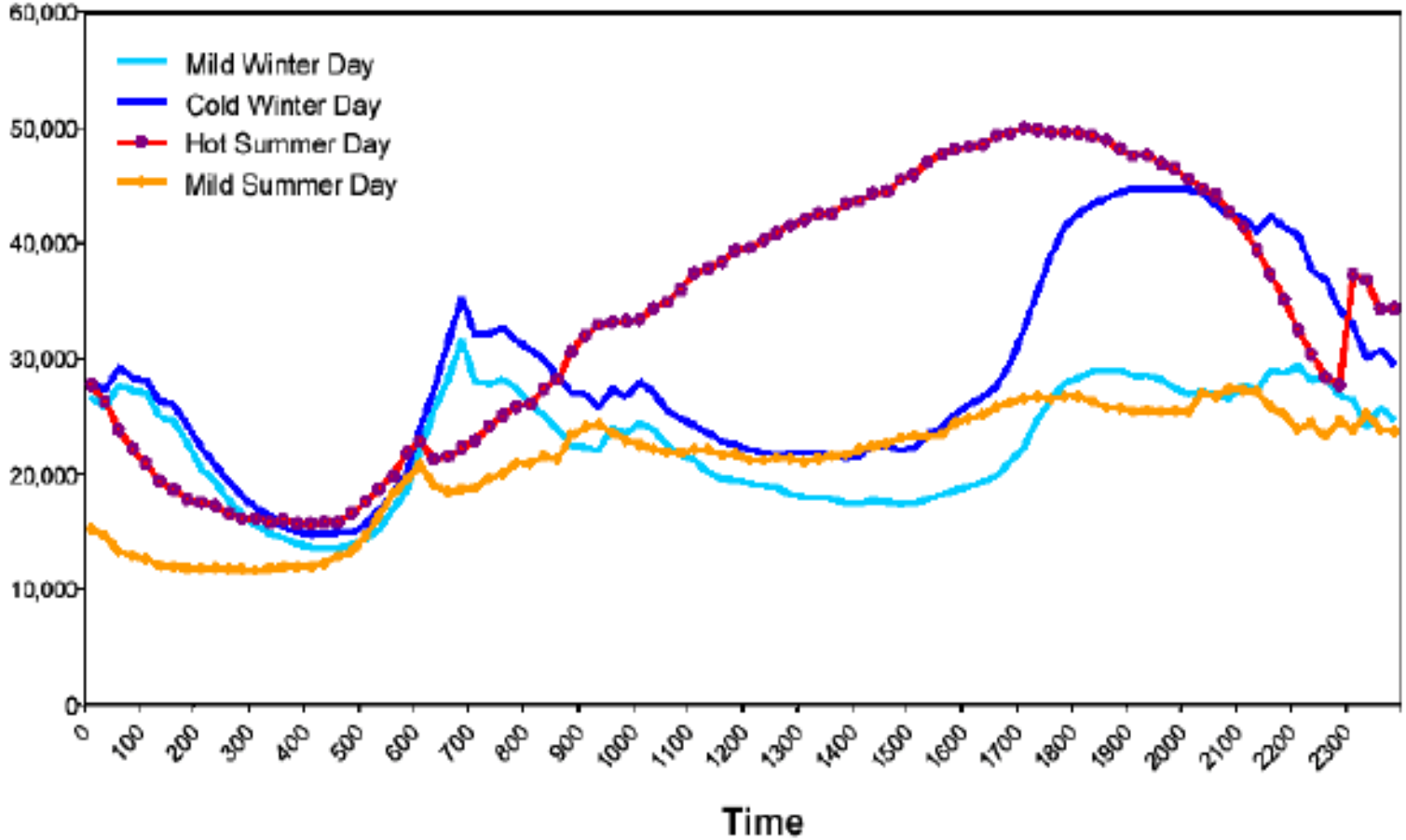


INTEGRAL energy
The power is in your hands

ENERGY FUTURES AUSTRALIA

Why Use DSM? (2)

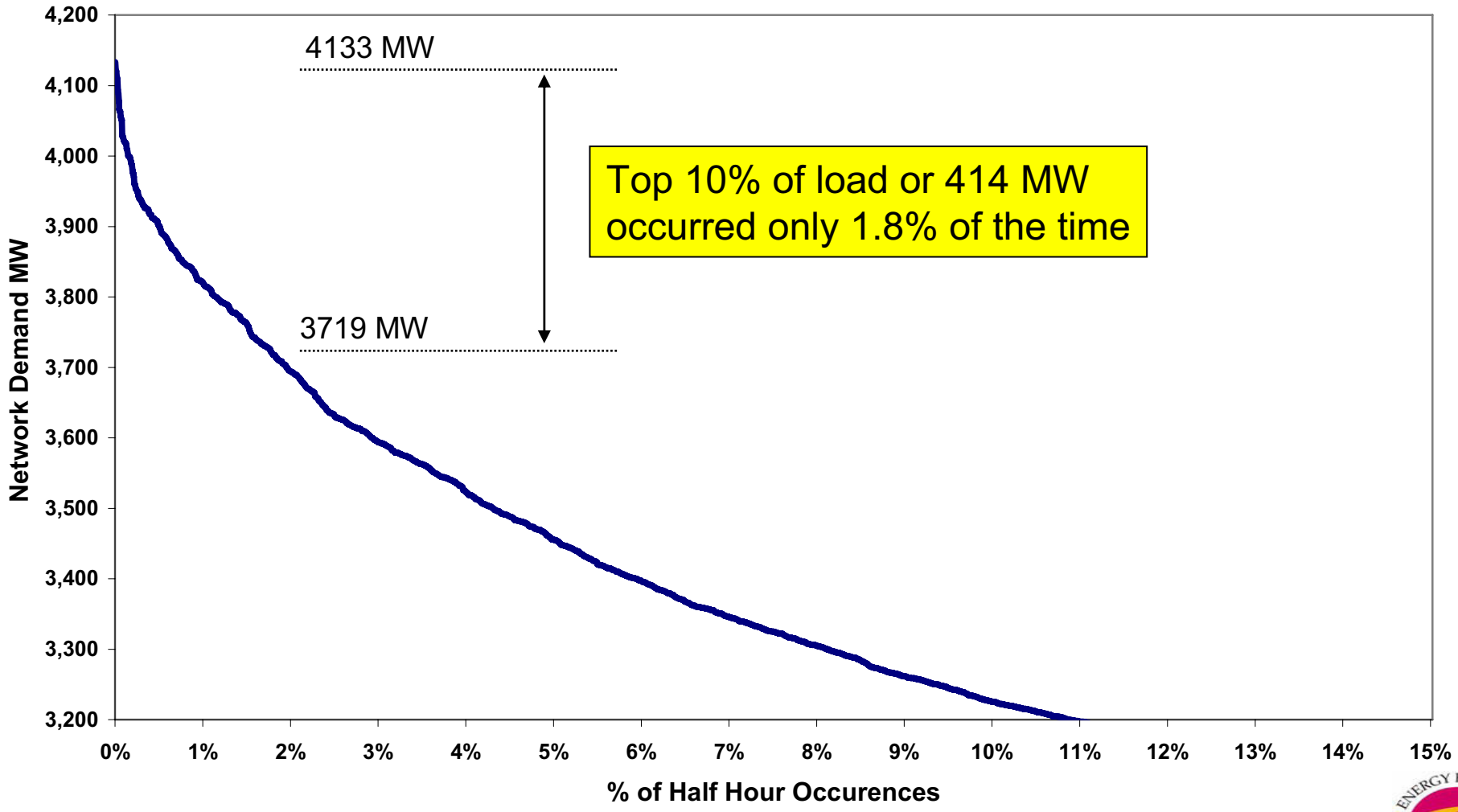
Predominantly Residential Load Profile



INTEGRAL energy
The power is in your hands

ENERGY FUTURES AUSTRALIA

Why Use DSM? (3)


4133 MW
3719 MW
Top 10% of load or 414 MW occurred only 1.8% of the time
Network Demand MW
4,200
4,100
4,000
3,900
3,800
3,700
3,600
3,500
3,400
3,300
3,200
0%
1%
2%
3%
4%
5%
6%
7%
8%
9%
10%
11%
12%
13%
14%
15%
% of Half Hour Occurences

What is Network-driven DSM (1)?

- Network-driven DSM comprises demand-side measures used to relieve network constraints and/or to provide services for electricity network system operators
- In Task XV, network-driven DSM is defined as follows:

  Network-driven demand-side management is concerned with reducing demand on the electricity network in specific ways which maintain system reliability in the immediate term and over the longer term defer the need for network augmentation

What is Network-driven DSM (2)?

- Task XV identifies the following two prime objectives for network-driven DSM:
  - ►to relieve constraints on distribution and/or transmission networks at lower costs than building ‘poles and wires’ solutions; and/or
  - ►to provide services for electricity network system operators, achieving peak load reductions with various response times for network operational support

Characteristics of Network Constraints

- Network-driven DSM measures must address the particular characteristics of network constraints
- In relation to timing, network constraints may be:
  - narrow peak related – occurring strongly at the time of the system peak and lasting seconds, minutes or a couple of hours; or
  - broad peak related – less strongly related to the absolute system peak, occurring generally across the electrical load curve and lasting several hours, days, months, years or indefinitely
- In relation to the spatial dimension, network constraints can:
  - occur generally across the network; or
  - be associated with one or more specific network elements such as certain lines or substations

Motivation, Objectives and Work Plan for Task XV

Motivation for Task XV (1)

- Prior to initiating Task XV, the IEA DSM Programme had not undertaken any work on the potential for DSM to cost-effectively relieve electricity network constraints
- However, such constraints are becoming a significant problem in countries where electricity demand is increasing and network infrastructure ('poles and wires') is ageing
- As loads grow and infrastructure reaches the end of its economic life, the potential cost of augmenting networks is increasing exponentially
- In certain limited situations, network-driven DSM may be able to cost-effectively defer or even eliminate the requirement to build a 'poles and wires' solution

Motivation for Task XV (2)

- In addition to relieving network constraints, DSM measures can also provide operational support services for electricity networks
- Such network support services include: reactive supply and voltage control, regulation and frequency response, energy imbalances, spinning reserves, supplemental reserves, and generator imbalances
- Task XV also covers the use of DSM measures to provide network support services.

Task XV Objectives (1)

- To identify a wide range of DSM measures which can be used to:
  - relieve electricity network constraints and/or
  - provide network operational services
- To further develop the identified network-driven DSM measures so that they will be successful in cost-effectively achieving network-related objectives
- To investigate how existing network planning processes can be modified to incorporate the development and operation of DSM measures over the medium and long term

Task XV Objectives (2)

- To develop 'best practice' principles, procedures and methodologies for the evaluation and acquisition of network-driven DSM resources
- To communicate and disseminate information about network-driven DSM to relevant audiences
- To investigate in detail the role of load control and smart metering in achieving network-related objectives

Task XV Work Plan

- Subtask 1: Worldwide Survey of Network-Driven DSM Activities
- Subtask 2: Assessment and Development of Network-Driven DSM Measures
- Subtask 3: Incorporation of DSM Measures into Network Planning
- Subtask 4: Evaluation and Acquisition of Network-Driven DSM Resources
- Subtask 5: Communication of Information About Network-Driven DSM
- Subtask 6: Role of Load Control and Smart Metering in Achieving Network-related Objectives

Task XV Results So Far

Survey of Network-driven DSM Projects (1)

- The survey identified 45 network-driven DSM projects undertaken over about the last 10 years
- The survey focused on projects carried out in the original four countries participating in Task XV, Australia, France, Spain and the United States, but it also includes some projects from other countries
- Detailed case studies of the projects were prepared and included in an on-line case study database

Survey of Network-driven DSM Projects (2)

- The network-driven DSM projects included in the survey were classified by the major DSM measure implemented, as follows:
  - distributed generation, including standby generation and cogeneration
  - energy efficiency
  - fuel substitution
  - integrated DSM projects
  - load management, including interruptible loads, direct load control and demand response
  - power factor correction
  - pricing initiatives, including time of use and demand-based tariffs

Survey of Network-driven DSM Projects (3)

- The survey showed that network-driven DSM options can effectively:
  - ►achieve load reductions on electricity networks that can be targeted to relieve specific network constraints; and
  - ►provide a range of network operational services

Survey of Network-driven DSM Projects (4)

- The survey also showed that all types of DSM measures can be used to relieve network constraints and/or provide network operational services
- However, whether a particular DSM measures is appropriate and/or cost effective in a particular situation will depend on:
  - the specific nature of the network problem being addressed; and
  - the availability and relative costs of demand-side resources in that situation

Assessment & Development of DSM Measures (1)

- Task XV concluded that the value of a network-driven DSM project varies among categories of stakeholders
- The value may even vary among individual stakeholders (eg customers located in network-constrained areas vs customers located outside these areas)
- Because the benefits are distributed among many different stakeholders, the project proponent is unlikely to capture all the benefits from such a project
- Other parties who have not contributed to the cost of implementing the project may well receive some of the benefits

Assessment & Development of DSM Measures (2)

- To provide significant value to the proponent of a network-driven DSM project, the total benefits must be quite large and the proponent must be able capture a significant proportion of these benefits
- Task XV also identified a number of external and internal factors that may contribute to the success of network-driven DSM projects
- Network-driven DSM projects containing the same DSM measures tend to have a common set of factors which contribute to their success
- To this extent it is possible to identify sets of success factors that apply to each category of DSM measure

Assessment & Development of DSM Measures (3)

- The challenge in designing a network-driven DSM project that will ultimately be successful in achieving its objectives is to:
  - clearly identify the success factors for each of the DSM measures included in the project
  - and then concentrate on optimising each of these factors

Assessment & Development of DSM Measures (4)

- Task XV also:
  - identified the network problems that each category of network DSM measures can address
  - characterised the success factors which apply to each category; and
  - examined how the DSM measures in each category should be implemented for them to be most effective in achieving network-related objectives

Incorporation of DSM into Network Planning (1)

- Among the four countries so far studied in Task XV, planning processes for electricity transmission and distribution systems vary significantly
- Variation occurs particularly in relation to:
  - the types and functions of the various organisations involved
  - the detailed planning processes and methodologies used
  - the policy and regulatory regimes within which electricity network businesses operate
- However, there is sufficient commonality to identify a number of key areas in which changes could be made to enable increased use of demand-side resources as alternatives to network augmentation and to support electricity networks

Incorporation of DSM into Network Planning (2)

There are four key areas in which such changes can and should be made:

1. Forecasting future electricity demand
2. Communicating information about network constraints
3. Developing options for relieving network constraints
4. Establishing policy and regulatory regimes for network planning

Incorporation of DSM into Network Planning (3)

1. Forecasting future electricity demand

- Forecasting methodologies frequently reduce global load forecasts by an assumed (usually small) amount to take account of DSM activity
- Such methodologies discount the potential contribution by DSM towards supporting electricity networks
- Forecasting methodologies for network planning should be modified to recognise more accurately the potential contribution of DSM

Incorporation of DSM into Network Planning (4)

2. Communicating information about network constraints

- Information about future network constraints is often retained inside electricity network businesses
- It is then very difficult for anyone else to propose options for relieving network constraints
- Network businesses should make this information publicly available so that other organisations with the required expertise can develop DSM options to relieve the constraints

Incorporation of DSM into Network Planning (5)

3. Developing options for relieving network constraints

- Network businesses should provide formal opportunities for third parties with expertise in DSM to participate in the development of options that use demand-side resources to relieve network constraints

Incorporation of DSM into Network Planning (6)

4. Establishing policy and regulatory regimes for network planning

- Governments and regulators should change policy and regulatory regimes to reduce the disincentives faced by network businesses that use demand-side resources to support electricity networks
- There are two ways in which this can be achieved:
  - by providing policy and regulatory incentives to network businesses; and/or
  - by imposing policy and regulatory obligations on network businesses

Evaluation and Acquisition of DSM Resources (1)

- A survey of electricity network business practices in Australia, France, Spain and the United States identified a range of processes for evaluating, acquiring and implementing DSM resources to provide support for electricity networks
- The details of these processes varied substantially, particularly depending on the regulatory regime applied to the network businesses

Evaluation and Acquisition of DSM Resources (2)

- Good DSM resource acquisition processes include the following stages:
  - assessing the need for DSM resources
  - identifying and evaluating available DSM resources
  - contacting potential providers of DSM resources
  - negotiating the provision of DSM resources; and
  - acquiring and implementing the DSM resources
- Best practices within each of these stages are tailored to the nature of each DSM resource and to the specific purpose for which the resource is required

Role of Load Control and Smart Metering

- An on-line database of load control and smart metering technologies has been established
- The database currently contains details of 11 technology products
- This number will be increased as participating countries send information about products

Further Work in Task XV

Further work to be carried out includes:

- Subtask 1: Development of not less than five new case studies of load control and smart metering projects
- Subtasks 2, 3 and 4: Addition of material from the new participating countries: India, New Zealand and South Africa
- Subtask 5: Production of two editions of the Task XV Newsletter
- Subtask 6: Identification of best practice in the use of load control and smart metering to achieve network-related objectives

Selected Case Studies

Classification of DSM Activities in the Survey

- DG - distributed generation, including standby generation and cogeneration
- EE - energy efficiency
- FS - fuel substitution
- IP - integrated demand management projects
- LM - load management, including load shifting, direct load control, interruptibility and market-driven demand response
- PC - power factor correction
- PI - pricing initiatives, including time of use and demand-based tariffs

Network DSM Case Study 1

DG04 Chicago Energy Reliability and Capacity Account - USA

- This project makes extensive use of distributed generation, including standby generators and photovoltaics
- Chicago City developed a SCADA system to link natural-gas fired standby generators located in public buildings to a central operating facility; this makes them available as a network of distributed generators for use in system emergencies
- The City also expects to dispatch the standby generators at periods of high system prices; income from power generation at peak periods will help to pay for the costs of the program
- The City has also negotiated an arrangement with a photovoltaics manufacturer to locate a manufacturing plant in Chicago and has installed photovoltaic arrays at schools and museums throughout the City

Network DSM Case Study 2

EE01 Efficient Lighting Project DSM Pilot - Poland

- This pilot project was designed to use compact fluorescent lamps (CFLs) to demonstrate to Polish electric utilities the use of DSM to defer distribution and transmission investments
- The pilot aimed to reduce peak power loads in geographic areas where the existing electricity network capacity was inadequate
- Three cities and their regional electricity utilities were selected to participate in the DSM pilot; the cities had areas with electricity network capacity problems
- Subsidised CFLs were made available to city residents using discount coupons; the largest discounts were available to residents of network constrained areas
- Modelling results showed that during the local peak hour on the peak day of the year, load reductions of about 15% were achieved in the target network constrained areas

Network DSM Case Study 3

FS02 Binda Bigga Demand Management Project - Australia

- The aim of this project was to defer the need for the upgrade of a rural feeder line by reducing the demand for energy during the winter evening peak periods
- Country Energy developed a package that enabled local residents to affordably switch from electric to gas appliances; the package offered residents:
  - discounted gas room heaters and cooking stoves
  - free installation of gas appliances and gas bottles, and removal of electrical appliances for metal recycling
  - gas credits of AUD 170 per appliance
- Overall 70 customers purchased an Energy Saver Package, installing 106 appliances in total; this exceeded the target load reduction of 200kVA

Network DSM Case Study 4

IP04 Olympic Peninsula Non-wires Solutions Pilot - USA

- Bonneville Power Authority is carrying out several pilot projects to determine whether it is possible to use “non-wire solutions” to defer a transmission line construction project
- DSM measures being employed in pilot projects on the Olympic Peninsula include: direct load control, demand response, voluntary load curtailments, networked distributed generation and energy efficiency
- One particularly interesting DSM measure is the use of Grid-Friendly™ appliances which sense frequency disturbances in the electricity network and reduce load to act as spinning reserve - no communications technology is required beyond the network itself
- Some DSM measures will be aggregated into a demonstration of how a future electricity network might function

Network DSM Case Study 5

LM06 LIPAedge Direct Load Control Program - USA

- Long Island Power Authority uses central control of residential and small commercial air-conditioning thermostats to achieve peak load reduction
- The system operator interfaces with the resource through a web-based system; two-way pagers are used to transmit a curtailment order to 20,000 thermostats and to receive acknowledgment and monitoring information
- The thermostats take immediate action or adjust their schedules for future action, depending on what the system operator ordered
- The command is received and acted upon by all loads, providing full response within about 90 seconds; this is far faster than generator response, which requires a 10-minute ramp time

Network DSM Case Study 6

PC01 Marayong Power Factor Correction Program - Australia

- This project aimed to reduce the load on particular zone substation and thereby defer the capital expenditure required to strengthen a specific feeder
- The local electricity distributor, Integral Energy, installed power factor correction equipment in the low voltage network outside customers' premises (not on the customer side of the meter)
- Integral paid for the equipment and the installation
- This program was implemented without the involvement of customers

Network DSM Case Study 7

PI05 End User Flexibility by Efficient Use of ICT - Norway

- This was a large scale pilot project involving two network operators and six technology vendors
- The project included: two way communication to 10,984 mainly residential customers; automated meter reading; and direct load control of water heaters
- Customers were offered a choice of a standard or TOU network tariff and/or a standard or hourly spot price retail tariff
- Average load reductions per household:
  - ToU network tariff – 0.18 kWh/h
  - Hourly spot price for energy – 0.4 - 0.6 kWh/h
  - Direct load control of water heaters – 0.5 kWh/h
  - ToU network tariff plus hourly spot price – 0.3 - 1.0 kWh/h

Conclusion

Conclusion (1)

- While there is increasing use of DSM measures to support electricity networks, Task XV is the first broad and systematic investigation of this particular application of DSM
- So far, Task XV has concluded that DSM can be successfully used to support electricity networks in two main ways:
  - by relieving constraints on distribution and/or transmission networks at lower costs than building 'poles and wires' solutions; and/or
  - by providing services for electricity network system operators, achieving peak load reductions with various response times for network operational support

Conclusion (2)

- Through participating in Task XV to date, country Experts and representatives have been able to:
  - understand the advantages and disadvantages of network-driven DSM measures as alternatives to network augmentation
  - gain information about network-driven DSM measures currently in use in other countries and about the relative effectiveness of these measures
  - understand the factors which lead to a network-driven DSM measure being effective

Conclusion (3)

- Participating in the Task XV extension will enable countries to:
  - understand how load control and smart metering can be used to defer network augmentation and to provide network operational services
  - gain information about the functionalities and capabilities of load control and smart metering devices
  - gain information about load control and smart metering projects currently being implemented in other countries and about the relative effectiveness of these projects
  - identify best practice in the use of load control and smart metering to achieve network-related objectives

Information Sources

- David Crossley: crossley@efa.com.au
- Reviews of documents on DSM and energy efficiency in Australia are available at my company's website: www.efa.com.au/dsmdocs.html
- The International Energy Agency DSM Programme website is at: www.ieadsm.org
- The IEADSM Task XV website is at: www.ieadsm.org/ViewTask.aspx?ID=16&Task=15&Sort=0

IN THE MATTER OF

BRITISH COLUMBIA TRANSMISSION CORPORATION

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

CENTRAL VANCOUVER ISLAND TRANSMISSION PROJECT

DECISION

December 10, 2008

Before:

A.W. Keith Anderson, Panel Chair & Commissioner
Anthony J. Pullman, Commissioner
Michael R. Harle, Commissioner

receive service from the public utility", as well as Sections 64.01 and 64.02 for the achievement of electricity self-sufficiency.

The Commission Panel agrees with BCTC that the sole Intervenor who questioned the need for the Project may have misinterpreted BCTC's response to BCUC 1.16.2, and notes that the Project received support from several Intervenors.

In the situation at hand the Commission Panel finds that BCTC's use of the N-1 standard is an acceptable planning standard for system reliability. The Commission Panel determines that BCTC has established the need to reinforce the CVI transmission system by an ISD of October 2010 to provide adequate transmission infrastructure in order to reliably serve BC Hydro's load in the region.

2.3 Potential "Non-wires" and Other Solutions

BCTC states that as well as the alternatives discussed in Section 2.4 below it examined the following "non-wires" and other solutions:

- Demand Side Management ("DSM");
- Local Generation;
- Remedial Action Schemes;
- Curtailment; and
- Juan de Fuca Cable Project ("JdF").

<u>Demand Side Management</u>

BCTC states that one of the purposes of DSM initiatives is to defer the need to add infrastructure to meet growing demand, but, in the case of the CVI Project, existing customer demand already exceeds the firm capacity of the 138 kV transmission system with the result that DSM programs

have very little effect in managing the existing customer demand relative to the shortfall in capacity. BCTC also points out that the existing forecast of demand growth from the BC Hydro 2006 Substation Load Forecast includes the impacts of existing and planned DSM programs, so the forecast load growth in the CVI Area Study is the residual load growth after the effects of demand side programs have been taken into account (Exhibit B-1, p. 43).

Local Generation

BCTC states that a new generation supply source in the Nanaimo area at Duke Point would have resolved the capacity constraints on the 138 kV transmission system in CVI by alleviating the overloading on both circuits 1L115/116 and the transformers at VIT, by injecting a new supply source directly into the 138 kV transmission system near Nanaimo, the major load centre in CVI. However, since that project was cancelled, no other generation projects in the region have been proposed that would alleviate the need to upgrade the transmission system. In addition, any new generation project that may be announced would not likely be in service by October 2010, to meet the required ISD for the proposed solution to the capacity constraints in CVI (Exhibit B-1, p. 43).

Remedial Action Schemes

BCTC states that it will continue to employ RAS on its transmission systems, because they are an effective means of deferring the additions of infrastructure. In the case of the CVI transmission system, it notes that customer demand has exceeded the ability of the existing RAS to maintain the 138 kV transmission system during times of heavy usage, and is no longer effective. BCTC notes that redeploying the RAS to LTZ or PVL from JPT would not be an option, because it would increase the loading on the VIT transformers, and would not mitigate the need for additional firm transmission capacity in the CVI area to prevent load shedding during peak usage and a single contingency outage (Exhibit B-1, p. 44).

Curtailment

BCTC does not address curtailment in its Application. However, BCTC addressed the Customer Capacity Curtailment Contracts entered into by BC Hydro and certain of its customers, and stated that two such curtailment contracts could result in load curtailment in the CVI area, and that the maximum load curtailment that might be available was 150 MW in the vicinity of VIT and 6 MW in the vicinity of JPT (Exhibit B-8, BCUC 3.117.4). BCTC stated that while these contracts can result in load curtailment, the nature of the contracts is such that they cannot be used to avoid or defer construction of the CVI Project, and that they were intended to serve as a resource option for supply to the BC Hydro system during periods of constraint in generating capacity. In particular, the Customer Capacity Curtailment Contracts were to serve as an alternative to the import of energy or the use of Burrard Thermal Generating Station for generation purposes when the cost of energy is high. Consequently, these contracts were designed to meet system generation deficiencies when other alternatives would likely still be available for system supply purposes, not constraints within the CVI regional transmission system.

BCTC stated that the Customer Capacity Curtailment Contracts were based on voluntary load curtailment of large customers that could facilitate an orderly shut down of their plant processes in a way that incurred minimal cost to them, including any disruption to their production process, with four hours notice, but that load curtailment in this manner was not sufficient to meet transmission system constraints since, in order to avoid system voltage collapses and excessive thermal overloads, a fast means of load shedding was required, rather than the planned and orderly curtailment of load over a period of four hours. BCTC concluded that the existing load curtailment contracts located in the CVI area were not practical options to resolve transmission system constraints (Exhibit B-9, BCUC 3.117.4.1).

In addition, BCTC stated that there was no guarantee that the customer would curtail the required load in the CVI area when load curtailment was requested, because the contract for 150 MW of curtailment covered more than one plant, and provided the customer with the latitude to determine which of its plant(s) would provide the requested load curtailment, and to what extent.

The extent of load curtailment at any one plant was at the sole discretion of the customer and could depend on the status of the plant itself or market conditions for the products produced by any specific plant, and that there was no requirement, and no certainty, that customers would curtail load in the CVI region.

BCTC stated that the Customer Capacity Curtailment Contracts do not avoid load shedding under N-1 conditions, and that they are not sufficient to ensure adequate capacity under an N-1 contingency condition for the remaining unshed load. In other words, load shedding at distribution substations will be required after customers with curtailment contracts have been curtailed (Exhibit B-9, IR 3.117.4.2).

Juan de Fuca Cable Project

In addition to potential "non-wires" solutions BCTC stated that it considered JdF, a proposed international transmission interconnection between Pike Lake Substation in the Victoria area, and Port Angeles, WA. JdF has reported that the first phase of this cable project using HVDC Light technology could be in-service in 2009 to provide up to 550 MW of capacity. BCTC states that neither JdF, nor any other bulk transmission supply source such as the Vancouver Island Transmission Reinforcement Project ("VITR"), will provide relief to the capacity constraints that exist on the CVI system, since the capacity constraints are the result of customer demand exceeding the capacity of the existing 138 kV transmission system in the CVI area, and that adding a new source of supply to the 230 kV transmission system up stream of VIT and DMR supply points does not help alleviate the constraints that result in overloading on the 138 kV transmission system (Exhibit B-1, pp. 42-43).

CALIFORNIA natural resources AGENCY

ARNOLD SCHWARZENEGGER, Governor
MIKE CHRISMAN, Secretary for Natural Resources

For Immediate Release: Aug. 3, 2009

Contact: Sandy Cooney
(916) 653-9402

California Climate Adaptation Strategy Released

Discussion Draft Announcement Triggers 45-Day Public Comment Period

Sacramento, Calif. — California's Natural Resources Agency today released a comprehensive plan to guide adaptation to climate change, becoming the first state to develop such a strategy. The 2009 California Climate Adaptation Strategy Discussion Draft summarizes the latest science on how climate change could impact the state, and provides recommendations on how to manage against those threats in seven sector areas. Today's release sets in motion a 45-day public comment period.

"In keeping with the Governor's effort to fight climate change head on, re-examining the way we work and making adjustments accordingly is in many ways the most important thing we can do," said Secretary for Natural Resources Mike Chrisman. "Of all the difficult challenges that we've faced on this planet, environmental or otherwise, the greatest positive influence has happened when people acknowledge the problem, recognize their role in solving that problem and alter their behavior so that the change lasts. Adapting to climate change is a fundamental example of this principle"

Adaptation is a relatively new concept in California climate policy. The term generally refers to response efforts that combat the impacts of climate change – adjustments in natural or human systems to actual or expected climate changes in order to minimize harm or take advantage of opportunities.

In addition to Natural Resources, the state agencies involved in developing the draft strategy include Environmental Protection, Business, Transportation and Housing, Health and Human Services and the Department of Agriculture. The discussion draft focuses on seven different sectors that include: Public Health; Biodiversity and Habitat; Ocean and Coastal Resources; Water Management; Agriculture; Forestry; and Transportation and Energy Infrastructure. The strategy is a direct response to Gov. Schwarzenegger's November 2008 Executive Order S-13-08 that specifically asks to the Natural Resources Agency to identify how state agencies can respond to rising temperatures, changing precipitation patterns, sea level rise, and extreme natural events. As data continues to be developed and collected, the state's adaptation strategy will be updated to reflect current findings.

Rather than address the detailed impacts, vulnerabilities, and adaptation needs of every sector, those determined to be at greatest risk are prioritized.

-more-

Preliminary recommendations include:

• Establish a Climate Adaptation Advisory Panel to further assess California's climate change risks.
• Consider project alternatives that avoid significant new development in areas prone to flooding, sea-level rise, temperature changes, and precipitation changes.

• To the extent possible, communities should amend general plans and local coastal plans to avoid potential climate impacts.

• Fire fighting agencies should begin immediately to include climate change impact information into fire program planning.

• Major development and infrastructure projects should consider climate change impacts in order to comply with California Environmental Quality Act guidelines.

• Alter water use patterns as climate change will likely shift existing supplies and flows including Delta water supply and water quality. Improve Delta ecosystem and stabilize water supplies as developed in the Bay Delta Conservation Plan.

• Implement strategies to achieve a statewide 20 percent reduction in per capita water use by 2020, expand available state water storage, and implement the Delta Vision Cabinet Group recommendations to improve Delta water supply, water quality, and ecosystem conditions. Support agricultural water use efficiency.

• Coordinate hazard mitigation plans and assessments for managing increasing fire risk, flood, heat induced mortalities, and other hazards due to climate change.

• The California Department of Public Health will develop guidance for use by local health departments and other agencies to assess mitigation and adaptation strategies, which include impacts on vulnerable populations and communities and assessment of cumulative health impacts.

• Manage public health, infrastructure or habitat, to the extent that these are subject to climate change impacts, from sea level rise, increased temperature, and changing precipitation. This includes assessments of land use, housing and transportation proposals that could impact health, greenhouse gas emissions, and community resilience for climate change in keeping with SB 375 that addresses creating sustainable communities.

• Identify key California land and aquatic habitats and species from existing research that could be extinct this century due to climate change and develop a plan for expanding existing protected areas or altering water management systems that allow for climate change impacts.

• Work to meet projected population growth and increased energy demand with greater energy conservation. Renewable energy supplies should be enhanced through the Desert Renewable Energy Conservation Plan to reach a goal of 33 percent of the state's energy supply from renewable sources by 2020 in ways that protect sensitive habitat.

-more-

• Climate change research can and should be used for state planning purposes, and new climate change impact research should be funded and expanded. By January 2010, a Web-based map and interactive Web site should be developed and regularly updated by the California Energy Commission so as to be useful for local decision-makers.

California's ability to manage its climate risks through adaptation is dependent upon a number of critical factors including; economic resources, technology, infrastructure, institutional support and effective governance, public awareness, access to the best available scientific information, sustainably-managed natural resources, and equity in access to these resources. As the 2009 California Climate Adaptation Strategy Discussion Draft illustrates, the state has the ability to strengthen its capacity in all of these areas.

Two public meetings will be held to discuss the 2009 California Climate Adaptation Strategy Discussion Draft.

Public Stakeholder Meeting Schedule:

Thursday, Aug. 13, 2009
California Department of Food and Agriculture Building
1220 N Street, Sacramento, CA 95814
9 a.m. to 1 p.m.

Call In Number: 1-877-536-5793
Participant Code: 344390

Second Meeting
Date and Time TBA
Los Angeles, CA

Comments may also be submitted in writing to:

Adaptation
Natural Resources Agency
1416 Ninth Street, Suite 1311
Sacramento, CA 95814

or by email adaptation@resources.ca.gov.

To view the 2009 California Climate Adaptation Strategy Discussion Draft in its entirety, visit http://www.climatechange.ca.gov/adaptation/.

-30-

Executive Summary

2009 California Climate Adaptation Strategy

Discussion Draft

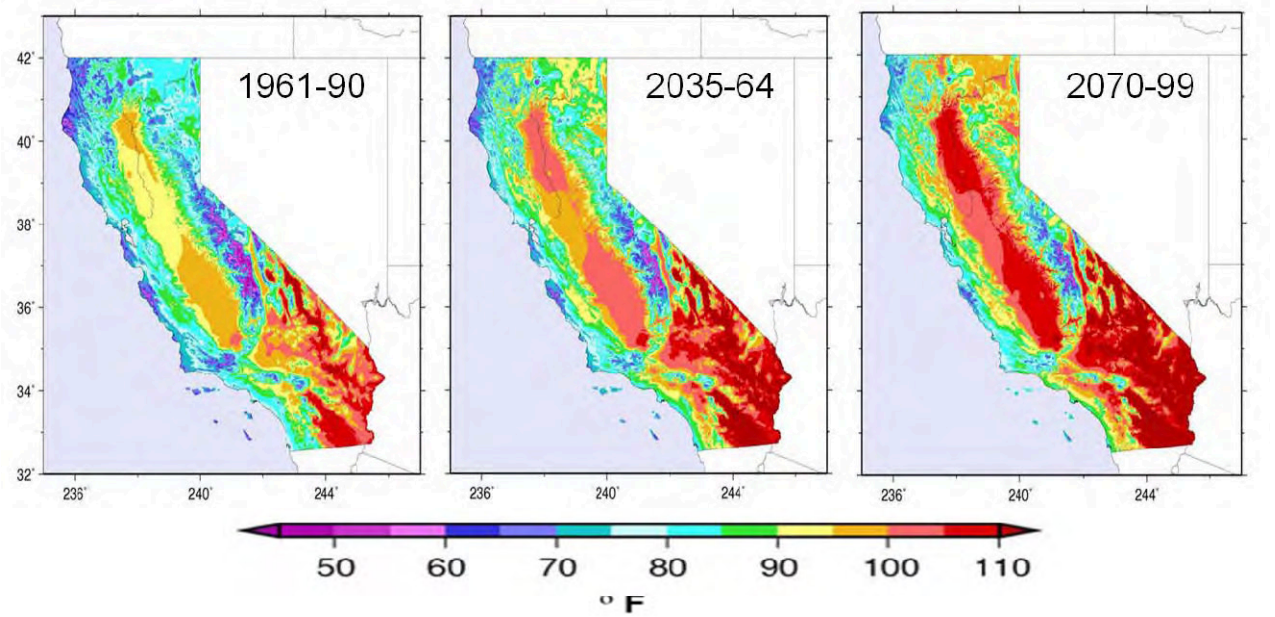
A Report to the Governor of the State of California in Response to Executive Order S-13-2008

Public Review Draft

California natural resources AGENCY

Appendix H

Figure 1. California Historical & Projected July Temperature Increase 1961-2099



Source: Dan Cayan et al. 2009.

Appendix H

TABLE OF CONTENTS

LIST OF FIGURES AND TABLES

EXECUTIVE SUMMARY

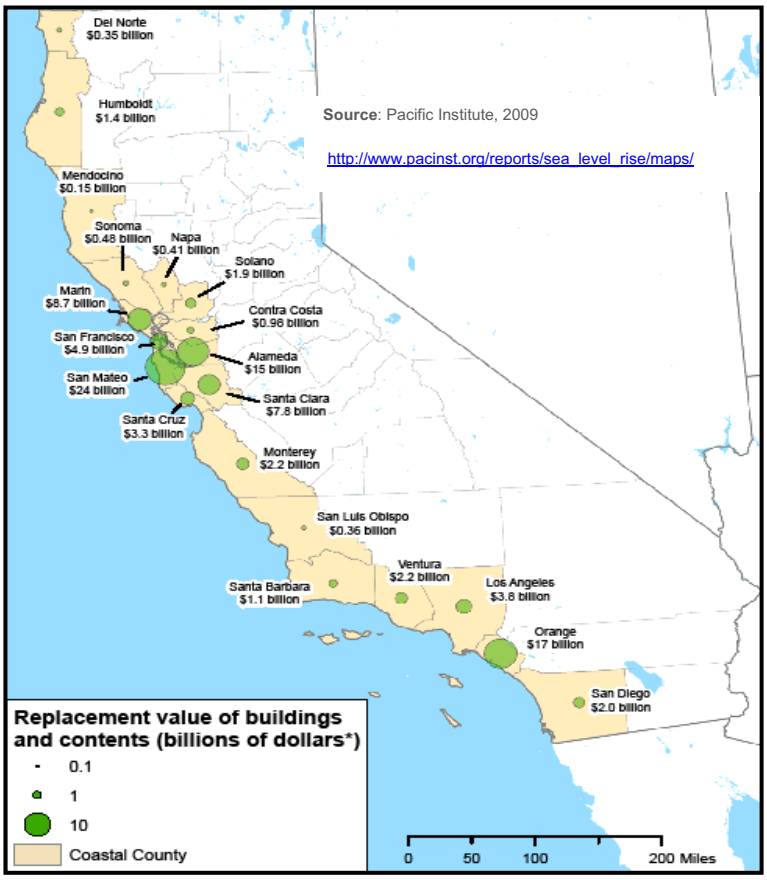
The Golden State at Risk

Climate change is already affecting California. Sea levels have risen by as much as seven inches along the California Coast over the last century, increasing erosion and pressure on the state's infrastructure, water supplies, and natural resources. The state has also seen increased average temperatures, more extreme hot days, fewer cold nights, a lengthening of the growing season, shifts in the water cycle with less winter precipitation falling as snow, and both snowmelt and rainwater running off sooner in the year.

These climate driven changes affect resources critical to the health and prosperity of California. For example, forest wildland fires are becoming more frequent and intense due to dry seasons that start earlier and end later. The state's water supply, already stressed under current demands and expected population growth, will shrink under even the most conservative climate change scenario. Almost half a million Californians, many without the means to adjust to expected impacts, will be at risk from sea level rise along bay and coastal areas. California's infrastructure is already stressed and will face additional burdens from climate risks. And as the Central Valley becomes more urbanized, more people will be at risk from intense heat waves.

If the state were to take no action to reduce or minimize expected impacts from future climate change, the costs could be severe. A 2008 report by the University of California, Berkeley and the non-profit organization Next 10 estimates that if no action is taken in California, damages across sectors would result in "tens of billions of dollars per year in direct costs" and "expose ***trillions*** of dollars of assets to collateral risk." More specifically, the report suggests that of the state's $4 trillion in real estate assets "$2.5 trillion is at risk from extreme weather events, sea level rise, and wildfires" with a projected annual price tag of up to $3.9 billion over this century depending on climate scenarios (www.next10.org/research/research_ccrr.html). The figure at right, from a study by the Pacific Institute, shows coastal property at risk from projected sea level rise by county with replacement values as high as $24 billion in San Mateo County.

Figure 2: *Replacement value of buildings and contents vulnerable to a 100 year coastal flood with 1.4 meters of sea level rise*



Source: Heberger et al. 2009.

California understands the importance of addressing climate impacts today. The state strengthened its commitment to managing the impacts from sea level rise, increased temperatures, shifting precipitation and extreme weather events when Governor Arnold Schwarzenegger signed Executive Order (EO) S-13-08 on November 14, 2008. The order called on state agencies to develop California's first strategy to identify and prepare for these expected climate impacts.

The *2009 California Climate Adaptation Strategy Discussion Draft* report summarizes the best known science on climate change impacts in the state to assess vulnerability and outline possible solutions that can be implemented within and across state agencies to promote resiliency. This is the first step in an ongoing, evolving process to reduce California's vulnerability to climate impacts.

The California Natural Resources Agency (CNRA) has taken the lead in developing this draft adaptation strategy, working through the Climate Action Team (CAT). Seven sector-specific working groups led by 12 state agencies, boards and commissions, and numerous stakeholders were convened for this effort. The strategy proposes a comprehensive set of recommendations designed to inform and guide California decision makers as they begin to develop policies that will protect the state, its residents and its resources from a range of climate change impacts. The CNRA will revise this draft adaptation strategy based on public input gathered over the next 45 days.

California's Climate Adaptation Strategy

As the climate changes, so must California. To effectively address the challenges that a changing climate will bring, climate adaptation and mitigation (i.e., reducing state greenhouse gas (GHG) emissions) policies must complement each other, and efforts within and across sectors must be coordinated. For years, the two approaches have been viewed as alternatives, rather than as complementary and equally necessary approaches.

Adaptation is a relatively new concept in California policy. The term generally refers to efforts to respond to the *impacts* of climate change – adjustments in natural or human systems to actual or expected climate changes to minimize harm or take advantage of beneficial opportunities.

California's ability to manage its climate risks through adaptation depends on a number of critical factors including its baseline and projected economic resources, technologies, infrastructure, institutional support and effective governance, public awareness, access to the best available scientific information, sustainably-managed natural resources, and equity in access to these resources.

As the *2009 California Climate Adaptation Strategy Discussion Draft* illustrates, the state has the ability to strengthen its capacity in all of these areas. In December 2008, the California Air Resources Board released the state's *Climate Change Scoping Plan*, which outlines a range of strategies necessary for the state to reduce its GHG emissions to 1990 levels by 2020. Many climate mitigation strategies, like promoting water and energy efficiency, are also climate adaptation strategies. By building an adaptation strategy on existing climate science and frameworks like the Scoping Plan, California has begun to effectively anticipate future challenges and change our actions that will ultimately reduce the vulnerability of residents, resources and industries to the consequences of a variable and changing climate.

To ensure a coordinated effort in adapting to the unavoidable impacts of climate change, the *2009 California Climate Adaptation Strategy Discussion Draft* was developed using a set of guiding principles:

- Use the best available science in identifying climate change risks and adaptation strategies.
- Understand that data continues to be collected and our knowledge about climate change is still evolving. As such, an effective adaptation strategy is "living" and will itself be adapted to account for new science.
- Involve all relevant stakeholders in identifying, reviewing, and refining the state's adaptation strategy.
- Establish and retain strong partnerships with federal, state, and local governments, tribes, private business and landowners, and non-governmental organizations to develop and implement adaptation strategy recommendations over time.
- Give priority to adaptation strategies that initiate, foster, and enhance existing efforts that improve economic and social well-being, public safety and security, public health, environmental justice, species and habitat protection, and ecological function.
- When possible, give priority to adaptation strategies that modify and enhance existing policies rather than solutions that require new funding and new staffing.
- Understand the need for adaptation policies that are effective and flexible enough for circumstances that may not yet be fully predictable.
- Ensure that climate change adaptation strategies are coordinated with the California Air Resources Board's AB 32 Scoping Plan process when appropriate, as well as with other local, state, national and international efforts to reduce GHG emissions.

The *2009 California Climate Adaptation Strategy Discussion Draft* takes into account the long-term, complex, and uncertain nature of climate change and establishes a proactive foundation for an ongoing adaptation process. Rather than address the detailed impacts, vulnerabilities, and adaptation needs of every sector, those determined to be at greatest risk are prioritized.

The development of the adaptation strategies presented within this report was spearheaded by the state's resource management agencies. CNRA staff worked with seven sector-based Climate Adaptation Working Groups (CAWGs) focused on the following areas: public health; ocean and coastal resources; water supply and flood protection; agriculture; forestry; biodiversity and habitat; and transportation and energy infrastructure.

Working group experts have an intimate knowledge of California's resources, environments, and communities, and also of the state's existing policy framework and management capabilities. This understanding informs the draft adaptation strategy and ensures a realistic assessment of adaptive capacities, current limitations, and future needs.

A Collaborative Approach

This draft adaptation strategy could not have been developed without the involvement of numerous stakeholders. Converging missions, common interests, inherent needs for cooperation, and the fact that climate change impacts cut across jurisdictional boundaries will require governments, businesses, non-governmental organizations, and individuals to minimize risks and take advantage of potential planning opportunities.

Throughout the development of this report, it became increasingly clear that overlapping missions and goals will require agencies and organizations at all levels to work together to develop close partnerships with regard to climate adaptation. This is the only means by which the far reaching effects of climate impacts can be addressed efficiently and effectively while avoiding potential conflicts. The Comprehensive State Adaptation Strategies chapter underscores the need for collaboration and identifies where cross-sector relationships are necessary.

To further enhance stakeholder participation, seven Climate Adaptation Working Groups (CAWGs) initiated a process that allowed for consultation with stakeholders through public workshops and review opportunities. This input has considerably shaped the content and refinement of this draft report. However, future updates of the draft adaptation strategy will require ongoing input through active stakeholder engagement and an even closer integration of state agency efforts. Public comment gathered during the next 45 days will be incorporated into recommendations and a final version of the report (see www.climatechange.ca.gov/adaptation).

In order to best analyze climate change risks, the *2009 California Climate Adaptation Strategy Discussion Draft* draws on years of state-specific science and impacts research, largely funded through the California Energy Commission's Public Interest Energy Research (PIER) Program and an engaged research community. The research provides for an understanding of the climate-related risks California will face and has significantly contributed to greater public awareness of climate change. As data continues to be developed and collected, the state's adaptation strategy will be updated to reflect current findings.

Preliminary Recommendations

The preliminary recommendations outlined in this draft adaptation strategy were developed by CNRA staff, CAWGs, the CAT, and from public comments. The public comment period will collect input from stakeholders about how these draft recommendations should be modified, if necessary. It is recognized the implementation of the following strategies will require significant collaboration among multiple stakeholders to ensure they are carried out in a rational, yet progressive manner over the long term. These strategies distinguish between near-term actions that will be completed by the end of 2010 and long-term actions to be developed over time, and are covered in more detail in the sector chapters in Part II of this report.[1]

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[1] Each of the twelve Executive Summary strategies is drawn from multiple strategies within the subsequent sector specific and cross-sector adaptation strategy chapters. The recommendations here may not reflect exact wording of individual sector recommendations but relate to their core message. Each Executive Summary recommendation here lists the sector and recommendation number using the following acronyms to identify the sector: Public Health (PH), Biodiversity

Key recommendations include:

1. A Climate Adaptation Advisory Panel (CAAP) will be appointed to assess the greatest risks to California from Climate Change and recommend strategies to reduce those risks building on California's Climate Adaptation Strategy. This Panel will be convened by the California Natural Resources Agency, in coordination with the Governor's Climate Action Team, to complete a report by December 2010. The CNRA will continue to act as the lead Climate Adaptation Office until subsequent guidance is provided by the CAAP.

2. California must change its water management and uses because climate change will likely create greater competition for limited water supplies needed by the environment, agriculture, and cities. As directed by the Governor, state agencies must implement strategies to achieve a statewide 20 percent reduction in per capita water use by 2020, expand surface and groundwater storage, implement the Delta Vision Cabinet Group recommendations to fix Delta water supply, quality, and ecosystem conditions, support agricultural water use efficiency, and improve state-wide water quality. Improve Delta ecosystem conditions and stabilize water supplies as developed in the Bay Delta Conservation Plan. (BH-2, W-3, 6, and 7; A-3; TEI-3).

3. Consider project alternatives that avoid significant new development in areas that cannot be adequately protected (planning, permitting, development, and building) from flooding due to climate change. The most risk-averse approach for minimizing the adverse effects of sea level rise and storm activities is to carefully consider new development within areas vulnerable to inundation. State agencies should generally not plan, develop, or build any new significant structure in a place where that structure will require significant protection from sea-level rise, storm surges, or coastal erosion during the expected life of the structure. However, vulnerable shoreline areas containing existing and proposed development that have regionally significant economic, cultural, or social value may have to be protected, and in-fill development in these areas should be accommodated. State agencies should incorporate this policy into their decisions, and other levels of government are also encouraged to do so. (CS-2; OCR-1 and 2; W-4; TEI -1).

4. All state agencies responsible for the management and regulation of public health, infrastructure or habitat subject to significant climate change should prepare as appropriate agency-specific adaptation plans, guidance, or criteria by September 2010. (PH-8; BH-1, 2, and 6; OCR-3; F-1 and 2; TEI-2 and 5).

5. All significant state projects, including infrastructure projects, must consider climate change impacts, as currently required under CEQA Guidelines Section 15126.2. (BH-2).

6. The California Emergency Management Agency (Cal EMA) will collaborate with CNRA and the seven sector-based Climate Adaptation Working Groups (CAWGs) to assess California's vulnerability to climate change, identify impacts to State assets, and promote climate adaptation/mitigation awareness through the Hazard Mitigation Web Portal and My Hazards website as well as other appropriate sites. The transportation sector CAWG, led by Caltrans,

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and Habitat (BH), Ocean and Coastal Resources (OCR), Water Management (W), Agriculture (A), Forestry (F), Transportation and Energy Infrastructure (TEI), and Cross-Sector (CS).

will specifically assess how transportation nodes are vulnerable and the type of information that will be necessary to assist response to district emergencies. Climate change impacts were recognized in the 2007 State Hazard Mitigation Plan (SHMP) as having an effect on primary hazards such as flooding and wildfires and secondary hazards such as levee failure and landslides. Special attention will be paid to the most vulnerable communities impacted by climate change. (CS-3 and 5; PH-4 and 5; OCR-5; W-4; F-2 and 3; TEI-5, 6 and 8).

7. The State should identify key California land and aquatic habitats from existing research that could change significantly this century due to climate change. Based on this identification the state should develop a plan for expanding existing protected areas or altering land and water management practices to minimize adverse effects from climate change induced phenomena. (BH-1; W-5; F-5).

8. The California Department of Public Health will develop guidance by September 2010 for use by local health departments and other agencies to assess mitigation and adaptation strategies, which include impacts on vulnerable populations and communities and assessment of cumulative health impacts. This includes assessments of land use, housing and transportation proposals that could impact health, GHG emissions, and community resilience for climate change, such as in the 2008 Senate Bill 375 regarding Sustainable Communities. The best long-term strategy to avoid increased health impacts from climate change is to ensure communities are healthy to build resilience to increased spread of disease and temperature increases. (PH-3).

9. Communities with General Plans and Local Coastal Plans should begin when possible to amend their Plans to assess climate change impacts, identify areas most vulnerable to these impacts, and to develop reasonable and rational risk reduction strategies using the Draft California Adaptation Strategy as guidance. Every effort will be made to provide tools to assist in these efforts. (BH-1; OCR– 2 and 4; CS-2).

10. State fire fighting agencies should begin immediately to include climate change impact information into fire program planning to inform future planning efforts. Enhanced wildfire risk from climate change will likely increase public health and safety risks, property damage, fire suppression and emergency response costs to government, watershed and water quality impacts, and vegetation conversions and habitat fragmentation. (PH-4 and 5; F-1; TEI-3).

11. State agencies should meet projected population growth and increased energy demand with greater energy conservation and increased use of renewable energy. Renewable energy supplies should be enhanced through the Desert Renewable Energy Conservation Plan that will protect sensitive habitat that will help reach the state goal of having 33 percent of the state's energy supply from renewable energy by 2020. (TEI-2).

12. Existing and planned climate change research can and should be used for state planning and public outreach purposes; new climate change impact research should be broadened and funded. By September 2010, a user friendly web-based map and interactive website will be developed and regularly updated by the California Energy Commission to synthesize existing California climate change scenario and climate impact research and to encourage its use in a way that is useful for local decision-makers. Every effort will be made to increase funding for climate change research. (CS-4 and 6; PH-7; BH-4; OCR-6; W-8, 9, and 10; A – 8; F-4 and 5; TEI-3 and 9).

Natural Resources Canada Ressources naturelles Canada

Canada

Natural Resources Canada > Earth Sciences Sector > Priorities > Climate Change Impacts and Adaptation

Climate Change Impacts and Adaptation

From Impacts to Adaptation: Canada in a Changing Climate 2007

From Impacts to Adaptation: Canada in a Changing Climate 2007 reflects the advances made in understanding Canada's vulnerability to climate change during the past decade. Through a primarily regional approach, this assessment discusses current and future risks and opportunities that climate change presents to Canada, with a focus on human and managed systems. It is based on a critical analysis of existing knowledge, drawn from the published scientific and technical literature and from expert knowledge. The current state of understanding is presented, and key knowledge gaps are identified. Advances in understanding adaptation, as well as examples of recent and ongoing adaptation initiatives, are highlighted throughout the report.

The assessment team involved experts from across the country, acting as advisory committee members, authors and editors. The completed report consists of eleven chapters.

For media inquiries, please contact the NRCan Media Relations team.

Table of Contents

Download [PDF, 19.7 Mb, viewer]

Appendix I

the full report, 448 pages.

For further information, please contact adaptation@NRCan.gc.ca.

Date Modified: 2008-11-27

http://adaptation.nrcan.gc.ca/assess/2007/index_e.php

Appendix I

Carbon Tax Rates

The proposed tax rates, effective July 1, 2008, are based on $10 per tonne of carbon dioxide equivalent (CO_2e) emissions from the combustion of each fuel. CO_2e is the amount of carbon dioxide, methane and nitrous oxide released into the atmosphere, with the non-carbon dioxide emission levels adjusted to a carbon dioxide equivalent basis.

The proposed tax rates will increase over the next four years, based on the dollars per tonne of CO_2e emissions, as set out below:

- July 1, 2009 - $15 per tonne of CO_2e emissions
- July 1, 2010 - $20 per tonne of CO_2e emissions
- July 1, 2011 - $25 per tonne of CO_2e emissions
- July 1, 2012 - $30 per tonne of CO_2e emissions

The specific tax rates will vary for each type of fuel, depending on the amount of CO_2e released as a result of its combustion. For example, at $10 per tonne, the tax on gasoline would be 2.41 cents per litre and for diesel, 2.76 cents per litre.

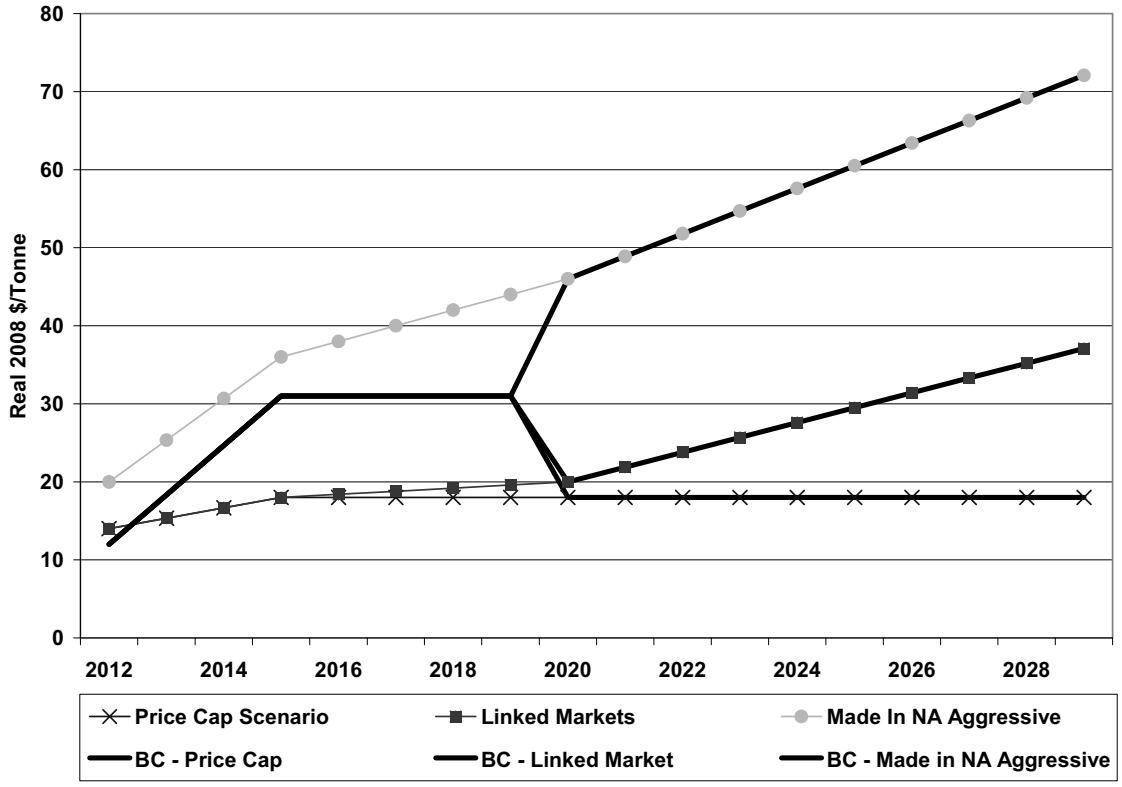
The following table lists the fossil fuels that are expected to be subject to the carbon tax and the proposed carbon tax rate for each type of fuel.

Carbon Tax Rates by Fuel Type

	Units for Tax Rates	July 1 2008	July 1 2009	July 1 2010	July 1 2011	July 1 2012
Liquid Fuels						
Gasoline	¢/Litre	2.41	3.62	4.82	6.03	7.24
Diesel	¢/Litre	2.76	4.14	5.52	6.89	8.27
Light Fuel Oil	¢/Litre	2.76	4.14	5.52	6.89	8.27
Heavy Fuel Oil	¢/Litre	3.11	4.67	6.22	7.78	9.33
Aviation Gasoline	¢/Litre	2.45	3.67	4.90	6.12	7.34
Jet Fuel	¢/Litre	2.62	3.93	5.25	6.56	7.87
Kerosene	¢/Litre	2.56	3.84	5.12	6.40	7.68
Gaseous Fuel						
Natural Gas	¢/GJ*	49.88	74.82	99.76	124.70	149.64
Propane	¢/Litre	1.53	2.30	3.06	3.83	4.60
Butane	¢/Litre	1.76	2.65	3.53	4.41	5.29
Ethane	¢/Litre	0.98	1.46	1.95	2.44	2.93
Pentane	¢/Litre	1.76	2.65	3.53	4.41	5.29
Coke Oven Gas	¢/GJ*	42.31	63.47	84.62	105.78	126.93

Figure presents both the broader planning scenarios as well as the scenarios that would relate to B.C. until the GHG offset markets link. The methodology of how the GHG price forecast is incorporated is described in Chapter 5.

Figure 4-1 GHG Offset Cost Scenarios in Portfolio Analysis



4.2.4.2 Accounting for Indirect Impacts of GHG Regulations

In addition to the direct impacts identified above, there is an indirect impact of GHG regulations for utilities' resource planning environment through the scenario forecasts of natural gas and electricity market prices. This impact is described in the following sections on natural gas and electricity markets that follow.

Table 3 – Price Estimates for Three Planning Scenarios

Price Estimates for Planning Scenarios[91] (CDN $2008)								
Year		2010	2012	2015	2020	2030	2040	2050
Price Cap Scenario		$14	$14	$18	$18	$18	$18	$18
Linked Markets Scenario	Price Range	n.a.	Canada: $14 U.S.: $12-18	Canada: $18 U.S.: $11-17 [92]	$15-25	$24-54	$39-59	$63-97
	Mid Point		Canada: $14 U.S.: $15	Canada: $18 U.S.: $14	$20	$39	$49	$80
Made in North America Aggressive Targets Scenario	Price Range	n.a.	$16-24	$24-47	$35-57	$65-84	$112-124	$166-187
	Mid Point		$20	$36	$46	$75	$118	$177

1. Price Cap Scenario

- In this scenario, Canada and U.S. remain outside of an international agreement and implement less ambitious but what appear to be politically feasible policies (regional and state/provincial initiatives except California's are superseded by federal regulations);
- Prices presented in Table 3 are prices in Canada based on the price cap under the current proposed Federal Regulatory Framework. No economic models were used to estimate prices for this scenario.
- The program proposed by the Government of Canada specifies price cap values through 2017.[93] For purposes of this Price Cap scenario, we assume the price cap continues through 2050 (it increases based on the rate of nominal GDP growth

[91] In 2012, only one pricing estimate was available in each of the Linked Markets and the Made in North America Climate Champions scenarios. In each case when only a single numerical result from a model is available, the range is calculated based on +/-20% of the model pricing estimate.

[92] The price range in 2015 ($11-17) is lower than the price range in 2012 ($12-18). This result is counter-intuitive, and can be explained as follows. There is only one price estimate available for 2012 ($15). To provide a range, we adjusted that estimate by +/-20% resulting in $12-18 in 2012. In contrast, there were several model estimates available in 2015, ranging from $11 to $17, which we did not adjust by a factor of +/-20%. (Note that the study providing the $11 estimate in 2015 did not provide an estimate for 2012.)

[93] The price cap in the Regulatory Framework for Canada is derived from the allowable contributions by industrial emitters to a Technology Development Fund. There are two components to the fund – a technology deployment component that ramps down to near zero in 2017 and a technology research fund for which there is no specified sunset. In the Price Cap scenario, we assume that there is sufficient pressure brought to bear on the federal government to agree on an indefinite continuation of both components of the Fund through to 2050 or alternatively the creation of another price cap vehicle.

Table 7: Summary of GHG Cost Adders[117]

Entity	Process	GHG Adder Range[118] (CDN$2008/tonne of CO_2e)	Timeframe of Analysis for GHG Adders
PacifiCorp	IRP (2007)[119]	$0 - $69.60	2007-2026
Northwestern Energy	RPP (2005)[120]	$6.50 - $36.93	2010-2025
Puget Sound Energy	IRP (2007)[121]	$7.19 - $48.97	2012-2027
Idaho Power Company	IRP (2006)[122]	$0 - $60.06	2006-2025
Avista Utilities	IRP (2007)[123]	$0 - $41.57	2015-2027
Portland General Electric	IRP (2007)[124]	$8.36 - $69.19	2010-2027
Seattle City Light	IRP (2006)[125]	$6.01 - $101.16	2006-2026
Tri-State	IRP (2007)[126]	$11.71 - $43.65	2007-2026
Colorado Springs	IRP (2007, Draft)[127]	$0-$108.26	2010-2027
Southern California Edison	LTPP (2006)[128]	$10.22	2007-2016

[117] Original prices were converted to January 1, 2008 CDN dollars per metric ton (tonne) of CO_2e as follows. Prices per short ton were converted into prices per tonne based on 1 short ton = 0.9072 metric tons. Next, prices were converted to US $2007 based on Consumer Price Index (CPI) data from the Bureau of Labor Statistics (BLS) of the U.S. Department of Labor. Specifically, prices expressed in terms of future year dollars (2008 and beyond) were converted into $2007 using a discount factor equal to the average inflation rate over the past 10 years, approximately 2.66% (http://data.bls.gov/cgi-bin/cpicalc.pl). Prices expressed in past year dollars (prior to 2007) were converted into US $2007 using historical annual inflation rates based on "CPI -All Urban Consumers 1982-84=100 - CUUR0000SA0" data series (http://www.bls.gov/cpi/home.htm). Subsequently, adder prices were converted into $CDN using an exchange rate of US $1 = CDN $1.05 obtained from www.xe.com on July 20, 2007. Lastly, prices were converted to 2008 CDN dollars based on the Bank of Canada's CPI projections for the 3rd and 4th quarter of 2007 (http://www.bankofcanada.ca/en/mpr/pdf/update120707.pdf).

[118] These ranges include all GHG values assumed over time in each IRP/LTTP. As the table illustrates, the specific timeframe of analysis considered in each IRP/LTTP differs (see discussion in subsection A of this section for additional detail on this and other assumptions).

[119] PacifiCorp 2007 Integrated Resource Plan, http://www.pacificorp.com/File/File74765.pdf

[120] NorthWestern Energy's 2005 Electric Default Resource Procurement Plan, http://www.montanaenergyforum.com/plan.html

[121] Puget Sound Energy 2007 Integrated Resource Plan, http://www.pse.com/energyEnvironment/pse2007irpView.aspx

[122] Idaho Power Company's 2006 IRP, http://www.idahopower.com/pdfs/energycenter/irp/2006/2006_IRP.pdf

[123] Avista's 2007 Electric Integrated Resource Plan, http://www.avistautilities.com/resources/plans/electric.asp

[124] Portland General Electric 2007 Integrated Resource Plan, http://www.portlandgeneral.com/about_pge/current_issues/energy_strategy/pge_irp_2007.pdf

[125] Seattle City Light 2006 Integrated Resource Plan, http://www.seattle.gov/light/news/issues/irp/docs/SCLIRP2006.pdf

[126] Tri-State Generation 2007 Integrated Resource Plan, http://www.tristategt.org/NewsCenter/NewsItems/Tri-State%20IRP%2002-15-2007.pdf

[127] Colorado Springs 2007 Electric Integrated Resources Plan Presentation, April 20, 2007 http://www.csu.org/about/projects/eirp/participation/13744.pdf

Canadian Federal program and the U.S. in 2012-15. To reiterate, the Linked Markets scenario assumes that the current Canadian Federal GHG program, including the price cap, continues through 2015, and a U.S. federal program with targets consistent with a 550 ppmv global concentration target (e.g. S. 280) begins in 2012.

Starting in 2020, estimated prices in all jurisdictions are those associated with the Linked Markets scenario. This scenario appears to be the most likely scenario among those considered in this analysis starting in 2020, subject to the caveats and conditions discussed in Sections III and IV and other significant uncertainties. By 2020, it appears that BC would harmonize its approach with the Canadian Federal Government, and WCI/WECC states would adopt the U.S. Federal Government's GHG targets. Different requirements at the state and Federal level will be difficult to maintain over time, given the added cost burden and compliance complexity that this would impose on the private sector and the likely opposition of companies that own and operate assets in states with more stringent targets and GHG policies or that have differing targets and GHG policies.

Table 8: GHG Price Estimates for Policy Scenarios Assessed to be Most Likely in 2012-15 and 2020-50

Year	2012	2015	2020	2030	2040	2050
Most Likely Policy Scenario	WCI/WECC Compliance Instruments Only		Linked Markets Scenario			
BC Price Ranges (all prices CDN$2008/tonne CO_2e)	$9-14	$16-46	$15-25	$24-54	$39-59	$63-97
BC Mid-Point	$12	$31	$20	$39	$49	$80
Canadian Federal Program (intensity target and price cap through 2015) Price Ranges	$14	$18	$15-25	$24-54	$39-59	$63-97
Canadian Mid-Point	$14	$18	$20	$39	$49	$80

U.S. Federal Program (McCain-Lieberman or similar in 2012) Price Ranges	$12-18	$11-17[191]	$15-25	$24-54	$39-59	$63-97
U.S. Mid-Point	$15	$14	$20	$39	$49	$80

[191] The price range in 2015 ($11-17) is lower than the price range in 2012 ($12-18). This result is counter-intuitive, and can be explained as follows. There is only one price estimate available for 2012 ($15). To provide a range, we adjusted that estimate by +/-20% resulting in $12-18 in 2012. In contrast, there were several model estimates available in 2015, ranging from $11 to $17, which we did not adjust by a factor of +/-20%. (Note that the study providing the $11 estimate in 2015 did not provide an estimate for 2012.)

BC HYDRO LONG -TERM ACQUISITION PLAN JUNE 2008

TESTIMONY OF DR. MARK JACCARD

ON BEHALF OF THE
INDEPENDENT POWER PRODUCERS ASSOCIATION OF B.C.

Among other things, I am a member of the National Round Table on the Environment and the Economy. In my view if the Government of Canada is to reach its goal of long-term (2050) national emission reduction targets for greenhouse gas (GHG) the required emission prices for CO2e are likely to be in the range suggested by the table below:

Table ES 1: Greenhouse gas price simulated in this report ($2005 / tonne CO_2e)

	2011-2015	*2016-2020*	*2021-2025*	*2026-2030*	*2031-2035*	*2036-2040*	*2041-2045*	*2046-2050*
Greenhouse Gas Price	$15	$115	$215	$300	$300	$300	$300	$300

My view is based on the attached report entitled "Draft Report Technology Roadmap to Low Greenhouse Gas Emissions in the Canadian Economy; A Sectoral and Regional Analysis" dated July 1, 2008 which was prepared by J&C Nyboer for the National Round Table on the Environment and the Economy.

HIGHER CARBON PRICES WITH FRAGMENTED POLICY ACROSS JURISDICTIONS

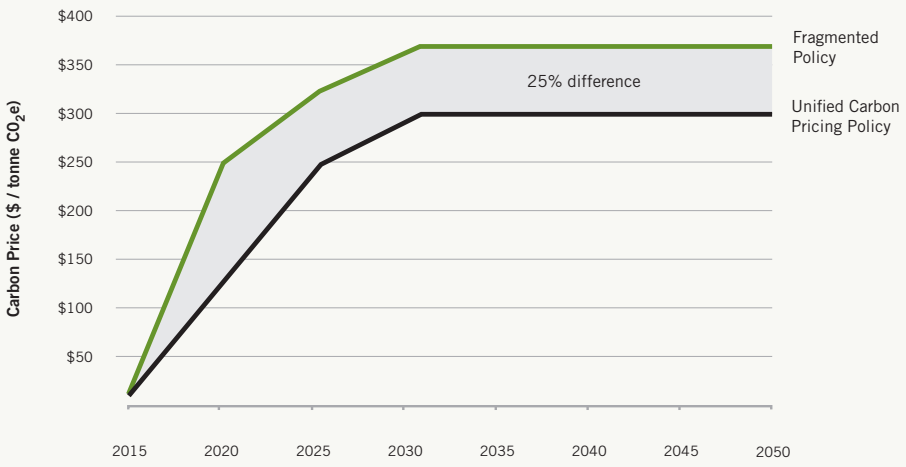


FIGURE 5

Unify carbon prices through a single national cap-and-trade system

The central design question for carbon pricing policy is the choice of a pricing policy instrument. At the outset, the NRTEE determined that in designing an effective carbon pricing policy we would not simply choose between the two principal instruments: carbon taxes and cap-and-trade systems. Each offers a benefit that carbon pricing policy seeks: price certainty through carbon taxes, emissions reduction certainty through cap-and-trade. Put another way, one offers *price-setting* certainty, the other offers *quantity-setting* certainty. In reality, price-setting approaches (taxes) can be blended with quantity-setting approaches (cap-and-trade) as we manage the trade-offs between the two. Figure 6 is a notional illustration of how existing and proposed carbon pricing instruments in Canada are neither a "pure" carbon tax nor a "pure" cap-and-trade system; rather, they blend aspects of one another to deliver on goals of price and emissions quantity certainty.

THE RAPIDLY RISING DOMESTIC COSTS OF ABATEMENT

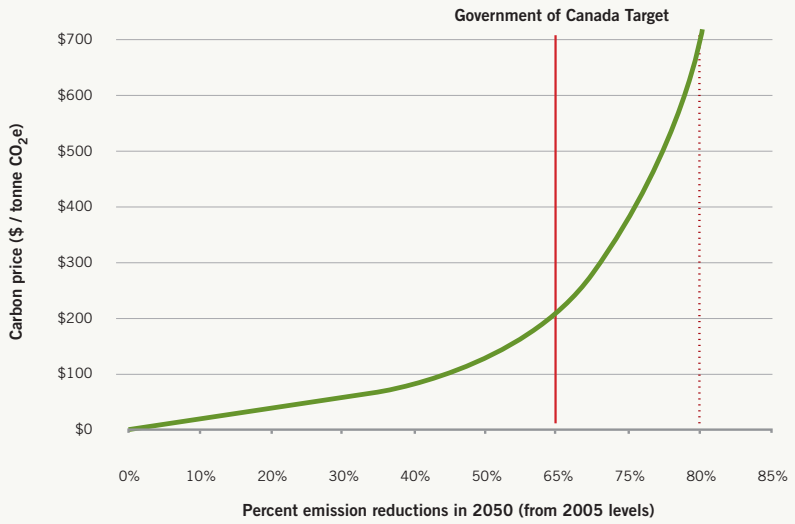


FIGURE 7

COST-EFFECTIVENESS COMPARISON BETWEEN DOMESTIC-ALONE VS. INTERNATIONAL TRADING AND PURCHASES

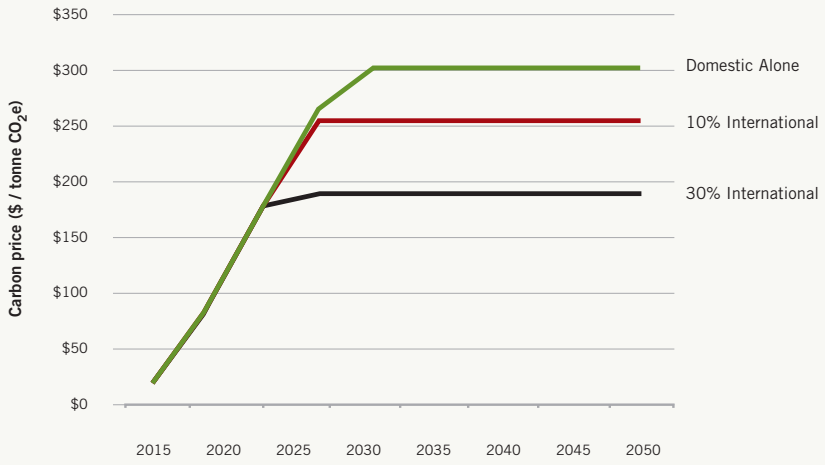
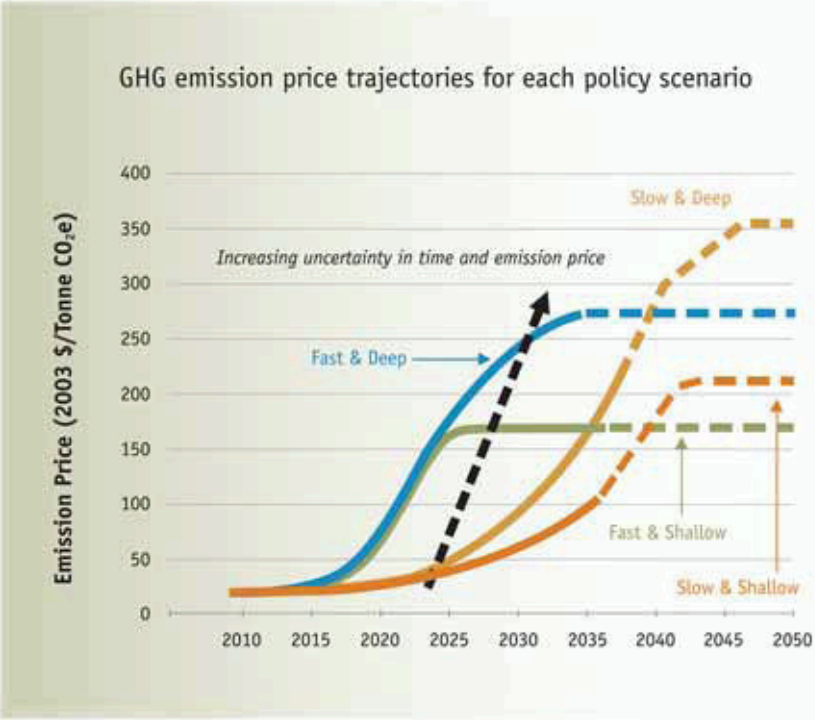


FIGURE 8

influenced by international emission prices and market conditions. Hence the prices are depicted as dotted lines in Figure 3 at higher levels and further into the future.

Figure 3: GHG emission price trajectories for each policy scenario



Note: See Section 5.5 for the key scenario assumptions in CIMS, including starting energy prices for natural gas, electricity, coal, gasoline, oil and other refined petroleum products.

Pathway Trade-offs

The NRTEE research demonstrates that the choice of pathway to a low-GHG emission future involves trade-offs between environmental objectives and economic outcomes, as is illustrated in Figures 2 and 3. Clearly there is a potential for greater economic cost (in terms of $/tonne CO_2e) associated with deeper (65%) GHG emission reductions. In considering these trade-offs, the NRTEE found that any delay in abatement action sooner rather than later could lead to three specific risks:

- not attaining deep emission reduction targets;
- higher economic costs; and,
- higher cumulative GHG emissions.

and increased to \$200/t CO_2e by 2020 would still result in emissions that are slightly higher than target currently promoted by ENGOs.

Throughout the rest of this report, emission prices refer to the values in 2020. The trajectory of prices leading up to 2020 is assumed in the general equilibrium modelling but not referred to directly.

Due to modelling limitations and time constraints, the carbon price path to 2020 outlined in this report does not take into account any complementary measures or the purchase of international carbon credits. This exclusion means that the carbon prices reported here are higher than might be required in practice, if accompanied by other measures.

TABLE 2
Optimal Price Path to Achieve GHG Targets in 2020 – Path that Minimizes GDP Loss (some industrial fugitive emissions only)

CARBON PRICE PATH TO 2020 (2003\$/T CO_2e)			EMISSION REDUCTION IN 2020 RELATIVE TO:		
2010	2015	2020	1990	2006	2020 BAU
\$25	\$45	**\$75**	+10%	-12%	**-21%**
\$40	\$65	**\$100**	+1%	-19%	**-27%**
\$55	\$90	**\$150**	-12%	-30%	**-35%**
\$75	\$130	**\$200**	-19%	-35%	**-40%**

Source: Reduced form model of CIMS (minimize GDP loss to achieve target reduction)

ASSESSMENT OF REVENUE USE OPTIONS

This report investigates how alternative mechanisms for carbon price revenue utilization might change the economic impact of carbon pricing. Some of the revenue utilization schemes analyzed here are revenue neutral, while others are not. In this report, we use the term revenue neutrality in reference to revenue from a specific source, rather than overall government revenue. For example, if the revenue raised from carbon pricing were used to lower the personal income tax rate, revenue neutrality (as defined in this report) implies that the revenue from the carbon price would exactly make up for the shortfall in revenue caused by reduction in the income tax rate. Because of other feedbacks in the economy however, government collection of other taxes may change, leaving overall government revenue changed.

Six alternative tax shifting and revenue recycling options are examined:[30]

- **Lump-sum recycling to households** (**LUMPSUM**). In this scenario, all emission price revenue is collected by government and then totally disbursed as rebates to households. In this scenario, both government revenue and expenditures (transfers) increase relative to business as usual. This scheme therefore, is net revenue neutral, after accounting for government transfers to households. In this report, the LUMPSUM scenario is treated as a comparison benchmark for all other scenarios.
- **Recycling to industrial emitters based on output** (**production**) (**OUTPUT**). In this scenario, all emission price revenue is returned to firms proportionately to their economic output.[31] This recycling scheme provides an incentive for firms to increase output if they can do so without substantially increasing emissions. As a result, it should provide a stimulus to economic growth. Like the previous scenario, this one sees both government revenue and expenditures (transfers) increase relative to the business as usual case. Again, we consider the scheme net revenue neutral, since it involves transfers by government to firms but no increase in government expenditures;

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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-92-09

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Inc.
for the Approval of a Net Metering Rate Schedule 95

BEFORE: P.E. Vivian, Commissioner
A.A. Rhodes, Commissioner July 29, 2009

O R D E R

WHEREAS:

A. On April 17, 2009, FortisBC Inc. ("FortisBC") submitted an application (the "Application") to the British Columbia Utilities Commission (the "Commission") for approval of a Net Metering Rate Schedule 95 and resulting revisions to the FortisBC Electric Tariff Index and Rate Schedule 80; and

B. FortisBC proposed the Net Metering Rate Schedule in response to the Provincial Energy Plan, the *Utilities Commission Act* section 64.01, Commission Order G-117-05 and stakeholder requests; and

C. On April 28, 2009, the Commission issued Order G-43-09 establishing a written hearing process to review the Application; and

D. In accordance with Order G-43-09, a written regulatory process was conducted from May 22, 2009 to July 6, 2009. Commission and Intervenor Information Requests were received on May 27, 2009. FortisBC responded to Information Requests by June 10, 2009; and

E. FortisBC made its Final Submission on June 17, 2009, Intervenor Final Submissions were received on June 19, 2009, and FortisBC's Reply Submission was received on July 6, 2009; and

F. The Commission has reviewed the Application, the responses to Information Requests and the Submissions of FortisBC and the participating Intervenors.

NOW THEREFORE the Commission orders as follows:

1. The Commission approves the FortisBC Net Metering program as proposed in the Application with the modifications described in the Reasons for Decision accompanying this Order.

2. The Net Metering program may commence subsequent to approval by the Commission of a revised FortisBC Net Metering Tariff - Rate Schedule 95 which incorporates the directives described in the Reasons for Decision accompanying this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 30th day of July 2009.

BY ORDER

Original signed by:

P.E. Vivian
Commissioner

Attachment

FortisBC Inc.
Net Metering Program

REASONS FOR DECISION

GENERAL APPROVAL

The Commission Panel generally approves the FortisBC Net Metering Tariff Application as filed. Prior to implementation, the Commission Panel directs FortisBC to incorporate the directives and determinations, as discussed in these Reasons, into the program.

Net Metering-Monitoring and Evaluation Report	Required
Existing Electro-Mechanical Meters	Acceptable
Rate Schedule 95 (Net Metering)	Modifications
Site Inspections Provisions	Modified
Reconciliation Costs	Modified

NET METERING-MONITORING AND EVALUATION REPORT

The Commission Panel directs FortisBC to file a Net Metering-Monitoring and Evaluation Report (the "Report"). The Report should contain information similar in nature to that required for the BC Hydro Net Metering program (Commission Order G-26-04, Appendix A, Section 2.6). FortisBC should file the Report with the Commission within 60 days of the anniversary date of program commencement.

The Commission Panel agrees with the Okanagan Environmental Industry Alliance (the "Alliance") and the B.C. Sustainable Energy Association and the Sierra Club of British Columbia ("BCSEA") that having FortisBC produce and file a report similar to BC Hydro's will provide a more complete picture of the progress of net metering in the province. The collected reports will contribute to future net metering policy development.

The BC Hydro report must contain information on net metering activities in other jurisdictions. For the FortisBC Report, that effort need not be replicated. Instead, the Report should be limited to descriptions and data on FortisBC program penetration, costs and recommended future changes. As FortisBC offers Time-of-Use pricing, the Report should address net metering program results for customers on regular rates as compared to those under Time-of-Use rates. FortisBC should also make recommendations for amendments to the Net Metering program that it deems necessary. The Commission will provide FortisBC with additional guidance on specific content closer to the due date, if requested.

ELECTRO-MECHANICAL METERS

The Application does not allow for the use of standard electro-mechanical meters, spinning in both directions, to measure energy exchange. (Exhibit B-1, p. 11) Instead, FortisBC proposes that a customer-generator be connected through a single meter, with separate registers for each flow direction. The Commission Panel considers that the evidence does not support ruling out the use of existing, electro-mechanical meters.

As part of a response to an information request, FortisBC supplied Measurement Canada Information Bulletin 2007-04-20. The Bulletin describes Measurement Canada's policy on the use of electro-mechanical meters in net metering applications. Among other details, the Bulletin states that electro-mechanical meters may be inaccurate in favour of the utility:

> "MC has performed a study on the effect of operating electro-mechanical meters in the reverse direction. This study indicated that at low currents, the accuracy trend of electro-mechanical meters taken from a small sample of meters tested shows the errors to be in favour of the contractor. The report included results showing that some errors at low currents may be as high as 8% slow." (Exhibit B-2, BCUC Appendix 8.1, p. 3)

Bulletin 2007-04-20 specifies that electro-mechanical meters may be used for net metering until the earlier of either the replacement of the existing meter or December 31, 2013. Measurement Canada allows electro-mechanical meters in net metering applications. (Exhibit B-2, BCUC Appendix 8.1, Section 7)

FortisBC gave no indication in either the Application or responses to information requests that there is a safety reason why electro-mechanical meters cannot be used.

The Commission Panel anticipates that, further to the Advanced Metering Decision and Order G-168-08, FortisBC will be bringing forward a plan to generally replace existing meters with advanced meters in the relatively near future. In order to decrease the likelihood of making two meter replacements, existing, electro-mechanical meters should not be precluded from use in Net Metering.

The Commission Panel considers that electro-mechanical meter inaccuracy should be balanced against the cost to the customer of replacing existing meters. Allowing customers the option of using existing, electro-mechanical meters should improve the economics of the program.

The Commission Panel therefore directs FortisBC to provide customers with the option of using existing electro-mechanical meters for Net Metering, subject to the requirements of Measurement Canada Information Bulletin 2007-04-20, Section 7.2.

RATE SCHEDULE 95 – AMENDMENTS

The proposed Net Metering Rate Schedule 95 does not sufficiently describe two matters that the Commission Panel considers should be clarified for the benefit of potential customer-generators.

First, the terms "facility" and "Generating Facility" are used in proposed Rate Schedule 95. The Commission Panel considers that clear definitions of these terms are required. The proposed Rate Schedule 95 instead defines "Net Metered System." The BC Hydro Net Metering Service Rate Schedule (RS1289) (copy attached as Appendix 1) may be used as a guide for the definitions. Therefore, the Commission Panel directs FortisBC to submit a revised Rate Schedule 95 that includes definitions for "facility" and "Generating Facility" as applicable to the Net Metering program.

Second, the proposed Rate Schedule 95 does not clearly describe General Liability provisions. The Net Metering program poses potential negligence issues that are beyond what would commonly confront a residential customer. Therefore, the Commission Panel directs FortisBC to include in Rate Schedule 95, a more explicit description of the proposed general liability provisions as they relate to the utility and the Net Metering customer-generators. The description should include specific information regarding the exposure of each of the utility and the customer-generator to negligence and consequential damages.

PROPOSED INSPECTION PROVISIONS AND THE SAFETY STANDARDS ACT

The Application indicates that a site inspection may be required prior to interconnection. As proposed, site inspections could apply to cases where FortisBC has concerns over the nature of the installation, either for safety reasons or for adherence to interconnection standards.

The Commission Panel agrees that a customer-generator must follow FortisBC interconnection requirements. However, the Commission Panel considers that, while FortisBC may elect to conduct a site safety inspection, as it is not inherently a utility function, a fee should not be charged to the customer.

The *Safety Standards Act* establishes installation, inspection, and operating requirements applicable to facilities downstream of the utility meter. If a customer can demonstrate to FortisBC that its facility has been properly certified under the *Safety Standards Act*, the Commission Panel is not persuaded that a FortisBC inspection is required. Production of required certifications issued under the *Safety Standards Act* should obviate the need for further inspection costs which only serve to adversely affect the economics of net metering.

The Commission Panel notes and agrees with the comments of Intervenor Resolution Electric: "Considering an electrical permit from the BC Safety Authority would be required to perform the installation work at a cost of approximately $670 for a 2.5kW Photo Voltaic system it could be questioned what value there is in performing the inspection by two different inspection bodies, with a potential cost of $1160." (Resolution Electric, Final Submission, p. 1)

The Commission Panel determines that a FortisBC inspection may be appropriate where Fortis BC is not satisfied with the customer-generator's documentation or certificate or is otherwise concerned that the customer-generator's facility poses safety or system problems. However, such inspection, if considered necessary by FortisBC, shall be for the account of FortisBC. In the event that any FortisBC inspection discovers a safety deficiency, FortisBC is to follow good utility practice and may decline to proceed with the net metering connection.

RECONCILIATION COSTS

The Application presents $160 as the expected, annual cost of reconciling customer-generator accounts. The Commission Panel considers that FortisBC should use actual, incremental net metering program reconciliation costs in any financial report, rather than applying the proposed rate of $160.

The Commission asked FortisBC to comment whether a customer-generator recording a credit balance would create a $160 reconciliation cost. In response, FortisBC stated that "The reconciliation cost is lower if the credit balance is carried over since a cheque does not have to be issued to the customer. The $160 is an estimated average cost for reconciling both customers that request a refund and those that carry their credit balances over. The cost differential is approximately $50." (Exhibit B-2, BCUC 1.10.1) The Commission Panel expects the

reconciliations associated with the program to not require expenses beyond those commonly needed for a non-net metering account. There is no evidence that the proposed metering creates a complicated calculation justifying an incremental cost of $160.

Intervenors also noted the expected reconciliation cost. In a letter to FortisBC dated March 30, 2009, Resolution Electric noted and questioned the magnitude of the expected reconciliation costs. (Exhibit B-1, p. 20)

The Commission Panel directs FortisBC to record any incremental costs incurred for net metering account reconciliation during the first 12 months of the program. FortisBC is to include a summary of the costs as a section in its Net Metering–Monitoring and Evaluation Report.

INTERVENOR ARGUMENTS

The Commission Panel is not persuaded by the Alliance arguments that the payback period should be lessened by incentive pricing. The Province has yet to give direction to the Commission requiring net metering programs to contain incentive pricing. Consistent with the recent Commission decision on the BC Hydro net metering program, an incentive price component is not required as a condition of approval at this time:

> The Province has not yet issued a directive to the Commission with respect to incentive pricing and the specific role of the Net Metering program in achieving conservation objectives. Until the time that such a directive is issued, the Commission cannot presume the details of potential Government policy. The Commission is therefore not persuaded that it should order BC Hydro to include an incentive component into the Net Metering price at this time. (Commission Order G-4-09)

The Alliance proposes that Government or Commission policy should be released requiring an incentive component to net metering programs. The Commission, as per the BC Hydro Decision excerpt above, does not establish such policy.

The Alliance proposes that FortisBC should include a report of world-wide programs that offer incentive premiums as part of net metering. (Alliance Final Submission, Section 3) The Commission Panel considers that, as BC Hydro has been directed to update external net metering programs as part of its reporting requirements, there is no need for FortisBC to duplicate that effort. Nonetheless, the Commission Panel expects FortisBC to keep abreast of external net metering program attributes that could be beneficially applied to its service area in the future.

The existing FortisBC Tariff includes a Time-of-Use pricing option. A Commission information request asked whether, in FortisBC's view, the combination of the proposed Net Metering program and the Time-of-Use rate class constituted a price incentive.

> "The existence of Time-of-Use rates does constitute an incentive for participation in the Net Metering program, compared to BC Hydro's program. On-peak rates for residential Time-of-Use are 15.9 cents per kWh in summer and 16.522 cents per kWh in winter, compared to 7.46 cents for non Time-of-Use residential rates. Although FortisBC's summer peak is growing more rapidly than its winter peak, the Company does not consider that further incentives for participation are required, particularly given the expected size of installations under the Net Metering program." (Exhibit B-2, BCUC 1.19.1)

The Commission Panel accepts FortisBC's response that the combination of net metering and Time-of-Use pricing forms an acceptable incentive to participate in the net metering program. A customer on the Time-of-Use pricing would have a shorter payback period, and therefore a greater incentive to participate in net metering.

The Final Submissions of the other registered Intervenors indicated support for the proposed Net Metering program without condition.

FINAL APPROVAL

The Commission Panel expects to grant final approval for the FortisBC Net Metering program subsequent to FortisBC filing the appropriate Tariff pages containing the revisions necessary to comply with the above determinations and directives, and a finding by the Commission Panel that the requirements described in these Reasons are satisfied.

APPENDIX 1

BC HYDRO – RATE SCHEDULE 1289 NET METERING SERVICE

SCHEDULE 1289 - NET METERING SERVICE

Definitions

"Generating Facility" for purposes of this Rate Schedule means a generating facility that:

(a) Utilizes water, wind, solar, fuel cell, geothermal, biogas, biomass, municipal solid waste, cogeneration or other energy resources or technologies meeting the requirements of the Province of British Columbia's definition of "BC Clean Electricity" to generate electricity;

(b) Has a nameplate rating of not more than fifty (50) kilowatts; and

(c) Is owned by the Customer and is located on the same parcel of land as the Customer's Premises for which service .is being provided under any of the Rate Schedules listed above, or on an adjacent parcel of land owned or leased by the Customer, and is connected to the same Point of Delivery as the Customer's Premises being served under any of the Rate Schedules listed above;

and includes all wiring, protection-isolation devices, disconnect switches, and other equipment and facilities on the Customer's side of the Point of Delivery.

Metering

1. Inflows of electricity from the BC Hydro system to the Customer, and outflows of electricity from the Customer's Generating Facility to the BC Hydro system, will normally be determined by means of a single meter capable of measuring flows of electricity in both directions.

2. Alternatively, if BC Hydro determines that flows of electricity in both directions cannot be reliably determined by a single meter, or that dual metering will be more cost-effective, BC Hydro may require that separate meters be installed to measure inflows and outflows of electricity.

3. The Customer shall install, at its cost, the meter base and any wiring, protection-isolation devices, disconnect switches, and other equipment and facilities on the Customer's side of the Point of Delivery as required under BC Hydro's "Net Metering Interconnection Requirements, 50 kW and Below". BC Hydro will supply and install the meter or meters and make the final connections.

4. Any meters or meters required for purposes of this Rate Schedule shall be in addition to any demand meters (if applicable) required under the Rate Schedule under which the Customer is receiving service from BC Hydro.

Special Conditions

6. If BC Hydro in its discretion deems it necessary to require the Customer to interrupt or disconnect its Generating Facility from BC Hydro's system, or for BC Hydro to itself effect the interruption or disconnection of the Generating Facility from its system, as provided in the Net Metering Interconnection Agreement, or as a result of the suspension or termination of service to the Customer in accordance with Special Condition 3 above, then except to the extent caused by the wilful misconduct or gross negligence of BC Hydro, its servants or agents, BC Hydro and its servants or agents shall not be liable to the Customer for any loss or damage whatsoever resulting from such interruption or disconnection.

December 6, 2008
By Paul Gipe

Frequently Asked Questions about Feed-in Tariffs, Advanced Renewable Tariffs, Renewable Tariffs, and Renewable Energy Producer Payments

What Are Feed-in Tariffs?

Feed-in tariffs are payments, or tariffs, for renewably-generated electricity. They are paid to the producer for every kilowatt-hour of electricity they generate.

Why Are They important?

Feed-in tariffs are a powerful policy mechanism that has produced rapid growth of renewable energy in Europe, especially in Germany, France, and Spain. Equally as important, feed-in tariffs are more egalitarian than other policy mechanism and have allowed people from all walks of life to participate in the renewable energy revolution—for profit.

Why Should We Use Feed-in Tariffs?

Systems of feed-in tariffs have been highly successful at developing large amounts of geographically dispersed renewable sources of generation quickly, at low cost and with minimal administration. And because feed-in tariffs are not dependent upon the tax status of the owner, they are available to everyone who wants to use them.

What are Advanced Renewable Tariffs?

Advanced Renewable Tariffs are a comprehensive system of feed-in tariffs that are differentiated by technology, project size, application, and in the case of wind energy by resource intensity. Advanced Renewable Tariffs are the modern version of the simpler feed-in tariffs that were used previously in Denmark and Germany.

Where Have Feed-in Tariffs Been Used Successfully?

Feed-in tariffs are widely used in continental Europe. Advanced Renewable Tariffs are prominently used in Germany, France, Spain, and Switzerland. Germany and Spain have become worldwide leaders in renewable energy because of their sophisticated systems of Advanced Renewable Tariffs.

Where are Feed-in Tariffs Being Used Now in North America?

Ontario, Canada, and California have implemented simplified systems of feed-in tariffs. Both jurisdictions are in the process (2009) of greatly expanding their programs.

Why are there So Many Different Names for Feed-in Tariffs?

Feed-in tariffs have been most successfully used in continental Europe and there is no single best English translation of the terms used in Germany, France, or Spain. The term "feed-in tariff" is a literal translation from Germany's 1991 *Stromeinspeisungsgesetz* (StrEG), the law on feeding electricity into the grid.

North Americans have attempted several adaptations using "payments" instead of using the term "tariffs" as tariffs sometimes has a negative connotation in North American English. These coinages have resulted in Renewable Energy Payments and Renewable Energy Producer Payments.

The term "feed-in tariff" itself doesn't capture the sophistication of the system of feed-in tariffs used in Europe. For this reason, renewable energy advocates in Ontario, Canada coined the expression Advanced Renewable Tariffs to convey the modern system of feed-in tariffs that are differentiated by technology, size, application, and resource intensity.

Sometimes feed-in tariffs and Advanced Renewable Tariffs are shortened to simply "renewable tariffs."

Occasionally feed-in tariffs are incorrectly referred to as Standard Offer Contracts. This is especially true in North America. Systems of Advanced Renewable Tariffs rely on "Standard Contracts" but specifically do not use "Standard Offers." In systems of Advanced Renewable Tariffs, the "offers" differ by technology, size, application, and resource intensity and are thus are not "standard."

In Ontario, Canada, the program of feed-in tariffs is formally called the Standard Offer Contract Program. However, the Minister of Energy had directed staff to produce a program of standard contracts, not standard offers. The ruling party had previously endorsed the expression Advanced Renewable Tariffs.

Are Feed-in Tariffs the Same as Tax Credits?

No. Feed-in tariffs are simply payments for generation. They have nothing to do with taxes or subsidies. Thus, feed-in tariffs are more egalitarian because they allow everyone to be paid for their electricity even those who do not pay a lot in taxes.

Are Feed-in Tariffs Just Another Subsidy?

Feed-in tariffs are not subsidies. They do not subsidize the cost of the equipment used to produce renewably-generated electricity, like solar panels or wind turbines, nor do the payments come from taxpayers. Instead, feed-in tariffs are simply payment for the generation of electricity. Society decides whether it wants a certain form of renewable energy, then it decides what it costs to pay for it. That's all there is to it. Some technologies, such as solar photovoltaics, cost more than other technologies and, thus, they must be paid more for their electricity than, say, the electricity from wind turbines.

Are Tariffs Taxes?

Tariffs are the rate paid for commodities like electricity. Electricity tariffs are the price paid per kilowatt-hour of electricity consumed, or in this case, generated. The term is commonly used in North America's electric utility industry. The term is also commonly used in Europe. Tariffs are not taxes nor in this context customs duties on goods crossing international borders.

Who Pays for Feed-in Tariffs?

Consumers of electricity pay for feed-in tariffs through charges on their electric bills just like they do now for electricity from conventional power plants. This is more equitable than paying through taxes because consumers who use a lot of electricity will pay more for renewable generation than those who use less. There are also programs in most states and provinces that protect low-income consumers from paying high prices for their electricity, especially during the winter months.

How Much Do Feed-in Tariffs Cost Consumers?

Very little at first because it takes several years for renewable sources of generation to become a significant part of electricity supply. Even in places such as Germany and Spain the additional cost of renewable energy is modest because the costs are spread fairly across all consumers. In Germany in 2007, the average household paid outright less than $50 per year for the world's largest concentration of wind turbines, solar panels, and biomass plants, and the 250,000 new jobs these industries have created. The German government estimates that the actual cost is near zero, because the benefits in reducing carbon emissions and other air pollutants, as well as offsetting the cost of expensive fossil-fired generation offsets the cost of the renewable energy.

Do Feed-in Tariffs Allow You to Sell Back to the Grid?

No. Feed-in tariffs allow you to "sell" to the grid, not "sell back" to the grid. There's an important difference. Selling "back" to the grid implies that you are already buying from the grid, that is, you are a customer and already have a

kilowatt-hour meter. In such cases as net metering, the potential of the program is limited by the amount “consumed” by the utility customer. Feed-in tariffs allow you to generate electricity and sell it to the grid even if you are not presently a customer. Feed-in tariffs allow the development of green-field sites, such as the installation of wind turbines in a field that are owned by groups of neighborhood investors, cooperative, or traditional business.

How Do We Know That Feed-in Tariffs Will Work?

Like any policy mechanism, feed-in tariffs can be misapplied. The most common problem is setting the prices, the tariffs, too low and not attracting the desired amount of development. Another common problem is setting a limit on project size, or a limit that is far too low, or setting a limit on program size that is too low to allow ample industrial capacity to develop. These problems have been encountered in programs that were timidly implemented because proponents were not serious about dramatically increasing the supply of renewable generation. However, where there was serious political commitment for the programs to succeed they have done so as seen especially in Germany, France, and Spain.

How Do Feed-in Tariffs Differ from Net Metering?

Net metering is a policy that allows you to produce some of your own electricity when you can, store excess on the grid when you produce more than you need—effectively running your kilowatt-hour meter backwards--and taking the electricity you “stored” on the grid when you need it. With net metering, you can never produce more electricity than you consume

In contrast, feed-in tariffs pay for the delivery of electricity to the grid. To use feed-in tariffs, you need a kilowatt-hour meter that measures the delivery of electricity for sale to the grid. The electricity is not “stored” on the grid, rather it is “sold” to the grid for a profit. Thus, you are not selling “back” to the grid, you are “selling to” the grid.

In Australia, some forms of net metering are incorrectly called feed-in tariffs. Thus, in Australia, true feed-in tariffs are called “gross” feed-in tariffs because all the electricity is sold to the grid.

Will Feed-in Tariffs Allow “Double Dipping” into State Rebate or Subsidy Programs?

Feed-in tariffs are designed to provide sufficient financial incentive to develop renewable energy without capital grants, rebates, or other capital subsidies. Thus, in most states or provinces where they have been proposed, those who opt for feed-in tariffs can not also use capital grants or rebates.

However, in the United States the federal Investment Tax Credit for solar systems and small wind turbines has been extended for eight years. As a consequence, most feed-in tariff programs proposed in the USA will include provisions for using the federal ITC alongside the feed-in tariff.

Can Feed-in Tariffs Work in Parallel with Existing Programs?

Yes, the feed-in tariff programs proposed in North America have all been designed to work alongside and in parallel to existing policies, such as net metering and renewable energy standards.

How Do Feed-in Tariffs Enable Distributed Generation?

The tariffs or prices in systems of Advanced Renewable Tariffs are designed to encourage development of renewable projects of all sizes, from residential rooftop to farms of large wind turbines, and in all locations, from sunny and windy sites to those sites less well endowed with wind and solar resources. When well designed, these differentiated tariffs result in the geographical distribution of renewable development and in the distribution of technologies in numerous different applications. While feed-in tariffs are also used to develop centralized renewable sources of generation, they are best known for increasing the role of distributed renewable resources.

What Renewable Energy Sources Are Included?

In systems of Advanced Renewable Tariffs, where the tariffs are differentiated by technology, programs can be designed to include all renewable sources of generation or only those that society wants in a particular jurisdiction. Some jurisdictions may want to use feed-in tariffs only for solar, or only for wind. Others, such as Germany, France, and Spain have tariffs for a host of different technologies, including onshore and offshore wind energy, rooftop and ground-mounted solar systems, hydro, various forms of biomass and biogas, geothermal electricity generation, and concentrating solar power.

How Are the Tariffs Calculated?

The tariffs are determined through a transparent political process based in input from industry, independent consultants, and users among others. In systems of Advanced Renewable Tariffs, prices are based on the cost of generating electricity with a specific renewable technology under specific conditions, plus a reasonable profit. In the successful programs, for example in Germany, France, and Spain, the tariffs are not determined by the cost of the conventional generation the renewable sources offset. In this way, the tariffs are not only high enough to spur development, but not so high that they create excessive profits.

Do Feed-in Tariffs Eliminate Environmental Review?

No. Projects using feed-in tariffs must comply with the same laws and environment requirements as any other projects. Feed-in tariffs typically only apply to the mechanism for getting access to the grid, for selling electricity to the grid, and the price that is paid for the electricity.

What Are the Key Elements of Advanced Renewable Tariffs.

Successful programs of Advanced Renewable Tariffs must

- Be simple, comprehensible, and transparent,
- Provide simplified interconnection,
- Provide sufficient price per kilowatt-hour to drive development,
- Provide contract length sufficient to reward investment, and
- Provide tariffs differentiated by technology, size, and resource intensity.

Does PURPA Prohibit Feed-in Tariffs in the US?

No. PURPA, the Federal Public Utility Regulatory Policies Act (1978), regulates only qualified facilities, or QFs. States retain jurisdiction to regulate electricity rates and special programs for developing renewable energy. For example, Renewable Energy Credit (RECs) trading programs created as part of a state Renewable Portfolio Standard (RPS) are permitted by the Federal Energy Regulatory Commission under PURPA. So to would be any special program that paid tariffs above the “wholesale” price specified under PURPA. Independent power producers would have no need to register as “qualified facilities” under PURPA if there was a program of Advanced Renewable Tariffs that guaranteed access to the grid and paid higher prices than those under PURPA contracts.

Currently, several states have feed-in tariffs and two states, Washington and Wisconsin, have tariffs that pay more than the PURPA defined “wholesale” rate. Washington has a special net-metering program that pays up to $0.54/kWh for five years for generation from solar photovoltaics (PV) components that were assembled in the state. This tariff is well above the wholesale cost in the Pacific Northwest. Several utilities in Wisconsin also pay special incentive rates for small solar, wind, and biomass generators that are above the wholesale cost of generation.

What are Degression Rates?

In some systems of Advanced Renewable Tariffs, the tariff offered for new projects declines annually from one year to the next at a fixed rate. Degression differs from the regular, scheduled review of tariffs that occurs in all programs. Degression rates, in percent, are based on the expectation that the cost of generation will decrease as the technology advances "down the learning curve." As such, degression assumes that the cost of the technology declines from one year to the next or it is intended to force development along this path. Unfortunately, the cost of generation from a particular technology doesn't always decline. Sometimes, as in the case of wind energy during the period 2006 to 2008, the cost of generation actually increased from one year to the next. For more on this topic, see Degression of Renewable Tariffs.

Are Feed-in Tariffs Adjusted for Inflation?

Yes. In many programs there are adjustments in the tariff or payment with respect to an index of inflation. This varies from program to program. There is no inflation protection in the German program, but there is in the French and Spanish programs. For more on this topic, see Inflation Adjustment of Renewable Tariffs.

Is Legislation Required to Implement Feed-in Tariffs?

In some states, provinces, and municipalities, feed-in tariffs can be implemented administratively. Most municipalities with their own municipal utilities have the authority to implement feed-in tariffs directly. In others legislation maybe required.

What Can I Do to Put Feed-in Tariffs on the Policy Agenda in North America?

During 2008, the grassroots movement for feed-in tariffs in North America has blossomed from a few committed individuals to groups active across Canada and the United States. If you would like to help, contact the Alliance for Renewable Energy and ask if there is a group active in your area. Contact your local, regional, and federal elected representatives and ask them to support introduction of legislation implementing systems of Advanced Renewable Tariffs.

Where Can I Find More Information on Feed-in Tariffs?

There are several web sites that feature news and articles about feed-in tariffs. The most comprehensive site can be found at http://www.wind-works.org/articles/feed_laws.html. On this page there are links to more detailed information on the following subjects.

- Renewable Tariffs by Country
- Renewable Tariffs in Ontario, Canada

Appendix L

- Renewable Tariff Design
- Model Advanced Renewable Tariff Legislation
- Renewable Tariff Pricing
- Renewable Tariffs Overview
- Tables of Feed-In Tariffs Worldwide
- The Economic Case
- Reviews of Books on Feed-in Tariffs
- Links to More on Feed-in Tariffs

Books on Feed-in Tariffs

There several books with detailed information on feed-in tariffs and renewable tariff policy. You can find information about these books at the links below.

- Feed-in Tariffs by Miguel Mendonca--a Review
- Energy Switch: Proven Solutions for a Renewable Future
- Switching to Renewable Power by Volkmar Lauber

Web Sites on Feed-in Tariffs

There are several web sites that feature articles on feed-in tariffs, renewable tariff design, and news updates on the movement for feed-in tariffs in North America.

- German Experience with its Renewable Energy Sources Act
- European Feed-in Cooperation
- International Feed-in Tariff News Group
- Californians for Feed-in Tariffs News Group
- World Future Council's Feed-in Tariff Pages
- WFC's Feed-in Tariff Design Guide
- The Feed-In Tariff Channel--Audio and video interviews with policy leaders by Marc Strassman (Note: a video player will install on your browser)
- Green Thoughts: Sustainability, Renewable Energy and Marketing by Micheal Hoexter
- Green Energy War: Former California Energy Commisioner John Geesman blogs on global climate and energy politics

Appendix L

- the Alliance for Renewable Energy: An alliance of policymakers, renewable energy experts, citizens, research institutions, and large and small businesses promoting the use of feed-in tariffs (Renewable Energy Payments) in North America.
- Florida Alliance for Renewable Energy
- Wind-works.org: One of the world's most extensive collection of articles and reports on feed-in tariffs.

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Appendix L

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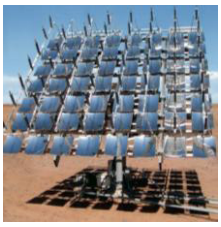
The Green Political Foundation

THE NEW RULES PROJECT



Feed-in Tariffs in America

Driving the Economy with Renewable Energy Policy that Works

By John Farrell
New Rules Project

April 2009

Appendix M

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The **Transatlantic Climate Policy Group** is a two year program, launched by the Heinrich Böll Foundation, which aims at fostering transatlantic dialogue and cooperation on climate and energy policies. The Transatlantic Climate Policy Group seeks to engage policymakers, research analysts, experts, and media on both sides of the Atlantic in order to achieve two major goals: to identify common ground and future challenges for transatlantic energy and climate cooperation, and to increase collaboration between U.S. cities and EU cities, U.S. States and the member states of the EU, and finally U.S. federal and EU policy institutions.
http://www.boell.de/climate-transatlantic/

Transatlantic Climate Policy Group

The **Institute for Local Self-Reliance** was formed in 1974 with a mission to provide innovative strategies, working models, and timely information to support environmentally sound and equitable community development. To this end, ILSR works with citizens, activists, policymakers and entrepreneurs to design systems, policies and enterprises that meet local or regional needs; to maximize human, material, natural and financial resources; and to ensure that the benefits of these systems and resources accrue to all local citizens. A program of ILSR, the **New Rules Project** helps policy makers to design rules as if community matters.
http://www.ilsr.org/index.html www.newrules.org

Table of Contents

Appendix M

Executive Summary

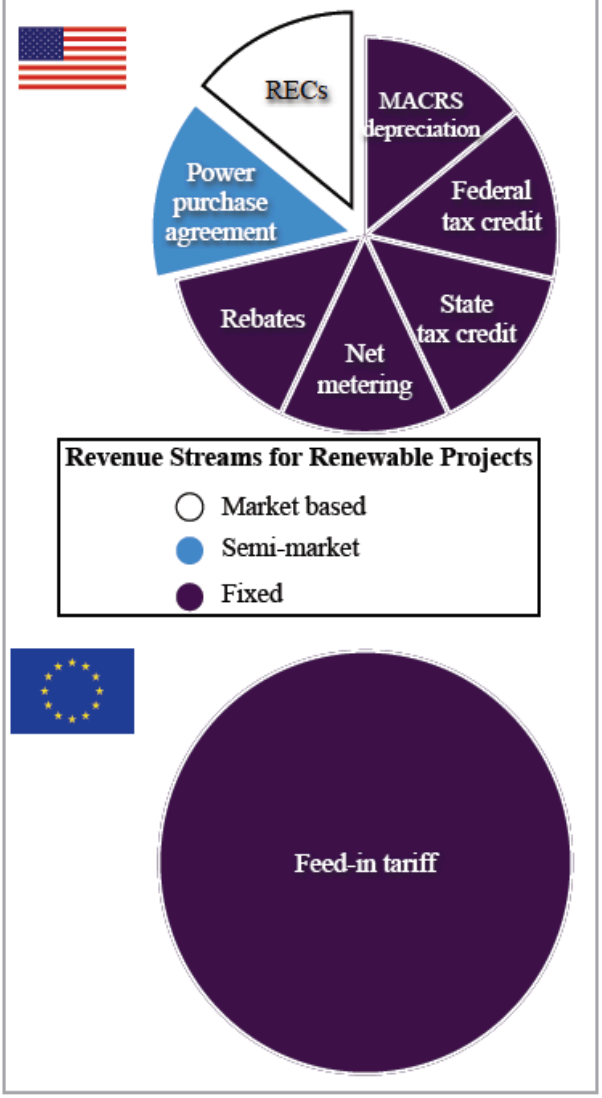
American renewable energy policy consists of a byzantine mix of tax incentives, rebates, state mandates, and utility programs. The complexity of the system results in more difficult and costly renewable electricity generation, and hampers the ability of states and communities to maximize the benefits of their renewable energy resources.

Evidence from Europe suggests that a simpler, more comprehensive policy achieves greater renewable energy development, but at a lower cost and with greater economic and social benefits like local ownership. It is called a feed-in tariff, a price for renewable energy high enough to attract investors without being so high it generates windfall profits. The tariff can be varied to spur new emerging technologies or to achieve social ends.

Denmark and Germany both used a feed-in tariff to drive renewable electricity generators to more than 15 percent market share. This policy also resulted in large-scale local ownership, with near half of German wind turbines and over 80 percent of Danish ones owned by the residents of the region.

In 2009, one Canadian province (Ontario) and one US municipal utility (Gainesville, FL) have enacted a feed-in tariff. As many as 11 U.S. state legislatures are seriously considering adopting the system as a complement to their renewable electricity mandates. State and federal policy makers should strongly consider turning to a feed-in tariff as the key mechanism for encouraging renewable energy development. It's fairness, simplicity, and stability can help the United States maximize the benefits of the renewable energy revolution.

Figure 1 – One Source of Revenue Makes Financing European Renewable Energy Projects Simpler



Feed-in Tariff Success, by the numbers:

- Germany: 15% renewable electricity, 280,000 jobs in the renewable industry, a net benefit of 6 billion Euros per year.
- Denmark: 28% renewable electricity, 21,000 jobs in the wind industry

The Power of Feed-in Tariffs

In the United States, renewable energy policy consists of an uncoordinated and often haphazard combination of state and federal incentives and mandates. A company or person wanting to install a wind turbine or solar electric system must negotiate a bewildering array of incentives (**Figure 1**). Each of the incentives has an overhead cost. Rebates, for example, might require a cumbersome paperwork process. Tax incentives require one to put together a group of profitable corporations with sufficient tax liability to make use of the incentives, and in the process the tax equity investors divert some of that incentive away from the actual project. Having gained sufficient financing, the developer must then engage in lengthy and costly negotiations with the local utility to develop a contract with a price and with often onerous and costly interconnection requirements.

This process impedes the growth of renewable energy, may well raise its cost, and certainly discriminates against small and locally owned projects. It may also undermine states' renewable energy efforts.

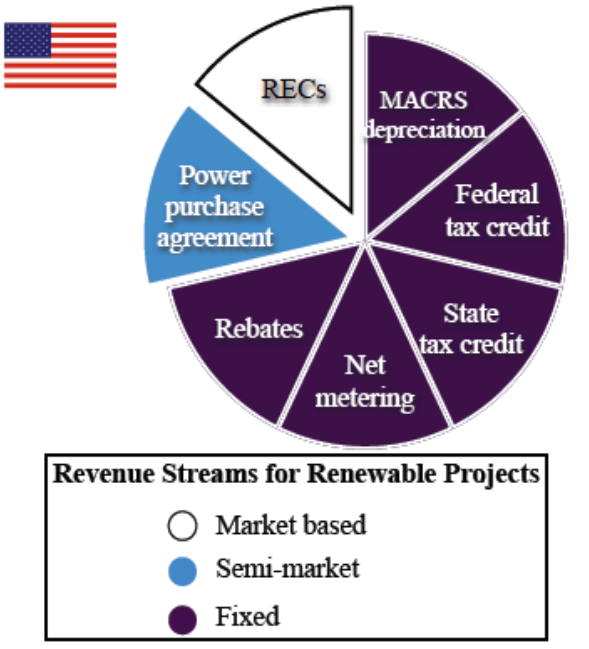
In the last few years, 38 states adopted renewable electricity mandates. These mandate a specific quantity of renewable electricity based on the overall electricity consumption and leave the price up to the "market," a market, as noted, that largely consists of financial incentives. A number of states may be falling behind their interim benchmarks.

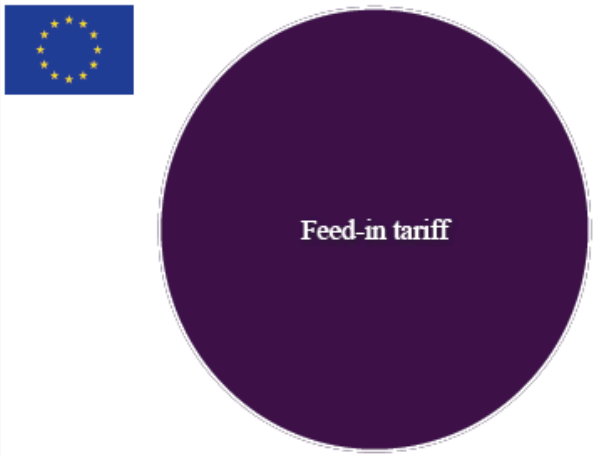
Europe has taken a different approach. It has mandated a specific price for renewable electricity and leaves the quantity achieved up to the "market."

In the 1980s and early 1990s, European nations imitated U.S. renewable energy policies (i.e. incentives) and found them ineffective. First Denmark and then Germany, France and Spain adopted a new, simpler policy. They set a price (tariff) sufficient to attract investors.

This policy has several attractive impacts. By establishing a price, it does away with the need for multiple incentives and the financing of projects largely based on their value in reducing tax liabilities. By reviewing the

Figure 1 – One Source of Revenue Makes Financing European Renewable Energy Projects Simpler





price every few years, European states can lower the price if they find that it results in windfall profits and attracts too many renewable energy proposals and raise it if they find it insufficiently attractive. Prices can be varied by technology and scale of production, thereby providing an incentive to emerging technologies and to renewable energy projects that have attractive social or economic impacts (e.g. on site generation, local ownership).

European nations further require utilities to interconnect renewable energy projects on demand. The utilities bear the cost of connecting to higher voltage transmission lines and the utilities must offer a short, uniform contract that includes interconnection requirements.

Empirical studies of the European system have found that it spurs more renewable energy at a lower price than do incentive programs or stand-alone renewable mandates.

> A **Feed-In Tariff** (FIT) provides three key provisions to renewable electricity generators: **a guaranteed grid connection**, a **long term contract**, and a **fixed price** sufficient for a reasonable return on investment.

In Europe this new policy is called a Feed In Tariff. A tariff is the traditional term that describes a utility price structure. Feed-in means that this is a price paid to producers that feed their electricity into the grid system. European nations require that those who accept a feed in tariff must "export" all of their electricity into the grid, unlike many U.S. states that offer **net metering** arrangements whereby the output of a rooftop solar array, for example, would first be used inside the building and spin the meter backwards, with any excess sent into the grid. **Figure 2** illustrates the difference between net metering and a European feed-in tariff for a household with a solar panel, with data in kilowatt-hours (kWh).

Figure 2 (a) – Under net metering, the homeowner uses power to offset domestic use and gets paid at the wholesale rate for excess power

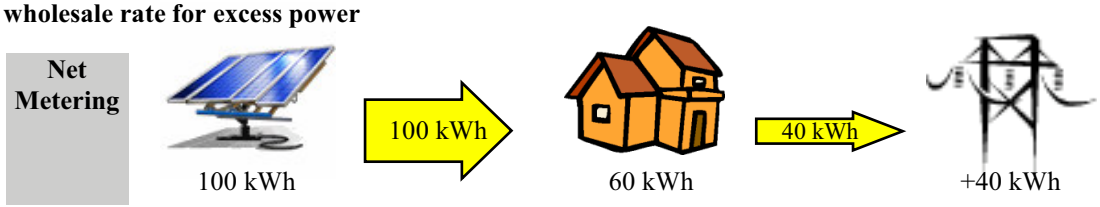
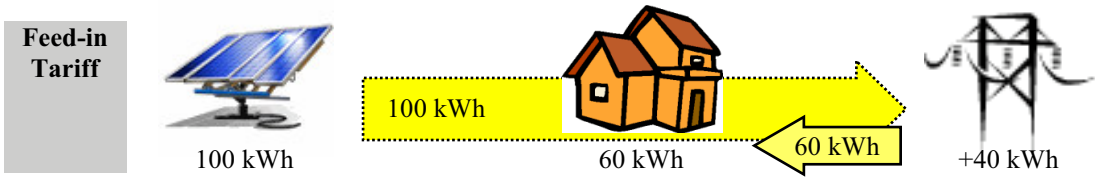


Figure 2 (b) – Under a feed-in tariff, the homeowner sells all their power to the grid for a premium price, but buys all their power from the grid at retail rates



The two policies are really just accounting measures, because the electrons from the solar panel will serve the home first in either case. However, they have a very different impact on the building owner's decision about the size of the renewable energy facility that will be installed. Under net metering, the owner will probably size the unit to the building's internal use, because excess power

is purchased at low (wholesale) rates. Under a feed-in tariff, the producer is paid a premium for every kilowatt-hour generated and there is often no limit on the size of the facility that will earn that payment. The project is an investment – the system will be sized to maximize the rate of return. This could have a significant impact on the economics of rooftop arrays. In the United States a typical photovoltaic (PV) system might cover a third of a roof. Later as PV panel costs decline, the system could be expanded, but because installation is a significant percentage of the overall cost, the second install may offset the lower priced panels. A feed-in tariff that encourages the maximum sized facility to be installed in the first place may lower long term costs.

Outside Europe, feed-in tariffs go by many names: advanced renewable tariffs, renewable energy payments, or feed laws. We prefer to use the name feed-in tariffs (since it's the name used in Europe), although renewable energy payments (REPs) are somewhat more intuitive to the typical American.

This paper presents the case for an American feed-in tariff, based on the European history, the elegance of the policy and the preponderance of evidence that feed-in tariffs generate greater social and economic benefits than alternative policies for the same level of renewable energy deployment.

The European Experience

Two countries in particular provide an illustration of the success of the feed-in tariff: Denmark and Germany.

Denmark: The Rise and Fall of Feed-In Tariffs

Denmark's history of renewable energy policy is one of early commitment, rapid success under a feed-in tariff, and then stagnation from a changed policy. In the 1980s, the Danes were among the first to encourage renewable energy development, a step ahead of many other national efforts to respond to the Arab oil crisis. Their head-start meant that the California wind farms – representing the early renewable energy efforts of the United States in the post oil crisis era – were largely powered by Danish turbines. However, while the U.S. abandoned many of its initiatives as the price of oil fell during the 1980s, the Danes remained committed to their energy independence goals, including the development of renewable energy. A strong anti-nuclear movement also increased the Danish commitment to wind power.[1]

The following timeline illustrates the history of Danish renewable energy policy.

1980s

1979-1992: Fostering a wind industry

In 1979, the Danish legislature (Folketing) introduced the first incentives for wind power, a subsidy for 30 percent of total project costs that decreased over time.[2] Wind power generation first exceeded 100 megawatts (MW) under this proposal, an impressive feat since most were turbines less than 100 kilowatts (kW) in size.

In 1988, the Danes took a step closer to a feed-in tariff, reducing the capital subsidy but requiring utilities to interconnect and purchase power from wind projects. Utilities were also required to provide a "fair price."[3] Wind power capacity increased to near 300 MW.

1990s

By 1992, the "fair price" for wind power was set at 85 percent of the retail electricity rate.[4] The Danes provided guaranteed interconnection and power purchase. The price was still set relative to retail rates and not relative to the cost of production for wind generators.

1993-2002: The FIT and the Surge in Production

In 1993, the Danes formally established a Feed-In Tariff, decoupling the power purchase price from electricity rates. The price paid for power from wind turbines was set at 85 percent of utility production and distribution costs.[5] Wind projects also received a refund of the Danish carbon tax and a partial refund on the energy tax. These refunds effectively doubled the payment to wind projects for the first five years of the project.

In 1998, the price language was changed slightly, though the support level remained largely the same. The new law required utilities to purchase the wind turbine's output at "85 percent of the consumer price of electricity plus ecotax

1990s

relief." These costs were largely borne by the utilities, who received a payment to offset their costs,[6] but turbine operators were responsible for the initial grid connection. "The costs of grid connection are paid by the wind mill owners exactly until the nearest 10 or 20 kV line."[7]

2000s

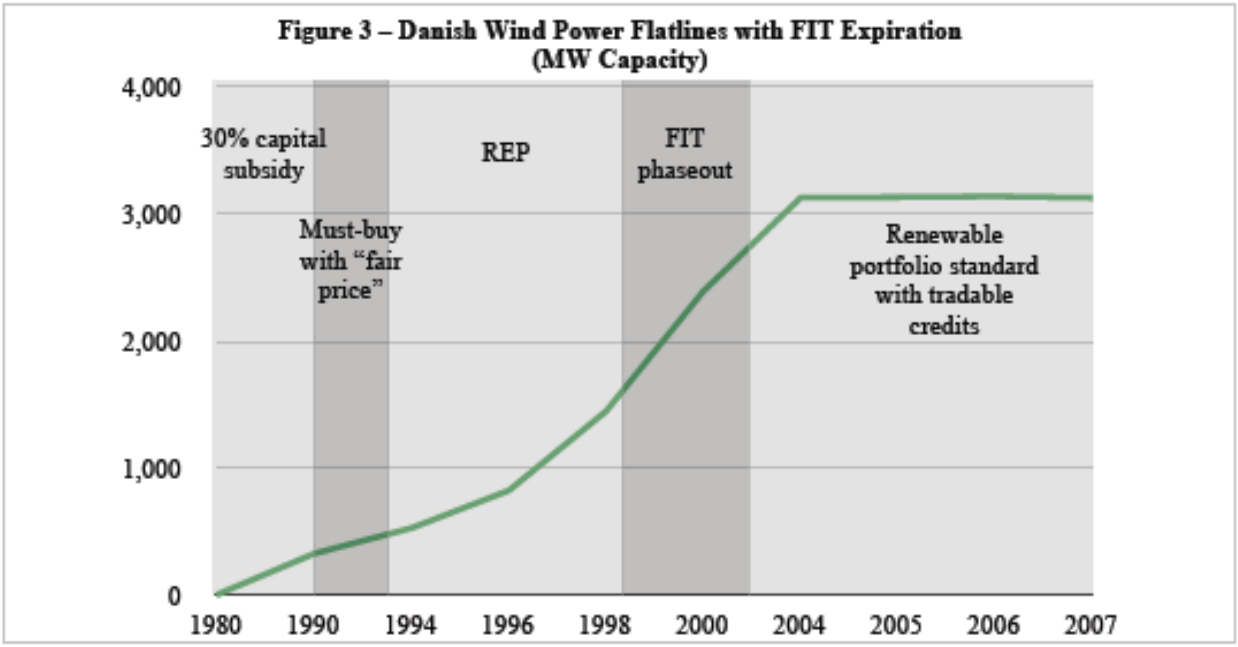
In 1999 the election of a center-right government ended the feed-in tariff in Denmark. Instead, the renewable energy program was changed to an American-style renewable portfolio standard with tradable credits.[8] The new program was phased in, so some producers who came online through 2002 were still able to get the prior tariff rate locked in for 10 years.[9]

2003-Present: U.S.-style quotas and stagnant development

By 2003, all wind generators connecting to the grid had to do so under the new renewable portfolio standard, earning the market price plus a premium. This premium was capped, setting a maximum price that wind producers could receive. The new scheme also no longer guaranteed interconnection. Additions to wind power capacity declined precipitously.[10]

From 1993 to 2004, Danish wind power grew from 500 MW to over 3,000 MW. Since the feed-in tariff was abandoned in 2004, development has stagnated at that level (**Figure 3**).

The new government also offered incentives and a higher payment cap for repowering, making replacement of old turbines more lucrative than adding new wind projects.[11] Developers would remove several small turbines and replace them with one, larger one. The repowering incentives were so lucrative that one wind cooperative sold its turbine for decommissioning in 2005 for the same price it paid in 1988.[12] In 2005, the government responded to stagnating wind development by removing the cap on wind payments, but the net increase in wind power capacity was less than 25 MW between 2004 and 2007.[13]



Danish Results: Energy and Industry

Despite the recent stagnation in wind energy growth, the feed-in tariff's legacy is striking:

- A domestic wind industry with over 20 billion DKK in turnover ($37 billion), employing 21,000 people.[14]
- Denmark gets more electricity from renewables than nearly every other country. In 2007, 28 percent of electricity came from renewable sources,[15] with 20 percent from wind power.[16]
- Over 150,000 families have invested in wind turbines individually or through cooperatives, owning over 80 percent of the country's turbines (with about 60 families per MW).[17]

Denmark: Locally owned wind power

In keeping with a tradition of cooperative ownership in their electricity generation system, the Danes strongly encouraged cooperative ownership of wind projects. The key policy was a tax exemption on revenue from cooperative wind enterprises, a provision that essentially doubled the income from a wind project because of a marginal tax rate close to 50 percent.[18] This exemption dates back to at least 1985 and is a significant reason that cooperatives own over 80 percent of Danish turbines and distribute the revenues to over 150,000 families.

Germany: The Rise and Rise of Feed-In Tariffs

In Germany the motivation for a renewable energy plan was somewhat different than Denmark. Concerns about climate change and environmental degradation motivated the initial commitment to renewable power in the late 1980s, as did an interest in developing a native industry. Later, Green Party participation in the government added an anti-nuclear component to renewable energy policy.

The following timeline illustrates Germany's road to feed-in tariffs.

1990s

1987-1990: A small start

Individual German states offered wind power incentives as early as 1987, when Niedersachsen provided a 50 percent capital subsidy that was phased out by 1995.[19] The federal renewable energy program was started in 1989 with a market stimulation program. It provided a fixed price payment for wind power (with a total budget sufficient for up to 250 MW) and investment incentives for private operators (e.g. farmers) to invest in renewable energy. The program did not yet guarantee interconnection for small producers.[20]

1991-1999: Feed-In Tariff accelerates wind, some solar

In 1991, the Germans adopted feed-in tariffs when they enacted their Electricity Feed-In law. Utilities were required to purchase renewable energy generation and to pay 80 percent of the historical average retail price to producers of qualified renewables.[21] The program was capped at 5 percent of a utility's generation.[22]

In 1999, Germany introduced a parallel incentive for solar PV, known as the 100,000 Roofs Program. It provided zero interest loans and a grant worth 12.5 percent of the system cost. The program ended in 2003 with 346 MW installed across the country.[23]

2000s

2000-Present: Revised FIT broadens German renewable development

In 2000, major revisions were made in the form of the Renewable Energy Act (EEG). This landmark law decoupled feed-in tariff prices from retail rates and instead based prices on the cost of production. There was a guaranteed payment for 20 years and the cap on renewables was removed. The EEG was scheduled for review every two years starting in 2007.[24]

The law also introduced more sophisticated elements to feed-in tariffs, including tariff degression to account for improving technology, stepped tariffs based on the size of a energy producer and the quality of the renewable resource, and set rates separately for wind, solar, and other technologies.[25] The EEG also created the cost-sharing program where the incremental costs of renewable generation are spread among all high-voltage grid operators and end customers.[26]

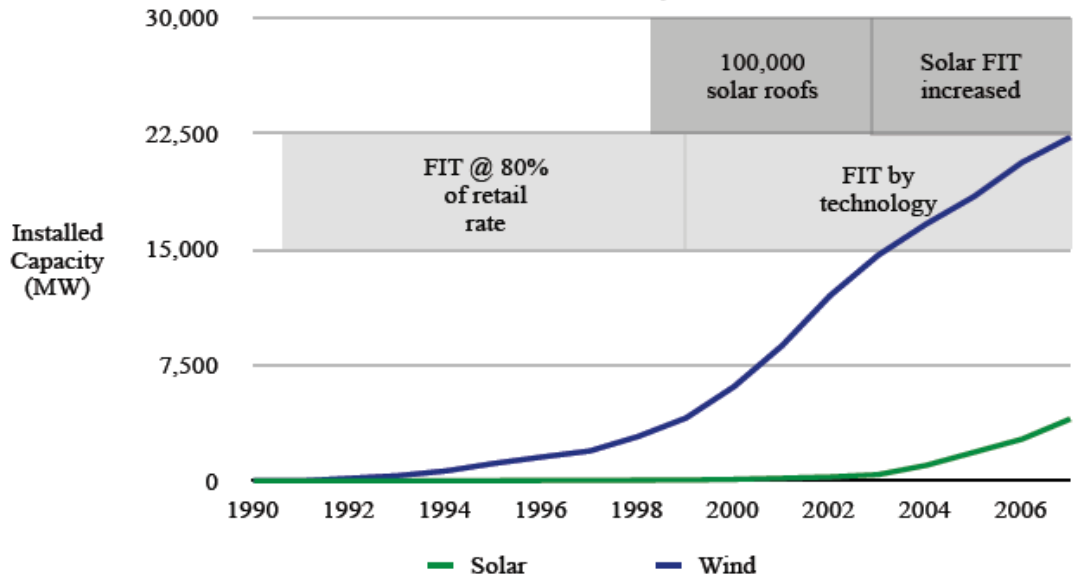
> **Tariff degression** – an annual decrease in the new contract price for a feed-in tariff.
>
> *Example: 5% solar tariff degression*
> - A 2008-installed solar panel gets 60 cents per kWh for 20 years
> - A 2009-installed solar panel gets 57 cents per kWh for 20 years

2000s

In August 2004, the EEG was revised (with support from conservatives), adding firm targets for renewable energy generation and revising tariff prices. Solar PV received a price increase, as did several other technologies, and onshore wind generators saw their tariff decrease.[27] The law also enforced the guaranteed connection and priority access for renewable energy systems.

The result of the German commitment to renewable energy has been a staggering increase in renewable energy production as well as jobs and industry. **Figure 4** illustrates the fruits of Germany's commitment to the feed-in tariff – substantial increases in wind and solar power capacity.[28]

Figure 4 – Feed-In Tariff Turbocharges German Wind and Solar Development



German Results: Energy and Industry

- From 1995 to 2005, Germans increased the share of renewables in their electricity mix from 1 percent to 12 percent.[29] By 2007, Germany received 14 percent of its electricity from renewable sources.[30]
- German renewable energy industries had sales of nearly 11 billion Euro to worldwide customers in 2007 ($15 billion), 44 percent from solar, 21 percent from wind.[31] Germany has 249,000 jobs in renewable energy industries.[32]

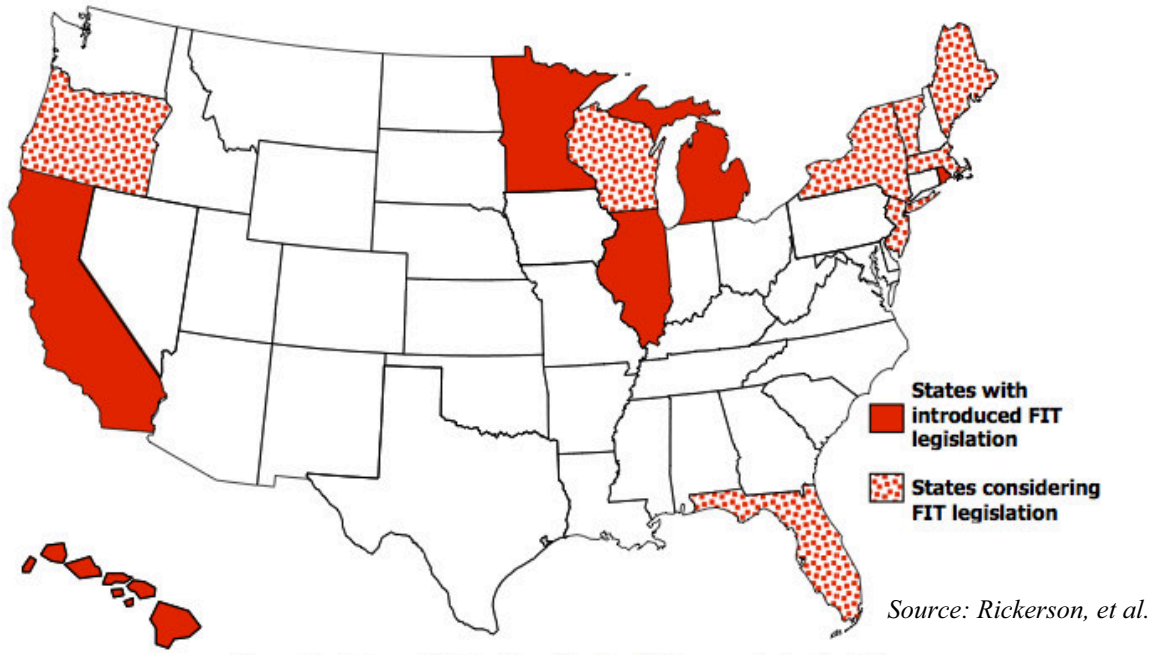
Germany: Locally owned renewable energy

In Germany, high population density and a deep environmental sensitivity encouraged dispersed generation from wind projects and helped enable local ownership. The other factor was the interest of farmers, who helped develop the financing for early wind projects by providing their land as collateral.[33] One-third of Germany's wind power is owned by over 200,000 local landowners and residents.[34]

Feed-In Tariffs in the United States

The stunning success of European policy has encouraged American policy makers to consider feed-in tariffs at the federal, state, and local level. Bills have been introduced in at least eight states to establish feed-in tariffs. Two municipal utilities have proceeded without legislation.[35] Rep. Jay Inslee (D-WA) introduced a bill to encourage nationwide feed-in tariffs in the U.S. House during the summer of 2008.[36] **Figure 5** illustrates the breadth of the feed-in tariff fervor.[37] Since the map was drawn, at least two other states (Iowa and Indiana) have been added to the list.

Figure 5 – Status of Feed-in Tariff Proposals in the United States (2008)



Source: Rickerson, et al.

Thirty years ago, the United States briefly flirted with feed-in tariffs after the federal Public Utility Regulatory Policies Act (PURPA)[38] policy ended the utility monopoly on electricity generation, requiring them to buy electricity from independent producers at a price based on their avoided costs. In the early 1980s California required utilities to offer a standard 10 year contract with a high fixed price for wind energy that was in essence a feed-in tariff. The standard offer contracts were abandoned in the early 1990s as California opted to pursue retail electricity deregulation.

> We need to get something on the table that allows community projects to get financed, move ahead, and not get bogged down in all the B.S. that's involved in large power generation.
>
> *–Dan Juhl, community wind developer, Minnesota*

The contrast between the U.S. and Europe is stark. In the U.S. a producer must juggle periodically expiring incentives, 50 independent renewable energy markets, hard-to-use tax credits, and complex and protracted negotiations with utilities over contracts nearly a hundred pages long.

Wind developer Dan Juhl described the U.S. situation at a recent conference on feed-in tariffs in Minnesota, pointing out the many challenges for community-based wind projects.[39] Getting a project on the grid begins with a utility's request for proposal, and a community-based developer bases their project preparation – price quotes for turbines and installation, and other parts of the wind project – on the utility's timeline. The utility usually advertises a particular date for the selection of the winning bid. But once the developer wins the bid process, they begin the power purchase agreement negotiation. Dan noted,

> "It takes a year...[there are] land mines in the power contract...You have to negotiate them out or you will not get financing."

By the time the power purchase contract is negotiated, the community-based developer may be required to renegotiate purchase agreements with suppliers since so much time has elapsed. The entire project is jeopardized. Dan sees a need for legislation to simplify the process:

> "We need to get something on the table that allows community projects to get financed, move ahead, and not get bogged down in all the BS that's involved in large power generation."

Power purchase contracts in the U.S. can be very complex and lengthy. In Germany, a producer gets a 20-year, all-in-one contract that ensures a reasonable profit. The contract is five pages long.[40]

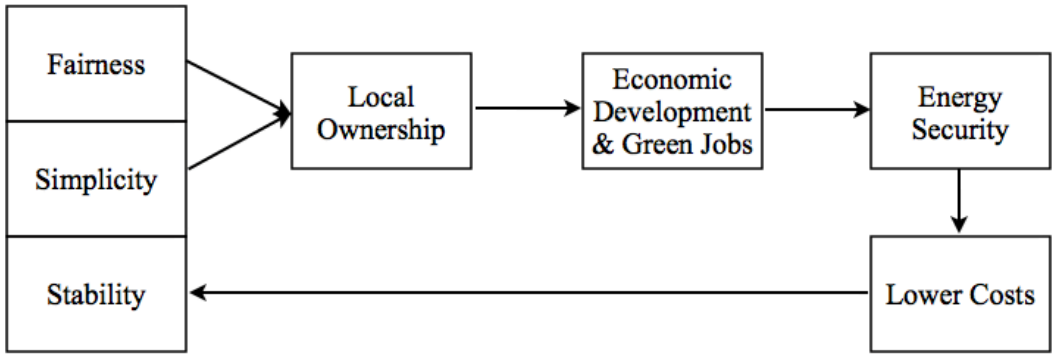
European renewable energy leaders were driven by more than environmentalism – they wanted to capture the economic benefits and green jobs from their renewable energy development. FITs created a vast, competitive market for renewable energy production by creating a truly level playing field for development. With prices set for reasonable cost recovery and profit, a producer need not rely on attracting the relatively few individuals or corporations with large amounts of tax liability (like in the U.S.). The opportunities for ownership were dramatically broadened.

The result of this market democratization was significant. In Germany, 45 percent of wind projects are locally owned. In Denmark, 83 percent of wind projects are owned by individuals or local cooperatives.[41] And for each of these locally owned projects, more of the investment dollar stays in the community and country, creating a cycle of more investment and jobs.

Why Feed-In Tariffs Work

A feed-in tariff incorporates three basic principles for increasing renewable energy generation: fairness, simplicity, and stability (**Figure 6**). Policies based on these principles tend to achieve three goals: a) much broader and dispersed ownership of renewable energy; b) economic development and c) energy security. Evidence from countries with FITs shows that it often achieves these benefits at a lower cost than alternative renewable energy incentives.[42]

Figure 6 - Basic principles of a Feed-in Tariff



Simplicity

A feed-in tariff makes generating renewable energy simple. If you build a renewable electricity generator, you'll get paid one specific price for every kilowatt-hour you produce. Prices are set to guarantee a reasonable rate of return, encouraging further development and more potential owners.

> **Consider the Paper Trail**
> A typical American power purchase agreement between a producer and the utility is 85 pages. In Germany, the contract is 2-4 pages.

Figure 7 (page 17) illustrates how someone interested in renewable energy is compensated under a feed-in tariff, and how this contrasts with the status quo in the United States.

In contrast to existing incentives like the federal production tax credit, with a FIT there's no negotiating with utilities, partnering with tax-credit-hungry investors, or uncertainties about Congress.

Stability

A feed-in tariff makes the market stable. Utilities must connect renewable generators and buy their electricity at the incentive rates for 20 years.

Contrast the FIT with the existing system, where federal incentives can expire, creating boom-and-bust cycles in the market. This stability is a significant reason that Denmark and Germany generate more than 15 percent of their electricity from renewable energy, while the U.S. achieved only 3 percent in 2007.[43]

Fairness

A feed-in tariff makes the market fairer because it removes the barriers to participation from a number of players. A FIT allows people with little tax liability or non-taxable entities – cities, counties, states, non-profits – to pursue renewable energy projects.

Most current U.S. incentives are in the form of tax credits, which are only valuable to individuals or businesses with a lot of tax liability. This unfair system reduces the pool of potential renewable energy investors and dollars, to everyone's detriment.

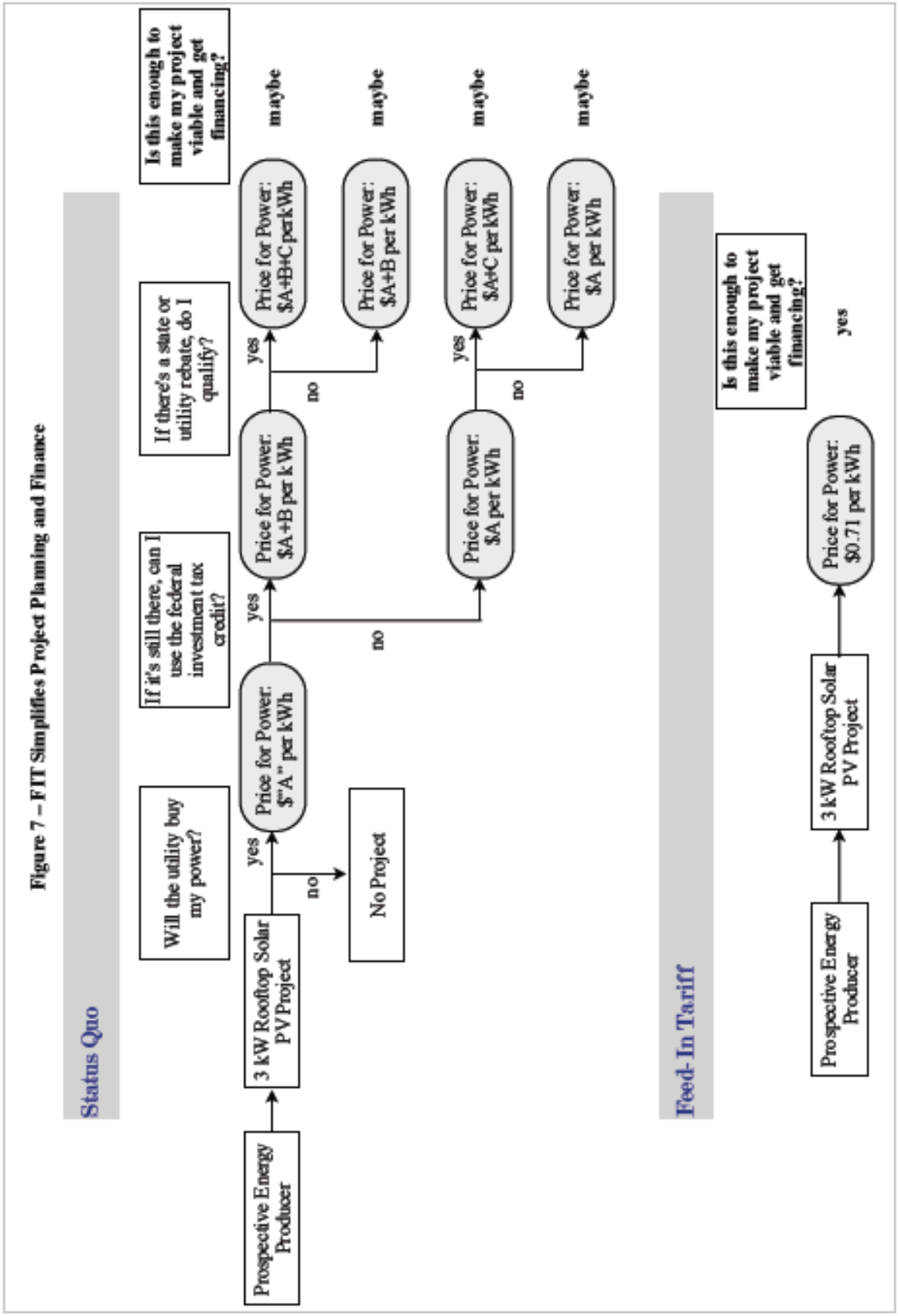


Figure 7 – FIT Simplifies Project Planning and Finance

Appendix M

Designing a Feed-In Tariff

There is no one-size-fits-all feed-in tariff policy. There are many variations as policymakers adapt the core design to their local context and needs.

Setting FIT Rates

Figure 9 (page 20) illustrates the price setting process for a feed-in tariff that supports solar PV, biomass, and wind electricity generation. The following step-by-step process corresponds to the steps on the chart.

1. Offer a reasonable return

Utility investments in regulated states typically receive a guaranteed 10-12 percent return on investment. Feed-In Tariffs are often set to provide a 8-10 percent internal rate of return. This strategy is used in Germany and in a proposed national FIT for the United States (Renewable Energy Jobs and Security Act of 2008).[44] Spain and a few other countries also set a FIT as a premium over retail electricity rates.

2. Configure by technology

Feed-In Tariffs encourage multi-technology investment in order to accelerate the technological learning curve and achieve manufacturing economies of scale. Since costs to generate electricity differ for solar, wind and biomass, payments are adjusted accordingly to encourage a diversity of renewable energy technologies and industries.

3. Award innovation

Some feed-in tariff plans are designed to foster innovation and to achieve social goals. For example, solar on rooftops instead of fields preserves open space and turns shelter into power generation. Placing solar panels on building facades helps increase a building's self-sufficiency. FIT rates can increase for these technologies to encourage their development.

4. Accommodate various sizes

In order to encourage a diversity of dispersed renewable generators, FIT rates are often slightly higher for smaller projects. For example, this may encourage development of wind power projects in areas with lower wind speeds, but greater available transmission capacity.

Adjusting FIT Rates

5. Adjust for experience

FIT prices for new projects often decrease each year to reflect improving technology.

6. Adjust for inflation

Though technological investment reduces costs, even wind and solar are subject to the prices of basic commodities like steel, concrete or silicon. FIT prices can be adjusted to help cover inflation.

7. Provide a long-term contract

A feed-in tariff guarantees a long-term purchase contract for electricity to help investors recover their investment. Renewable energy projects like wind and solar have no fuel costs, so their entire investment is up front. Long term contracts, generally 20 years, ensure that energy producers recover their costs and help them secure financing.

8. Share the Cost

A feed-in tariff promotes simple cost-sharing of the benefits of renewable energy. Any incremental increase in the cost of electricity from projects using the FIT is spread across the entire set of electricity consumers. In European countries, this cost-sharing is national, with partial exemptions for electricity-intensive industries. In the U.S. it may be on a state or on a utility basis.

Example for Setting FIT Rates:

Figure 8 – Size Scaling of Germany's Biomass Tariff

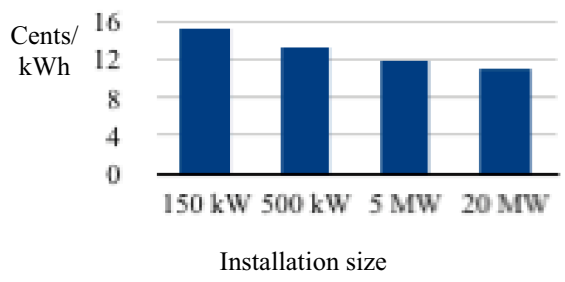
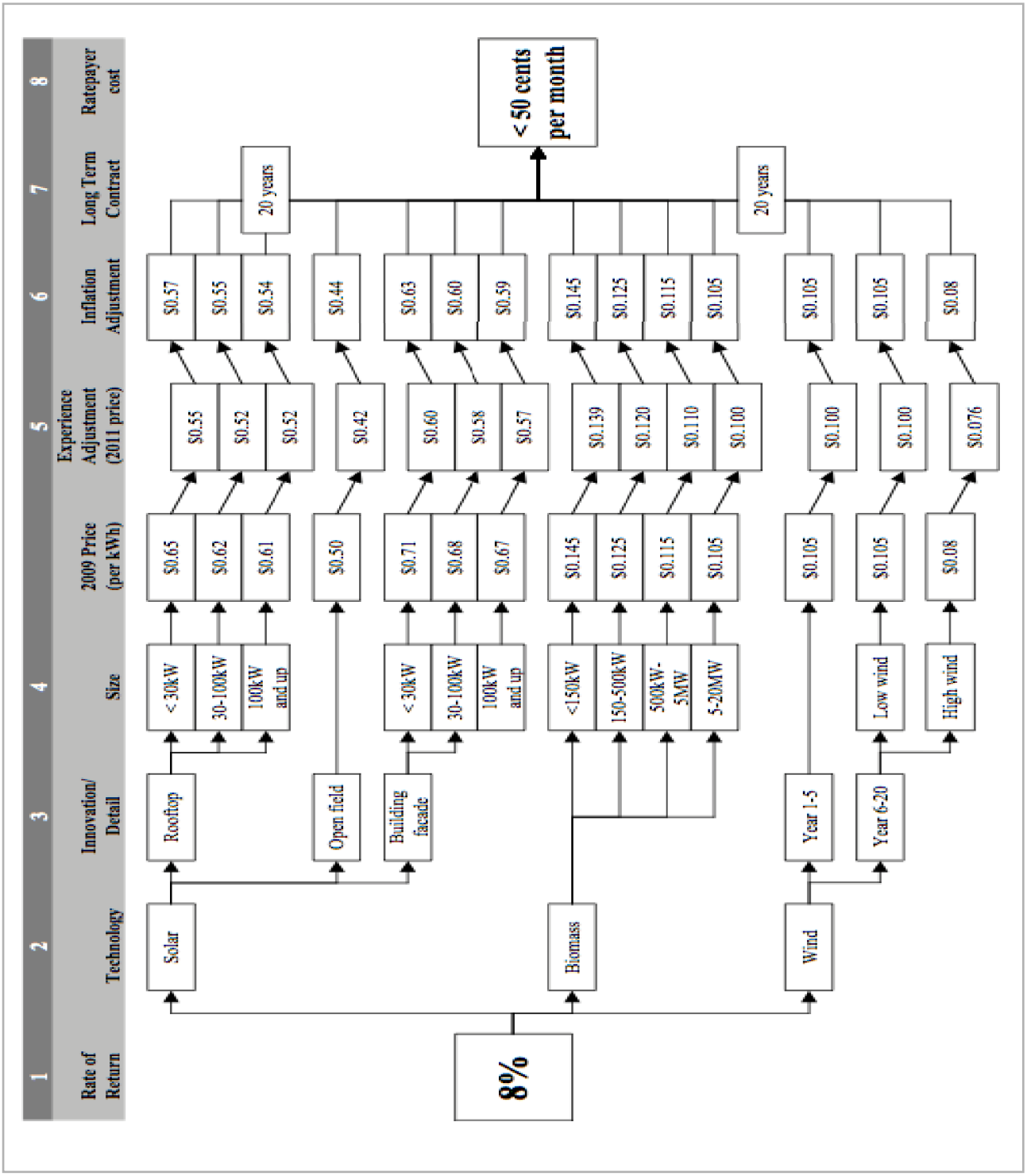


Figure 8 illustrates how Germany scales its biomass tariff to encourage projects at small and large scale.

Figure 9 – A Nuanced Price System Helps Create a Vibrant Renewable Energy Market at Low Cost



Appendix M

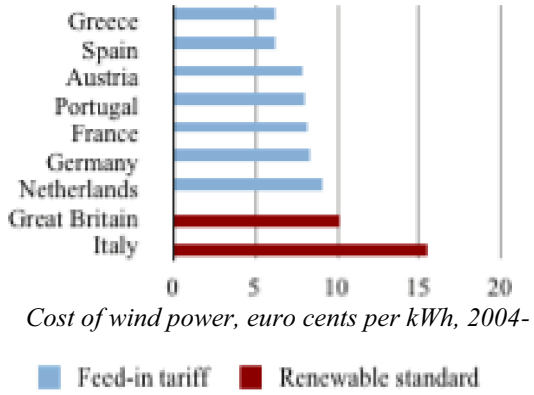
The Economics of a Feed-in Tariff

The motivation for simple renewable energy policy like a FIT is the potential to secure more of the economic and social benefits of a transition to renewable energy than using a patchwork policy approach. Evidence from European countries with feed-in tariffs suggests that this is exactly what happens. This section outlines several ways that feed-in tariffs have improved economic development in the countries that use them.

Cheaper Renewable Power

Studies of the European electricity markets find that electricity from wind turbines is less expensive in countries with feed-in tariffs than those with quantity-based renewable energy policies like renewable portfolio standards (**Figure 10**).[45] Great Britain, for example, requires wind producers to obtain much of their economic value from selling renewable energy credits (RECs) – a certificate of renewable energy produced that utilities must buy – and the uncertainty of REC prices increases financing costs and, ultimately, the cost of wind power for ratepayers.

Figure 10 – Wind Power is Cheaper with a Feed-in Tariff



Cheaper Electricity

If renewable electricity is prioritized – e.g. utilities must buy and feed-in that power to the grid first – then renewable energy displaces other generators. This "merit order" reduces the use of expensive peaking plants and can drive down the overall cost of electricity supply (**Figure 11**).[46] This has been the case in Germany.

Figure 11(a) – Merit Order: Total Cost of Electricity before Renewables

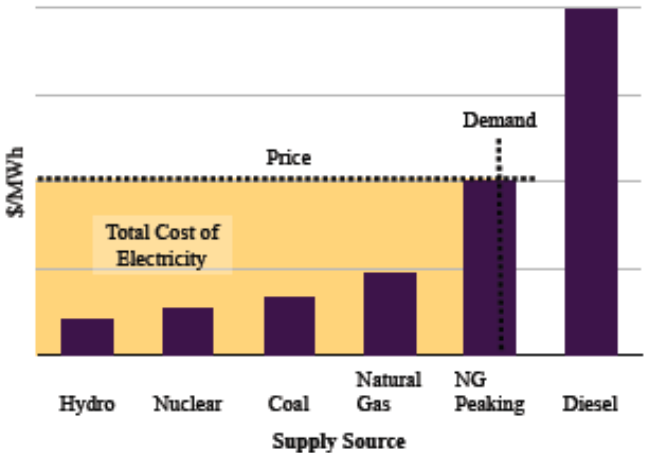


Figure 11(a) illustrates the total price of electricity without renewables. The vertical dotted line represents the peak demand and the horizontal line is the price paid for that peak electricity.

Peak demand requires the use of natural gas peaking plants, which have a high price. This increases the total cost of electricity to consumers, represented by the shaded area.

Figure 11(b) – Merit Order: Renewables Lower Electricity Cost

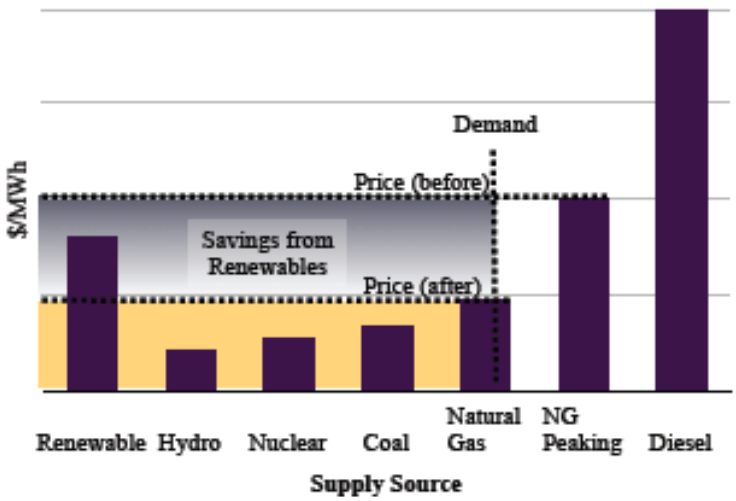


Figure 11(b) illustrates the total price of electricity *with* renewables.

The vertical dotted line (Demand) shows that prioritizing renewable generators reduces the use of natural gas peaking plants. The lower horizontal dotted line (Price - after) shows how this lowers the total cost of electricity. The gradient area shows how the lower wholesale price generates savings that offset and sometimes may eliminate the additional cost to the utility of buying renewables at a premium price (represented by the bar for renewables).

In Germany, the merit order savings from renewables exceeds the premium price paid under the feed-in tariff. In Denmark and Spain, the savings recoup over 80 percent of the higher feed-in tariff costs.

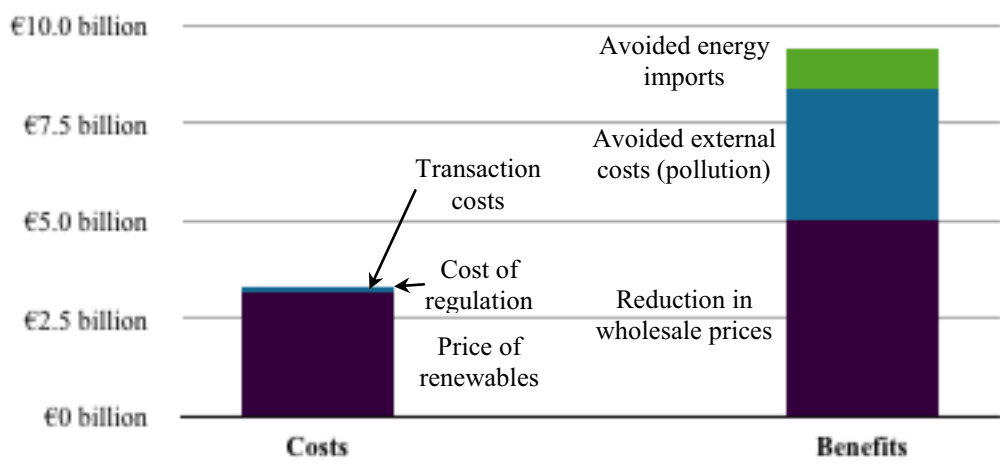
Substantial Job Growth

Both Germany and Denmark were early adopters of feed-in tariffs, and the investment in renewable power has paid back several-fold to their economies. =In Germany, almost 280,000 jobs have been created in the renewable energy industry. In Denmark, there are over 21,000 jobs in the wind industry.

Total Benefits Far Outweigh the Costs

Overall, the benefits of a feed in tariff can outweigh the costs of the premium paid to renewables even without taking into account the economic development impacts. The German ministry overseeing their feed-in tariff estimates that the total benefits of the legislation have exceeded the costs by a factor of three (**Figure 12**).[47]

Figure 12 – Benefits of German Feed-in Tariff far outweigh costs



Local Ownership

A feed-in tariff levels the playing field for local ownership because the all-in-one price drastically simplifies the development process for community-based or individually-owned projects. Rather than having to cobble together an unwieldy structure of local investors and tax equity investors as is the case in the United States, in European countries with feed-in tariffs the profits come from utility revenues, thus avoiding the need to find investors with tax liability. This is important since the economic benefits from encouraging this type of ownership are substantial.

Take a particular wind project, for example, with ten 2 MW turbines located on a farmer's land. **Figure 13** shows that the cash flow for owning the turbines is significantly higher than if the farmer simply leases their land and wind rights to an absentee developer.[48]

This drastic difference also accounts for the much higher economic benefits to a region when wind projects are locally owned rather than absentee owned. **Figures 14 and 15** show both the economic impact and employment impact advantages of local ownership.[49]

Figure 13 – Total Landowner Payments for a 20 MW Wind Project Based on Ownership of Project

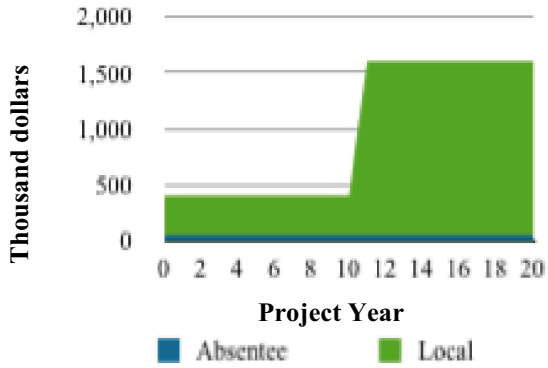


Figure 14 – Local Ownership Means Significantly Higher Economic Impact

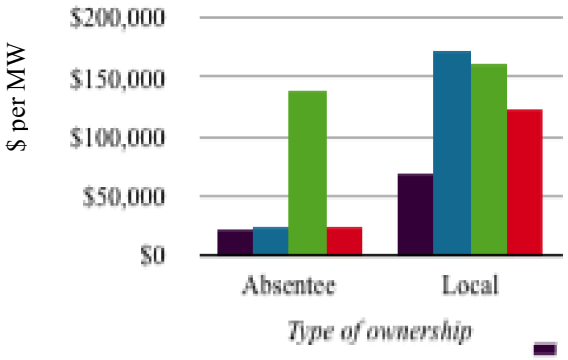
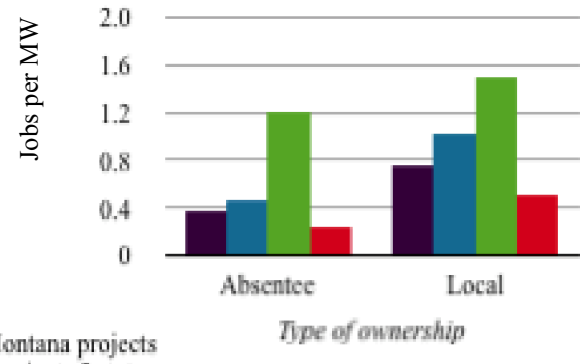
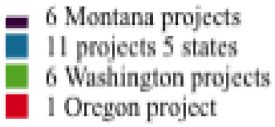


Figure 15 – Local Ownership Means Significantly more Jobs





Minnesota: A Case Study

Minnesota first considered a feed-in tariff in 2008 and the bill introduced in the 2009 session reflects an effort to adapt successful European policies to Minnesota's unique needs. Minnesota already has a nascent wind industry, with over 1,200 MW of wind projects in the ground and many hundreds more planned.

Additionally, the state has shown a strong commitment to encouraging locally owned, community-based renewable energy projects. Like Germany and Denmark, the state has a significantly higher rate of local ownership than other regions of the U.S (approximately 20 percent of wind projects). And yet, development of community-based projects has lagged as incentives continue to favor absentee ownership and larger scale projects and discriminate against locally owned and smaller projects.

Thus, the feed-in tariff proposal for Minnesota has a few key features:

- Local ownership – only locally owned projects can use the feed-in tariff incentive (as defined by the Community-Based Energy Development law)[50].
- Smaller wind projects –the revised FIT bill will only support wind projects under 20 MW in size.
- Program cap: the Minnesota legislation includes a capacity cap, set at 20 percent of the 25 percent Renewable Energy Standard by 2025 (approximately 5 percent of retail sales).

Costs and Benefits of a Minnesota Feed-in Tariff

What might be the costs and benefits of a Minnesota FIT as currently designed?

For illustration purposes, the following analysis assumes that the feed-in tariff in Minnesota would be enacted in 2010 and that up to 20 percent of the state's renewable energy goal could be covered by projects in the FIT program. This would be close to 5 percent of each utility's load. It is assumed that wind will be 95 percent of projects and solar 5 percent, equivalent to 1042 MW of wind power and 151 MW of solar PV by 2025.

Costs to Ratepayers and Taxpayers

The cost to Minnesota ratepayers of the amount of renewable energy generated in this example is very small, approximately 41 cents per household per month at its peak. Because the prices step down over time, however, the feed-in tariff will eventually lower electricity bills by more than this, saving households around 8 cents per month in 2025.

The ratepayer cost of Minnesota's feed-in tariff is small, peaking at 41 cents per household per month.

The primary reason for lower costs is stability. Unlike expiring state and federal incentives or tax credits, a tariff is a long-term, fixed price for electricity that is available to everyone regardless of tax liability. This is particularly important to small producers, who can't depend on multiple, diverse projects to support them if an income stream dries up. Such stability is not only less expensive, it's more effective at reaching renewable electricity generation goals.[51] Mandate systems have volatile prices because the producers may rely on the sale of their renewable certificates to supplement the power purchase price. Because selling these credits on the market is more unpredictable than a long-term, fixed-price contract, feed-in tariffs create more investor confidence and lower the cost of capital.[52]

> "I live out on the Buffalo Ridge...I look out my window and I see hundreds of wind turbines. When I look at those turbines I'm happy and I'm sad... Most of those turbines are owned by our friends, the foreign multinationals. Out of two counties in Minnesota we export about 80 million dollars a year to france, florida, italy, portugal, spain.
>
> All of our energy future is going out the door when we could be turning that into something real for us."
>
> *–Dan Juhl, community wind developer, Minnesota*

Benefits to the State

The renewable energy projects supported by a feed-in tariff will provide a premium in economic development, in jobs and financial impact on the local economy because of their broad ownership structure.

Several studies have documented the significantly higher impact of local ownership of renewable energy projects on employment and economic benefits. The research typically shows nearly two-thirds again as many jobs in a locally owned project compared to an absentee owned one, and anywhere from two to five times the economic impact.[53] **Figure 16** illustrates the potential impact of a feed-in tariff on Minnesota's economy, given the research findings.

Figure 16(a) – 1042 MW of Minnesota Wind Produces More Jobs if Locally Owned

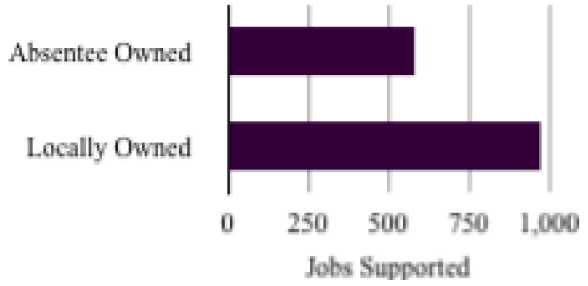


Figure 16(b) – 1042 MW of Minnesota Wind Produces More Economic Impact if Locally Owned

Questions about Feed-In Tariffs

With a history of favoring market interventions based on quantity rather than price, many U.S. utility and regulatory representatives raise concerns about feed-in tariffs. Here are some answers to common questions or criticisms.

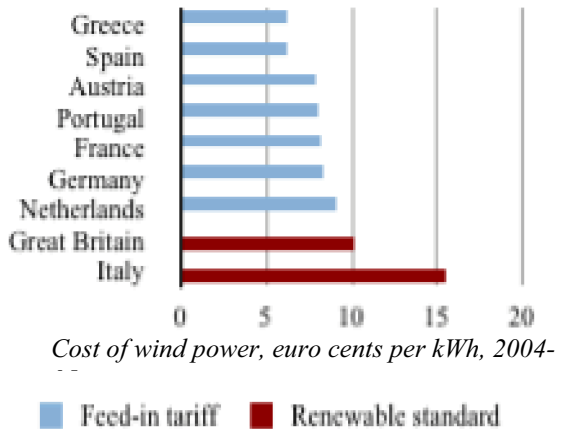
Won't a Feed-In Tariff be Expensive?

No. In fact, studies suggest that a feed-in tariff may be a less expensive route than other policies to expanding renewable energy production, while generating greater domestic or local economic benefits.

Because it sets all-in-one prices, a feed-in tariff tariff often looks a lot bigger than the prices utilities are used to paying or governments are used to providing. The difference is an accounting one. Wind and solar producers will get a price under a FIT as they do in the current market with its byzantine array of incentives, rebates, and tax advantages. But a guaranteed, long term contract reduces the risk premium for financing renewable energy projects, often reducing the cost of capital and, thus, the cost of getting more renewable energy.

The cost difference is highlighted in **Figure 17,** which shows that European countries with feed-in tariffs have substantially lower acquisition costs for wind power than those with quantity-based policies.

Figure 17 – Wind Power is Cheaper with a Feed-in Tariff



Studies have also found that the additional cost of feed-in tariffs is offset, sometimes almost completely, by reducing the wholesale cost of electricity. In most countries with feed-in tariffs, renewable energy is the highest priority electricity source, so it supplants other generators such as nuclear, coal and natural gas. This "merit order" actually reduces the overall cost of electricity (**Figure 18**).

Figure 18(a) – Merit Order: Total Cost of Electricity before Renewables

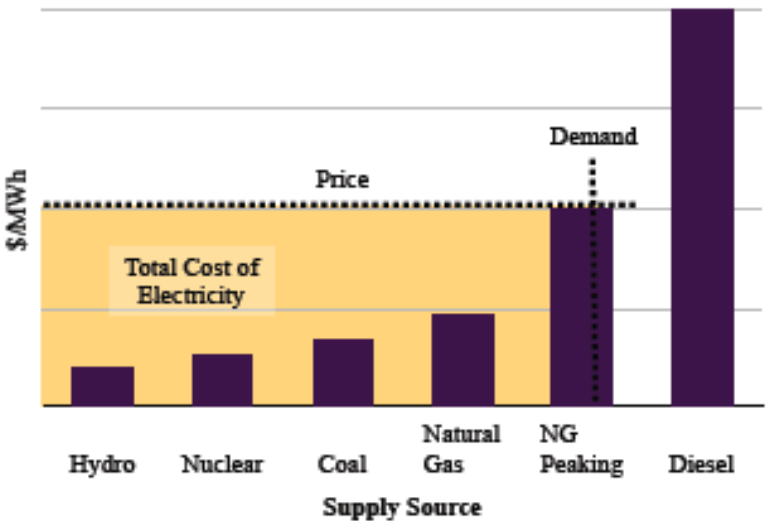


Figure 11(a) illustrates the total price of electricity without renewables. The vertical dotted line represents the peak demand and the horizontal line is the price paid for that peak electricity.

Peak demand requires the use of natural gas peaking plants, which have a high price. This increases the total cost of electricity to consumers, represented by the shaded area.

Figure 18(b) – Merit Order: Renewables Lower Electricity Cost

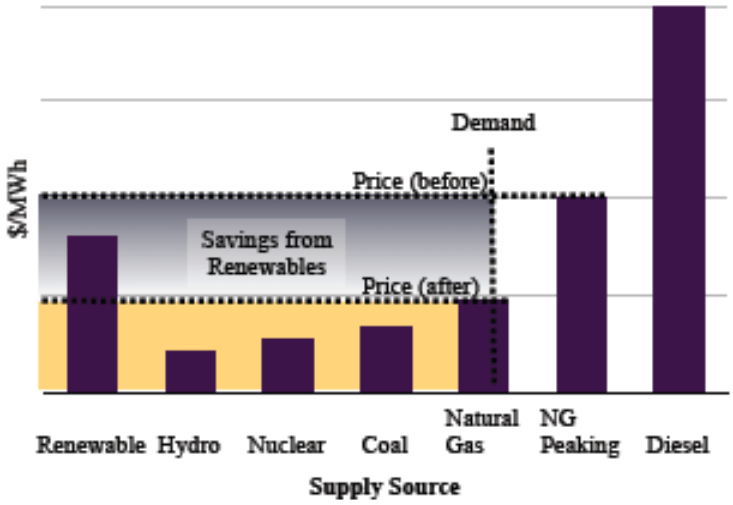


Figure 11(b) illustrates the total price of electricity *with* renewables.

The vertical dotted line (Demand) shows that prioritizing renewable generators reduces the use of natural gas peaking plants. The lower horizontal dotted line (Price - after) shows how this lowers the total cost of electricity. The gradient area shows how the lower wholesale price generates savings that offset and sometimes my eliminate the additional cost to the utility of buying renewables at a premium price (represented by the bar for renewables).

If we have an RPS, do we need a Feed-in Tariff?

Yes. An RPS provides a timeline to the utilities, but does not push projects forward. A FIT sends a signal to investors; it makes projects happen. Moreover, a FIT can be designed to not only accelerate renewable energy but to do so in a way that achieves economic development or other important social goals, such as allowing more energy consumers to become energy producers.

By supporting local ownership and dispersed generation, a feed-in tariff can increase the economic benefits and reduce the cost of acquiring more renewable energy. Both policies can increase the level of renewable electricity generation, but the feed-in tariff is a more comprehensive strategy.

Isn't an RPS more market-oriented?

No. An RPS sets a quantity (and is often supplemented and driven by tax incentives, rebates, and other price interventions). A feed-in tariff focuses on price. Neither is a fully market-based policy. Nor is the abundant use of tax incentives and rebates a market-based policy.

The advantage of a feed-in tariff is that it shifts competition in the market. Instead of a free-for-all where wind fights solar fights biomass and large fights small for the lowest bid, the competition is among developers and manufacturers to reduce prices to maximize their welfare. And the data shows that this kind of market competition achieves less expensive renewable energy (**Figure 17**, previous page).

Conclusion

The United States would benefit from a change in renewable energy policy to a feed-in tariff. The lesson from Europe is clear: Americans can continue to debate "market-based" ideas and tax credits or they can jump to the solutions that work.

> "We decided we will reduce CO_2 until 2020, 40 percent, [and by] 2050 with 80 percent. And then we debated the instruments.
>
> I hear arguments [at this Conference] we discussed in Germany 10 or 15 years ago. It's the same debate....In Germany, we had a decision, we made a law...the Renewable Energy Resources Act. And it worked. You can see the results."
>
> *–Willi Voigt, former minister in the German state of Schleswig-Holstein*

In addition to turbocharging renewable energy development, a feed-in tariff unlocks the potential of dispersed generation and community ownership. Compared to the byzantine array of incentives and rules facing renewable energy producers, a feed-in tariff decreases the economic and legal costs of doing business and increases the social and economic benefits.

About the Author

John Farrell is a research associate on the New Rules Project at the Institute for Local Self-Reliance, where he examines the benefits of local ownership and dispersed generation of renewable energy. His latest paper is Rural Power: Community-Scaled Renewable Energy and Rural Economic Development. You can find more of his work and more information on the New Rules Project at www.newrules.org. He can be reached at: jfarrell@ilsr.org or 612-379-3815 x210.

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Wind-Works.org

by Paul Gipe

Britain to Launch Innovative Feed-in Tariff Program in 2010

Proposes World's Highest Tariffs for Small Wind Turbines

July 23, 2009

By Paul Gipe

They said it couldn't be done, but Britain has risen to the challenge. Britain's Secretary of State for Energy and Climate Change Ed Miliband has released long-awaited details on the Labour Government's feed-in tariff policy.

Miliband, an up-and-coming politician in the cabinet of besieged Prime Minister Gordon Brown, has done what was once unthinkable, put a British stamp of approval on feed-in tariffs as a policy mechanism for developing renewable energy.

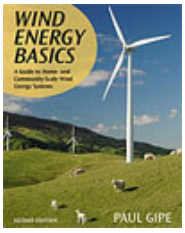
The move has potentially far reaching ramifications in the English speaking world where there has been reluctance to use full-fledged systems of feed-in tariffs, sometimes on ideological grounds. Now that Britain, Ontario, and South Africa, two of Britain's former colonies, have definitively moved toward implementing sophisticated feed-in tariff programs, there may be less reticence to do so elsewhere in the Anglophone world.

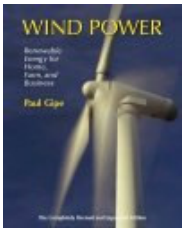
Of course, like politicians everywhere, Miliband had to rebrand feed-in tariffs to something more to his liking. His "clean energy cash back" creates yet another term for what everyone else calls, sometimes grudgingly, feed-in tariffs.

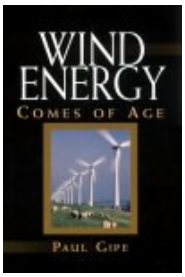
Nevertheless, the program's designers took their task seriously and didn't opt for a system of faux or false feed-in tariffs, what North American campaigners have begun derisively calling FITINOs, feed-in tariffs in name only.

The British proposal has also contributed several innovative new twists on feed-in tariff design that will mark the program as "made in the United Kingdom".

One new feature is the inclusion of tariffs for Combined Heat &

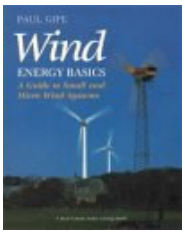






Appendix N

Power (CHP). While not a first, it is one of the few programs to do so. Another feature of the proposed program is a distinct tariff for small solar PV systems on new homes, and a separate tariff for existing homes.



Most significantly, program designers have included a mechanism to encourage homeowners and small businesses to reduce their electricity consumption. For example, a solar PV generator will be paid for all their generation. However, they will receive a bonus, currently at £0.05/kWh ($0.08 USD/kWh, $0.09 CAD/kWh), for electricity delivered to the grid over and above their domestic consumption. Thus, if a homeowner is able to cut their domestic consumption, and sell more electricity to the grid as a result, they are paid the bonus on top of the posted feed-in tariff.

The proposed program, like the successful programs it was modeled after, was designed to "set tariffs at a level to encourage investment in small scale low carbon generation." This is in contrast to faux feed-in tariffs that set the tariffs on the "value" of renewable energy to the system as in the California Public Utility Commission's largely ineffective program.

British designers were instructed to calculate tariffs not on ideology or economic theory but on the tariffs needed so "that a reasonable return can be expected for appropriately sited technologies" to meet the country's renewable energy and carbon mitigation targets.

Unfortunately, the program's targets are timid at best, two percent of Britain's electricity consumption by 2020, and the tariffs are limited by law to projects less than 5 MW to protect the country's stumbling Renewable Obligation, the preferred mechanism for developing larger projects.

The two percent target requires the generation of only 8 billion kWh (TWh) per year. For comparison, Germany generated 40 TWh in 2008 from wind energy and more than 4 TWh from solar PV. France, Britain's longtime cross-channel rival, generated nearly 6 TWh from wind energy in 2008 from its system of feed-in tariffs.

Some of the proposed tariffs are not competitive with those on the continent, or those in Ontario. "For community-scale or larger on-site projects," says David Timms, a senior campaigner with Friends of the Earth (UK), "the rates [tariffs] are inadequate."

The tariff proposed for large wind turbines is low by international standards. Britain has some of the best winds in Europe. Nevertheless, many of the smaller projects that may be built under the feed-in tariff program may not be as advantageously sited as commercial projects under the Renewable Obligation. Consequently, the proposed tariff for wind projects from 500 kW to 5 MW may be insufficient to drive development.

Timms also adds that the "degression for solar PV is quite aggressive" at 7 percent per year and that the bonus payment of £0.05/kWh for export to the grid may not be bankable. Because the bonus payment will fluctuate with the "market price" it won't

Appendix N

necessarily have a fixed value and, consequently, it will be discounted by banks providing debt for projects financed under the feed-in tariff.

If implemented as proposed, though, the British program will offer some of the highest tariffs for small wind energy in the world. The tariffs will rival those in Italy, Israel, Switzerland, and Vermont, possibly reflecting the British government's belief that it can encourage development of a domestic small wind turbine industry. For example, the tariff proposed for small wind turbines from 1.5 kW to 15 kW is £0.23/kWh ($0.38 USD/kWh, $0.42 CAD/kWh) about that paid in Italy and Israel.

The proposed program also includes a number of anti-gaming provisions to avoid breaking up bigger projects into several small ones to fit within the 5 MW project size cap. These will prevent companies from moving big wind projects from the Renewable Obligation to the feed-in tariff program.

Britain's feed-in tariff program is expected to begin in early April, 2010 after an extensive consultation. Below is a summary of the program's key elements.

- Program Cap: 2% of Supply, 8 TWh in 2020
- Project Cap: 5 MW
- Generator can be green field (doesn't have to be a metered customer)
- Contract Term: 20 years, solar PV 25 years
- Program Review: 2013
- Costs for the program will be borne by all British ratepayers proportionally

While limited in scope, Britain's proposed feed-in tariff program is as sophisticated, if not more so, as any proposed in the United States, and will put the country on the world map of innovative renewable energy policy.

Consultation on Renewable Electricity Financial Incentives 2009: Program Details

Consultation on Renewable Electricity Financial Incentives: Background Documents & Reports

Appendix N

Renewable Tariffs in Great Britain (Proposed)						
07/23/09						
		Tariff				
			1.1564	1.57323	1.41779	
	Years	£/kWh	€/kWh	CAD/kWh	USD/kWh	Degression
Wind Energy	20					
<1.5 kW		0.305	0.353	0.555	0.500	0
>1.5 kW<15 kW		0.230	0.266	0.418	0.377	0
>15 kW<50 kW		0.205	0.237	0.373	0.336	0
>50 kW<250 kW		0.180	0.208	0.327	0.295	0
>250 kW<500 kW		0.160	0.185	0.291	0.262	0
>500 kW<5 MW		0.045	0.052	0.082	0.074	0
Solar PV	25					
<4 kW		0.310	0.358	0.564	0.508	-7%
<4 kW Retrofit		0.365	0.422	0.664	0.598	-7%
>4 kW<10 kW		0.310	0.358	0.564	0.508	-7%
>10 kW<100 kW		0.280	0.324	0.509	0.459	-7%
>100 kW<5 MW		0.260	0.301	0.473	0.426	-7%
Stand Alone System		0.260	0.301	0.473	0.426	-7%
Hydro	20					
<10 kW		0.170	0.197	0.309	0.279	0
>10 kW<100 kW		0.120	0.139	0.218	0.197	0
>100 kW<1 MW		0.085	0.098	0.155	0.139	0
>1 MW<5 MW		0.045	0.052	0.082	0.074	0
Anaerobic Digestion	20					
Electricity Only		0.090	0.104	0.164	0.148	0
CHP		0.115	0.133	0.209	0.189	0
Biomass	20					
<50 kW		0.090	0.104	0.164	0.148	0
<50 kW<5 MW		0.045	0.052	0.082	0.074	0
CHP		0.090	0.104	0.164	0.148	0
Bonus for Export	20	0.050	0.058	0.091	0.082	0
Existing microgenerators transferred from RO.	20	0.090	0.104	0.164	0.148	
Begins April 10, 2010 though systems installed up to that time can qualify.						
Solar PV term is 25 years.						

-End-

back to **Archive of Articles**

Home Books **Articles** Workshops Photos Biography Top

Appendix N

Ontario Unveils North America's First Feed-In Tariff

Price Guarantees for Large and Small Renewable Energy Projects will Create Jobs

March 12, 2009

Ontario is poised to introduce new electricity pricing to encourage the development of renewable energy from a diverse range of producers including homeowners, community-based groups and larger scale commercial generators.

As North America's first guaranteed pricing structure – called a feed-in tariff (FIT) – for various forms of electricity production, it would offer a stable, competitive price combined with a long term contract. A FIT would establish prices for energy generated from renewable sources, including on-shore and off-shore wind, hydroelectric, solar, biogas, biomass and landfill gas. Proposed prices and program guidelines announced today will form the basis of an eight-week consultation process with renewable energy stakeholders and several general information sessions for the interested public.

"The proposed feed-in tariff program would help spark new investment in renewable energy generation and create a new generation of green jobs," said George Smitherman, Deputy Premier and Minister of Energy and Infrastructure. "It would give communities and homeowners the power and tools they need to participate in the energy business in the new green economy."

"Ontario has made great progress in procuring renewables, becoming Canada's leading province for wind power," added Colin Andersen, CEO of the Ontario Power Authority. "This proposed FIT program would build on our success and ensure that more contracts turn into projects sooner."

The proposed Green Energy Act (GEA), if passed, would establish Ontario as North America's leader in renewable energy, drive green investment in the province and create 50,000 jobs in the first three years. Additional changes proposed under the GEA would also make it easier and faster for projects to get connected to the grid. Other countries – particularly Germany, Spain and Denmark – have successfully used FITs to encourage the development of renewable energy projects.

The proposed FIT prices were developed based on experience here in Ontario and in other jurisdictions. Prices differ based on project size and type of renewable energy technology. They cover capital, operating and maintenance costs and allow for a reasonable rate of return on investment over an approximate 20-year period. They also provide special categories for community-based projects.

Appendix O

Ontario's Energy Supply Mix

SUPPLY TYPE	FUEL TYPE	LOCATION	CURRENT/PROPOSED PRICE (kWh)
Peaking fuel for reliability*	8% natural gas	various plants	8.5¢ - 14¢
Renewable Opportunities**	TBD% – new renewables portfolio	wind solar biomass biogas landfill gas new hydro	8¢ - 44.3¢
	1-2% rooftop solar***		53.9¢ - 80.2¢
Baseload 76%*	53% nuclear	Pickering Darlington Bruce	6¢ - 7¢
	23% hydroelectric	Niagara Falls St. Lawrence River Northern rivers	5.7¢ - 6.2¢

* Existing supply
** Emerging supply
*** 1% = approximately 100,000 residential rooftops

Solar micro-generation, 10 kilowatts and under, will enjoy the highest tariff in order to incent Ontarians to participate. If the proposed FIT program leads to 100,000 residential solar rooftop installations, it will amount to one percent of Ontario's supply mix.

The OPA will begin consulting with renewable energy stakeholders on the proposed design of a FIT program, including eligibility criteria and proposed pricing next week. Weekly sessions run from March 17 to May 5, 2009.

Quick Facts

- In 2008, 25% of Ontario's electricity generation came from renewable energy sources.
- Nearly 1,200 megawatts of wind capacity will be online by end of 2009, enough to power almost 325,000 homes.
- Investments in new renewable energy projects already in place or under construction in Ontario total about $4 billion.
- Rooftop solar prices should drive installations in urban centres, matching areas with high summer air conditioning demand.
- Methane capture at landfill sites will provide significant greenhouse gas emission reductions.
- Many waterpower projects and partnerships with First Nations and Métis involvement are anticipated, especially in the North.
- In some cases, like farm-based biogas and hydroelectric production, an on-peak producing incentive will be offered.

Appendix O

Proposed Feed-In Tariff Prices for Renewable Energy Projects in Ontario

Technology	Proposed size tranches	Proposed ¢/kWh
Biomass*		
	Any size	12.2
Biogas*		
	≤ 5 MW	14.7
	> 5 MW	10.4
Waterpower*		
	≤ 50 MW	12.9
Community Based	≤ 2 MW	13.4
Landfill gas*		
	≤ 5MW	11.1
	> 5 MW	10.3
Solar PV		
Rooftop	≤ 10 kW	80.2
	10 – 100 kW	71.3
	100 – 500 kW	63.5
	> 500 kW	53.9
Ground Mounted	≤ 10 MW	44.3
Wind		
Onshore	Any size	13.5
Offshore	Any size	19.0

Appendix O

Community Based	≤ 10 MW	14.4

*on/off peak pricing applies (see Backgrounder for details)

Print

Appendix O

Proposed Feed-In Tariff Prices for Renewable Energy Projects in Ontario Base Date: July 8, 2009			
Renewable Fuel	**Proposed size tranches**	**Proposed Contract Price ¢/kWh**	**Escalation Percentage****
Biomass*^			
	≤ 10 MW	13.8	20%
	> 10 MW	13.0	20%
Biogas*^			
On-Farm	≤ 100 kW	19.5	20%
On-Farm	> 100 kW ≤ 250 kW	18.5	20%
	≤ 500 kW	16.0	20%
	>500 kW ≤ 10 MW	14.7	20%
	> 10 MW	10.4	20%
Waterpower*^			
	≤ 10 MW	13.1	20%
	> 10 MW	12.2	20%
Landfill gas*^			
	≤ 10MW	11.1	20%
	> 10 MW	10.3	20%
Solar PV			
Any type	≤10 kW	80.2	0%
Rooftop	> 10 ≤ 250 kW	71.3	0%
Rooftop	> 250 ≤ 500 kW	63.5	0%
Rooftop	> 500 kW	53.9	0%
Ground Mounted^	≤ 10 MW	44.3	0%
Wind^			
Onshore	Any size	13.5	20%
Offshore	Any size	19.0	20%

*Peak Performance Factor applies.

^Aboriginal Price Adder and Community Price Adder eligible as outlined in Appendix A below.

**Escalation Percentage will be applied to eligible Renewable Fuels as calculated in Exhibit B of draft FIT Contract.

Draft

Appendix A: Maximum Aboriginal Price Adder and Maximum Community Price Adder*:

Renewable Fuel	Wind	PV (Ground Mounted)	Water	Biogas	Biomass	Landfill Gas
Maximum Aboriginal Price Adder (¢/kWh)	1.5	1.5	0.9	0.6	0.6	0.6
Maximum Community Price Adder (¢/kWh)	1.0	1.0	0.6	0.4	0.4	0.4

* The percentage of the Maximum Aboriginal Price Adder or Maximum Community Price Adder added to the Contract Price is based on the Aboriginal or Community Participation Level as defined in the FIT Rules.

News

General Motors Corporation

GM Communications
Detroit, Mich., USA
media.gm.com

For Release: 8:00 AM EDT
August 11, 2009

Chevrolet Volt Expects 230 mpg in City Driving

First mass-produced vehicle to claim more than 100 mpg composite fuel economy

Tentative EPA methodology results show 25 kilowatt hours/100 miles electrical efficiency in city cycle

- Plugging in daily is key to high-mileage performance

WARREN, Mich. – The Chevrolet Volt extended-range electric vehicle is expected to achieve city fuel economy of at least 230 miles per gallon, based on development testing using a draft EPA federal fuel economy methodology for labeling for plug-in electric vehicles.

The Volt, which is scheduled to start production in late 2010 as a 2011 model, is expected to travel up to 40 miles on electricity from a single battery charge and be able to extend its overall range to more than 300 miles with its flex fuel-powered engine-generator.

"From the data we've seen, many Chevy Volt drivers may be able to be in pure electric mode on a daily basis without having to use any gas," said GM Chief Executive Officer Fritz Henderson. "EPA labels are a yardstick for customers to compare the fuel efficiency of vehicles. So, a vehicle like the Volt that achieves a composite triple-digit fuel economy is a game-changer."

According to U.S. Department of Transportation data, nearly eight of 10 Americans commute fewer than 40 miles a day **http://tinyurl.com/U-S-DOTStudy**.

"The key to high-mileage performance is for a Volt driver to plug into the electric grid at least once each day," Henderson said.

Volt drivers' actual gas-free mileage will vary depending on how far they travel and other factors, such as how much cargo or how many passengers they carry and how much the air conditioner or other accessories are used. Based on the results of unofficial development testing of pre-production prototypes, the Volt has achieved 40 miles of electric-only, petroleum-free driving in both EPA city and highway test cycles.

Under the new methodology being developed, EPA weights plug-in electric vehicles as traveling more city miles than highway miles on only electricity. The EPA methodology uses kilowatt hours per 100 miles traveled to define the electrical efficiency of plug-ins. Applying EPA's methodology, GM expects the Volt to consume as little as 25 kilowatt hours per 100 miles in city driving. At the U.S. average cost of electricity (approximately 11 cents per kWh), a typical Volt driver would pay about $2.75 for electricity to travel 100 miles, or less than 3 cents per mile.

The Chevrolet Volt uses grid electricity as its primary source of energy to propel the car. There are two modes of operation: Electric and Extended-Range. In electric mode, the Volt will not use gasoline or produce tailpipe emissions when driving. During this primary mode of operation, the Volt is powered by electrical energy stored in its 16 kWh lithium-ion battery pack.

When the battery reaches a minimum state of charge, the Volt automatically switches to Extended-Range mode. In this secondary mode of operation, an engine-generator produces electricity to power the vehicle. The energy stored in the battery supplements the engine-generator when additional power is needed during heavy accelerations or on steep inclines.

“The 230 city mpg number is a great indication of the capabilities of the Volt’s electric propulsion system and its ability to displace gasoline,” said Frank Weber, global vehicle line executive for the Volt. “Actual testing with production vehicles will occur next year closer to vehicle launch. However, we are very encouraged by this development, and we also think that it is important to continue to share our findings in real time, as we have with other aspects of the Volt’s development.”

About Chevrolet

Chevrolet is one of America's best-known and best-selling automotive brands, and one of the fastest growing brands in the world. With fuel solutions that go from "gas-friendly to gas-free," Chevy has nine models that get 30 miles per gallon or more on the highway, and offers three hybrid models. More than 2.5 million Chevrolets that run on E85 biofuel have been sold. Chevy delivers expressive design, spirited performance and provides the best value in every segment in which it competes. More information on Chevrolet can be found at www.chevrolet.com. For more information on the Volt, visit media.gm.com/volt.

General Motors Company, one of the world's largest automakers, traces its roots back to 1908. With its global headquarters in Detroit, GM employs 235,000 people in every major region of the world and does business in some 140 countries. GM and its strategic partners produce cars and trucks in 34 countries, and sell and service these vehicles through the following brands: Buick, Cadillac, Chevrolet, GMC, GM Daewoo, Holden, Opel, Vauxhall and Wuling. More information on the new General Motors Company can be found at www.gm.com.

# # #

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Appendix Q

EXPLORING VANCOUVER ISLAND'S ENERGY FUTURE

A Workshop with BC Hydro & Rocky Mountain Institute

July 14, 2003

Final Report

September 29, 2003

Prepared by:
Rocky Mountain Institute

Project Manager:
Joel N. Swisher, PhD, PE

Appendix R

Table of Contents

Appendix R

EXPLORING VANCOUVER ISLAND'S ENERGY FUTURE

A Workshop with BC Hydro & Rocky Mountain Institute
July 14, 2003

Introduction and Summary

BC Hydro faces complex technical and economic challenges in formulating a least cost and resilient resource plan for Vancouver Island (VI). In the short term, due to the retirement of the HVDC transmission line from the Mainland, Vancouver Island will need at least 200 MW of new supply capacity by 2006 to meet reliability criteria. Although BC Hydro has a proposal for a new combined-cycle plant and gas transmission pipeline, regulatory hurdles could delay or halt construction. Therefore, a comprehensive contingency plan is required. Long term, regardless of whether the new gas facility is completed, BC Hydro needs to determine how to best utilize the total energy infrastructure (gas, power, renewable sources, end use demand) to meet its customers' energy service needs.

On Monday, July 14, 2003, Rocky Mountain Institute and BC Hydro held a workshop with BC Hydro staff and several external experts to explore the long-term energy needs of Vancouver Island. The workshop was designed to provide the opportunity for participants to brainstorm about Vancouver Island's electricity future, identify long-term (up to 20 years) potential options, and consider intermediate steps to realize such potential.

RMI's perspective is that solutions to these vexing problems require a broad, integrated perspective. Remarks by Amory Lovins and Kyle Datta reflect this view, "BC Hydro currently has an imminent 200 MW of capacity supply problem. If VIGP/GSX is delayed, the alternatives we have discussed as longer-term solutions become important contingency options, because they buy time. The question, then, is *how can VI get 200MW from a constellation of distributed resources* and maximize the value of the present gas and power infrastructure?

"*Price signals are key*. BC Hydro can effect change in customer behavior fast by ensuring that price signals are set up to produce the intended effect. Concerns over the intermittency of alternative, renewable options can be addressed by implementing a combination of technologies that will provide firmness: efficiency, renewable generation, cogeneration. *Pilot projects are needed now* to find out such things as how do customers respond to price. As a result of the workshop, BC Hydro has a range of options to consider."

While the focus of the workshop was on meeting the energy service needs of Vancouver Island, given the impending de-rating and retirement of the HVDC transmission from the Mainland, it is important to consider the broader context of British Columbia and the regional energy system as a whole. For example, new thermal generation on Vancouver Island may require additional gas transmission capacity, while any transmission-based solutions must include the generation options on the Mainland. Given the supply constraints on Vancouver Island, however, it is timely and relevant to consider supply and demand-side solutions tailored to the specific local needs.

The RMI/BC Hydro workshop on Vancouver Island's long term energy future served as an *initial brainstorming session* to pool the collective expertise and insights across BC Hydro departments, together with external representatives from government, academia and industry, facilitated by RMI to come up with twelve "breakout" ideas for further analysis. There are no "magic bullets" in these twelve ideas, nor are they a menu that can be combined arbitrarily. Rather, they are new options that BC Hydro can integrate into a robust portfolio. In this report, we suggest additional ideas and priorities that can complement the twelve proposed ideas from the workshop to better satisfy BC Hydro's planning goals.

The twelve proposed ideas cluster into four categories:

Marginal Costs and Price Signals:
- Peak load reduction through time-of-use rates, possibly island-specific
- E+ rate phase out
- Modify distribution extension policy, possibly including "feebates"

Demand-Side Management:
- Power Smart for peak reduction
- Smart water heaters
- Industrial curtailment

Generation and Distributed Resources:
- Energy storage on VI
- Cogeneration using natural gas or biomass
- Tidal, wave or wind power on VI

Transmission and Distribution Grid Solutions:
- Real-time metering to reduce line losses
- Convert 230kV Dunsmuir-Sahtlam line to 500 kV
- Modify transmission extension policy

In our view, several important themes underlie these twelve ideas:

- BC Hydro needs to know the *full marginal costs of service on an area- and time-specific basis,* including generation, transmission, and distribution, and costs should be risk adjusted to recognize the inherent pricing risks of increased gas reliance. This information will support the design of new pricing structures and provide a clear set of

economic criteria for prioritizing investments in different types of DSM and supply resources, including distributed resources (DR) in the course of the IRP process.

- It is imperative to *get the price signals right*, within existing regulatory constraints, to guide customer behavior and investment decisions. Some pricing strategies should be designed specifically to limit peak demand and to shift electric hot water and space heating loads to gas or biomass.

- A *renewed regulatory compact* is needed in British Columbia to enable BC Hydro to reform its pricing structure and to provide financial incentives to implement all cost-effective demand-side management (DSM), energy efficiency and load management. This includes addressing the policy issues regarding province-wide equity when defining rate options.

- *Power Smart is one of BC Hydro's most important resources*. The present, expanded Power Smart can be augmented to reach more ambitious goals, to focus more on peak demand savings, and to target electric hot water and space heating, especially on Vancouver Island. The appropriate level of program expansion should be dictated by economic cost-effectiveness, using the full locational marginal costs.

- BC Hydro has a *range of generation options to purchase from the private sector*, which can provide long-term flexibility or provide alternatives in case the VIGP/GSX project is not completed. Options include other on-island generation, Mainland generation (and the needed transmission capacity), and *distributed resources*, such as cogeneration, energy storage and some intermittent renewable sources. Note that intermittent renewables will need to be combined into firm portfolios with other resources in order for some of their capacity to be considered dependable.

- The *full distributed benefits of a portfolio of measures* should be understood in terms of marginal costs, risk management, operational benefits, and reliability improvement. The challenge goes beyond electricity, as BC Hydro will need to determine the *highest value and best use of gas delivered* to Vancouver Island in terms of services provided.

- No single measure is a magic bullet, but BC Hydro can build a *combination of DSM and supply technologies, programs, and prices* into a successful portfolio. A portfolio of firm capacity can be assembled from resources whose production (or savings) profiles balance each other, even if each individual resource is not firm. This approach allows certain intermittent renewable sources to be harnessed for their capacity, energy, and emissions reduction value.

- Transmission and distribution access and costs are key to the development of future DSM and supply resources in BC, and especially on VI. Reliance on new generation sources on the Mainland would require additional transmission to VI as well as reduced transmission constraints on the Mainland. Meanwhile, *transmission extension policy modification for intra-Vancouver Island transmission* and a collaborative approach to financing could facilitate the realization of much of the *renewable generation* potential on VI.

We address these themes further below, as part of the discussion of the four categories of proposed ideas and resources. The categories are Marginal Costs and Price Signals, Demand-Side Management, Generation and Distributed Resources, and Transmission and Distribution Grid Solutions.

For each category, we provide a brief introduction, followed by a discussion of key strategies and conceptual themes. Then, we present the proposed ideas for that category in further detail. In some cases, we draw attention to related ideas that were not addressed in detail by group.

List of Workshop Participants

Speakers:	Ron Monk
Larry Bell, BC Hydro	Jai Mumick
Bev Van Ruyven, BC Hydro	Dennis Nelson
Amory Lovins, RMI	Peter Northcott
	John Oliver
RMI Facilitators:	Ted Olynyk
Kyle Datta	William Peterson
Michael Kinsley	Bruce Ripley
Joel Swisher	Catherine Roome
Kitty Wang	Bruce Sampson
	Glen Smyrl
BC Hydro Participants:	Rohan Soulsby
Jeff Barker	Steve Watson
Al Boldt	Ralph Zucker
Murray Bond	
Lester Dyck	**External Participants:**
Craig Folkestad	Hadi Dowlatabadi, University of BC
Richard Fulton	Alexis Fundas, Ministry of Energy
Devinder Ghangass	Dan Green, Ministry of Energy
Don Gillespie	John Hall, Cossette Communications
Mary Hemmingsen	Michael Margolick, Global Change Strateiges
Derek Henriques	Glenn McDonnel, Sigma/Synex
Lexa Hobenshield	Rose Murphy, Simon Fraser University
Steve Hobson	John Nyboer, Simon Fraser University
Nadja Holowaty	Andrew Pape-Salmon, Ministry of Energy
Altaf Hussain	Kirk Washington, Yaletown Ventures
Mike Krafczyk	Paul Willis, Willis Energy
Trudy Kwong	Tom Wilson, Keen Engineering
Richard Marchant	
Ken McDonald	**BC Hydro Recorders:**
Rick McDougall	Amandeep Basi
Ryanne Metcalf	Matt Good
Brian Moghadam	Amy Jenkins Swan
	Ryan Robertson

Appendix R

Marginal Costs and Price Signals

In the course of discussing potential solutions to BC Hydro's capacity imbalance on Vancouver Island, workshop participants observed that there seem to be discontinuities between the costs of service on VI and the tariffs that some or all customers pay. This discontinuity was most evident regarding the apparent incentive to install electric hot water and space heating on VI, despite the cost and potential reliability problems resulting from this source of new on-peak demand. Similarly, there is now little incentive to develop distributed cogeneration because the relative retail prices of natural gas and electricity (i.e., the retail "spark spread") are so unfavorable.

Therefore, before we address the many technology solutions that were proposed at the workshop, we first consider the problems and solutions related to BC Hydro's marginal costs and the tariffs that it charges to its customers. These potential solutions involve improving the alignment between BC Hydro's cost structure and the use of cost information to determine prices and conduct resource planning. Although any potential change in the pricing structure will take time and involve significant policy debate, the internal work to align costs and rates could begin soon. To prepare for future pricing reform, while supporting planning efforts in the shorter term, we suggest a three-part strategy:

1. Develop an improved understanding of the *full marginal cost of supplying power* at different times of the day and year, including generation, transmission, and distribution
2. Design customer tariffs to *align price signals with the actual costs* of service in space and time, within existing regulatory constraints, to guide customer behavior
3. Use the improved cost information in *evaluating and prioritizing potential supply and demand-side resources* as part of BC Hydro's integrated resource planning (IRP) process

At the workshop, the group reported in detail on proposed ideas mostly related to customer tariffs (strategy 2). These ideas are covered in detail following a discussion of costs and pricing. The proposed ideas are the following:

Peak load reduction through TOU rates, possibly island-specific
E+ rate phase out
Modify distribution extension policy, possibly including "feebates"

Problems with Energy Pricing in BC and VI

The basic problems with energy pricing in BC, as observed with regard to VI, are the following:

- Customer prices are based on historical embedded costs of service, not forward-looking marginal costs, which leads to situation where BC Hydro sells power at a loss (negative margin) to certain customer and/or at certain times.
- System-wide, postage stamp pricing fails to capture the area-specific nature of the cost of supplying electricity service, due to local T&D cost variations. At the very least, it seems reasonable that VI tariffs should be different from those on the Mainland, although this would introduce a significant policy issue.

- Pricing that is constant or that only bluntly captures time-of-use variations fails to capture the time-specific costs of meeting peak demand on a seasonal basis, which can be better achieved using new products such as real-time pricing or critical peak pricing.
- Uniform pricing across a rate class fails to capture variations in customers' tolerance of ability to reduce or curtail loads during times of high costs or capacity constraints, while more individualized curtailable rates can save both customers and the utility money.
- Pricing structures that require customers to accept gas-price risk for direct gas use, but force the electric utility to absorb this risk for gas-fired generation, creates a bias against direct gas use and against distributed cogeneration.
- Extension policies that socialize the marginal cost of new electric heating installations, while assigning the marginal cost to each new renewable generation source, create the incentive for inefficient investments and discourage new distributed resources.
- Customer prices do not reflect social and environmental costs of electricity production that are external to BC Hydro's direct cost structure.

Many of these issues can be resolved through a combination of the three strategies suggested above. The following discussion elaborates somewhat on some of our recommendations on the use of marginal cost analysis and getting the price signals right.

Best Practices in IRP and Marginal Cost Analysis

The problems identified above with regard to the price signals received by BC Hydro customers, especially on Vancouver Island, suggest that improved price signals would more directly reflect BC Hydro's true marginal costs of service. In order to support the reform of the price signals and the regulatory compact in BC, a full understanding of the structure of BC Hydro's marginal costs is necessary. Therefore, it may be helpful to reinforce BC Hydro's analysis of its cost structure and to communicate the results to managers and planners throughout the company.[1]

In addition to supporting the design of new pricing structures, an updated marginal cost analysis will provide a clear set of economic criteria for prioritizing investments in different types of DSM and supply resources, including distributed resources (DR). This information will be useful in BC Hydro's IRP process, and it will help put DSM, DR and traditional supply options on more of a level playing field in economic terms.[2] While the competitive tender process will reveal the relative costs of different supply options, it is useful to understand the cost-related attributes of each resource type, in order to set transparent criteria for evaluating supply and demand-side resources that make different contributions to meeting energy and capacity needs.

A marginal cost analysis should achieve the following objectives:

- Understand *when costs are high*, by time of day and year, by isolating the types of peak loads and supply variations or constraints that drive time variations in costs
- Understand *where costs are high*, by determining the financial impacts of incremental increases or reductions in loads at different locations in the grid (especially on VI)

[1] Possible shepherd for further discussion: Richard Marchant

[2] See J. Swisher, G. Jannuzzi and R. Redlinger, 1998. *Tools and Methods for Integrated Resource Planning: Improving Energy Efficiency and Protecting the Environment*, UNEP Collaborating Centre on Energy and Environment, Roskilde, Denmark.

Appendix R

- Provide a formal basis for comparing DSM and DR options at different locations, rather than relying on the rather distorted price incentives that customers see.
- Enable DSM and DR to be *considered as planning options early enough in the IRP* process to allow them to compete with traditional supply options.
- Identify the financial interests of all parties directly involved in the development of DSM, DR and traditional supply options, to enable effective design of incentive mechanisms.
- Account explicitly for intangible or external costs in analyzing resource costs, *even if these costs are not internalized in the planning process.*

To achieve these goals, today's best practices in utility marginal cost analysis and IRP process design are recommended. Some of the methods are rather data-intensive and may be difficult to implement fully with available information. Existing regulatory constraints will also limit the application of some of the methods. However, it should be possible to use some or all aspects of the recommended practices, as indeed BC Hydro already does, and the results should provide insights regarding the potential need for additional information and/or regulatory reform. The best practices in marginal cost analysis are outlined briefly below.[3]

- *Starting point*: The default supply plan, based on minimizing revenue requirements, provides a familiar costing framework and a reference point to compare other options.
- *Review process*: Screen for viable alternatives, including DSM and DR, with the initial plan as a benchmark, and iterate to find better solutions.
- *Project costing*: Use forward-looking engineering-based capital and O&M costs for each identified option. Historical costs can be a guide for projects costs but are not part of the marginal cost methods.
- *Marginal capacity costs*: Use a present worth method, which yields the cost of a given planning option and the value of deferring investment due to an incremental increase or decrease in net load. Econometric methods are backward looking and inappropriate.
- *Locational variation of marginal capacity costs*: Analyze area-specific costs by planning area, based on the present value of each area's expansion plan and load growth. Variations result from differences in resource costs, load profiles, and mostly from differences in capacity costs of local transmission and distribution expansion.
- *Time allocation of marginal capacity costs*: Allocate costs to hourly and monthly time periods according to their contribution to peak demand and supply variations or constraints.
- *Non-monetary costs*: Identify intangible and external costs explicitly, and include them in the results only if there is a mechanism to monetize these costs.

The result of using these methods will be a set of marginal cost streams on an area- and time-specific (ATS) basis. This information provides the basis from which to construct rate designs, such as those recommended in the workshop, that capture variations in location and time-of-use. Applying these methods should enable BC Hydro to deliver price signals that realistically reflect the situation on Vancouver Island, namely the isolated location of many VI loads (area-specific) and the contribution of peak loads to BC Hydro's capacity costs (time-specific). Another aspect

[3] See Knapp, K., et al., *Costing Methodology for Electric System Planning*, Energy Foundation, November 2000.

of the time-specific nature of marginal costs is that the marginal supply resource, and therefore its cost, varies seasonally and annually due to variations in hydroelectric production.

The marginal cost analysis will also provide an economic ranking of proposed DSM, DR and traditional supply options. This is useful in order to, for example, construct the utility resource supply curve for the IRP process and prioritize investments in new resources.

Getting the Price Signals Right: Toward a New Regulatory Compact

At the workshop, there was broad consensus that distortions in the energy pricing structure in BC encourage customers to use energy inefficiently and make it difficult for BC Hydro to implement efficient technical solutions. Stepped rates for industrial customers are already planned and represent a step in the right direction. The reaction of customers and the degree of political openness to this new rate option should provide an indication of the barriers and incentives for more comprehensive pricing reform in the future.

Workshop participants also recognized that Hydro can not, by itself, make radical changes to the pricing structure. Rather, Hydro will need to work with the BCUC and other government and stakeholder organizations to reform the regulatory compact in BC. This reform would enable the development of more efficient pricing structures in BC generally and on Vancouver Island in particular.

Some of the basic requirements of an effective regulatory compact regarding energy costs and pricing are the following:

- Keep the recovery of fixed costs usage-based from the customer viewpoint, rather than as fixed charges, to capture this component of the cost of service in customer price signals.
- Decouple the recovery of fixed costs for the utility from total usage or sales, to remove the incentive to encourage customers use more energy and avoid "lost revenues."
- Recover the costs of demand-side management investments from the full rate class, to remove the disincentive to help customers use energy efficiently.
- Make utility shareholder return performance-based, to reward efficient operation.
- Use revenue limits, not price limits, to define utility performance incentives, to allow performance-based incentives to reward energy efficiency rather than increased sales.

We recommend a new regulatory compact that both addresses the lost revenue problem and sustains performance-based incentives for managers of demand-side management (DSM) programs. We do not attempt here to design all elements of a regulatory compact for BC Hydro; our resources do not allow it, and such an exercise would be presumptuous in any event prior to consultation with other stakeholders. But experience elsewhere prompts some specific observations about key issues to address in the design process.

BC Hydro should propose to retain the current formula for incorporating fixed costs in usage-based charges, but the company should also propose modest annual rate adjustments that automatically correct for unexpected fluctuations in electricity use. If traffic over the wires exceeds or falls short of estimates made at the time rates are set, and the company either under-

or over-recovers the fixed costs approved by the regulator, rates for the next year should be adjusted modestly to compensate for the under- or over-recovered revenue requirement.

The recovery of the company's fixed costs is then independent of the total volume of electricity passing over the wires, although the ratio of energy-charge revenues to demand-charge revenues is not affected. The investor-owned distribution companies in California have received approval for this regulatory treatment of their fixed distribution revenues (Sempra/SDG&E, Southern California Edison, and Pacific Gas & Electric). Undoubtedly they are motivated in part by recent evidence that electricity and gas throughput is volatile in both directions, but all have also cited the importance of aligning societal and shareholder interests in improved energy efficiency.

With a combination of usage-based charges and regular true-ups of electricity rates, distribution companies can help ensure that energy efficiency successes do not undermine their financial health. Aggressive energy efficiency improvement and load management can stabilize or reduce electricity use through encouragement from the local distribution company.

Electricity rates will then increase slightly to cover costs and restore the un-recovered fixed costs, but the *customers' electricity bill will drop* as cost-effective efficiency eliminates the need to purchase kilowatt-hours that would cost more. The utility will distribute less energy commodity with no corresponding fixed-cost-recovery penalty, while customers will benefit from avoiding the economic and environmental costs of unnecessary electricity generation. And distribution companies need not temper enthusiasm for tougher building and appliance efficiency standards with anxiety about cutbacks in the budgets that sustain reliable grids.

The most controversial feature of decoupling mechanisms is the potential need for small annual changes in rates, which are needed to prevent unexpected fluctuations in sales from affecting recovery of the utility's fixed costs. This can be made more palatable to all parties through upfront assurances about customers' maximum exposure to annual rate changes. The mechanism can be applied either to the system as a whole or to major customer classes individually.

The chart below compares the performance of the recently adopted decoupling mechanism that operated for PacifiCorp's Oregon system from 1998 to 2001.

RATE IMPACTS OF PACIFICORP'S DECOUPLING MECHANISM, 1998 - 2001

NOTE: In May of 1998, the Oregon PUC adopted a true-up mechanism similar in some ways to this proposal, as part of an Alternative Form of Regulation (AFOR) for PacifiCorp. Three annual true-ups occurred under the mechanism before it expired in July 2001 (no decision has yet been reached on its successor). Rate impacts of the true-ups were extremely modest for all classes, and went in both directions:

	1999	**2000**	**2001**
Residential:	-0.39%	+1.90%	+1.85%
Small General Service:	+0.60%	+0.22%	+0.06%
General Service:	-0.83%	-0.31%	+0.09%
Large General Service:	+0.61%	+0.33%	+0.30%
Irrigation:	+0.45%	+0.25%	-0.20%

Appendix R

Utilities traditionally have been able to increase their fixed cost recovery over time in proportion to increases in throughput, which provided additional capital to meet the needs of an expanding grid (although obviously there is no guaranteed and precise relationship between throughput trends and incremental capital needs). Since decoupling removes this opportunity, an alternative formula is needed to allow the revenue requirement to grow (or contract) between rate cases to track the changing needs of the system.

One option is to set the fixed-cost revenue requirement for each rate class on a per-customer basis, so that a growing customer base provides equivalent additions to BC Hydro's fixed-cost recovery (even as BC Hydro would share the pain of a contracting economy). An alternative is for the Utilities Commission to set the rate of increase in a rate class's fixed-cost revenue requirement between rate cases at the average rate of increase recorded for the class over the past decade, based on increases in throughput or customer population over that time. The Commission also could use an independently maintained index that tracks either general inflation (the Oregon Commission's choice) or local economic activity, with annual changes in the fixed-cost revenue requirement tied directly to changes in the index.[4]

An additional design issue involves allocation of weather-related sales risk, which will assume increasing significance as air conditioning use and loads grow. If the preference is to leave the risk with the utility, then throughput must be weather-adjusted before the true-up is calculated, and the Commission will need to approve a weather-adjustment methodology for this purpose.

Decoupling mechanisms, however well designed, are a necessary but not sufficient part of a sound DSM regulatory compact. They eliminate a strong disincentive to cost-effective DSM programs, and they remove the temptation to make DSM expensive (to use up DSM budgets without reducing sales). However, decoupling does not by itself reward success. We recommend that BC Hydro seek to combine performance-based incentives with its lost revenue recovery mechanism, under a renewed regulatory compact based on revenue, not price, regulation.

Once the utility's cost recovery is decoupled from sales, and DSM cost recovery is assured, the remaining issue regarding DSM incentives is to reward successful and efficient DSM programs. The problem with conventional performance-based ratemaking (PBR) is that its incentives are based on limiting revenue requirements per unit of sales, i.e., the average energy price. This approach is contrary to the decoupling strategy, as it rewards increased throughput.

Therefore, it is essential that the renewed regulatory compact provide incentives to limits the revenue requirement per customer, rather than per unit of sales. This is commonly referred to as *revenue-cap, rather then price-cap regulation.* Designing the details of a revenue-cap PBR regime is beyond the scope of this assignment, but we can outline some of the objectives.

The main objective is to minimize customers' bill through an optimized combination of DSM and supply investments. A revenue-limited PBR will therefore provide the utility with a higher return on any investments that meet customer needs at lower net cost. DSM programs that save

[4]See Public Utility Commission of Oregon, Order No. 98-191 (May 5, 1998) (adopting "alternative form of regulation" based on proposal by PacifiCorp, the Oregon Department of Energy, the Citizens Utility Board, the Natural Resources Defense Council, and the Northwest Energy Coalition).

energy at less cost than the marginal supply costs will therefore earn a return for utility shareholders, and this return should be higher than that on more expensive options.

Thus, this approach encourages DSM programs where they are cost-effective, which will likely increase the rate of DSM investment. It also rewards the utility for making DSM programs more cost-effective, by achieving greater savings per dollar invested, and this will eliminate the present incentive to make DSM more expensive.

Peak Demand Reduction Through Time-of-Use Rates for Residential & Commercial Customers

NEXT STEPS: Establish a TOU rate structure for residential and commercial customers on VI
Develop the technical design and requirements to implement the rate
Make a business case to justify the investment

BC Hydro currently has time-differentiated rates only for industrial customers and then only at a crude (low time-resolution) level. Establishing aggressive time-of-use (TOU) rates for residential and commercial customers and coupling the rates with the targeted load would encourage customers to curtail energy use during peak periods and possibly shift loads to non-peak periods. This will further one of the new goals being considered for Power Smart, which is to focus on capacity reduction initiatives in addition to energy initiatives.

Applying TOU rates with targeted load management could possibly reduce peak consumption by an additional 70MW on top of the 125 MW reduction in the current CPR plan, bringing the total reduction to about 200 MW in 10 years, or possibly 20 MW/year. The benefits are larger in the winter months when rates would be higher. Together with planned Power Smart measures, this one measure could eliminate almost all of the projected annual peak growth on VI, assuming that further study confirms the estimated 70 MW potential. The new rate would be applied to all new and existing customers, and would be time-of-day and season dependent. The costs of implementing this program will need to be studied in further detail.

Barriers to implementing the program include a lack of local-area & time-specific avoided costs, possible opposition to changes in rate structures, the additional cost of installing smart meters, and the currently low rates charged for electric service. To accelerate the timeframe of this project, BC Hydro could implement a small TOU rate pilot program in the near term and learn from it. Ontario already has a high temperature water heater designed with a timer. In 1997 West Kootenay implemented this approach on a voluntary basis, and also offered an interruptible rate.

Additional questions:

- Is advanced metering required? It is not necessary for water heater control, but to give customer credit from time of use you need it.
- Are the metering costs justified, especially for small customers?
- Are there additional synergies involved in advanced metering, such as labor savings from automated meter reading, that would justify the costs of metering?
- Is it worth changing out meters? Although studies have found mis-wiring in meter change-out programs, there is also synergy with automatic metering, and the utility could put in meters that track water, gas and electricity at one time.

Another idea that was proposed but not developed further: Vancouver Island-specific rates. Based on a comprehensive area- and time-specific marginal cost analysis, BC Hydro could determine the cost premium for serving Vancouver Island. This premium would be the basis for establishing a separate rate from the postage-stamp rates used for the remainder of the province.

If combined with aggressive TOU, RTP or CPP rates, an island-specific rate could send the correct price signals to customers, i.e., prices that indicate the marginal cost of supply.

A change from the existing postage-stamp rates would have to be addressed at the policy level, as one argument for the traditional rate structure is that postage-stamp rates are equitable, regardless of the cost premium of serving one area compared to another.

Because this approach would likely increase average rates on VI, it would of course be unpopular. Therefore, the establishment of island-specific rates would have to be accompanied by an increase in DSM and other customer-service initiatives on VI. Targeting DSM to Vancouver Island would be indicated in any case by marginal cost analysis showing relatively high avoided costs and thus valuable savings on VI.

E+ Rate Phase Out

NEXT STEPS: Initial business case and explanation of the project.

Currently, BC Hydro has a special "E+" rate of around 3 cents/kWh that is charged to some customers who have a secondary heating source. Instituted many years ago, this rate is no longer appropriate in today's energy climate in B.C. It sends the wrong signal to customers because it encourages energy consumption rather than conservation. Eliminating the E+ rate, then, would remove this perverse price signal while, at the same time, making rates (hopefully) more transparent.

Savings from phasing out E+ rates on VI would probably be about 80 GWh/yr, with peak savings of approximately 40MW. Fuel consumption improvements will depend on the efficiency of new versus old equipment. Environmental impact will depend on the fuel source of the alternative heating resource. The exposure to gas-price risk will likely decrease for BC Hydro as a result of reduced energy consumption, but might increase for the customers as their direct exposure to the gas market increases.

A possible approach to executing the E+ rate phase out could entail the following:

1. BC Hydro sends a letter to existing E+ customers providing them information on what it is and announcing BC Hydro's intention to phase out the rate.
2. BC Hydro first encourages customers to voluntarily stop using the rate, then offers to help them implement efficiency upgrades and/or upgrades to secondary heating systems in order to compensate for the increase in their electricity bills. BC Hydro could show these customers that it is possible to keep the same energy bill despite the higher rates through the use of efficiency measures.
3. Start charging customers 18 cents per kWh during peak times to force curtailment, as allowed by the rate (but not done to date), or increase the rate incrementally over three years or so, until it matches rates charged to non-E+ customers.
4. Gradually phase out E+ rate.

BC Hydro will need to ensure that the E+ rate phase-out is accomplished fairly. The rate currently is not fair to non-E+ customers who must pay higher rates. An important question to consider is the political dimension of E+. BC Hydro will need to be careful that existing E+ customers are not low income and/or are representative of the population of BC Hydro service territory.

Modify Distribution Extension Policy

NEXT STEPS: Develop business case, including possibly "feebates"
Coordinate with Terasen and other stakeholders such as Home Builders Associations, etc.
Determine actual cost of new supply on VI

The current distribution extension policy does not motivate residential customers to choose gas space heat over electric heat. Due to the relatively short time gas has been available on Vancouver Island (since 1991), customers tend to expect their homes and water to be heated electrically. But as natural gas becomes the electric generation source at the margin, it is less efficient to use gas-fired electricity for resistance heating than using the gas on site to heat buildings directly where possible.[5] Also, once customers experience homes heated with gas, they tend to prefer it, regarding it as more controllable and comfortable.

Furthermore, increasing the number of electrically heated homes is counter to BC Hydro's current and future goals on VI. BC Hydro has an incentive structure for residents to adopt gas heating. Modifying the extension policy to discourage electric heating while making customers more aware of gas incentives would help alleviate short- and long-term capacity supply constraints facing the island.

Currently, customers who apply for a distribution extension from BC Hydro are subject to the System Extension Test (SET). The SET compares projected revenues against the cost of extending a line. Customers with positive net margins are not charged an extension fee but instead pay a connection fee. Customers with negative net margins are considered uneconomic and are charged an extension fee equal to the net margin in addition to a connection fee. Following payment, some qualifying customers are given refunds while uneconomic customers are provided financial assistance to cover the additional payments if such need is demonstrated.

If a SET were implemented to discourage the use of electric space heating and hot water, a preliminary calculation suggests that the VI peak demand growth would drop by about 8.4 MW per year. About 4000 new homes are constructed on VI each year. This is a combination of single-family and multi-family homes. It is assumed that 75% of these homes use electric heat and hot water.[6]

The up-front cost for BC Hydro would be the design and implementation of a new SET, along with the costs of regulatory approval. These costs would be relatively low, under $1 million. Operational costs would be low as well. This idea would be a modification of the existing SET and as such should not require significant incremental costs.

Slowing peak demand growth on the VI electric system should have a positive impact on the reliability of the electric system. Gas system reliability should not be negatively impacted with

[5] On the other hand, if natural gas does not become the marginal generation source, and if BC Hydro achieves a long-term system vision of 100% renewable energy, then at least from an emissions perspective direct gas heating would appear less attractive. Under this scenario, the lowest-emission technology might be advanced heat pumps.
[6] It is also assumed that the capacity impact of electric heat is 2 kW and hot water is .8 kW. So the combined impact on VI peak is: 4000 homes x 75% x (2 kW + .8 kW) = 8,400 kW or 8.4 MW on VI Peak.

increased load growth, especially if current load growth is below that for which Terasen VI has planned. There is little to no risk to BC Hydro. However, consumers may be exposed to higher and more volatile natural gas prices because they will be purchasing the gas service directly, rather than paying BC Hydro a regulated electricity rate.

Additional questions:

- Might BC Hydro provide rebates for very efficient building envelopes (Terasen benefit)? Should customers with super efficient electric homes be allowed to keep the electric heat?

Another idea that was proposed but not developed further: "Feebates." Amory Lovins and others suggested a "feebate" approach, which might be explored as part of the business case development. Such a scheme could include a fee to inefficient homes, which would then be used to provide rebates to more efficient homes. A coordinated feebate with Terasen might make the most sense. For example, the fee could be high enough that the consumer switches to gas space and water heat (Terasen benefit) and installs very efficient lights and appliances (BC Hydro benefit). Although BC Hydro would lose revenues, due to the high marginal cost of serving such loads, it would probably result in improved margins, especially if electricity tariffs are modified to decouple earnings from sales.

Demand Side Management

BC Hydro's potential capacity imbalance on Vancouver Island results from continual load growth in the residential and commercial sectors in the southern part of the island. While the rather uniform, high load-factor industrial load is declining, this decrease is more than overcome by growth in the building sectors. As a result, demand on VI is not only increasing, but it is imposing sharper peak loads (lower load factor) on the BC Hydro system during cold winter weather. Total peak demand on VI is now somewhat more than 2000 MW and average demand is about 1200 MW, with total annual consumption of about 10,000 GWh.

Research and analysis by RMI and others, as well as the successful track record of Power Smart and other utility program, demonstrate that improving end-use energy efficiency can save energy at less cost than producing energy from new sources. Similarly, it is often cheaper to manage peak loads at the end use than to install additional production capacity to meet peak demand.

The strategy of demand-side management (DSM) combines the following four strategies for meeting customers' demand for energy services at least cost:

1. Reduce energy demand through *end-use efficiency, using improved technology* to serve new and existing loads.
2. Shift or reduce peak demand using *load management and demand response* technologies, including communication of the occurrence of peak loads to customers.
3. Fuel shifting from *electricity to natural gas or biomass*, for loads such as hot water and space heating, which can be met more efficiently by non-electric energy carriers.
4. Price signals that indicate the *full marginal cost of supplying power* at different times of the day and year, to influence the amount and timing of customer usage.

Strategy 4, improved price signals based on BC Hydro's marginal costs, is discussed in detail under Marginal Costs and Price Signals. Some of the pricing strategies are designed specifically to create or strengthen incentives to shift away from electric hot water and space heating. Thus, fuel shifting (strategy 3) is also addressed under Marginal Costs and Price Signals.

At the workshop, the group reported in detail on proposed ideas mostly related to peak load management (strategy 2), which is discussed in detail below:

Power Smart for peak reduction
Smart water heaters
Industrial curtailment

Energy Efficiency

Although improving energy efficiency is the core of any DSM strategy, including that of BC Hydro's award-winning Power Smart program, efficiency measures were not singled out for discussion at the workshop as much as peak load management strategies. This is because Power Smart has many successful on-going efficiency programs, which are now being expanded, and efficiency was therefore not treated as a new option at the workshop, which focused on new and

longer-term options. Nevertheless, the importance of maintaining and extending BC Hydro's energy efficiency efforts on Vancouver Island should be emphasized.

Power Smart has recently produced a comprehensive Conservation Potential Review (CPR). The CPR identifies achievable energy savings on VI of 840–1270 GWh/year by 2012. Capacity savings resulting from efficiency programs would be 105–165 MW by 2012. These savings amount to approximately one-half to two-thirds of the projected demand growth during the same period. I.e., only one-third to one-half of VI's net load growth needs to be met by new supply-side resources, if the achievable efficiency potential identified in the CPR is captured.

Although these levels of savings would represent ambitious targets, the CPR may be somewhat conservative. Additional savings may be possible from actions not included in the Conservation Potential Review, such as programs to encourage customers to use gas space and water heat rather than electric. This strategy can reduce the need for electricity supply capacity to meet peak loads, as well as fuel demand and emissions at the margin.

Some of the key energy efficiency initiatives that were identified during the workshop for further development include the following:

- Efficiency measures for loads that specifically coincide with winter peak demand, e.g., Light Emitting Diode (LED) holiday lighting
- Minimum performance standards for buildings, focusing on overall system performance to encourage green, whole-system design and possibly building on the BC Building Code
- Minimum performance standards for appliances and other end-use equipment
- Overall market transformation strategy for buildings and end-use equipment
- Integration of efficiency with load management, fuel switching and rate design to "stretch" the Power Smart targets to achieve and expand the overall load reduction potential

Of course, there are barriers to further market penetration of energy-efficient technologies, including lack of consumer awareness, misaligned incentives, and varying or inadequate program funding. These barriers would need to be identified and overcome to reach or expand the achievable efficiency potential.

One national initiative that could help support the implementation of energy efficient technologies is the recently announced Climate Action Plan, is which relevant funding commitments include the following:

- $73.4 million in incentives to encourage energy-efficiency retrofits in existing houses
- $56.6 million in incentives to encourage efficiency retrofits in commercial buildings
- $47.2 million to encourage new commercial buildings to exceed National Energy Codes
- $25 million in incentives to encourage use of renewable energy in buildings

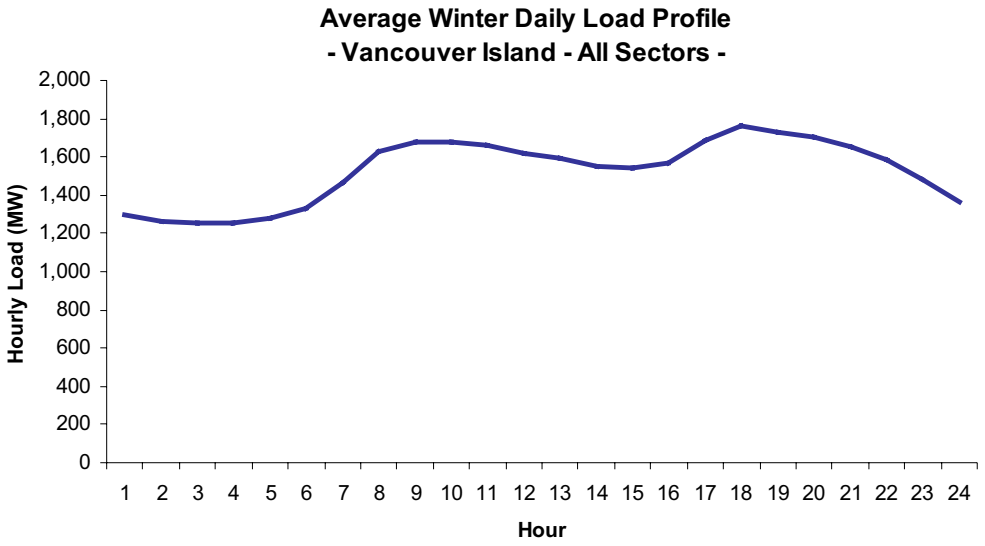
Peak Load Management

Most measures considered in the Conservation Potential Review address savings in energy (GWh), which is the primary planning parameter for a mostly hydro-based, energy-limited

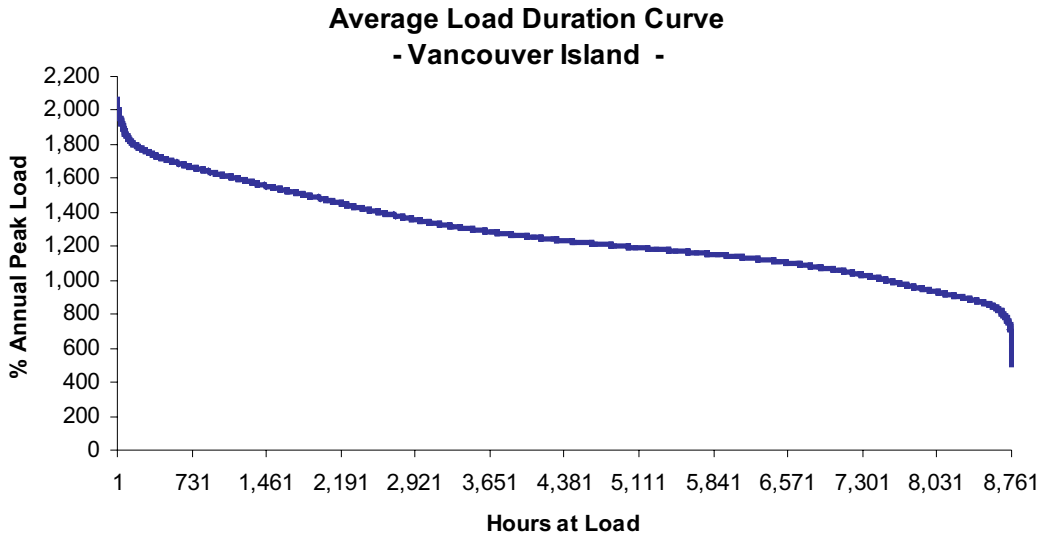
system. However, because of capacity constraints on VI, its system is limited by its capacity to meet peak demand, rather than strictly energy. In the future, the BC Hydro system as a whole will also become more capacity-limited. In a capacity-limited system such as on VI, savings in peak demand (MW) may be valuable and important to ensure reliable service. Thus, demand savings from peak load management, direct load control, and demand response programs would be a major addition to the demand-side resource potential identified for VI in the CPR.

The Load Shaping Challenge

BC Hydro faces a uniquely challenging problem: shaping peak daily loads on Vancouver Island. The pervasive penetration of residential baseboard electric heat and hot water cause a dual peak in the morning from 7:00-9:00 and in the evening from 17:00-20:00. The difference between the morning and evening peak is approximately 100 MW on an average winter day and about 150 MW on the peak day. The afternoon trough is approximately 200-250 MW below the evening peak on an average winter day and about 300 MW on the peak day.



Vancouver Island's load duration curve suggests that approximately 200 MW of peak load management could clip the system peak and improve load factor. The challenge is to install load management measures that can shift both the morning and evening peak cost effectively.



Peak load management should be viewed by BC Hydro as a complement, not a substitute for Power Smart's focus on reducing energy consumption. Efficiency will still be the most cost effective method for managing overall energy demand on Vancouver Island. Moreover, Power Smart efficiency programs can augment load management efforts on VI to the extent they reduce energy use in end-uses that coincide with the peak demand periods.

Benefits of Creating Demand Response

Demand response is a necessary prerequisite to fully functioning electricity systems and an important tool for maintaining reliability at reasonable cost. Demand response on Vancouver Island can provide the critical reserve needed to maintain reliability in case of a first contingency failure of a power supply resource. Control technologies now allow instantaneous control of end users loads as part of the utility's control system. Together with smart meters, demand response technologies impact can now be measured and verified in real time (15 minute intervals).

Demand response is also a critical tool for financial risk management in the more volatile, deregulated power markets. Customers must be sent timely price signals and have an automated capability to respond to prices for the power markets to be "tamed" and price volatility reduced. Once this capability has been created, demand response becomes an important risk management tool for load serving entities, in that it enables them to manage their spot purchases and fundamentally reduce the spot price by reducing their demand.

Residential load management can provide seven different types of value to load serving entities, as shown in the table below.

Value Drivers	Details
Lower Supply Costs – Reduction in Capacity and Reserve Margin Requirements	▸ Load management reduces the utility's system peak thus reducing capacity and reserve margin requirements
Lower Supply Cost: Energy	▸ The cost of supply will be reduced because: – Load management shifts load to lower cost energy time periods, lowering costs to serve directly
Risk Management	▸ Two types of risk management considered: – Energy hedging value: value of reducing exposure to peak costs, based on expected volatility. This allows more sophisticated supply portfolio management and trading interactions with the market – Power market can be "tamed" if 5% of total system load is shifted to demand response - dispatching GoodWatts during peak could both reduce the LSE's spot exposure and reduce the supply price to the remaining exposed load
Ancillary Services Value	▸ Load management can provide 10 - minute non-spinning reserve, and potentially spinning reserve as well
MDCC Value	▸ Utilities could avoid Marginal Distribution Capacity Costs by deploying "negawatts" intensively vs. distribution constraints
Meter Reading /Service Value	▸ Eliminate monthly manual meter reading by meter readers as well as special manual reads and rereads by using daily reads provided by the system. Total benefit includes reduction in all direct meter reading expense, supervisory expense, and materials.Additional value includes reduced service visits, uncollectibles and related expenditures
Option Value	▸ Because of potential for staged investment, Load management can be used as an option to manage the risk from future power market price spikes

Advances in Residential Load Management

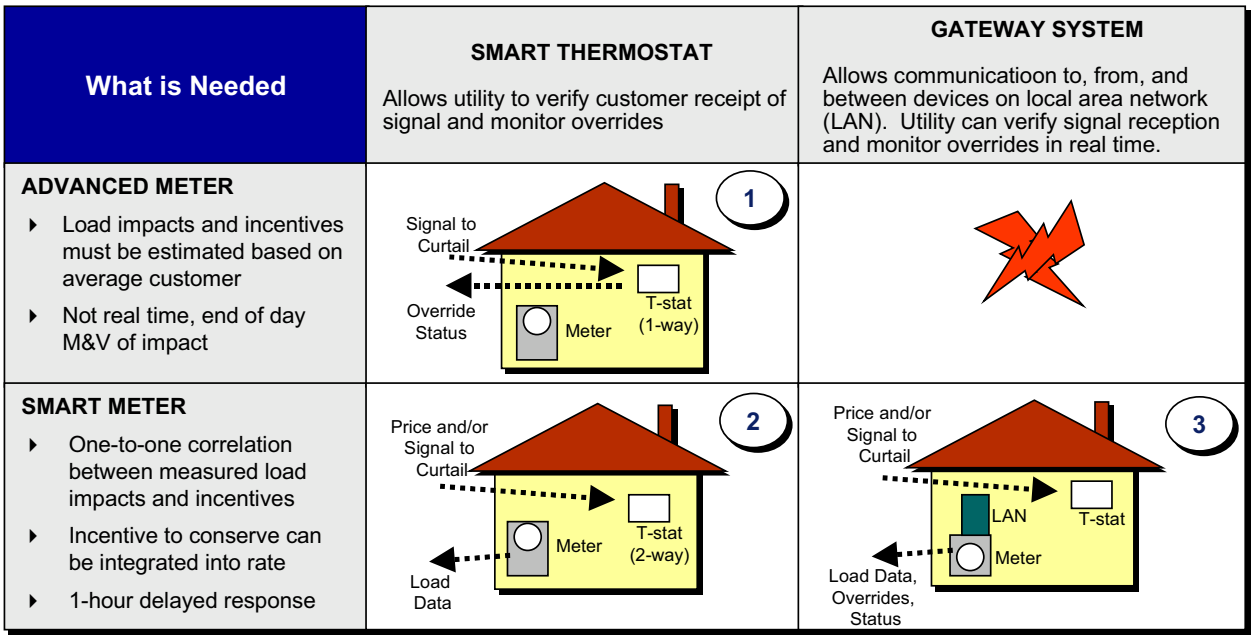
Residential load management has been used effectively to control air conditioning, heating, and hot water loads by several US and Canadian utilities. The prior generation of residential load control was primarily based on under-frequency relays to cut off power to the end use device.

This generation of technology suffered from several problems that limited its overall penetration:

1. There was no feedback loop to allow the customer to maintain the desired climate range in the home. Thus the customer was inconvenienced. The utility had no feedback on device status.
2. Real time measurement and verification systems were lacking, hence the utility would have to rely on statistical techniques to determine after the fact how much peak load was actually reduced.
3. Each device was controlled with a separate interruption system within a closed architecture, increasing the capital cost

The next generation of load management devices addresses these previous flaws. Typically, they are coupled with smart meters to allow real time measurement and verification and provide revenue quality data on customer responses in 15-minute intervals. This current generation of devices has two-way communication systems, which allow the utility to send signals, and measure the actual response, in real time, as well as maintain the climate settings within the customer's home to within the tolerable set points. The most advanced load management technologies communicate with multiple devices in the customers home, and use the same information and control protocols as the next generation of controllable appliances (e.g. dishwashers, refrigerators, etc.).

However, the benefits of load management depend on the system configuration. As shown in the figure below, the earlier generations of load management devices cannot capture all the potential values in the system.



Lessons Learned in Industrial Load Management

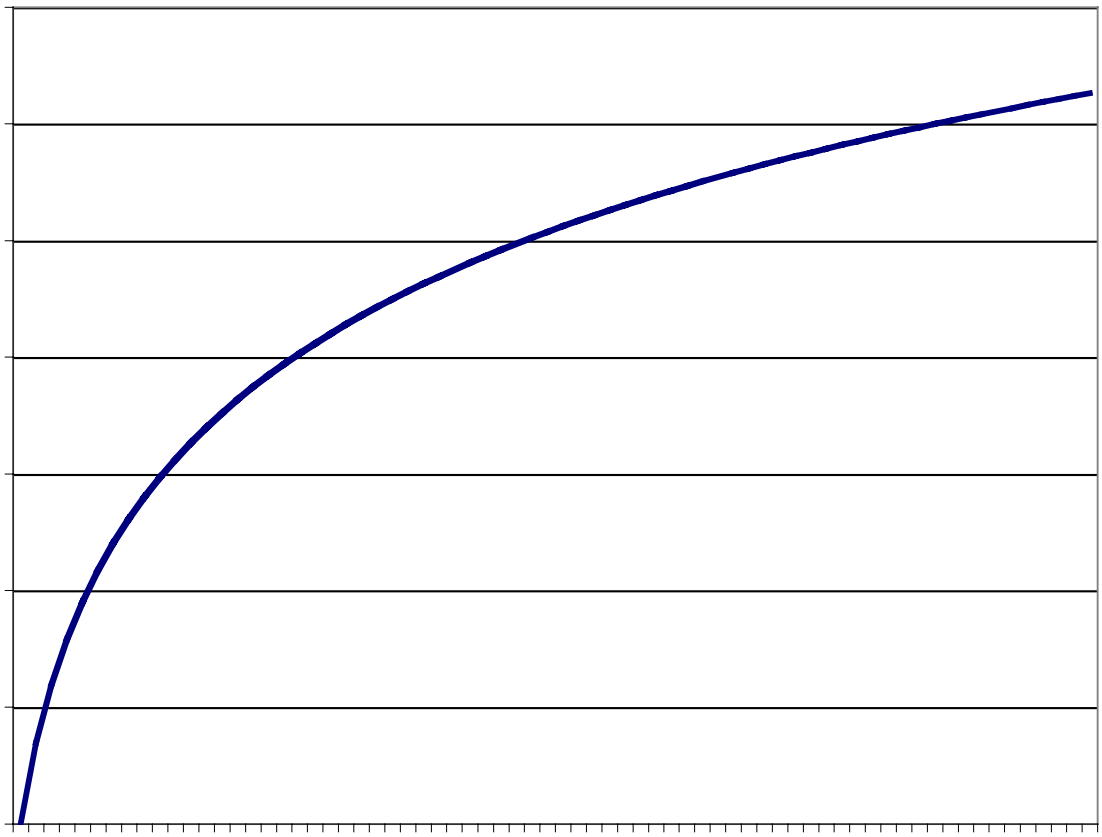
The recent power crises in the United States have provided important intelligence about how industrial consumers respond to load management initiatives. First, industrial consumers have greater price elasticity and manufacturing flexibility than most utilities recognized. What has been lacking was the economic price signals to create financial incentives for customers to shift loads. In this regard, Georgia Power's experiment with critical peak pricing demonstrated that the load shifted by industrial customers depends on the price signal (as shown below).

Second, the pricing signals must be sharp, not blunt, instruments. Hourly or real-time pricing signals generate a significant price response, whereas blunt time-of-use or peak/off peak prices do not. Georgia Power obtained 5,000 MW of load reduction from 1,700 large commercial and industrial customers using real-time pricing. Duke Power obtained 1,000 MW of load reduction from 100 large industrial customers using hourly pricing.

Third, some industrial customers fundamentally change their manufacturing processes (or shift locations entirely) in response to long-run price signals. This was evident in the response to the oil shocks of the 1970s and 1980s. It is becoming evident in response to the repeated power crises of the last several years. Large customers want protection from reliability-related business interruptions. They are simultaneously conserving energy and investing in physical insurance, through either distributed generation and/or UPS systems. Vancouver Island's industrial customers have paid artificially low power prices (compared to marginal costs) for years. Thus,

BC Hydro should expect some degree of structural change when the prices signals are rationalized.

Industrial Load Reduction in Response to Price Signals at Georgia Power



Source: Christensen Associates

Implications to BC Hydro

BC Hydro will need approximately 200 MW load management to shape its load, thereby averting reliability and cost problems. In order to get this magnitude of load management on Vancouver Island, BC Hydro will need to directly address the residential sector. Fortunately, the latest generation of load management technology makes such an endeavor viable. Given the urgency of the capacity situation, BC Hydro should be mobilizing to do an initial pilot of these technologies this winter, in order to have contingency capacity available in 2006.

Power Smart for Peak Reduction

NEXT STEPS: Firm up MW savings estimate
Identify specific opportunities and value them
Develop business case

Power Smart has historically focused its efforts on reducing annual energy consumption. This is typically the primary planning parameter for a mostly hydro-based, energy-limited system. However, because of the capacity constraints on VI, its system is limited by its capacity to meet peak demand, rather than strictly energy. In the future, the BC Hydro system as a whole will also become more capacity-limited. In a capacity-limited system such as on VI, savings in peak demand (MW) are especially valuable to ensure reliable service.

This idea would include specific new efforts such as the E+ rate phase out on VI, introduction of time-of-use rates, smart water heaters, and other ideas presented in this workshop. The current Power Smart Conservation Potential Report calls for 700 GWh and 125 MW of peak reduction over 10 years, at an average utility cost of $25/MWh. It should be possible to further reduce peak demand by an additional 75 MW over the same 10 years (see the idea description on time-of-use rates), for a total of 200 MW. Also, another 100 MW to 150 MW of load from water heaters could be shifted to off-peak periods (see next idea description), for a total reduction of 300-350 MW. Fuel savings are estimated to be 7.3 GJ gas/MWh. Environmental improvements would be located upstream close to generation, and is estimated to be 0.37 tonnes CO_2/MWh from reduced plant operation.[7]

Possible market risks include declining gas price and/or increasing cost of trade labor on VI. Possible barriers to achieving the additional peak reduction may be customer resistance, for example to the water heater load control, customer awareness of efficiency benefits, the accessibility of efficient and load management products, and the affordability of the products. BC Hydro has the ability to design programs such that these barriers are overcome. BC Hydro would need to determine the value of capacity on VI before implementing the peak reduction plan.

[7] Assuming the marginal generation source is a gas-fired combined-cycle plant with a heat rate of 7.3 GJ/MWh. Since the carbon content of natural gas is 51 kg-CO_2/GJ, the CO_2 emission intensity of saved electricity at the margin is 370 kgCO_2/MWh, or 0.37 metric tonnes CO_2/MWh. If the marginal resource is less efficient, the emission savings would be greater. If some non-fossil generation is also at the margin, the emission savings would be less.

Smart Water Heaters

NEXT STEPS: Field Study

Vancouver Island's load profile includes a demand peak in the morning as people head off to work and another peak in the evening. The evening peak is mostly due to lighting and cooking, plus heating in the winter. The idea is to install time-control shut-off switches, which will delay water heating until midday, after the morning peak that occurs during the 8am to 11am period.

The possible gross benefit to BC Hydro of this idea is $150 million. The amount assumes that 150MW can be shifted valued at $1000/kW. Each household might save $450, and BC Hydro could give each a $200 installation incentive plus $100 to help cover the upfront cost of the hardware. Assuming that water heaters average 4.5 kW, and that one-third are in use during any given peak period, this cost corresponds to $200/kW saved. To improve the reliability of peak demand savings, BC Hydro could charge $20 in liquidated damages for each customer override incidence.

The time frame for the project would be six to ten years, because electric water heaters generally last about ten years, and the controls could be built into the new heaters. In-line timers on the wires into the heater are an available technology. It is generally easier to retrofit new units at the shop than in customers' houses. To accelerate the learning process, BC Hydro could start a pilot program immediately with perhaps 100 households. BC Hydro would probably need to perform a one -year study to capture the total seasonal variability. In 1997 West Kootenay power implemented such a program. BC Hydro may be able to learn from their experience.

This idea would complement two other BC Hydro ideas: Developing a time-of -use rate strategy for residential and commercial sectors and controlling peak demand growth on VI. This could be an alternative to fuel switching of water heaters on VI.

Possible barriers to the successful implementation of this program include:

- Opposition to changes,
- Cost of meters
- Low electricity rates
- Need to establish time-of-use rate structure
- Need for technical infrastructure
- Need for a business plan

Additional questions:

- Is advanced metering required to establish time of use rates? GVRD is putting in new water meters – perhaps BC Hydro should piggyback this with the installation of inline water heater timers and time-of-use meter technology.

Temporary Curtailment of Pulp and Paper Mills

NEXT STEPS: Determine how many MW will be needed
Negotiate price w/ mills
Apply first contingency criterion based on transmission line failure

This initiative would free up capacity on VI during critical periods by encouraging the large pulp and paper plants at Crofton, Port Alberni and Campbell River to temporarily curtail their load at times (e.g. winter) of high demand for 2 weeks or more. This idea would include paying the mills for approximately two weeks paper storage on site to avoid revenue loss during the load curtailments. To further reduce costs, the mills could plan their annual maintenance shutdowns to correspond with one or more of the load curtailment periods, provided that the mills prepare to do the maintenance on relatively short notice when the shut down occurs. The mill owner might be persuaded that the inventory could be sold to the commodity market when prices are high.

Load curtailment would result in several benefits. It would bolster service reliability to other customers on the island. Also, natural gas consumption would be reduced during pulp and paper load curtailment. Efficiency improvements and distributed generation both on site and elsewhere in the BC Hydro system would reduce the amount that would need to be curtailed. Also, time-of-use rates could make demand more price-responsive in the long term.

BC Hydro could pay a mill to shut down parts of its plant on short notice. Also, BC Hydro could offer incentives to keep extra paper products in storage at a cost that would cover the mill's capital costs, which are approximately $20/kW. Given that the curtailment potential is probably around 300MW, the total cost of this idea would be about $6 million. Gas savings from this effort might amount to 10,000 GJ/day (out of a total 20,000GJ/day demand). Also, the mills could store wood waste for use in additional power generation during the winter periods. Because such a program could include sending employees home for unplanned vacation during curtailment., operational costs could be substantial and would need to be investigated further.

Of course, this idea would need the support of mills. That support is mostly likely if the mills are thoroughly involved in further development of the idea. Their early involvement will ensure that the idea works well for them. Also, it will significantly increase the potential that the mills feel that the idea is as much theirs as BC Hydro's. BC Hydro would need to determine how often curtailment would be triggered. Power Smart would then need to talk to the mill owner(s) and negotiate the 300MW curtailment.

Additional questions:

- This option might not offer the same reliability as a 300MW generator connected throughout the year. There could be unforeseen circumstances and multiple contingencies.
- Previous studies found it was worth about 1/5 of a generating system of the same size, though this assumes only a one-time occurrence per year. A critical component of this idea is the appropriate decision about when the particular time for curtailment has arrived. Once stored inventory has been fully depleted, another curtailment can't be repeated for the rest of the season. The capacity benefit of this idea is derated 80% because it does not meet the full contingency criteria.

Generation and Distributed Resources

BC Hydro's primary strategy for resolving the urgent need to increase its power delivery capacity to VI is the VIGP and GSX proposals. Assuming that these projects are completed as planned, VI might need additional generation capacity in the future to serve load growth or replace retired assets. On the other hand, if VIGP and GSX are not completed, BC Hydro will need contingency plans that include new generation. While energy efficiency and load management can mitigate future load growth and provide flexibility in operating the island's power supply system, these resources alone cannot replace the firm capacity now provided by the aging transmission infrastructure. Supply side solutions are also needed.

However, the VIGP and GSX proposals, and some of the proposed alternatives to these projects, represent only one of three basic strategies that BC Hydro can use to address the potential VI capacity shortfall through generation and distributed resources. With the ending of BC Hydro's historical monopoly over supply-side resource procurement, any of these strategies will have to be implemented by the private sector on a competitive tender basis.

The full range of options includes the following strategies:

1. Increase *on-island generation capacity*, such as VIGP, and fuel supply, such as GSX.
2. Increase *Mainland generation capacity*, together with transmission capacity to Vancouver Island and possibly on the Mainland.
3. Increase on-island *distributed resources*, such as cogeneration, energy storage and certain renewable sources.

The VIGP and GSX proposals (strategy 1) are well advanced in the regulatory approval process, and BC Hydro management is committed to completing these projects once they have been fully approved. Thus, VIGP/GSX was not treated as a new option at the workshop, which focused on longer-term options and to some degrees on alternatives in case VIGP/GSX is not approved. At the workshop, the group reported in detail on proposed ideas related to distributed resources (strategy 3), discussed below:

Energy storage on VI
Cogeneration using natural gas or biomass
Tidal, wave or wind power on VI

Note that the implementation of strategy 2, increased *generation on the mainland*, depends on the development of additional transmission capacity between VI and the Mainland as well as on relieving transmission constraints on the Mainland. These options are discussed under Transmission and Distribution Grid Solutions. The Mainland generation option that was most discussed in the workshop is *re-powering the Burrard steam turbine plant with CCGT technology* to increase its capacity and efficiency, while making use of the existing site, switchyard, etc.[8]

[8] Possible shepherd for continued discussion: Glen Smyrl

Distributed Resources

The full benefits of distributed generation should be more apparent on Vancouver Island, due to its comparative geographic isolation, than on most other areas of BC Hydro's system. Most utilities value distributed generation based on standard economic calculations of system-wide capacity and energy value, adjusted for lower line losses. RMI's perspective on distributed generation is that in addition to these benefits the most valuable distributed benefits can flow from three primary sources:

- Financial economics, including the lower risk of smaller modules with shorter lead times, portability, power market hedging (from demand response), and, if renewable sources are used, the elimination of fuel price volatility
- Electrical engineering benefits, including lower grid costs and losses, better fault management, voltage and reactive power support, and lower transmission and distribution operations & maintenance
- Reliability benefits if the distributed source can run in an "island mode," including avoided business interruption costs, lower probability of grid failure, and faster recovery time for the grid in the event of grid failure

Collectively, these additional benefits can increase the actual economic value of distributed generation from 3-5 fold. In total, we have found over 207 distinct benefits that are attributable to distributed resources.[9] Therefore, RMI's view is that it is imperative that BC Hydro correctly value the distributed resources when comparing them to the alternatives, particularly reliance on transmission of mainland generation resources.

Getting The Most From Gas

Due to its geographic isolation, Vancouver Island is fuel limited. Thus, an underlying issue for BC Hydro is to define the energy strategy that extracts the greatest value for the customers from the existing and future gas deliverability. Given the high heat loads on Vancouver Island, the question is whether direct heating from gas appliances would be more energy efficient and economically efficient than generating electricity, transmitting it to the end user, and then converting electricity to heat. The system efficiency of the direct gas energy pathway is 85-97%, whereas the system efficiency of the electric heating pathway is only about 50%, assuming CCGT generation (or about 35% with simple-cycle generation). Therefore, the energy efficiency of the direct gas-to-heat pathway is almost twice that of the most efficient electric pathway at the margin.[10]

The same issue applies to distributed generation. Will BC Hydro get the most value from using the available gas to power a combined-cycle gas turbine (CCGT) unit, or would BC Hydro be better off with a series of smaller cogeneration or combined heat and power (CHP) units. The

[9] Described in an *Economist* Book of the Year: *Small Is Profitable* (www.smallisprofitable.org).
[10] The average efficiency of the electric heating pathway could be improved by using a heat pump at the end use. However, at peak demand during cold winter weather, a conventional air source heat pump would switch to resistance heating mode to prevent the evaporator coil from freezing, resulting in at least as high peak demand as resistance heating.

total thermal and electric efficiency of CCGT is rarely more the 50%, whereas combined heat and power units have a 60-80% thermal efficiency, depending of the thermal load factor.

The difference in capital cost and fixed O&M between a combined cycle unit and cogeneration can be recovered from the fuel cost savings (when gas costs are greater than $ 4.5/GJ), before even counting the distributed benefits. The reason that cogeneration does not have greater penetration on BC Hydro's system is due more to pricing (cheap regulated electricity vs. expensive deregulated gas) than the underlying economics of the resource choices.

Utilizing the Potential Primary Energy on Vancouver Island

With transmission capacity deteriorating, and gas resources limited by gas transmission capacity, then utilizing the potential primary energy on Vancouver Island is necessary. *Vancouver Island has hydropower, biomass, wind, tidal and wave energy resources*. Much of these resources are in the northern part of the island. Improvements to the transmission system are likely required to transmit electricity from the northern to southeast part of the Island. Therefore, the renewable resource costs must also include the delivery costs to access the load centers in the southern part of the island. Traditionally, the incremental cost of transmission capacity to serve such sources would be assigned to each new source individually, making it prohibitively expensive. However, if the *transmission extension policy can be modified* in such a way that these costs are shared among multiple sources and spread over time, on-island renewable power would be more viable.

Also, renewable resources tend to be intermittent and need to be "firmed" either by using hybrid plants with fossil fuel backup or combining them in a generation portfolio. *A firm portfolio can be assembled from non-firm resources* if their production profiles balance each other.

For example, pumped-storage hydropower has proven to be a cost effective resource for firming renewable resources, and pumped hydro sites exist on Vancouver Island. The technical potential is large enough that this resource portfolio should be given serious consideration by BC Hydro. In order to be licensed on Vancouver Island, pumped storage would probably need to be closed loop, where the upper and lower reservoirs are constructed as part of the plant and water is only released to, and taken from, the environment during start up and maintenance.

Because these remote, intermittent renewable resources are not dispatchable or load following, and because they tend to increase rather than decrease transmission needs, they do not provide many of the distributed benefits described above. Indeed, these sources are more like central resources than distributed resources. However, do provide the economic (fuel price hedging) and environmental (emission reducing) benefits by virtue of being independent of fossil fuel.

Implications to Vancouver Island and BC Hydro

The implications to BC Hydro are clear. There is untapped potential of distributed and renewable resources on Vancouver Island than could be forged into a viable resource portfolio that would deliver firm capacity and energy at moderate cost. Such a portfolio could complement the VIGP/GSX project, or provide part of a contingency plan in case it is not completed.

The underlying economics of distributed generation (particularly cogeneration) could make it the least-cost option when the full avoided cost, risk management and reliability benefits are included. Regarding renewable sources, present needs are to pilot promising new technologies, such as tidal energy, to consider modifying the transmission extension policy regarding new generation sources, and to begin creating "firmed" portfolios of renewable projects.

Appendix R

Energy Storage for VI

NEXT STEPS: Identify costs for each storage technology
Identify existing storage capability
Identify the value of storage
Possibly contract out for the research
Integration with Resource Plan
Look at integration with H_2

Vancouver Island currently has little energy storage capacity, even with several (seven) existing hydroelectric dams. Hydroelectric storage potential has not been explored in detail; it appears that the potential is fairly small, especially if existing dam heights do not change. However, other energy storage technologies are available, including: pumped storage hydro, flywheels, batteries, fuel cells, compressed gas, direct hydrogen storage, and thermal energy storage combined with heat recovery chillers for buildings that could be made available to the island.

The benefits of having more energy storage capacity include support of load shifting and peak shaving options that Power Smart may pursue in their new effort to focus on controlling peak demand growth on VI. Energy storage would allow facilities that defer consumption during peak periods to use their equipment or appliances during off peak periods. Another benefit is to increase system reliability by firming up intermittent renewable generation sources that may be installed on the island in the future, such as wind, biomass, wave, tidal, and solar. Energy storage technologies can also provide ancillary services such as voltage support and spinning reserve. Finally, storage, especially in the form of fuel cells and hydrogen, would complement the idea of using barges, ferries, and other floating vessels as mobile generation sources for VI and the mainland.

BC Hydro currently has little in-house expertise on energy storage technologies other than pumped storage hydro. Basic research is needed to learn more about specific energy storage technologies, their technical and economic performance, available capacities, storage life, equipment life, and environmental impacts. BC Hydro will need to explore in more detail existing energy storage capabilities on VI. One idea mentioned was to increase the dam height of the existing reservoir on the Jordan River. Nexen Chemical's sodium chlorate plant near Nanaimo on VI produces hydrogen as its by-product. It would be a cheap source of hydrogen for setting up an initial pilot program on hydrogen storage for the island.[11]

Initial barriers identified include the possible high cost of energy storage at today's prices. Perhaps a subsidy program would need to be created that would allow benefit/cost sharing between BC Hydro, IPPs, and other third party partners.

[11] The recently announced Climate Action Plan includes funding commitments of $80 million for fuel cells and other technologies relevant to an emerging hydrogen economy.

Cogeneration

NEXT STEPS: Investigate rate and price structures.
If necessary, find additional gas required for cogeneration on Vancouver Island.
Initiate DSM – efficiency and / or load shifting – for natural gas.
Increase compression on existing pipeline.

Cogeneration is the simultaneous production of electricity and steam heat. This idea proposes to add electricity generation capability to existing facilities that have significant thermal loads and already purchase natural gas for heating. Thermal heat loads make cogeneration highly efficient, typically 80% thermal efficiency, with incremental heat rates between 4,500 and 5,000 Btu/kWh. Potential markets include commercial buildings, industry, hospitals, universities, and other institutional buildings and campuses.

Cogeneration on VI might add 300 MW of peak capacity from large-scale industrial installations and probably 20 MW total in small-scale installations, and annual generation of 2,000 GWh. Fuel requirements will be site specific. Cogeneration can contribute to system reliability, especially if the generation capacity is directly linked to the load (the two can move up and down together). However, there is a risk that cogeneration owners may shut down in the event of decreased market activity (e.g. decreased demand for pulp). This reliability concern would need to be addressed contractually.

The primary barrier to realizing Vancouver Island's cogeneration potential is the current pricing structure for power. Under the current pricing structure, the rates charged to small and medium industrial, commercial and institutional customers are insufficient to justify private sector investment in cogeneration ($31/MWh plus $6.4/kW-month demand charge). The prices offered by BC Hydro to purchase electricity from IPPs, particularly on-peak, may be too low to encourage new cogeneration. An adequate price offer would take into account both location and time of generation.

Cogenerators are exposed to fuel price risk in their power contracts with BC Hydro. The allocation of gas price risk may also be asymmetric. When BC Hydro uses natural gas to generate electricity, the gas price risk is passed on to consumers. In the case of cogeneration, the industrial partner or IPP takes on the gas price risk. To encourage cogeneration, BC Hydro could consider entering into tolling agreements with small IPPs, and passing the fuel price risk through to rates. If fuel price risk is passed through, it is still likely that a small cogeneration plant on the gas distribution system will pay more for gas than a large CCGT plant on the high-pressure gas system. Thus the appropriate economic analysis is whether the benefits from improved thermal efficiency offset the higher gas, capital and O&M costs.

If additional gas transmission to the Island is not built, another possible barrier to cogeneration is availability of gas on Vancouver Island. Therefore, it may be necessary to find additional gas for cogeneration on Vancouver Island via a combination of DSM – efficiency and / or load shifting – for natural gas as well as increasing compression to allow greater throughput in the existing pipeline.

Barriers may also exist in the organizations that could potentially invest in cogeneration. Another possible barrier is disinterest among potential institutional investors who may regard cogeneration as outside their core business, who may not understand cogeneration, or who lack planning tools with which they might understand, for example, payback periods. The distinction that BC Hydro draws between self-generation and cogeneration was also identified as a potential barrier.

Another idea that was proposed but not developed further: Biomass generation or cogeneration on VI.[12] An existing proposal is the Gold River biomass project at the Bowater mill site, which would have a capacity of 30 MW to start (using existing boilers) and the potential for up to 250 MW. The Gold River proposal calls for the import of wood waste materials from all along the West Coast. Although not explored further in the workshop, biomass could also fuel distributed cogeneration projects at industrial and commercial customers sites on VI.

[12] Possible shepherd for further discussion: Steve Watson

Tidal, Wave, or Wind Power on VI

NEXT STEPS: Resume discussions with private sector proponents to develop a Federal/Provincial/BC Hydro team to scope out funding for demonstration project.

Tidal power is an enormous resource around Vancouver Island, which has some of the best sites worldwide. Most of BC's tidal resource is located near the Queen Charlotte Islands and around V.I. Based on the study performed by Triton Consultants the total resource on VI exceeds 2 GW. The study assumed an average 3.5 m/s tide velocity and estimated a cost of 11c/kWh. However, Amory Lovins suggested that if the top seven sites were developed (2/3 of the ~2GW potential) the cost would be closer to 5 c/kWh (power increases by the cube of tidal velocity). The tides at some top sites, however, are so strong that existing turbine technology would be unable to withstand the forces generated. This is a technical barrier that can eventually be overcome.

As tides are a function of the orbits of the sun and the moon, they are extremely regular and can be predicted centuries into the future with great precision. Though they vary significantly through any given day, if several sites are developed, power can be phased into the electricity grid, taking advantage of energy peaking at different times at different sites. As a result, tidal current turbines can generate consistent supply. Based on tidal modeling studies, environmental and physical impacts of tidal current power generation are expected to be small.

Tidal power is a promising technology. There are four to five concepts being developed currently; one to three models are being commercialized in the U.K. and elsewhere. It is considered cost-effective by some U.K. authorities. Technical reliability can be high if well engineered for the marine environment. Tens of kW are generated per linear meter of tide and the resource is steady and predictable. For technologies that rely on tidal currents, generation is based on velocity rather than head, and the technology is similar to run-of-river turbines. The technology is clean and would therefore displace the emissions of the fossil-fired generation it displaces.

An initial estimate of energy generation is around 3.5 TWh at a 20% capacity factor. This is probably a conservative estimate given that total energy potential is estimated at 26 TWh/yr at a site with greater than 2 m/s average velocity. BC Hydro could test a pilot plant. A first unit could cost as much as $200/W. However, Verdant power (www.verdantpower.com) has a 10MW test unit currently being developed in the East River off Manhattan in New York City that is similar to the technology that BC Hydro might construct. Since the enormous tidal resource is located north of VI's energy consuming population, transmission upgrades and possibly new investments will likely be needed. Also, navigational and other marine issues (e.g. marine mammal and fish safety) would have to be resolved.

In addition to supplying electricity to consumers, tidal power would complement hydrogen generation. Hydrogen would serve as an energy storage medium for other renewable resources on the island. Because the resource is so large, BC could potentially develop an entire industry

around it, becoming the world leader in tidal power technology,[13] as Denmark has done with wind power.

Wave power is related to tidal power and also is a large resource around Vancouver Island. Wave power is predictable a few days ahead, although energy performance is very site dependent. The technology is expected to be cost effective in the kind of wave regime that exists off VI.

As in the case of tidal power, BC could develop an entire industry around wave power technology, integrating the technology with hydrogen and other renewable technologies. Bruce Sampson will resume discussions with proponents to scope out the costs for demonstration projects. The private sector and/or government could fund the difference between avoided generation costs and actual costs. BC Hydro could offer a green contract equivalent for non-commercial alternative energies. It could be a fifteen to twenty year contract at approximately 5 c/kWh. This would be less the risk-adjusted gas price delivered for VIGP/GSX.

Wind power appears to have significant potential in the northern part of VI. The potential is estimated to be up to 650 MW in areas with average wind speeds of 8 m/s, where a capacity factor of 35% or higher can be achieved. Unlike tidal and wave power, wind power is a mature technology, with about 7000 MW of new capacity installed worldwide during 2002.

On the other hand, variations in wind speed and power production are less regular and predictable than for wave and tidal power. Therefore, other resources such as pumped-storage hydro are useful to provide "firming" of the wind power. The wind resource on VI does appear to be stronger in the winter, when peak demand occurs, raising the value of the energy produced.

Some prospecting has been done on VI to identify high-potential offshore wind sites, where the (visual) environmental impact would be reduced. For example, a large offshore wind power project is under development for connection to the Mainland near Prince Rupert. There appear to be few offshore sites on VI with both strong winds and a shallow seabed, so onshore resources appear more promising on VI.

[13] For example, BC could develop a research program around biomimetic turbines modeled around the inside of sea turtle shells (see www.paxscientific.com). The flow of seawater inside and through these shells is a vortex laminar flow that is super efficient and does not harm fish that swim through it. Designing a turbine to move fluid in this way would also take advantage of its inherent efficiencies. (Current fluid handling equipment is designed around turbulent flow).

Transmission and Distribution Grid Solutions

The gradual deterioration and derating of the existing HVDC transmission lines to Vancouver Island are the main cause of BC Hydro's urgent need to increase its power delivery capacity to VI, either by additional transmission, on-island generation, or both. Indeed, even the generation solutions depend on adequate transmission and distribution capacity to reach customers.

The four basic strategies that BC Hydro can use to address the potential VI capacity shortfall through transmission and distribution grid solutions are the following:

1. Increase the *transmission capacity between Vancouver Island and the Mainland*. This can complement or substitute for on-island generation.
2. Improve the *operation of the transmission and distribution grid* on Vancouver Island. This can reduce losses and free up capacity to serve loads.
3. Increase the *transmission and distribution capacity available on Vancouver Island*. This can enable the interconnection of on-island renewable generation resources.
4. Increase transmission capacity to *relieve potential constraints on the Mainland*. This can enable additional VI load to be served with Mainland generation capacity, if transmission capacity between VI and the Mainland is increased.

At the workshop, the group reported in detail on proposed ideas, discussed below, that relate to strategies 1, 2 and 3 above. These are:

Convert Dunsmuir-Sahtlam line from 230kV to 500 kV
Real time metering to reduce line losses
Modification of transmission extension policy

Note that the implementation of strategy 1, increased transmission from the Mainland, depends on the development of both *new generation sources on the mainland*, as well as on strategy 4, relieving transmission constraints on the Mainland. Mainland generation is discussed briefly under Generation and Distributed Resources.

Also, strategy 3, increased transmission on VI, together with modification of the *transmission extension policy*, is probably a necessary prerequisite for realizing much of the *on-island renewable generation* potential that was identified. This proposal is also discussed in more detail below.

Convert Existing 230 kV Dunsmuir-Sahtlam Line to 500kV

NEXT STEPS: Planning study to determine requirements, benefits, and costs

Currently the 500 kV transmission line that runs north-south from Dunsmuir (near Qualicum) to Sahtlam (near Duncan) on VI is being operated as a 230 kV system. Converting the system to run at its true, higher capacity would decrease transmission losses, increase transmission reliability, and significantly increase the north to south transmission capacity on the island. The upgrade would also facilitate the planning and siting of VI's abundant renewable energy resources or other IPP proposals, many of which are located in the northern areas of the island and bring energy south to where the population is concentrated.

The conversion of the line to 500kV operation would provide approximately 100 to 300 MW in additional transmission capacity, and eliminate 20MW in losses resulting from the 230 kV rating. Altogether, this would increase the transmission capacity by approximately 30-50MW and save 87,600 GWh/year of energy.[14] This conversion is likely to happen, especially if new generation is added north of (Qualicum) Dunsmuir. The project cost would be around $40-$50 million for substation modifications over three to four years. The investment would be repaid by the energy savings from 20 MW (10 MW average) loss reduction.

In order for this idea to become reality, BC Hydro and BCTC staff will need to continue their planning efforts, including defining future generation needs and new plant locations. The significant investment required may require BCUC approval.

Another idea that was proposed but not developed further: Convert the existing system to DC operation. This could also double capacity, so either cable in the first contingency pair could handle the entire VI load, possibly at less cost than increasing AC capacity. The main weakness is that the capacity increment is too large to allow it to be out of service long enough to implement the conversion. This would take more time and money than replacing terminals on existing HVDC lines, but that step could possibly buy time for this one. It would be necessary to develop detailed information on system stability issues related to the conversion.

[14] Assuming a 50% capacity factor on the transmission lines.

Line Loss/Theft Reduction Via Real-Time Meters at Substations and Distribution Transformers

The idea involves the installation of new meters at or near residences and transformers with the ability to better measure actual electricity usage in real time. The idea also complements Power Smart's new effort to manage peak demand growth on VI through such measures as time-of-use rates for commercial and residential customers, and remote and smart metering.

Benefits from the installation of new and smart meters include an estimated 120 GWh/ year savings from theft prevention, and approximately 700 GWh/ year savings through customer change in behavior. BC Hydro anticipates a 10% savings from spontaneous customer behavior change from the availability of detailed analysis of time of day usage due to the meters. Capacity reduction from implementing the project could be 60-88 MW. Using a CCGT as a proxy, potential savings of 14 TJ/ day and 300,000 tonnes of CO_2 savings per year could be possible.

A rough approximation of project cost is $100 million amortized over 20 years for installation of meters. This assumes that meter readers can be eliminated or changed to new meters. Risks are assumed to be small to none, while the benefits include energy and emissions savings, and improved system reliability. Additionally, smart meters would allow for better load analysis and transfer capability, more efficient investments from planning and design, and better information for the development of DSM programs that target specific technologies to manage peak demand.

Modification of Transmission Extension Policy to Enable Renewable Generation

NEXT STEPS: Develop business case, including possible incentives
Determine marginal cost of new supply on VI

Connecting new green independent power producers (IPPs) on VI, particularly wind, wave and tidal power, will be difficult and possibly prohibitively expensive if these sources require additional transmission capacity. In the BC Hydro system, customers connect to the transmission system (69 kV and higher) for the following reasons:

1. The load is large enough (>5 MW) to justify the higher upfront cost of installing a substation and building a transmission line to the substation.
2. The site is remote and the transmission system is the closest point of connection.
3. For an IPP, the generator is large enough that it cannot be connected directly to the distribution system. A distribution feeder at 25 kV can only carry 10 MW to 15 MW.

If an IPP wants to connect to the transmission system, they have to pay BC Hydro (or soon the BC Transmission Company) to study the impact of connecting the generation source to the grid. The study determines what type of protection and control technology is required for the IPP to operate safely and prevent negative impacts on the system. From such studies, the IPP will be told what the costs are to connect to the system.

The IPP must also do their own study on building the transmission connection from the location of their plant to the existing BC Hydro transmission system. The IPP has the option to build this extension to BC Hydro's standards or to build it to a different standard to reduce costs. Usually they build to BC Hydro standards, in which case the IPP can turn over the transmission extension over to BC Hydro/BCTC to own, operate and maintain. In some cases, for example mines in remote locations, IPPs have built to a different standard to save costs. These IPPs own and operate their own line, and they must also construct a substation that steps the voltage to that of the transmission system.

If a customer pays for the transmission extension and a second customer later connects to this extension, then the first customer is paid a prorated amount from the second customer, based on the depreciated value of the portion of the extension the new customer is using. However, BC Hydro charges the new customer the replacement cost of the portion of the extension they are using. However, if a line is built to serve an IPP it would be sized for that IPP. If other IPPs come later, they may find that there is no capacity. If it is known when the line is designed that there are other viable projects in the area, then it would make sense to size the line to accommodate all the IPPs.

Thus, for a small IPP to locate in a remote area the cost to connect to the BC Hydro system can kill the economics of the project. There is a "Chicken and Egg" situation in that, if the line is in place, the projects would go ahead. However, the line will not go ahead unless the projects are there to justify it, and no single project can bear the cost of the line.

A possible solution would be to gather enough IPPs that could build projects in an area that would be served by a transmission line, so that the cost of the line can be shared between the

various projects. This would require a change to the BC Hydro extension policy and collaboration with the Provincial government to support the aggregated development of multiple renewable generation projects. Such support could include low-cost loans or contingent grants to cover the initial development costs, such as the necessary interconnection studies.

Appendix R