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July 7, 2009

Ontario Energy Board
2300 Yonge Street
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Toronto ON M4P 1E4

Attention: Ms Kirsten Walli
Board Secretary

Dear Ms. Walli:

Re: Regulatory Treatment of Infrastructure Investment
Board File No. EB-2009-0152

Introduction and Summary

These submissions are made on behalf of the Infrastructure Renewal Task Force ("IRTF"), which consists of Hydro One Networks Inc., Ontario Power Generation, Inc. and the Coalition of Large Distributors ("CLD", which consists of Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc., Toronto Hydro-Electric System Limited and Veridian Connections Inc.).

The IRTF came together because the need to remove regulatory barriers to investment in energy infrastructure is sector wide: the need for investment, and the regulatory barriers to that investment, apply to all components of the regulated value chain: transmission, generation and distribution.

The IRTF commends the Chair's initiative to review the regulatory treatment of infrastructure investment and largely agrees with the inventory of "alternative mechanisms" identified in Chapter 3 of the Board Staff's Report (the "Staff Report"). However, and with respect, the Staff Report has, in some fundamental ways, departed from the key insights demonstrated in the Chair's Statement that launched this initiative. The unfortunate effect of this is that the significance and coherence of the initiative has been diminished and the end goal blurred. It is hoped that the vision that informed the Chair's Statements will reinvigorate the Board's final treatment of this issue.

For example, the Chair's Statement recognized that there is a pressing need for energy infrastructure investment in Ontario. As the Chair stated: "The magnitude of current and future utility infrastructure investment has led me to consider how the Board could create conditions which would foster timely investment by utilities in required infrastructure."[1] Although the Chair noted that the *Green Energy and Green Economy Act* (the "*GEGEA*") will "further increase utility infrastructure investment", that Act is not the sole source of the need for revised regulatory treatment. The source of the problem is the need for infrastructure, not just the passage of the *GEGEA*.

In addition, the Chair's statement recognized that the solutions to this challenge should be integrated and forward looking. The Chair stated: "I should emphasize that these regulatory approaches should not be considered as discreet tools; rather, they should be considered and assessed as possible elements of an integrated cost recovery approach for infrastructure costs, one that would move beyond the traditional practice with which we are familiar."[2] The Staff Report takes a more narrow approach. Instead of identifying underlying principles and articulating an integrated approach, the Staff Report is primarily focused on *a priori* categorization of investments by reference to how they can be pigeon-holed into existing regulatory categories. Indeed, the Staff Report seems more focused on how to maintain these existing categories than on how to facilitate long term capital investment. However, if existing

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[1] Statement from the Chair, April 3, 2009.
[2] Statement from the Chair, April 3, 2009.

regulatory categories contain barriers to investment – even unintended barriers – then the IRTF suggests that they should be reconsidered.

These two points will be addressed in Part I, below. Part II of these submissions address the specific proposals contained in the Report and suggest additional areas to be considered. Part III contains a Table of responses to the questions enumerated in the Board Staff Report.

Part I – The Report in the Context of Ontario's Need for Electricity Infrastructure

Ontario's need for energy infrastructure investment has been recognized for several years now. In 2003, the Electricity Conservation & Supply Task Force ("ECSTF") was established to make recommendations on "attracting new generation, promoting competition, and enhancing the reliability of the transmission grid."[3] The need for energy infrastructure also informed the establishment of the Ontario Power Authority (the "OPA") in 2004. In 2007, the OPA identified the need for over $60 billion in electricity generation and transmission.

The factors leading to infrastructure deficit are not unique to Ontario. FERC Order 679 noted that investment in transmission facilities had declined and "that there is a significant need for new investment in transmission facilities."[4] This significant need is what informs the list of initiatives in Order 679 (many of which are incorporated as "alternative mechanisms" in the Board Staff Report). Similarly, the National Regulatory Research Institute ("NRRI") Report referred to in the Staff Paper[5], observed that there are multiple causes for the infrastructure deficit facing American jurisdictions: "growing demand, aging infrastructure, environmental requirements, an increasing call for the construction of renewable projects, and shrinking credit markets."[6] These factors are relevant to Ontario as well.

The point is that the need for additional energy infrastructure investment is a long standing issue in Ontario and other jurisdictions. Like the Chair, regulators in other jurisdictions recognize that

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[3] At p. i.
[4] At p. 8.
[5] National Regulatory Research Institute, *Pre-Approval Commitments: When and Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility Proposed Capital Projects?* (November, 2008)
[6] At p. iii.

traditional methods of public utility regulation have resulted in systematic barriers to long term capital investment.

This consequence is not surprising in light of the underlying assumptions towards capital investment that has informed public utility regulation in the past. The OEB, like FERC and other North American public utility regulators, has applied conventional regulatory practices in reviewing infrastructure projects. One of the key drivers for these practices is the need to review utility investment decisions to ensure that a utility does not "over invest" in utility facilities. In other words, the assumption underlying many of current practices is what Board Staff has described elsewhere as "the tendency identified in economic theory for regulated utilities to over-accumulate capital as a means of raising the volume of profit."[7] However, as leading commentators have noted, "This theory ignores many attributes of real regulatory institutions and it has little if any empirical support."[8]

In any event, even if this approach was right for its time, it is not the correct approach today. Given that the key challenge facing electricity infrastructure in Ontario is the need to invest in infrastructure, it is not surprising that conventions used to restrict infrastructure investment may no longer be appropriate. The remedies in Order 679 and the analysis in the NRRI Report represent an attempt to rethink some fundamental assumptions so that large long term capital investments are encouraged, not discouraged.

The advantage of the FERC/NRRI approach is that it identifies the way in which its traditional approach frustrates long term investment and thus tailors its approach to facilitate long term investment. In other words, FERC and NRRI focus on regulatory assumptions and approaches that may lead to unintended consequences. Thus, as the NRRI Report noted, if the regulatory system discourages long term investment, then there is under investment in that area and over-investment in other areas.[9] As a result, regulatory approaches that discourage long term

[7] The theoretical basis for that premise is described as the Averch-Johnson Effect: See Staff Discussion Paper in Relation to Generator Cost Responsibility Review (EB-2008-0003) at p. 22.

[8] Paul Joskow, "Incentive Regulation and Its Application to Electricity Networks" (2008), *Review of Network Economics*, 537 at 548.

[9] NRRI Report, at p. 24. This is also the emphasis of Joskow, *op cit.* Joskow stresses that the application of the A-J effect theory referred to above does not reduce overall utility approved costs; instead, it focuses on the "capital/labor

investment are not cost effective – they lead to distortions. The FERC/NRRI approach recognizes the need to reconsider some of the basic premises of rate making in light of the fact that traditional approaches have not resulted in appropriate levels of investment in long term capital projects.

The IRTF appreciates that the Board must approach the need for long term capital investment with a view to ensuring cost effectiveness in ratepayer expenditures. Managing both of those factors will require judgment and trade-offs on a case by case basis. The key imperative is that the trade offs take relevant factors into account. The concern about the approach in the Staff Report is that it does not provide a helpful approach to measure these trade-offs. Instead, it suggests a categorical approach by reference to how to characterize the investment within existing regulatory distinctions and by reference to whom is making the investment.[10]

Part II – The Alternative Mechanisms and the Problems they Mean to Address

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ratio" of approved costs. In other words, a regulatory decision based on this approach leads to approval of a disproportionately under representation of capital costs and a disproportionately over representation of O&M.

[10] There are also legal concerns with this approach. From a legal perspective, it is important to bear in mind that the *GEGEA* amends provisions of the *OEB Act* and the *Electricity Act*; its provisions must be incorporated into those Acts, but they do not entirely replace the remainder of those Acts. In other words, the GEGEA does not set out the totality of the Board's responsibilities or the totality of government policy. The OEB's responsibilities are reflected in the entire legislative scheme that governs the sector; government policies are reflected in a number of instruments, including directives, policy statements, and other public pronouncements. If the *GEGEA* illustrates that the OEB's past approach to large long term capital investment is in need of reconsideration, then that reconsideration should apply to large long term capital investment considered under the *OEB Act* and all investments that implement government policy, not just to investments that can be characterized as facilitating the GEGEA.

The Staff Report does not seem to capture this point. Rather, it states, on a number of occasions that the GEGEA reflects "government policy" that should be implemented by the OEB.

However, as legislation, the GEGEA is created by the legislature, not the government. The provisions of the GEGEA provide direction both to the government and to the OEB (as well as other statutory bodies). However, those provisions are supposed to be read as part of the entire legislative scheme. As the Board has noted on several occasions, its statutory powers must be exercised in accordance with the following "golden rule" of statutory interpretation:

> "Today there is only one principle or approach; namely, the words of an Act are to be read in their entire context and in their grammatical and ordinate sense harmoniously *with the scheme of the Act and the object of the Act, and the intention of Parliament.*" (EB-2006-0034 (2007), p. 7, quoting from E.A. Driedger, Statutory Interpretation, emphasis added).

In this context, the instrument through which infrastructure investment mechanisms will be implemented is the power of the OEB to make orders approving just and reasonable rates. In setting those rates in accordance with its statutory mandate, the OEB is to consider the entire legislative scheme, not just recent political initiatives or legislative changes. In other words, the Board's obligation is to set just and reasonable rates that relate to all capital investments. It should not approve one set of rates (one interpretation of "just and reasonable") for certain objectives and another set of rates (with a different interpretation of "just and reasonable") for other objectives.

The IRTF proposes that regulatory conventions that present serious barriers to infrastructure investment should be reconsidered. It is therefore important to specify the major categories of barriers, how specific regulatory practices contribute to these barriers; and how these barriers may be removed.

Major Categories of Barriers

Conventional regulatory review of infrastructure projects create barriers to investments that involve (i) major capital expenditures that have long lead times (the "Long Term Investment Barrier"); (ii) investment in new technologies (the "Technology Barrier); (iii) significant development costs (the "Development Cost Barrier"); (iv) expenditures that facilitate environmental and social policy objectives that may not be "low cost" as conventionally measured (the "Social Cost Barrier") and (v) incremental spikes in capital requirements (the "Incremental Investments Barrier"). It should be noted that these barriers overlap and many projects face numerous barriers and will fall into more than one of these categories.

The Staff Report identifies alternative mechanisms that address the first category (however in overly restricted circumstances); the remaining barriers have either not been addressed in the Staff Report or, if they have, are not accompanied by effective remedies.

Long Term Investment Barriers

Projects that fall within the category of Long Term Investments are typically marked by the following characteristics:

- Multi-year construction period;
- Investment as a relatively large proportion of rate base (for example 1%); and
- Subject to regulatory approvals, the success of which is not entirely within the applicant's control.

Most of the alternative mechanisms identified in the Staff Report are designed to overcome these barriers. The IRTF agrees generally with how the mechanisms are characterized. However, the Staff Report proposes to limit the application of these mechanisms by reference to extraneous factors that, in the IRTF's perspective, are not relevant.

The first way in which this arises is in the Staff Report's focus on the identity of the investor. The Staff Report's treatment of this issue starts with the observation that "Delaying rate recovery for new regulated assets until they are placed in service may, in the case of large, capital-intensive assets, have rate implications that may need to be mitigated."[11] It goes on to note examples of how this has been applied in other jurisdictions:

> "In response to these concerns and the need for significant investment in base load capacity, particularly nuclear power, many U.S. states have passed legislation and/or put in place regulations to allow for full or partial CWIP to be placed in rate base during the construction of these facilities. In effect, CWIP in rate base provides a smoothing, or phased in effect, on rates and thereby mitigates the rate impact that would otherwise take place when the large new plant is placed into service."

The Staff Report thus accurately characterizes the nature of the issue and how it has been addressed in other jurisdictions. However, despite this analysis, the Staff Report suggests a proposal which looks, not at the characteristics of the investment, but the identity of the investor. Thus, following the above statement, the Staff Report says that "Staff is uncertain as to whether this particular treatment is appropriate for most distribution infrastructure investments. As noted above, it is staff's understanding that this treatment has been generally reserved for large generation facilities. In the context of this Discussion Paper, staff thinks this treatment may only be appropriate for electricity transmitters…"

In other words, instead of recommending that this remedy apply to address the type of investment it is designed to encourage (large, long term investments), the Staff Report recommends that the remedy be confined to transmitters, suggesting that investments in distribution or generation that meet these characteristics be excluded. This restriction is not necessary.

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[11] Board Staff Report, p. 23

It is also clear that this approach is not aligned with the FERC/NRRI analysis. True, FERC's Order 679 is restricted to transmission, but that is because FERC's rate making jurisdiction is restricted to transmission. As for the NRRI Report, it expressly includes investments made by distributors,[12] and investments made in generation – nuclear,[13] IGCC[14] and wind.[15]

Thus, the Staff Paper is unique in seeking to limit alternative treatment by reference to the identity of the investor, as opposed to the nature of the investment.

The second area where the Staff Report provides a proposal that seems inconsistent with the underlying problems facing long term capital investment is with respect to the way in which an investment fits within traditional OEB regulatory categories. The discussion commences with the observation (with which the IRTF agrees) that OEB regulatory categories such as "'routine' versus 'non-routine incremental' versus '*GEGEA*-related' investments may not be practical or absolutely necessary." However, it then goes on to suggest that these categories should dictate whether or not projects qualify for alternative treatment.[16] This approach does not shed light on the underlying trade-offs that are necessary to categorize investment for the purposes of determining whether it should qualify for alternative treatment.

The IRTF proposes a more systematic approach that looks at the underlying nature of the investment, the barriers that face such an investment, and the mechanisms that should be considered to address those barriers. In the context of the Long Term Investment Barrier, the specific mechanisms that have been designed to address barriers are (a) recovery of costs of

[12] See examples cited in the discussion at p. 3 (footnotes 3 and 4).
[13] See examples cited in the discussion at pp. 2, 5, 13, 16, 18, 19, 20, 21, 22, and 23.
[14] See examples cited in the discussion at pp. 18, 19, 23 and 28.
[15] See example cited in the discussion at p. 20.
[16] The route to this conclusion is as follows. First, after noting that the categories of "routine" and "non-routine" are not helpful, the Staff Paper observes that the OEB has used this distinction in evaluating an application under the Incremental Capital Model ("ICM") in the context of the Board's 3rd Generation Incentive Regulation ("IR") plan. Under that approach, an LDC may qualify for ICM where it "clearly demonstrates that it is 'facing extraordinary and unanticipated capital spending requirements; i.e., something other than the normal course of business'". The Staff Paper then notes that this may include investments that are "associated with extended obligations to invest". The term "extended obligation to invest" is then equated with investments made to implement the GEGEA. In this way, the Staff Report seems to effectively be saying that the types of investments that should qualify for alternative treatment are investments that would qualify under the ICM, i.e., extraordinary and unanticipated capital requirements.

abandoned facilities; (b) accelerated cost recovery; and (c) incentive mechanisms. Each of these mechanisms has been addressed in the Staff Report. The following sections discuss how they have been addressed.

(a) Recovery of Costs of Abandoned Facilities

As the Staff Report notes, allowing the recovery of costs of abandoned facilities is already effectively included in the proposed policy for enabler transmission lines. The IRTF proposes that this approach be explicitly applied to all large capital investments where the completion of facilities may be abandoned for reasons outside of utility management's reasonable control. Allowing this recovery has become more standard practice as recognized by FERC and other regulators.[17] This is a refinement to the prudence standard because it removes risk from utility management where that risk is outside of its control. The Staff Report appears to suggest an additional requirement, i.e., that a utility must apply for this treatment at an apparently early stage in an application. This suggests that, if a utility does not specifically request this treatment, then the OEB may make the utility responsible for the risk, even if it is outside of its control. A preferred and more predictable approach would be for the OEB to apply this requirement whether specifically requested or not. In other words, when considering a claim for recovery of costs of abandoned assets, the focus of the inquiry should be on whether the abandonment was reasonable, not whether a utility had requested specific treatment up front.

(b) Accelerated Cost Recovery

As FERC noted, allowing recovery of CWIP in rates "removes a disincentive to construction costs of transmission, which can involve very long lead times and considerable risk to the utility that the project may not go forward."[18] Thus, the disincentive that this is meant to remedy arises because of the long lead times for projects. The IRTF submits that all rate regulated entities proposing projects with relatively long lead times have this remedy available to them. Also, because each project is different, the OEB should maintain flexibility on how these applications may be requested. This issue will be addressed more specifically in the Implementation section, below.

[17] See NRRI Report at pp. 10 and 21-22.
[18] At pp. 66-67.

In addition, the Staff Report notes that depreciation may be accelerated or timed to coincide with a renewable generation contract that underlies a specific facility. The IRTF proposes that the Board should be open-minded about depreciation schedules and entertain an application that addresses this point. However, there is no need, on a policy basis, to tie depreciation to a specific contract and, in fact, doing this could lead to unnecessary complications. For example, there may be several generation facilities with several contract terms (and hence, different depreciation schedules) that will be connecting to a specific facility. Although the Board should not categorically reject entertaining a specific proposal, it would be unnecessarily limiting for the Board to adopt a policy such as the one suggested in the Staff Report.

(c) Incentive Mechanisms

The two previous mechanisms – recovery of costs of abandoned assets and inclusion of CWIP in rates – do not provide incentives; they remove barriers. As FERC noted, the former is "more properly characterized as reducing a regulatory barrier – the potential lack of recovery of costs – to infrastructure development"[19]; and the latter "will remove an impediment – inadequate cash flow – that our current regulations can present to those investing in new transmission."[20]

The Staff Report apparently recognizes this approach and characterizes ROE based mechanisms as incentives; these are Project ROE Adders and Project-Specific Capital Structure. The IRTF is primarily concerned about removing barriers and understands this goal to be the primary focus of the Chair's Statements and this initiative. The IRTF believes it would be appropriate for the Board to maintain an open mind on both of these incentives, and notes that this issue is now being addressed in another forum[21]. Having said this, there are many potential investors in the sector and Project Specific Capital Structure may be important to meet the different needs of different types of investors.

Additional Alternative Mechanisms

The Staff Report proposes mechanisms to address the Long Term Investment issue (as discussed above). However, it does not address other barriers that also impede infrastructure investment.

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[19] At p. 17.
[20] At p. 18.
[21] See letter of OEB Secretary dated June 18, 2009 (EB-2009-0084).

These barriers relate to Technology Investment, Development Costs, Social Cost and Incremental Investments. Each will be addressed in turn.

The Technology Investment Barrier

FERC Order 679 invited utilities to apply for additional incentives for particular technologies. It noted that applicants may seek accelerated depreciation and the need to "recover the costs of obsolescent plant, thereby facilitating the addition of new, more technically advanced transmission infrastructure."[22] In its Proposed Policy Statement and Action Plan on the Smart Grid, FERC observed that a key consideration for a utility's decision to invest in new technologies is whether or not they are granted cost recovery for the investment as well as for stranded costs for legacy systems that are replaced by new technology. Recognizing that new technology is necessarily somewhat experimental, FERC adapted the "used and useful" standard so that a utility could get cost recovery if it demonstrated *in advance* that an investment met certain standard. According to FERC:

> "In other words, we propose to consider Smart Grid devices and equipment, including those used in a Smart Grid pilot program or demonstration project, to be used and useful for the purposes of cost recovery if an applicant makes the following showings.
>
> We propose that an applicant must show that the reliability and security of the bulk-power system will not be adversely affected by the deployment at issue. Second, the filing must show that the applicant has minimized the possibility of stranded investment in Smart Grid equipment by designing for the ability to be upgraded, in light of the fact that such filings will predate adoption of interoperability standards. Finally, because it will be important for early Smart Grid deployments, particularly pilot and demonstration projects, to provide useful feedback to the interoperability standards development process, we propose to direct the applicant to share information with the Department of Energy Smart Grid Clearinghouse, provided for in the ARRA."[23]

FERC has thus adopted an approach of "learning by doing" by removing regulatory risk for certain types of technology investment. It has also provided guidance by identifying its priority areas of smart grid functionality: wide area situational awareness, demand response, electric

[22] FERC Order 679, p. 151.
[23] FERC Proposed Policy Statement and Action Plan: SMART GRID POLICY (March 19, 2009), pp. 34-35.

storage, and electric transportation.[24] Although the IRTF appreciates that Ontario's approaches and priorities may be different than those in the United States, there is a concern that the approach in the Staff Report seeks to limit investment in smart grid, not facilitate it.

Thus, the Staff Report notes that FERC's approach is experimental and has been "debated vigorously". The conclusion it takes from this is not that Ontario should also explore this issue. Instead, it seeks to limit utility investment, suggesting that FERC's approach "could result in higher rates for consumers without sufficient offsetting benefits." It then asks a somewhat leading question of whether it is appropriate to apply mechanisms to investments in smart grid technology "while it is at an early stage of development and where governing standards are yet to be developed."[25]

This cautious approach is mirrored in the Board's proposed Filing Guidelines for Deemed Conditions of Licence regarding Distribution System Planning, where it limits amounts that can be recorded in smart grid deferral accounts (and therefore subject to recovery based on a traditional prudence test) to:

- Smart grid studies or demonstration projects;
- Smart grid planning; and
- Smart grid education and training.[26]

The consequence is that, if an investment is labelled as a "smart grid" investment, then it faces a *higher* hurdle for cost recovery.

The IRTF appreciates that it is necessary to learn more about smart grid technology and how it can contribute to improving Ontario's electricity systems. This means that there is a need to set priorities for what the province seeks to achieve (much like FERC has done). However, simply seeking to limit smart grid investment does not seem to contribute to achieving any strategic technology benefits. Given the OEB's statutory mandate is to "facilitate the implementation of a smart grid in Ontario", one would expect that the Board would want to encourage, not

[24] At pp. 26-32.
[25] Staff Report, pp. 17-18.
[26] (June 16, 2009), p. 7.

discourage, strategic investment in smart grid technology by developing a more facilitative regulatory approach.

The Development Cost Barrier

Development of infrastructure options is necessary in light of long lead times, coordination issues for generation and transmission/distribution, and the need to consider multiple options. Given the extensive need for infrastructure investment, the number of the proposed projects for which development costs will be required could significantly increase. It may be necessary for a utility to invest in the development of a number of options, even if it is determined that not all projects that incur such costs can or should be brought into service. Indeed, OEB policy has endorsed the development of options for generation that may or may not connect to the system.[27]

This has been recognized by FERC Order 679, the NRRI Report, and the Board's consultation on the Generator Connection Cost Recovery (Enabler Line) process. However, it seems to be missing from the Staff Report.

FERC Order 679 authorized the recovery of "pre-commercial operation" costs as they are incurred, as opposed to capitalizing them after a facility is brought into service. The costs included in this category are "preliminary surveys, plans and investigations, made for the purpose of determining the feasibility of utility projects and costs of studies and analysis mandated by regulatory bodies related to plant in service."[28]

[27] For example, the proposed TSC amendments respecting enabler transmission lines contemplates investing development costs in order to determine which lines should proceed to an application for leave to construct. Similarly, the Notice accompanying the Board's proposed amendments to the DSC respecting cost responsibility for distributed generation, states that "The Board anticipates that distributor investment plans will identify investments (both 'renewable enabling improvements' and 'expansions') that distributors will make in anticipation of the connection of renewable energy generation projects. The Board believes that these investments will be planned *prior to, or regardless of, a specific generator requesting connection* and will likely be of broader benefit to the distributor and its existing and future customers (both generators and loads)" (at p. 8, emphasis added). It is therefore entirely possible that the generation that is anticipated to be enabled by this investment does not come into service. In this case, the development of the option should not be at the risk of the utility.
[28] At p. 71, footnote 82.

Similarly, the NRRI Report refers to several examples where these types of development costs were recoverable from customers as they occurred.[29]

Finally, the OEB's Generation Connection Cost Responsibility review recommended the recovery of development costs, which include the following:

- Stakeholder, community and First Nations and Métis consultation;
- Technical system studies, including pre-feasibility studies;
- Engineering studies including line design;
- Route and site identification and assessment;
- Preparation and seeking approval of EA Terms of References;
- Acquisition of land rights;
- EA studies; and
- Seeking EA approval.

The IRTF therefore proposes that the Board policy emanating from this exercise expressly recognize that the lack of certainty and delayed timing for the recovery of development costs is a barrier to infrastructure investment that should be removed. This can be done by allowing utilities to apply for prior approval of development costs and allowing recovery of prudently incurred development costs whether or not specific facilities are brought into service.

[29] See for example, discussions at pp. 10 and 21-22.

The Social Cost Barrier

The traditional regulatory practice sometimes equates a "prudent" investment with a "lowest cost" investment. However, there are several types of utility investments that, in order to be implemented in a timely way, will require an investment of additional costs that bring about social value, even if it results in a project that is not "lowest cost" by conventional regulatory standards. Examples of these types of costs are those that relate, for example, to undergrounding transmission/distribution facilities, selecting a route that accommodates community concerns that are not otherwise prescribed in the permitting, approval or other legal requirements and perhaps engaging in partnerships etc. with local communities, First Nations and Métis people.

Although obtaining a social permission may be necessary to achieve successful installation of assets, it may require investments that may not be "low cost" as conventionally measured. In addition, society as a whole may benefit from these types of investments (as opposed to specific customers).

This has been recognized by Ofgem, which noted that, under amendments to its enabling legislation Ofgem has a duty to "have regard to the impact of distribution activities on the environment. It is also required to carry out its duties in such a manner as to contribute to the achievement of sustainable development."[30]In accordance with this mandate, it allowed additional cost recovery for limited undergrounding of distribution facilities.

Because traditional regulatory approaches to low cost requirements create a barrier to investing in social permission costs, the IRTF requests the Board to confirm that utilities' shareholders are not at risk for investments that provide a societal benefit or a "value-add" to specific communities or individuals. In addition, given that the beneficiaries of this approach are not restricted to customers within a specific franchise or territory, the Board should consider whether these costs should be collected from a wider variety of customers.

[30] Office of Gas and Electricity Markets, Electricity Distribution Price Control Review: Final Proposals, November 2004, p. 34.

The Incremental Investments Barrier

As indicated in both NRRI Report and FERC 679[31], cash flow may be a barrier to investment. One area where this can arise is where regulated cash flow assumes that capital expenditures are made on a steady state basis, but, in reality, some expenditures are required in an amount that deviates in a material way from expenditures in a previous period.

The limitation with assuming that annual expenditures will follow a predictable year to year pattern has been recognized in the design and experience with incentive regulation in several jurisdictions. Paul Joskow of MIT, perhaps the leading regulatory economist in North America, has commented on the inappropriateness of applying backward looking measures of appropriate capital expenditures:

> "The appropriate investment program may vary quite widely depending on variables like customer growth rates, load growth rates, equipment ages and replacement expenditures, underground vs. above ground facilities, service quality improvement needs, etc. with little necessary relationship to recent historical trends. Indeed, the rate of investment in electricity network infrastructure has historically been quite cyclical. As a result, it has proven difficult to develop useful statistical benchmarks for future capital additions."[32]

Thus, in the late 1990s, Ofgem carried out a fundamental reform of its price cap incentive regulation mechanisms to address the unique problems of capital investment. It required regulated distributors to forecast five years of capital expenditures, and, after adjusting those forecasts "to ensure that the allowances set are appropriate and represent fair value for customers"[33], Ofgem adopted a new model that allowed utilities to choose from a menu of regulatory options on how recovery of capital expenditures may be applied for.[34]
Ofgem was not alone in refining its price cap incentive regulation model to accommodate for annual changes in capital expenditures. Its adaptation reflected a growing consensus on the

[31] See quotations above at pp. 3 and 9.
[32] Paul Joskow, *Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks* , MIT, 2006, at p. 26.

[33] At p. 80. view: Final Proposals, November 2004, p. 34.
[34] For a detailed discussion and analysis of this process, see: Martin Crouch, "Investment under RPI-X: Practical Experience with an incentiveitve compatible approach in the GB distribution sector" (2006), *Utilities Policy* 14.

limitations of price caps to address capital expenditures. A review of the international experience conducted by Jose A. Gomez-Ibanez of Harvard University's John F. Kennedy School of Government, concluded that, although "price cap has to be judged a great success, primarily because of its stronger incentives to improve efficiency", it "has proved less successful in providing incentives for capital investment..."

> "With price-cap regulation, by contrast, the incentives are usually to under-invest. One reason is that price cap does not encourage efficiency improvements that have payback periods longer than the interval between price reviews."[35]

Similarly, according to Joskow, "Regulatory judgments about allowances for future capital expenditures has become a more sensitive issue for regulators in the UK (and the US) as reliability considerations have become of greater political importance, as excess capacity has been squeezed out of the legacy capital stock, and as the large amount of investment infrastructure investment made in the 1950s and 1960s reaches the end of its useful life."[36]

All of these factors are relevant to Ontario distribution investment as well. Thus, any review of the regulatory treatment of capital investment in Ontario should consider whether the current regulatory approach provides a too restricted approach to investment in distribution infrastructure. By not incorporating capital investments for major projects or related groups of projects into rate base until a rebasing under the OEB's price cap formula, the Board's policy effectively increases the time span between an incremental capital investment and its recovery in rates. In other words, although a distribution investment does not typically have the same lead time as a large transmission or capital intensive generation investment, the period of regulatory lag between the investment and the rebasing may be considerable.

However, the Staff Report does not address this point. Rather, it states that annual incremental changes to capital investment should only be entitled to cost recovery where a distributor would be able to clearly demonstrate that it is facing extraordinary and unanticipated capital spending requirements; i.e. something other than the normal course of business. Although it is

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[35] Jose A. Gomez-Ibanez, *Regulating Infrastructure: Monopoly, Contracts and Discretion* (Cambridge: Harvard University Press, 2003) at pp. 240-241.
[36] P. 25.

understandable that this approach could be adopted where the ultimate objective of the regulatory regime would be to retain an existing price cap formula, it is not clear how this approach follows from a review meant to remove barriers to capital investment.

Implementation Issues

Conditions

The Staff Report suggests that specific applications for alternative treatment be made on a case by case basis. The IRTF agrees with this approach.

The Staff Report also lists a number of considerations that the Board may take into account when a utility requests alternative treatment. The IRTF is concerned both with the list – which appears one-sided and tends to argue against alternative mechanisms– and with the more general suggestion that the Board Staff list should inform a specific proceeding. Specifically, each particular application will result in a series of issues for the Board to consider in light of the specific facts of the application. There is no need to supplement those considerations with a preconceived list of concerns.

The list of concerns appears to be one-sided and contain considerations that weigh against alternative treatment. For example, it includes a suggestion that, if alternative treatment is granted, a utility may have less incentive to act cost effectively. Although this consideration is, as the Staff Report notes, listed in the NRRI Report, that Report also notes, immediately after this statement that, "Conversely, if the regulator refrains from commitment, will the utility choose shorter-term, smaller, or more conventional projects over possibly more efficient but larger projects that involve greater risk?"[37]

The Staff Report also proposes detailed performance/program conditions and reporting requirements. Although some of this information may be required, it is important to consider that the reason for the Board carrying out this review is to *facilitate* capital investment, not make

[37] At p. 24.

it *more difficult*. Imposing conditions without a clear and specific rationale on what those conditions are meant to achieve will frustrate, not facilitate capital investment. Thus, if conditions and reporting requirements are to be imposed, they should be tailored to achieve specific goals. In other words, if the Board is going to require additional information, it should be clear on what it expects to do with that information and that it has the expertise to make use of it in a productive way.

It also important to consider that conditions of approval can emerge from specific applications to address issues that arise out of the application. It is not necessary to set these types of conditions up front as a matter of policy. On the contrary, it is not productive to do this. Conditions are meant to solve specific potential problems – it is important to know what those problems may be prior to crafting a solution to them.

Finally, another consequence of the case by case approach is that applicants may seek different degrees of approval. Thus, some applicants may seek annual revenue adjustments to assist in financing large projects, but not request that capital be included in rate base and subject to a rate of return until the project is brought into service. Other applicants may seek to have adjustments in rate base on an ongoing basis. The conditions and reporting requirements imposed by the Board in each circumstance may be quite different.

The IRTF proposes that the prime factor be taken into account when considering conditions and reporting requirements is that considerations of prudence should be made only once. Thus,

- If the Board grants prior approval to invest in facilities, it is appropriate to track actual expenditures against forecasted expenditures to determine whether there have been **material departures**, but it is not appropriate to reconsider approved expenditures or to second guess non-material departures from forecast;
- The Board should avoiding using regulatory devices that allow reopening past decisions. Having established the prudence of the investment at the time of project submission, it is open to the Board to use a tracking mechanism for the sole purpose of providing information that will allow it to examine whether there are material discrepancies from forecast costs, and deal with any such material discrepancies (if any) on a prospective basis at the time of subsequent rebasing; and

- Utilities should be granted flexibility in seeking prior approvals in light of the nature of the investment required. This flexibility should include:
    - whether approvals should be requested in relation to a specific project (or related group of projects) without opening up an entire rate review proceeding; and
    - whether expenses will (i) automatically go into rate base (and thus subject to a higher degree of scrutiny) or (ii) qualify for rate base upon a rebasing (where there will be less scrutiny on the front end and higher scrutiny for material departures at the time of rebasing)

Filing Requirements

The Staff Report raises the issue of how to integrate the applications for alternative treatment with different application methodologies (cost of service review, IR, Distribution Investment Plans, etc.). The IRTF proposes that, at this stage, especially while new processes are being developed for other filing requirements, the Board maintain considerable flexibility on how alternative treatment may be applied for and approved. It should encourage a variety of approaches – including single issue rate applications – and manage them as they arise. As the Staff Report notes, the Board has mechanisms, such as combining proceedings that it may use to coordinate proceedings if required.

With respect to filing requirements, the IRTF suggests that current filing requirements are already extensive and should not be expanded, especially on an *a priori* basis. Specifically, it would be unfortunate if the key deliverable from this initiative is a new set of incentive related filing requirements.

Conclusion

The IRTF commends the Chair and the Board for commencing this initiative to review the regulatory treatment of infrastructure investment and largely agrees with the inventory of "alternative mechanisms" identified in 3 of the Staff Report. The IRTF hopes that the vision that informed the Chair's statement will reinvigorate the Board's final treatment of this issue.

Sincerely,

George Vegh

Kristyn Annis

Counsel for the Infrastructure Renewal Task Force

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Part III – IRTF Response to Questions in Board Staff Paper

Question	Short Answer
1. Should the framework and mechanisms identified in this Discussion Paper apply to other rate-regulated entities? If so, why and for what types of projects?	Yes. The framework should be aimed at removing regulatory barriers to investments in Ontario's infrastructure. The Board should focus on the nature of the investment, and not the identity of the investor. The barriers relate to: • Long Term Large Investments; • Technology; • Development Costs; • Social Licence; and • Incremental Requirements.
2. Are there other broad classifications for investment, beyond "routine", "non-routine incremental", and/or "GEGEA-related" that should be considered? If so, what are they and what are the specific underlying drivers for such investment?	Deriving categories based on conventional OEB practices is not helpful. Creating these categories also result in legal, policy and practical problems. It is more productive to focus on the type of investment that is required and how current regulatory practices facilitate or frustrate that investment.
3. Should the mechanisms identified in this Discussion Paper apply to the recovery of costs incurred by electricity transmitters or distributors for investments to accommodate renewable generation or to develop the smart grid, or both? Why or why not?	See Above

4. Should the mechanisms set out in this Discussion Paper be applied to infrastructure investment if the cost of the investment is potentially recoverable through a Province-wide cost recovery mechanism? Why, or why not?	Yes. The mechanisms should be aimed at removing barriers to utility investment. The issue of "province wide recovery mechanisms" address cost allocation among customers and is not relevant to this issue.
5. Should the mechanisms set out in this Discussion Paper be applied to infrastructure investment in smart grid technology while it is at an early stage of development and where governing standards are yet to be developed? Why or why not?	Investment should not be discouraged solely on the grounds that they relate to smart grid technology. It is the nature of the investment, not whether it is categorized as a "smart grid" investment that should be important.
6. Should "routine" investment made by a transmitter or distributor be eligible for one or more of the alternative treatments identified in this Discussion Paper? Why or why not?	Deriving categories based on conventional OEB practices is not helpful. Creating these categories also result in legal, policy and practical problems. It is more productive to focus on the type of investment that is required and how current regulatory practices facilitate or frustrate that investment.
7. Should the mechanisms identified in this Discussion Paper be presumed to apply to certain types of investments (for example, to accommodate renewable generation)? Why or why not? If so, to which investments?	Yes. The framework should be aimed at removing regulatory barriers to investments in Ontario's infrastructure. The Board should focus on the nature of the investment, and not the identity of the investor. The barriers relate to: • Long Term Large Investments; • Technology; • Development Costs; • Social Licence; and Incremental Requirements.

8. Should the Board be more prescriptive as to which type of investment may qualify and which will not? If so, what criteria might the Board use to make a determination on which type of investment would qualify?	The Board should not be overly prescriptive. It is important that the Board clarify principles and rationale for alternative mechanisms so that applicants have direction that can be applied in specific cases.
9. Should the Board permit applicants to request confirmation from the Board that prudently-incurred costs associated with any abandoned projects will be recoverable in rates if such abandonment is outside the control of management? Why or why not?	Allowing recovery of costs where the risks are outside of the utility's control should become common practice at the Board. A utility should not have to apply for this specific remedy at an early stage of the proceeding; it is an integrated feature of CWIP in rates and prior approval.
10. Should the Board allow for full or partial CWIP to be placed in rate base during the construction of transmission facilities to accommodate the connection of renewable generation and/or develop the smart grid? Why or why not? Should the Board allow this particular treatment for distribution investment? If so, on what basis?	The framework should be aimed at removing regulatory barriers to investments in Ontario's infrastructure. The Board should focus on the nature of the investment, and not the identity of the investor. Recovering CWIP in rates should be available for long term large investments.
11. Should the Board allow depreciation to be adjusted to match a contract term or the useful life of the connecting renewable generation facility? Why or why not?	The Board should entertain depreciation adjustments when appropriate. Adjustments should be justified on a case by case basis. There is no reason to necessarily link a depreciation term to a contract term.

12. In light of a legislative context in which the Board may mandate infrastructure investments, are incentives necessary or appropriate in Ontario?	The Board should entertain applications for incentives on a case by case basis. There are many potential investors in the sector and Project Specific Capital Structure may be important to meet the different needs of different types of investors.
13. If the Board were to provide for incentives, should it allow project-specific ROE? If so, should the Board consider adopting a range rather than a specific adder? Further, how might the Board determine an appropriate range or ROE adder?	See Above. Investment specific ROEs and capital structures are appropriate as these should reflect the risk profiles of the underlying investments.
14. If the Board were to provide for incentives, should it allow project-specific capital structures?	See above. This should be considered on a case by case basis.
15. What other alternative mechanisms, if any, might the Board consider be made available to applicants? Why?	The framework should be aimed at removing regulatory barriers to investments in Ontario's infrastructure. The Board should focus on the nature of the investment, and not the identity of the investor. In addition to the mechanisms in the Staff Report aimed at addressing the barriers facing long term investments, the Board should also address barriers related to development costs, technology, obtaining social permission for projects and incremental investments.
16. In addition to the potential considerations identified, are there any other matters that the Board might consider in making decisions on requests for alternative treatment?	See Above

17. What performance conditions, if any, should be established?	Performance conditions should be tailored in a manner that does not delay recovery for specific projects and in light of: • the goal of having the project completed with fewer regulatory barriers, not more; • the specific mechanism requested; and • The specific risk presented by the approval applied for.
18. Are the reporting requirements suggested appropriate and adequate?	See Above.
19. Are there any other conditions that the Board might need to establish in relation to an approved alternative mechanism referred to in this Discussion Paper to protect ratepayer interests?	See Above
20. Beyond those already reflected in the Board's existing filing guidelines (e.g., the Z-factor test of causation, materiality, and prudence) and in the Board's jurisprudence, is there a specific test that successful applicants should be required to meet in order to be granted an alternative treatment?	The test that applicants should be required to meet should relate to the nature of the investment, not OEB regulatory categories. Deriving categories based on conventional OEB practices is not helpful. Creating these categories also result in legal, policy and practical problems. It is more productive to focus on the type of investment that is required and how current regulatory practices facilitate or frustrate that investment.

21. Are the Board's existing filing guidelines for electricity transmitters and distributors sufficient to support the case-by-case approach discussed in this Discussion Paper? If not, what additional information should an applicant provide?	The filing guidelines for different applications are already very extensive. They should not be expanded in light of this initiative. Information requests should be carefully tailored to shed light on a specific purpose.
22. Should the process for applying for the regulatory treatment of infrastructure investment discussed in this Discussion Paper be more prescriptive (e.g., the timing, sequencing, and/or combining of applications)? Should it be combined with the process for approving infrastructure investment plans? If so, why and in what way?	Prescription should be addressed in specific filing guidelines (See Above)
23. Should the Board permit applicants to seek approval prior to construction of the facilities to determine whether the facilities qualify for the requested alternative treatment(s)? Why or why not?	Yes, this is **necessary** for many alternative treatments (accelerated recovery) and supportive of all alternative treatments (uncertainty is a barrier).
24. What are the implications, if any, of using the single-issue rate review process?	A single issue rate review process is a productive approach as it allows focussed consideration and dynamic response to changing circumstances.

25. Is the use of rate riders an appropriate approach for implementing rate adjustments associated with the alternate treatments identified in this Discussion Paper? Alternatively, should the adjustments be made directly to base rates?	• The Board should avoiding using regulatory devices that allow reopening past decisions. Specifically, rate riders should not be used if, when amounts collected under rate riders are cleared, it is open for the Board to review amounts collected for prudence.
26. Should the Board allow applicants to seek approval of multi-year rate riders or should the applicant be required to apply every year to adjust its rate riders to reflect any changes in project costs?	See above.

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