Ontario Energy Board

EB-2009-0152

Staff Discussion Paper

on The Regulatory Treatment of Infrastructure Investment for Ontario's Electricity Transmitters and Distributors

June 5, 2009

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1 Overview

Ontario's electricity rate-regulated companies, particularly distributors and transmitters, are investing substantial amounts of capital to replace aging infrastructure, deploy smart meters, connect new load, and maintain system operability and reliability.

April 3, 2009 Statement of the Chair

On April 3, 2009, the Chair issued a statement to all interested stakeholders concerning a regulatory framework for approval of investment in infrastructure by electricity transmitters and distributors. In the statement, the Chair advised stakeholders that the Board intended to examine alternatives to the Board's current approach to cost recovery from ratepayers for capital investment.

The Green Energy and Green Economy Act, 2009

The *Green Energy and Green Economy Act, 2009* (the "GEGEA") received royal assent on May 14, 2009. The Chair's statement notes that the GEGEA will further increase infrastructure investment by electricity utilities. The GEGEA makes it clear that the connection of renewable energy generation facilities and the development of a smart grid are policy matters of priority for the Government. Among other things the GEGEA adds objectives for the Board relating to the promotion or facilitation, respectively, of these matters. The GEGEA also confirms the authority of the Board to provide incentives to electricity transmitters and distributors in relation to infrastructure investment and to provide for the recovery of costs incurred or to be incurred in relation to infrastructure investment activities.

June 1, 2009 Statement of the Chair

On June 1, 2009, in a second Statement the Chair advised of the development of three initiatives, one of which is to consider more innovative approaches to cost recovery, primarily in relation to infrastructure investments relating to the accommodation of renewable generation and smart grid development. The cost recovery mechanisms developed through this initiative may also be available in relation to other types of projects in appropriate circumstances.

This Discussion Paper is intended to solicit input from all interested stakeholders on a range of alternative mechanisms within an integrated framework for the regulatory treatment of infrastructure investment. The focus of this Discussion Paper is specifically on infrastructure investment by electricity transmitters and distributors. The GEGEA establishes a legislative framework that imposes responsibilities on electricity utilities in relation to smart grid development and renewable generation connection activities, and that requires the Board to be guided by the objective of promoting or facilitating such activities. Nonetheless, staff notes that this need not preclude the Board from considering use of such a framework for other rate-regulated entities.

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?

Issue for comment

This Discussion Paper sets out a range of mechanisms for the regulatory treatment of infrastructure investment that could be used to support the setting of rates. One or more of these mechanisms could be applied in the context of a cost of service review, a multi-year rate adjustment mechanism or a specific ("single issue") rate application. Other processes, such as the process for approving distributor and transmitter infrastructure investment plans, may also provide a forum in which some of the alternative mechanisms referred to in this Discussion Paper may be considered.

References used in drafting this Discussion Paper

Portions of this Discussion Paper draw heavily on the Federal Energy Regulatory Commission's ("FERC") July 20, 2006 Final Rule, *Promoting Transmission Investment through Pricing Reform* (Order No. 679; 116 FERC ¶ 61,057). Some of the mechanisms identified in this Discussion Paper are the same as those adopted by FERC. Portions of this Discussion Paper also draw heavily on a National Regulatory Research Institute ("NRRI") paper written by Scott Hempling and Scott H. Strauss, *Pre-Approval Commitments: When and Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?* issued in November, 2008. In staff's view, these two documents reflect a thoughtful analysis of the issues and concerns relating to new and more challenging infrastructure needs, as well as of potential approaches to dealing with those issues and concerns. While staff recognizes the need to ensure that solutions adapted from other jurisdictions are suited to the Ontario context, staff believes that these documents provide a sound basis for developing a similar approach in this Province.

Organization of this Discussion Paper

This Discussion Paper is organized as follows. Chapter 2 discusses various infrastructure investment drivers. Chapter 3 identifies alternative mechanisms that the Board might consider to ensure that its rate-making policies promote or facilitate appropriate infrastructure investment while protecting the interests of ratepayers. It also identifies the extent to which those alternative mechanisms may apply to the different types of investment discussed in Chapter 2. Chapter 4 discusses conditions for approval (i.e., conditions precedent to approval) and conditions of approval (i.e., conditions that may apply to an approval) that may be appropriate in cases where the Board might use one or more of the alternative mechanisms. Chapter 5 discusses certain implementation considerations. The Discussion Paper identifies a number of issues for stakeholder comment throughout, and

Chapter 6 provides a summary list of these issues. A draft template for potential reporting requirements associated with certain mechanisms set out in this Discussion Paper is provided in Appendix A.

2 Infrastructure Investment in Ontario

Context for electricity transmission and distribution infrastructure investment

Ontario's electricity rate-regulated companies, particularly distributors and transmitters, are investing substantial amounts of capital to replace aging infrastructure, deploy smart meters, connect new load, and maintain system operability and reliability. In addition, the extended obligations of electricity distributors and transmitters under the GEGEA include the preparing and filing with the Board of plans relating to: a) the expansion and reinforcement of their systems to accommodate the connection of renewable energy generation facilities, and b) the development and implementation of the "smart grid". Electricity distributors and transmitters will be expected to make investments in accordance with their approved plans, or otherwise as directed by the Board.

Routine, Incremental, and/or GEGEA-related investment

Capital project undertakings by electricity distributors and transmitters are usually a mix of activities. Examples of such projects include: reinforcements to accommodate new load or generation; replacement of system elements that are at or exceed useful life; and system enhancements to restore power quality or system reliability to acceptable standards. It is recognized that a company's objectives of optimizing resources and minimizing costs are achieved by incorporating various projects and programs in a single initiative or overlapping activities on the same system component(s); for example a distribution or transmission line. Precise breakdown of complex capital projects into "routine" versus "non-routine incremental" versus "GEGEA-related" investments may not be practical or absolutely necessary. For the purposes of the framework discussed in this Discussion Paper, the objective would be, to the extent practicable, to identify the primary driver for an investment so that applicable options for the regulatory treatment of the related project costs may be more clearly evident.

The brief descriptions provided in the sections below are included to illustrate what might be considered as different types of investments so as to facilitate consultation with stakeholders on investments that may qualify for the alternative mechanisms identified in this Discussion Paper. The descriptions are not intended to provide an exhaustive listing of investments that might be considered to fall within any of the categories identified below.

2.1 Routine Investment

System Sustainment

Capital expenditures ("CAPEX") for system sustainment may include the costs for investments in assets such as stations, lines and meters required to ensure that existing system facilities function as originally designed. Investments are needed to maintain the long term and short term functionality of assets, to ensure public and employee safety, to comply with regulations and applicable regulatory requirements.

Stations, lines and meter assets, and their components, are subject to deterioration that will eventually impede their ability to function as originally designed. Asset deterioration depends on factors such as geographic environment/location, utilization, age, weather and maintenance practices. As assets deteriorate, equipment performance reliability usually suffers, resulting in increased environmental risks, an increase in potential safety hazards to the public and employees, and decreased system reliability. Ultimately, assets deteriorate to the point that they are no longer able to perform their function in a cost-effective manner, at which point replacement, rather than repair and maintenance, becomes necessary.

System Enhancement

In the Distribution System Code an "enhancement" is defined as "a modification to an existing distribution system that is made for purposes of improving system operating characteristics such as reliability or power quality or for relieving system capacity constraints resulting, for example, from general load growth".

System Expansion

The Distribution System Code defines an "expansion" as "an addition to a distribution system in response to a request for additional customer connections that otherwise could not be made; for example, by increasing the length of the distribution system".

The rules relating to cost responsibility associated with connections and system upgrades or modifications are set out in the Board's Distribution System Code and Transmission System Code.

2.2 Non-Routine Incremental Investment

Under the Board's 3rd Generation incentive regulation ("IR") plan, the Board has provided a means for an electricity distributor to file an application requesting prospective rate relief for particular (i.e., non-routine) incremental CAPEX through the Incremental Capital Module ("ICM"). The ICM is intended to be reserved for unusual circumstances that are not captured as a Z-factor and where the electricity distributor has no other options for meeting its capital requirements within the context of its financial capacities underpinned by existing rates. The eligibility criteria for the ICM are materiality, need and prudence.

As stated in a May 13, 2009 Decision in response to an application from Hydro One Networks, Inc. (Board File No. EB-2008-0187):

> The Board's objective in establishing the incremental capital module was to enhance the regulatory efficiency of the incentive rate mechanism, which is intended to be formulaic and simplistic in its application, by adding a method to accommodate extraordinary capital spending requirements should they arise during the term of the incentive rate mechanism. The ability to address extraordinary capital spending requirements within the IRM framework increases the efficiency opportunities without requiring a full cost of service rebasing review.

Further, the Board states in that Decision:

> In its adoption of the incremental capital module as part of the third generation incentive rate mechanism the Board was providing the regulatory flexibility that is required to accommodate unanticipated events that may occur over an extended IRM term. The rapid policy evolution that is currently being experienced in the electricity distribution sector, such as the requirements under the Green Energy Act (Bill 150) may drive capital spending on an array of initiatives that would not typically be considered in a distributor's traditional planning exercise. This evolving policy environment is an example of the envisioned drivers that justified the provision of the regulatory flexibility that the incremental capital module is intended to create.

For the purposes of this Discussion Paper and as stated in the Decision cited above, a non-routine incremental investment would differ from a routine investment in that the utility 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". This may include, but not necessarily be limited to, investments such as those that may be associated with extended obligations to invest as discussed below.

2.3 Extended Obligations to Invest

The GEGEA is expected to further increase distribution and transmission infrastructure investment, both to accommodate anticipated increased levels of renewable generation and to establish a smart grid. As noted above, electricity distributors and transmitters will, as required by the Board, need to file plans and invest in their systems to be able to accommodate renewable generation. They will, also as required by the Board, need to file plans and make investments related to the development of the smart grid.

Electricity distributors and transmitters will be expected to build and make investments according to those plans once they are approved by the Board, or as otherwise directed by the Board.

2.3.1 Accommodating the Connection of Renewables

Distribution systems have been built to take power from the transmission system at one or a limited number of points and distribute it to loads within the service area. Two-way flow and distribution-connected generators are not always easily accommodated. Systems where there are supplies of renewable generation resources have been planned based on applicable load rather than available generation. Therefore, connecting distributed generation can involve costly reinforcement.

The GEGEA provides a mechanism by which Board-approved costs incurred by a distributor to make an “eligible investment” for the purpose of connecting or enabling the connection of a “qualifying generation facility” to its distribution system may be recovered through contributions payable by all consumers throughout the Province.

Proposed Changes to Connection Cost Responsibility Rules

Proposed Amendments to the Distribution System Code

Distribution System Connection Assets, "Expansions" to connect a specific generation facility, and "Renewable enabling improvements"

On June 5, 2009, the Board issued a notice of proposed amendments to the Distribution System Code (the "Notice") relating to the assignment of cost responsibility between distributors and renewable generators (consultation process EB-2009-0077). Under the proposed amendments, generators would remain responsible for the cost of "connection assets". However, distributors would be responsible for some or all of the costs associated with "expansions" and would be responsible for all of the costs associated with "renewable enabling improvements" in relation to the connection of renewable generation facilities. A revised definition of "expansion" and a new definition of "renewable enabling improvement" are included in the proposed amendments.

Proposed Amendments to the Transmission System Code

Transmission System

The Board is also currently consulting on proposed amendments to the Transmission System Code in relation to cost responsibility associated with the connection of generation facilities to electricity transmission systems (consultation process EB-2008-0003).

"Enabler" transmission facilities

The proposed amendments contemplate the implementation of a "hybrid" approach to cost responsibility in relation to "enabler" facilities, being transmission facilities, constructed, owned and operated by a transmitter, intended to connect multi-proponent clusters of renewable generation resources. Under the proposed hybrid approach, the costs associated with an enabler facility would be pooled temporarily, with generators making pro-rata contributions towards the cost of the enabler facility as and when they become ready to connect. The outstanding costs for any "unsubscribed" portions of an enabler facility would be included in the transmitter's rate base and be recovered from transmission ratepayers.

Cost Responsibilities May Change

Transmission & distribution system investment cost responsibilities may change

The proposed amendments to the Distribution System Code and the Transmission System Code described above contemplate that utilities will have cost responsibility for certain investments relating to renewable generation that they do not currently have. The final disposition of these proposed amendments may therefore affect the costs that transmitters and distributors may incur in relation to renewable generation in the future.

2.3.2 Smart Grid

The GEGEA defines a "smart grid" as advanced information exchange systems and equipment that when utilized together improve the flexibility, security, reliability, efficiency and safety of the integrated power system and distribution systems, particularly for the purposes of: (a) enabling the increased use of renewable energy sources and technology; (b) expanding opportunities to provide demand response, price information and load control; and (c) accommodating the use of emerging, innovative and energy-saving technologies and system control applications.

The implementation of smart grid technologies is expected to provide (among other things) the information necessary for electricity distributors to take a more active part in managing their systems to allow two-way flow and to use distributed generation and demand resources to meet the needs of loads. Some early investment in demonstration projects may be required to innovate, test and prove new emerging technologies that would subsequently allow electricity distributors to, amongst other things, implement proven smart grid solutions in a proactive manner.

Summary

This Chapter has discussed various infrastructure investment drivers and has suggested broad classifications for investment.

Issue for comment

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?

3 Treatment of Infrastructure Investment

3.1 Conventional Cost Recovery Mechanisms

Cost recovery for CAPEX has traditionally been allowed when construction is completed and the associated infrastructure is considered "used and useful". Regulatory approval and recovery in rates for CAPEX has traditionally been predicated upon assets being used and useful, and on their costs being confirmed by the Board as having been prudently incurred.

The mechanism used to recover costs associated with CAPEX differs with the method used to set or adjust the regulated entity's rates – i.e., through a cost of service review or through a multi-year rate adjustment mechanism. The cost recovery mechanisms that the Board has used are described below.

3.1.1 Under Cost of Service

Cost of Service / Rebasing

Through a cost of service review (may also be referred to as a rebasing review in the context of an incentive regulation regime), a rate-regulated company is allowed to recover in rates the revenue requirement associated with approved forecast CAPEX that are forecast to be in service during the test year. In the case of multi-year CAPEX, the Board allows interest to accrue during the construction period (i.e., an Allowance for Funds Used During Construction) and, once the assets are used and useful, the costs including the interest during construction are transferred into rate base.

3.1.2 Under Multi-year Rate Adjustment Mechanisms

Price Cap Index Adjustment

The Board's incentive regulation plans for Ontario's electricity distributors provide for annual rate adjustments through a price cap index. An implicit adjustment for "steady state" CAPEX exists in the price cap index because a historical level of CAPEX is built into the productivity factor, the principal offset to inflation in the price cap index. That is, rate relief for routine capital investments is provided by the application of the price cap index to the return of and on capital embedded in rates. Rate relief is also provided with the addition of new customers or increased loads where applicable.

Off-Ramp

Under the Board's 2nd Generation IR plan, if the IR adjustments are insufficient for specific cost pressures, such as capital investment substantially different from historical levels, electricity distributors may file a comprehensive cost of service application.

The Incremental Capital Module

Electricity distributors with an inordinately large capital spending program may best be accommodated through rebasing. However, in developing the 3rd Generation IR plan, the Board determined that some non-routine incremental capital investment needs may arise during the IR term and provided for a modular approach, the ICM, to accommodate such needs.

Distributors that receive relief through the ICM are required to report to the Board annually on the actual amounts spent. At the time of rebasing, the Board will carry out a prudence review to determine the amounts to be incorporated into rate base. Staff notes that during the IR plan term, differences may arise between forecast and actual capital spending. At the time of rebasing, the Board will also make a determination regarding the treatment of these differences.

3.2 Alternative Mechanisms

3.2.1 Introduction

Mechanisms to address unique challenges associated with certain investments

Identified below is an array of mechanisms for providing for unforeseen events, accelerating the cost recovery of, or for providing incentives for, certain infrastructure investments (see section 3.2.2) that the Board could consider if applied for by an electricity transmitter or distributor. These mechanisms are intended to address the unique challenges that may be associated with those investments, and to facilitate the timely development of infrastructure that is expected to be needed to accommodate increased renewable generation and to establish the smart grid, in keeping with the Board's objectives. The mechanisms adjust several conventional rate making policies to encourage appropriate infrastructure investment.

Case-by-case approach to encourage appropriate investment

Staff suggests that adopting a case-by-case approach to the review and approval of applications for one or more alternative mechanisms to encourage appropriate investment may provide the most effective way of balancing the unique challenges and the particular circumstances of an applicant with the public interest. Staff believes that an applicant should be required to demonstrate that there is a *nexus* between the treatment sought and the investment being made.

Meaning of "incentive"

FERC Order 679 identifies seven "incentives" that are available to all jurisdictional public utilities: the ROE adder, allowing CWIP in rate base prior to the asset coming into service, the hypothetical capital structure, accelerated depreciation, recovery of costs of abandoned facilities, deferred cost recovery, and single-issue ratemaking. While for the purposes of this paper, staff has distinguished classes of mechanisms differently than FERC, staff shares FERC's concern as explained in its Order 679 regarding the meaning of "incentives" in the context of infrastructure development. The alternative mechanisms described in this Discussion Paper are intended to provide "incentives" to construct appropriate infrastructure, but they do not constitute an "incentive" in the sense of a "bonus" for good behavior. Rather, if adopted by the Board, each should be applied in a manner that is rationally tailored to the risks and challenges faced in constructing the infrastructure. Not every mechanism would be available for every new investment (see section 3.3.2). In this way, the framework would continue to meet the just and reasonable standard by achieving an appropriate balance between consumer and investor interests on the facts of a particular case[1].

3.2.2 Investments that May Qualify for Alternative Mechanisms

As noted above, staff suggests that the Board should exercise its discretion to allow alternative treatment on a case-by-case basis for appropriate infrastructure investments by electricity transmitters and distributors in a manner that facilitates the achievement of the government's policy objectives as reflected in the GEGEA while protecting the interests of ratepayers.

Accommodating the connection of renewable generation and development of smart grid

Staff suggests that the mechanisms identified below should apply to the recovery of costs incurred by electricity transmitters or distributors to be able to accommodate the connection of renewable generation, or to develop the smart grid, or both. This may include investments as contemplated in the proposed amendments to the Codes noted in section 2.3.1 to the extent that the costs are, in accordance with the relevant Code, recovered through transmission or distribution rates rather than by customer capital contribution. In addition, staff thinks

[1] For examples that illustrate this point, see Order No. 679, FERC 116 FERC ¶ 61,057, Promoting Transmission Investment through Pricing Reform, Final Rule, July 20, 2006, paragraphs 27-29.

that the mechanisms should be able to be applied to infrastructure investment even if the cost of the investment is potentially recoverable through the Province-wide cost recovery mechanism referred to in section 2.3.1.

Beyond this, staff believes that it is premature at this time to attempt to more definitively identify which other types of investments may qualify for an alternative mechanism and which will not. Staff is also mindful of the fact that, as noted above, investments may have more than one driver.

With respect to smart grid investments, staff notes that rate treatments of smart grid investments are being debated vigorously before FERC.[2] In particular concerns have been raised that special incentives for smart grid investments should not be offered until complex technical issues, especially those relating to cybersecurity and connectivity, are resolved and comprehensive standards have been developed. Without some certainty on these issues concern has been raised that the FERC's proposed incentive rate treatments could result in higher rates for consumers without sufficient offsetting benefits.

Issues for comment

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?

4. Should the mechanisms set out in this Discussion Paper be applied to infrastructure investment if the cost of the investment is

[2] On March 19, 2009, FERC released its Proposed Policy Statement and Action Plan (Proposed Policy Statement) for stakeholder comment (126 FERC ¶ 61,253). Stakeholder comments were due on May 11, 2009.

potentially recoverable through a Province-wide cost recovery mechanism? Why, or why not?

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?

Staff notes that some stakeholders may be concerned that the potential exclusion of "routine" investments could be problematic in the sense that, for some transmitters and distributors, large capital expenditure plans (arising from various drivers) may increase company-wide risk. It may be argued that in such a case the cumulative effect of the capital program may create risk. However, staff does not believe that alternative mechanisms will frequently be warranted in relation to the “routine” investments described in section 2.1 above. Staff believes that rate-regulated companies should continue to apply for cost recovery of “routine” investments through the conventional mechanisms described in section 3.1 above. Staff believes that the Board’s annual rate adjustments reasonably compensate companies for the efficient and on-going management of their systems. Projects for the on-going management of transmission and distribution systems are generally routine in nature and generally do not involve the kinds of scope, effects, risks and challenges that may warrant the provision of alternative treatment.

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?

Issue for comment

Beyond identifying certain investments that would be presumed to qualify for alternative mechanisms, as stated above, staff does not believe that the Board should establish more detailed criteria at this time. Establishing criteria now would limit the flexibility of any new policies adopted by the Board.

Detailed criteria not established by FERC

In its policies, FERC has identified a limited number of investments which, if they meet specified criteria, will be presumed to qualify for incentive-based treatment unless a party convinces FERC otherwise (these are referred to by FERC as "rebuttable presumptions"). For all other investments, FERC has declined to establish detailed criteria that an applicant must meet to be eligible for the incentive-based rate treatments.

Except for the rebuttable presumptions addressed in FERC Order 679, FERC explains why it has not at this time established more detailed criteria that an applicant must meet to be eligible for incentive-based rate treatments. In FERC's view, "[e]stablishing criteria now would limit the flexibility of the Rule or improperly pre-judge which projects are acceptable for incentives. The Commission will, on a case-by-case basis, require each applicant to justify the incentives it requests. Because these proceedings will provide ample opportunity for parties to comment on any incentive proposal, we do not see the need for a technical conference or detailed criteria now".[3] Staff believes that this framework could be effective in Ontario and in keeping with the Board's objectives.

In keeping with the FERC approach, staff also suggests that an applicant should be allowed to request any combination of the mechanisms identified in this Discussion Paper. Further, applicants should not be prohibited from requesting mechanisms that are not listed in this Discussion Paper. In either case, staff anticipates that the applicant would fully support its request. As such, the Board could

[3] FERC Order No. 679, paragraph 43.

expect applicants to develop their proposals based on the specific requirements and circumstances of their projects.

Staff is mindful of the clarifications in a statement issued on December 21, 2006, by the Joseph T. Kelliher, then Chairman of FERC:

> "We clarify that an applicant will be required to demonstrate that the incentives sought are tailored to address the demonstrable risks and challenges faced by the applicant. This makes it clear an applicant must show a close link between incentives requested and the risks and challenges. We also clarify that we will balance an applicant's total package of requested incentives. If an applicant seeks a higher return to reflect the higher risk of a project, but also seeks recovery of construction work in progress and abandoned plant, which reduce project risk, the return granted may be lower than requested".

Interested stakeholders will have an opportunity to raise any concerns they may have when the Board considers an application for an alternative treatment.

Issues for comment

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?

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?

3.2.3 Provision for Unforeseen Events

Recovery of Costs of Abandoned Facilities

Risk associated with factors outside of management's control

Staff notes that applicants may encounter investment opportunities with significant risk associated with factors beyond their control, such as generation developers' decisions to change or cancel their plans to develop potential facilities or difficulty obtaining environmental assessment approvals. In these circumstances, staff believes that it may be appropriate to consider ways to reduce the risk associated with potential upgrades or other system improvements.

To reduce the uncertainty associated with higher risk projects, thereby facilitating investment in these projects, staff suggests that an applicant be allowed to request confirmation from the Board that prudently-incurred costs associated with any abandoned projects would be included in rates if such abandonment is outside the control of management. This is consistent with statements made by the Board in its April 15, 2009 *Notice of Revised Proposal to Amend a Code* regarding Transmission System Code amendments relating to "enabler" transmission facilities (EB-2008-0003). Specifically, the Board indicated that "[T]he transmitter that has been designated by the Board to undertake development activities in relation to an enabler facility will be permitted to recover all of the prudently incurred costs associated with those activities even if the enabler facility does not proceed to construction, provided that failure to proceed to construction is for reasons outside of the transmitter's control".

In the event that abandonment occurs, the applicant could file for recovery of abandoned plant costs in rates at the time the project is abandoned.

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?

Issue for comment

3.2.4 Accelerated Cost Recovery

Staff is aware that accelerated cost recovery mechanisms may create inter-generational inequities amongst ratepayers since current ratepayers would be required to pay for a portion of the costs of an asset that will serve future ratepayers. On balance, however, in light of the Board's objectives and the extended obligations of electricity transmitters and distributors to invest to be able to accommodate the connection of renewable generation and to invest in the development of the smart grid, staff thinks accelerated cost recovery may be an effective inducement to timely investment.

Construction Work In Progress ("CWIP")

Including construction work in progress ("CWIP") in rate base prior to the asset coming into service allows the rate-regulated company to recover the carrying cost on this capital investment, typically interest costs on debt and a return on the investment.

Impact on borrowing costs

Including CWIP in rate base is a regulatory treatment that can phase in the cost of large, multi-year projects, and mitigate the potential for a decline in company credit quality during a major construction program. In the U.S., some utilities have expressed the concern that, without inclusion of CWIP in rates, the funding needed for a major construction program can lead to a decline in credit quality and a corresponding increase in borrowing costs and ultimately in rates. 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.

Rate impact mitigation

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. While other approaches like levelizing the recovery of capital after the in-service date can assist in mitigating rate impacts, they tend to worsen the impact on borrowing costs.

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 with significant expenditures on major new infrastructure projects with long construction periods spanning several years.

Issue for comment

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?

Contract-term Depreciation

Depreciation is the allocation of the historical costs of an asset over the time period where the asset is employed to generate revenues. Depreciation can be based on the useful life of an asset, i.e., the expected period of time during which it will be productive. Depreciation can also be specifically set as has been done in FERC Order 679 as described below, or it can be based on contract terms.

FERC has provided for accelerated depreciation to increase cash flow to utilities in order to facilitate timely investment. Specifically, utilities may propose using accelerated depreciation for rate purposes over a period of time as short as 15 years. In addition, FERC will consider depreciable lives of less than 15 years because shorter depreciable lives may be appropriate in certain cases, such as advanced technologies for which the useful life is not necessarily known.

Adjusting depreciation to reflect a contract term instead of the useful life of the asset is another way to reduce risk, thereby facilitating timely investment.

Risk mitigation

In the context of the extended obligations of electricity transmitters and distributors to invest as discussed in section 2.3, staff believes that in certain circumstances it may be appropriate to adjust depreciation to reflect a contract term which will likely be consistent with the useful life of the connecting renewable generation facility. Doing so would reduce risk to the transmitter or distributor of under-recovery of their investment. For the purposes of this Discussion Paper, the contract term that may inform the adjustment of depreciation might be the term of the power purchase agreement with the first generator to connect to the facilities. In the event that at the time of approval it is anticipated that there would be multiple generators being connected over a multi-year period, then staff notes that the Board may need to consider that when setting an appropriate amortization period.

Therefore, staff suggests that applicants should be able to propose project-specific depreciation for significant infrastructure investments.

Issue for comment

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?

3.2.5 Incentive Mechanisms

FERC context

FERC states in Order 679 that it "will allow, when justified, an incentive-based ROE to all public utilities (i.e., traditional public utilities and Transcos) for new investments in transmission facilities that benefit consumers by ensuring reliability or reducing the cost of delivered power by reducing transmission congestion. By including this provision in the Final Rule, we meet the requirement of section 219 to provide an ROE that attracts new investment in transmission facilities (including related transmission technologies)".[4] FERC also provides for project-specific capital structures (referred to in FERC Order 679 as "hypothetical capital structures").

Ontario context

For the purposes of this Discussion Paper, staff has classified these two mechanisms in particular as "incentives" because they provide "cost plus" compensation to the regulated entity for its investment. It is staff's understanding that these incentives are of particular relevance

[4] FERC Order No. 679. Pursuant to the requirements of the Transmission Infrastructure Investment provisions in section 1241 of the *Energy Policy Act of 2005*, which adds a new section 219 to the *Federal Power Act*, FERC amended its regulations to establish incentive-based rate treatments for the interstate transmission of electricity by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing the cost of power by reducing congestion.

in the FERC context because the Commission does not have authority to order companies to invest in or build the needed facilities[5] envisioned in the referenced Transmission Infrastructure Investment provisions in section 1241 of the *Energy Policy Act of 2005*.

Staff notes that, in this respect, the legislative context in Ontario is different. Specifically, the GEGEA establishes extended obligations for electricity transmitters and distributors to make certain infrastructure investments, and empowers the Board to mandate those investments.

Issue for comment

12. In light of a legislative context in which the Board may mandate infrastructure investments, are incentives necessary or appropriate in Ontario?

Project ROE Adders

ROE incentives encourage investment by making the projects more attractive, and therefore more likely, when projects compete for capital in distribution and transmission capital planning.

Riskier projects may need equity financing

In cases where the investment is not mandated by the Board, some projects may be undertaken only at the election of investors.

Where an electricity transmitter or distributor is not "required" to undertake a project, and the project is perceived as particularly

[5] As indicated on the FERC's web site (http://www.ferc.gov/about/ferc-does.asp).

risky, a project-specific ROE may be appropriate to encourage proactive investment.

Issue for comment

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?

Project-Specific Capital Structure

Financing flexibility

Project-specific capital structures are a means of providing additional flexibility with regard to financing arrangements. A project or its proponent(s) may have unique financial and cash flow requirements, and too rigid of an approach to acceptable capital structures may affect the viability of some projects.

The Board relies on a deemed capital structure when setting the overall rate of return for distribution and transmission businesses. However, staff recognizes that an overly prescriptive approach to evaluating a proposed project-specific capital structure may not provide a sufficient incentive to some types of infrastructure investment. Accordingly, staff believes that the Board could allow applicants to file a project-specific capital structure, and give them the flexibility to refinance or employ different capitalizations as may be needed to maintain the viability of new infrastructure projects.

Consortium projects

Project-specific capital structures may be particularly effective for development of consortium projects. This can be especially important for projects with a diverse set of sponsors, some of which have different capital structures.

14. If the Board were to provide for incentives, should it allow project-specific capital structures? ***Issue for comment***

Summary

This Chapter has identified alternative mechanisms that staff believes the Board might consider to ensure that its rate-making policies promote or facilitate appropriate infrastructure investment while protecting the interests of ratepayers. It also identifies the extent to which those alternative mechanisms may apply to the different types of investment discussed in Chapter 2.

15. What other alternative mechanisms, if any, might the Board consider be made available to applicants? Why? ***Issue for comment***

4 Considerations and Conditions That May Apply

As stated previously, staff suggests that the Board use its discretion to allow alternative treatment on a case-by-case basis for certain infrastructure investments in a manner that facilitates the achievement of the government's policy objectives as reflected in the GEGEA while protecting the interests of ratepayers.

This case-by-case approach is intended to ensure that alternative treatment is well-tailored to particular circumstances.

4.1 Potential Considerations

Staff notes that the Board may consider the following[6], amongst other matters, when reviewing applications for the alternative treatments described in this Discussion Paper:

- Efficient utility management: Will the proposed regulatory treatment (or inaction) add (or subtract) certainty; to what extent, if any, will the applicant have less incentive to act cost effectively?

- Alignment of responsibility and risk: Does the approval allocate responsibilities, risks and benefits in an appropriate manner?

- Sound planning and timely investment: Will the decision encourage sound planning and timely investment?

[6] For a discussion of these and other matters, see NRRI Report, pp. 23-26.

- Access to capital: Will the approach allow the applicant to attract necessary capital on reasonable terms?

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? *Issue for comment*

4.2 Conditions that May Apply

4.2.1 Consistency with Board-Approved Plans

The GEGEA provides for Board approval of infrastructure plans. The Board's review and approval process is expected to establish specific investment needs and objectives and identify project options that may best satisfy those needs and objectives.

Once a plan has been approved, the Board may be more inclined to grant some form of alternative mechanism(s) for projects that are consistent with, if not explicitly identified in, that plan. Where a project is not identified in an approved plan, the Board may require applicants seeking alternative treatment to demonstrate that the project is consistent with the terms of the Board-approved plan.

4.2.2 Performance/Progress Conditions

Staff is of the view that the Board should establish project performance conditions to protect ratepayer interests.

For example, for multi-year projects the Board may require that a specified percentage of the costs of a project be incurred, or specific milestones of the project be completed, before any early recovery mechanism takes effect.

17. What performance conditions, if any, should be established? ***Issue for comment***

4.2.3 Reporting Requirements

Information regarding projected investments as well as information about completed projects will help the Board to monitor the success of the alternative treatments set out in this Discussion Paper in facilitating timely and appropriate investment. Further, where early cost recovery is authorized, such information may also help the Board to monitor the progress of construction of pre-approved facilities. To that end, staff believes that the Board should require project data, projections and related information that detail the level of investment.

The information proposed to be sought is not readily available in existing reporting requirements and would be required only from companies that have been granted alternative treatment for specific projects. At a minimum, staff thinks that the Board should require affected companies to report annually on approved projects no later than April 30th on the following data and projections:

- in dollar terms, actual investment for the most recent calendar year, and planned investments for at a minimum the next three years; and

- for all current and planned investments over the next five years, a project by project listing that specifies for each project the expected completion date, percentage completion as of the date of filing and reasons for any delay.

A template for the filing of this information is in Appendix A.

The reported information is to be provided for informational purposes only. Its purpose is not to establish the prudence of the amounts spent.

18. Are the reporting requirements suggested appropriate and adequate?

Issue for comment

Summary

This Chapter has discussed conditions for approval (i.e., conditions precedent to approval) and conditions of approval (i.e., conditions that may apply to an approval) that may be appropriate in cases where the Board might use one or more of the alternative mechanisms.

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?

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?

Issues for comment

5 Implementation Considerations

5.1 Potential Filing Guidelines

The Board has established *Filing Requirements for Transmission and Distribution Applications* for electricity transmitters and distributors to use when filing for rate adjustments, for leave to construct approvals, and for conservation funding[7].

The Board has also set out specific filing guidelines for applications by electricity distributors for rate adjustments on the basis of the 2nd Generation IR plan[8] and the 3rd Generation IR plan[9].

As indicated in the Chair's June 1, 2009 statement on *Initiatives to Implement an Integrated Regulatory Framework for Electricity Infrastructure Investment*, the Board will soon initiate a consultation on electricity distribution infrastructure planning to provide, among other things, guidance on the Board's expectations regarding planning for renewable generation connections and smart grid development.

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?

Issue for comment

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[7] Available on the Board web site under "Regulatory Instruments" at: http://www.oeb.gov.on.ca/OEB/Industry+Relations/Rules+Codes+Guidelines+and+Forms/Rules+Codes+Guidelines+and+Forms+-+Regulatory#filreq

[8] Please see Appendix to the December 20, 2006 *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (Board File No. EB-2006-0088/89).

[9] Please see Appendix to the September 17, 2008 *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (Board File No. EB-2007-0673).

5.2 Applications – When to Apply

As previously noted, one or more of the mechanisms identified in this Discussion Paper could be applied for in the context of a cost of service review, a multi-year rate adjustment mechanism or a specific ("single issue") rate application. Other processes, such as the process for approving distributor and transmitter infrastructure investment plans, may also provide a forum in which some of the alternative mechanisms referred to in this Discussion Paper may be considered.

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?

Issue for comment

5.2.1 Confirmation of Eligibility for Alternative Treatments

In certain instances, staff understands that it is valuable for an applicant to obtain confirmation from the Board indicating that a project qualifies for alternative treatment prior to commencing siting, permitting and construction activities, because such confirmation can facilitate financing and investment in new facilities. FERC policy refers to this kind of pre-commitment confirmation as a "pre-approval".

To provide applicants with as much flexibility as possible, staff suggests that the Board could permit applicants to seek approval prior to construction of the facilities to determine whether the facilities qualify for the requested alternative treatment(s). In its application, an

Option to seek "pre-approval" as to whether investment qualifies for alternative treatment(s)

applicant would be expected to identify which alternative mechanisms it seeks to implement and to provide justification for each.

Confirmation first, cost recovery later

Staff clarifies that, in its view, any decision stemming from the review of such an application should only rule on whether the applicant's proposal qualifies for alternative treatment and which treatment will be granted. Board staff does not envision that the decision will generally result in an immediate change in the applicant's rates. Rather, the applicant would apply for cost recovery as part of a future rate filing (i.e., a separate single-issue filing or at the time of the next scheduled rate filing). That rate proceeding would be limited to a review of the applicant's rates and would not revisit the issue of whether the applicant's project qualifies for alternative treatment. Therefore, if an interested stakeholder believes an applicant does not qualify for alternative treatments or that the alternative treatments requested by the applicant are not justified, the stakeholder must raise its objections when the application for approval of the alternative treatments is filed and not wait to raise them in any subsequent rate setting proceeding. If an applicant obtains approval for an alternative treatment and its project changes in a material way from the facts on which the approval was issued, the applicant may file an amended application or wait to confirm the application of the alternative treatment to the modified project in a subsequent rate proceeding. In that event, interested stakeholders may challenge the application of the alternative treatment to the modified project in the amendment application or rate setting proceeding.

Issue for comment

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?

5.2.2 Single Issue Rate Review

A single issue review would typically be initiated by specific application from a proponent, where the review would focus on the particular circumstances of the applicant. Where a particular matter is of relevance to more than one regulated entity, the single issue review may be initiated by the Board, either in a generic proceeding commenced on the Board's own motion or in a combined proceeding to address an issue that is common to a number of pending applications.

Specific Application

Staff suggests that the Board might consider project-specific applications that deal with the specific rate making implications of a new project. Single-issue ratemaking is designed to allow for the expeditious evaluation of the rate implications associated with new infrastructure based on the risks and returns of that project, without re-opening the applicant's entire base rates for review.

24. What are the implications, if any, of using the single-issue rate review process?

Issue for comment

Combined Proceeding or Proceeding on the Board's Own Motion

Where the Board determines that there are a number of common issues that could best be determined on a generic basis, it may decide to proceed on its own motion or to have a combined hearing (where the common issues are raised in multiple pending applications). Through such a proceeding, the Board would make certain determinations on such common or generic issues.

The Board held such a proceeding in 2005-2006 to deal with a number of common issues arising from applications to set 2006 electricity distribution rates (Proceeding RP-2005-0020 / EB-2005-0529). Amongst other things, the Decision with Reasons issued in that proceeding established a Smart Meter-related specific dollar per meter-month charge that each affected distributor would be allowed to include in its revenue requirement.

5.3 Recovery of Infrastructure Investments

Under Incentive Regulation

As previously noted, in developing the 3rd Generation IR plan, the Board determined that some non-routine incremental capital investment needs may arise during the IR term, and provided for a modular approach, the ICM, to accommodate such needs. The Board's filing guidelines contemplate that the Board-approved revenue requirement will be recovered by means of a rate rider until rebasing. At the time of rebasing, the Board will carry out a prudence review to determine the amounts to be incorporated into rate base.

Under Cost of Service

During a cost of service review, the revenue requirement associated with Board-approved capital investments are incorporated into rate base.

Use of Rate Rider

Consistent with the above approach, staff suggests that during an IR year any rate adjustment associated with an alternative treatment be implemented by means of a rate rider until such time that the company's rate are rebased.

Issue for comment

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?

5.3.1 Recovery of Costs for Multi-year Projects

In the 3rd Generation IR filing guidelines, the Board states its expectation that a detailed calculation of the applicant's proposed rate rider(s) be provided for each year of the IR plan term in relation to the ICM.

For multi-year projects, staff suggests that the Board could allow applicants to seek multi-year rate riders designed to increase over time through automatic "step increases" according to a pre-determined schedule, as the company's project costs rise. Staff thinks that this mechanism could be particularly suited to distributors for whom the Board has approved an investment infrastructure plan. In such a case, the distributor would be required to set out its proposed annual rate rider adjustments in relation to its approved plan. In each subsequent year of the approved plan, the distributor would notify the Board, through appropriate reporting requirements, that the investments required as preconditions for the forecasted step increase in the rate-rider have been made. In the event that there appears to be a material departure from the Board-approved plan, the Board may exercise its discretion to make adjustments to the rate riders previously approved. At the time of rebasing, the Board would carry out a prudence review to determine the amounts to be incorporated into rate base.

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?

Issue for comment

6 Summary of Issues for Comment

Chapter	For Comment
1 Overview	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?
2 Infrastructure Investment in Ontario	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?
3 Treatment of Infrastructure Investment	Investments that May Qualify for Alternative Mechanisms 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? 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? 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? 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? 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? 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? Provision for Unforeseen Events 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?

Chapter	For Comment
	Accelerated Cost Recovery 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? 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? Incentive Mechanisms 12. In light of a legislative context in which the Board may mandate infrastructure investments, are incentives necessary or appropriate in Ontario? 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? 14. If the Board were to provide for incentives, should it allow project-specific capital structures? General 15. What other alternative mechanisms, if any, might the Board consider be made available to applicants? Why?
4 Considerations and Conditions That May Apply	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? 17. What performance conditions, if any, should be established? 18. Are the reporting requirements suggested appropriate and adequate? 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? 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?

Chapter	For Comment
5 Implementation Considerations	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? 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? 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? 24. What are the implications, if any, of using the single-issue rate review process? 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? 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?

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Appendix A: Draft Report of Investment Activity

Company Name: ____

Table 1: Actual and Projected Capital Spending

	Actual at Dec 31st	Projected Investment (Incremental Investment by Year for Each of the Succeeding Calendar Years)				
Year →	20__	20__	20__	20__	20__	20__
Capital Spending on Facilities[1] ($ 000's)						

Table 2: Project Detail [2]

Project Description	Project Type [3]	Expected Project Completion Date (month/year)	Completion Status [4]	Is Project On Schedule? (Y/N)	If Project Not On Schedule, Indicate Reasons For Delay [5]

[1] Facilities are defined to be those eligible for alternative treatment as contained in this Discussion Paper.
[2] Respondents must list all projects included in the actual and projected capital spending table.
[3] Project types are New Build, Upgrade of Existing, Refurbishment/Replacement, or Generator Connection.
[4] Completion status designations are Complete, Under Construction, Pre-Engineering, Planned, Proposed, and Conceptual.
[5] Reasons for delay designations may include Siting, Permitting, Construction, Delayed Completion of New Generator, or Other (specify).