# Board Staff Interrogatories

## Licence Amendment Application Exemptions from Distribution System Code

## Hydro One Networks Inc.
## EB-2010-0229

**September 9, 2010**

## DSC REQUESTED AMENDMENTS IN REGARD TO UNFORESEEN TECHNICAL ISSUES WITH RENEWABLE ENERGY GENERATION PROJECTS

1. Please confirm if the investments by Hydro One to connect any of the generators described in the application can be reasonably expected at the time of construction to connect any other customers to the distribution system based on documents such building permits..etc.

2. Does Hydro One intend to charge generators for these costs, in part or full, in the event that the Board does not grant the requested exemptions? Please provide information on alternatives being considered by Hydro One.

3. <u>Ref: (a)</u> Exh B/Tab 1/Sch 1/p.3/lines 5-12
   <u>Ref: (b)</u> Exh B/Tab 1/Sch 1/p.7/ lines 13-21

   <u>Questions:</u>

   (i) At Reference (a), page 3, lines 5-6, please confirm whether or not the concerns outlined in this application are addressed in Hydro One's existing approved Green Energy plan.

   (ii) Does Hydro One intend to file an updated Green Energy plan? If so, when is that filing planned?

   (iii) At Reference (b), Hydro One indicated that it can be argued that the noted investments should rightly qualify as "eligible investment" costs, as set out in Ontario Regulation 330/09 and section 79.1(5) of the Act. Please provide detailed eligibility criteria that support this argument, for each of the three areas addressed:
   - Distance Limitation;
   - Transformers With Delta-Y Winding Configuration;
   - Dual Winding Secondary Transformers.

4. Ref: Exh B/ Tab 1/Sch. 1/p. 8/ lines 1-10

Question:

(i) Notwithstanding the rationale used by Hydro One to support its application, please comment on the view that any decision by this Board in regard to deeming the investments in question as eligible investments under Ontario Regulation 330/09, would be exceeding its jurisdiction, since it would in effect be altering the intent of Ontario Regulation 330/09 and section 79.1(5) of the Act.

5. Ref: (a) Exh B/Tab 1/Sch 1/pp. 1-2/Sec 1.0 Introduction

Ref: (b) Presentation to The Ontario Smart Grid Forum titled "DG Integration Key to Smart Grid", dated September 22, 2008, by Manager – Distr. Gen &Advance Grid Development, System Investment, Hydro One Networks. A copy is attached as Appendix "A" to Board Staff Interrogatories.

Ref: (c) Exh B/Tab 1/Sch 2/Sec 5/pp. 3-6, Table 1 (p. 4) & Table 2 (p. 6)

Preamble:

- In Reference (a), Hydro One stated in part that:

  *"Hydro One has committed to connect a number of generators under the terms of Connection Impact Assessments ("CIAs") and the (then) Connection Cost Recovery Agreements ("CCRAs," currently referred to as Connection Cost Agreements or "CCAs") made prior to Hydro One's discovery of technical problems with these connections.* ***These problems are excessive voltage fluctuations in the case of generators connecting at a distance from the station ("distance limitations")…[bolding added for emphasis]****, All of these technical issues have the potential to adversely affect the provision of distribution services to other customers connected to Hydro One's distribution system. Each of these issues arose as a result of the unique circumstances with the implementation of the renewable generation connections program. Hydro One has not experienced these types of*

*problems previously and they could not have been reasonably foreseen.*

- In Reference (b), the evidence seems to indicate that Hydro One Distribution was aware of the implications of connecting distributed generation including voltage management under various conditions. For instance on page 8 of Reference (b), the illustrative graph shows the voltage variation profiles of three scenarios – No Gen, Max Gen @ Max Load, and Max Gen @ Min Load. Page 9 depicts the voltage profile (variation) for three cases – for a case "Without DG", for a case with"2 X 9MW DGs near TS" and a third case with "Full DG penetration".

- Also in Reference (b), on page 12, the presentation includes a description on one of the "Challenges" described as:
  Rural Feeders – "Long, weak, light"
  Low stiffness, low short circuit, poor voltage control; 50% 1-ph.

- In Reference (c), the evidence indicate that the costs for the two groups "Projects with Longer-Term In- Service Dates" and "Projects with Lower Probability of Problems" are not yet very well defined and vary with an estimate of $40 million.

- Board staff also notes that since the mid 1980s, Hydro One and its predecessor Ontario Hydro connected many distributed generators on low voltage feeders at varying distances from transformer stations, including run-of-the river hydraulic generation whose electricity generation outputs are unpredictable. The impact on customers attributed to voltage fluctuation of the run-of the river hydraulic sites would be similar to the impact of other renewable resources such as photo-voltaic and wind generation.

Questions:

(i) In light of the Hydro One Presentation depicted in Reference (b), and the experience gained from connection of run-of-the-river hydraulic generation to the distribution system, please explain why Hydro One indicates in Reference (a) that it has not experienced the excessive voltage fluctuation problem in the case of generators connecting at a distance from the station ("distance limitations"), and why this problem could not have been reasonably foreseen.

(ii) Notwithstanding whether or not the noted problems could have been reasonably foreseen, are the magnitude of costs to deal with this issue of "distance limitations" material with respect to Hydro One Networks Inc.'s Distribution Revenue Requirement?

(iii) Notwithstanding whether or not the noted problems could have been reasonably foreseen, please indicate what oversight is needed to approve projects described in Reference (c) that have costs up to $40 million with little information in regard to project definition.

6. Ref: (a) Exh B/Tab 1/Sch 2/pp. 1-6

Preamble:
Notwithstanding Hydro One's submission that it lacked knowledge or experience in dealing with generators connecting at various distances from the transformer station, there is a view that the required investments as described by Hydro One in Reference (a), are expected of a distributor such as Hydro One Distribution in connecting distributed generators. The technical aspects of connecting distributed generators under changing cost responsibility arrangements are viewed as technical risks with associated costs. These risks are recognized in the form of a higher regulated rate of return.

Question:
(i) Does Hydro One agree or disagree with the view expressed above?

Please provide a detailed explanation with supporting reasons.

7. Ref: (a) Exh B/Tab 1/Sch 2/pp. 3-6

Questions:

(i) In regard to Reference (a), on page 5, for “Project with Near Term In-Service Dates, please provide specific information on each of the projects regarding:
  (a) Location, name of supplying TS;
  (b) Description of the feeder – length, location of load customers and their loads in kW or MW, location of generators, their types and size of each in kW or MW;
  (c) Description of the problem and the solution, and cost.

(ii) When will Hydro One know, for each of the nine projects classed as “Projects with Longer-Term In-Service Dates”, whether or not they will require similar treatment as the first group

8. Ref: (a) Exh B/Tab 1/Sch 1/pp. 1-2/sec 1.0 Introduction
   Ref: (b) Exh B/Tab 1/Sch 3/p. 2/Sec 3.0 and Section 5.0

Preamble:

- In Reference (a), Hydro One stated in part that:

  *“Hydro One has committed to connect a number of generators under the terms of Connection Impact Assessments (“CIAs”) and the (then) Connection Cost Recovery Agreements (“CCRAs,” currently referred to as Connection Cost Agreements or “CCAs”) made prior to Hydro One’s discovery of technical problems with these connections.* ***These problems are ….. over-voltage conditions identified with generators using a step-up transformer with a Delta-Y winding configuration [bolding added for emphasis]”***

- In Reference (b), Sec 3, Hydro One indicated that it was aware of the trade off between the two standards.

- In Reference (b), Sec 5, Hydro One indicated that the total cost of the program is between $4.5 and $6.5 million.

<u>Questions:</u>

(i) Given that Hydro One was aware for some time of the trade off between the two standards, please provide a response to a view that the responsibility for changing its transformer specification standard should rest with Hydro One Distribution, and the associated cost responsibility should be that of Hydro One Distribution and not the cost responsibility of the Hydro One distribution rate payers or the provincial electricity consumers.

(ii) Notwithstanding the argument of the cost responsibility, please provide reasons for viewing the amount of investment as sufficiently material enough to warrant efforts to assign the responsibility to others.

9. <u>Ref: (a)</u> Exh B/Tab 1/Sch 4/pp. 1-6
<u>Ref: (b)</u> Notice of Amendment to a Code – Amendments to the Distribution System Code ("DSC"), EB-2009-0077, dated October 21, 2009, Part III "Summary of Comments……" - Sec B "Cost Responsibility for Transformer Stations"

<u>Preamble:</u>

- At Ref: (b), it is stated in part that:

  *"Some stakeholders commented on the issue of cost responsibility for transformer stations, noting among other things that a transformer can be owned by either a distributor or a transmitter and that the definitions or descriptions of the terms "expansion" and "renewable enabling improvement" do not refer specifically to transformer stations.*

  *At the present time, all transformer stations owned by a distributor have been deemed by the Board to be distribution assets. As such, they form part of the distributor's rate base, and the Board confirms that they are therefore part of the distributor's main distribution*

> *system for the purposes of the DSC. As a result, cost responsibility for such a transformer station would be determined in the same manner as for all other modifications or additions to the main distribution system of the distributor to whose system the renewable generation facility is connecting.*
>
> *Were it to be the case that a transformer station owned by a distributor was not deemed to be a distribution asset (in other words, the transformer station is a transmission asset), then the station would not form part of the main distribution system of the distributor to whose system the renewable generation facility is connecting. In such a case, cost responsibility for the transformer station would be the same as for upstream costs; namely, the cost of the transformer station would be passed through to and borne by the generator.*
>
> *The Board recognizes that its approach to cost responsibility under the DSC results in a treatment of transformer station costs that varies depending on the classification of the transformer station, and will be mindful of this implication when it considers future Ontario Energy Board - applications where the classification of a distributor-owned transformer station is involved. "*

- Board staff notes that in Hydro One's case, the TS dual winding transformer issue is a transmitter issue as opposed to a distribution issue, and would therefore be subject to the cost responsibility criteria of the Transmission System Code.

<u>Questions:</u>

(i) In light of the evidence in Reference (b), with excerpts depicted in the Preamble above, the Board is aware of situations where reinforcements to a transformer station classed as a transmission asset is based on a "User Pay" approach as set out in the Transmission System Code, please explain, the rationale for reopening that issue.

(ii) In the Notice of Amendment noted in Reference (b), the Board outlined its understanding of the issue, recognizing the differences between the two Codes in regards to cost responsibility - the Transmission System Code and the Distribution System Code. Please confirm that Hydro One is aware of the Board's view and provide Hydro One's view.

(iii) Notwithstanding the views expressed by the Board and quoted above [excerpts from Reference (b)], please provide an estimate of the amount of investment, over the medium term, that Hydro One would be required to undertake to address the unbalanced flows in Dual Winding Secondary Transformers. Please provide this information in a Table similar to Table 1, page 6 of Reference (a) setting out in separate columns, the location, the number of generation projects, and the total capacity of these projects in MW.

(iv) Given that the Transmission System Code criteria regarding cost responsibility for transformer stations is based on User Pay principles, would Hydro One be seeking a new Transmission cost recovery mechanism to facilitate the process?

## DSC REQUESTED AMENDMENTS TO ADDRESS PROCESSING ISSUES FOR LARGE RENEWABLE ENERGY GENERATION PROJECTS

10. Ref: (a) Exh C/Tab 1/Sch 1/p.1/lines 18-24

**Please have the IESO and Hydro One Transmission, as required, provide the pertinent information needed in this interrogatory**

Question:

(i) Please provide a Table identifying all the projects that are classed as large, and for each project provide a column for each of the following:
  (a) the size of the project;
  (b) date when application was filed with the IESO to complete the System Impact Assessment ("SIA") study;
  (c) date when the request was submitted to Hydro One Transmission to complete the Customer Impact Assessment ("CIA") study.

11. Ref: (a) Exh C/Tab 1/Sch 1/Section 1.0 INTRODUCTION/pp. 1-2

**Please have the IESO and Hydro One Transmission, as required, provide the pertinent information needed in this interrogatory**

Preamble:

In the evidence at Reference (a), it is stated in part that:

> *"Hydro One believes that this six-month timeline is generally feasible for small and mid sized generators, as their review consists of a distribution connection impact assessment ("distribution CIA") and a potential Transmission Station ("TS") review (where needed). However, the IESO's Market Rules require that large generator connection applications must also undergo a System Impact Assessment ("SIA") by the IESO and a Transmission Customer Impact Assessment by Hydro One Transmission. Ontario Regulation 326/09 made under the Electricity Act. 1998, stipulates up to 150 days to accommodate these studies. Should upgrades to the transmission system be required as a result of these assessments, further time is needed to develop the scope of work and detailed cost estimates. These additional time requirements could result in the removal of the proponent's capacity allocation well before the completion of the cost estimates and the CCA".*

<u>Questions:</u>

(i) Please have the IESO provide a Table listing for each distribution connected generator project that is classed as large, with a column for each of the following:

(a) the name of the distributor in whose territory the large project is located;
(b) the size of the generation project;
(c) date when application was filed with the IESO to complete the SIA study;
(d) date when Hydro One Transmission received the request to complete the CIA study;
(e) expected completion date.

(ii) How many SIAs did the IESO managed to complete within the 150 day period set out in Ontario Regulation 326/09. Please identify these projects.

(iii) How long (on average) is it taking for the IESO to complete an SIA for distribution connected generators of 10 MW or larger?

(iv) Please provide the scope of a typical SIA study that was performed in the past on distribution connected generators classed as large (10 MW or larger). Please compare that SIA scope to a scope of a larger transmission connected generator. Please comment on the view that for distribution connected generation projects, the IESO is not likely to carry out a full SIA for each project. Please provide a response for each of the following generator capacity ranges:

- 10-15 MW;
- 5-20 MW;
- 20-30 MW;
- Larger than 30 MW.

(v) It is viewed by some that the processing issues identified may be generic in nature and could potentially affect other distributors. Does Hydro One Distribution believe that the identified issues are specific to large renewable generators connecting to Hydro One's distribution system? If so, please provide a detailed explanation.

12. Ref: (a) Exh C/Tab 1/Sch 1/Section 1.0 INTRODUCTION/pp. 1-2
**Please have the IESO and Hydro One Transmission, as required, provide the pertinent information needed in this interrogatory**

Preamble:
In the evidence at Reference (a), it is stated in part that:

> *"Hydro One believes that this six-month timeline is generally feasible for small and mid sized generators, as their review consists of a distribution connection impact assessment ("distribution CIA") and a potential Transmission Station ("TS") review (where needed). However, the IESO's Market Rules require that large generator connection applications must also undergo a System Impact Assessment ("SIA") by the IESO and a Transmission Customer Impact Assessment by Hydro One Transmission. Ontario Regulation 326/09 made under the Electricity Act. 1998, stipulates up to 150 days to accommodate these studies. Should upgrades to the transmission system be required as a result of these assessments, further time is needed to develop the scope of work and detailed cost estimates. These additional time requirements could result in the removal of the proponent's capacity allocation well before the completion of the cost estimates and the CCA".*

Questions:

(i) How many Customer Impact Assessments (CIAs) has Hydro One Transmission completed for distribution connected large generators? Please provide a list of requests made by distributors other than Hydro One Distribution, and for each, provide the size of the generator.

(ii) How long (on average) is it taking for Hydro One Transmission to complete a CIA study for distribution connected generators of 10 MW or larger?

(iii) Please provide the scope of a typical CIA study that was performed in the past on a distribution connected generator that is classed as large (10 MW or larger). Please compare that CIA scope to the scope of a larger transmission connected generator. Please comment on the view that the CIA study for a large distribution connected generator is not likely to be comparable in scope and effort level to the scope and effort level that is required for a CIA study of a larger generator connected to the transmission system? In your response please provide information for a range of sizes such as 10-15 MW, 15-20 MW, and 20-30 MW (likely requiring dedicated feeders to be directly connected to a transformer station).

13. <u>Ref: (a)</u> Exh C/Tab 1/Sch 1/Section 2.0 THE CURRENT SITUATION/pp. 2-5

Ref: (b) Exh C/Tab 1/Sch. 1/p. 5/Diagram 1

**Please have the IESO and Hydro One Transmission, as required, provide the pertinent information or opinions as needed in this interrogatory**

<u>Preamble:</u>

At Reference (a), Hydro One presents its understanding in regard to the current situation and described Phase 1 (3 months) and Phase 2 (5 months), and ended the description of Phase 2, with a paragraph stating that:

> *"Hydro One's **experience[bolding added for clarity**] is that the steps in this phase are sequential, that is, that the IESO cannot begin the SIA until it receives the distribution CIA and similarly, that a prerequisite for beginning the Transmission Customer Impact Assessment is the receipt of the prior two reviews. The allowed time period for this phase is 150 days (O. Reg. 326/09)."*

<u>Questions:</u>

(i) Please provide a detailed description of the “experience” referred to in Reference (a) that led Hydro One to believe that the steps described in Phases 1 and 2 are or should be sequential.

(ii) Assume that the connection process can proceed in parallel fashion, whereby in a revised Phase 1, the following steps would commence simultaneously:

- The distribution Connection Impact Assessment (DX-CIA);
- The Host Distribution (Dx-CIA) -if applicable;
- The IESO’s SIA;
- The Transmitter’s Customer Impact Assessment (Tx-CIA), if required

Assuming the process as described above is implemented, please describe the process that Hydro One Distribution needs to follow to ensure proper coordination between:

- The Applicant;
- The Embedded Distributor, where applicable;
- The Host Distributor (Assume Hydro One Distribution is the Host Distributor);
- The IESO; and
- The Transmitter (Assume Hydro One Transmission to be the Transmitter)

(iii) Please provide a revised Diagram 1, page 5 of Reference (b), assuming that the parallel process described in (ii) above is implemented, and in addition provide comments especially in regard to the (variable) Phase under the two possibilities discussed in pages 3 and 4 of Reference (a) under the heading Phase 3 (Variable).

(iv) Please have the IESO and Hydro One Transmission comment on the feasibility of proceeding in a parallel fashion to reduce the overall timeline for distribution connected medium and large generators.

**Appendix A**
**To Board Staff Interrogatories**
**September 9, 2010**

**<u>Presentation to The Ontario Smart Grid Forum</u>**
**"DG Integration Key to Smart Grid", dated September 22, 2008, by Manager – Distr.Gen & Advance Grid Development, System Investment, Hydro One Networks**

**Proceeding - Licence Amendment Application Exemptions from Distribution System Code ("DSC")**
**Hydro One Networks Inc.**
**EB-2010-0229**

Presentation to The Ontario Smart Grid Forum

# DG Integration Key to Smart Grid

**Ravi Seethapathy**

Manager- Distr. Gen & Advance Grid Development

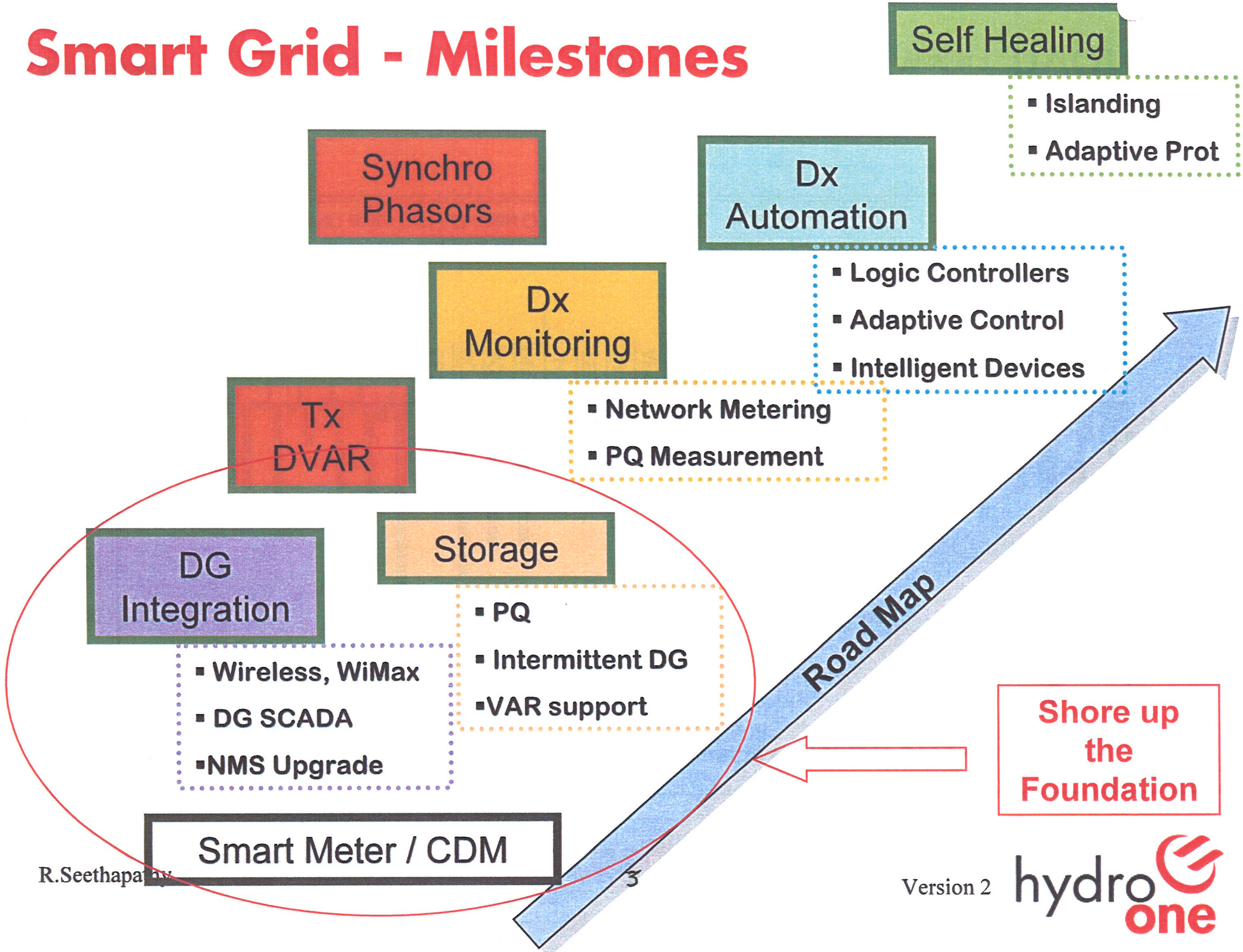
System Investment, Hydro One Networks

September 22, 2008

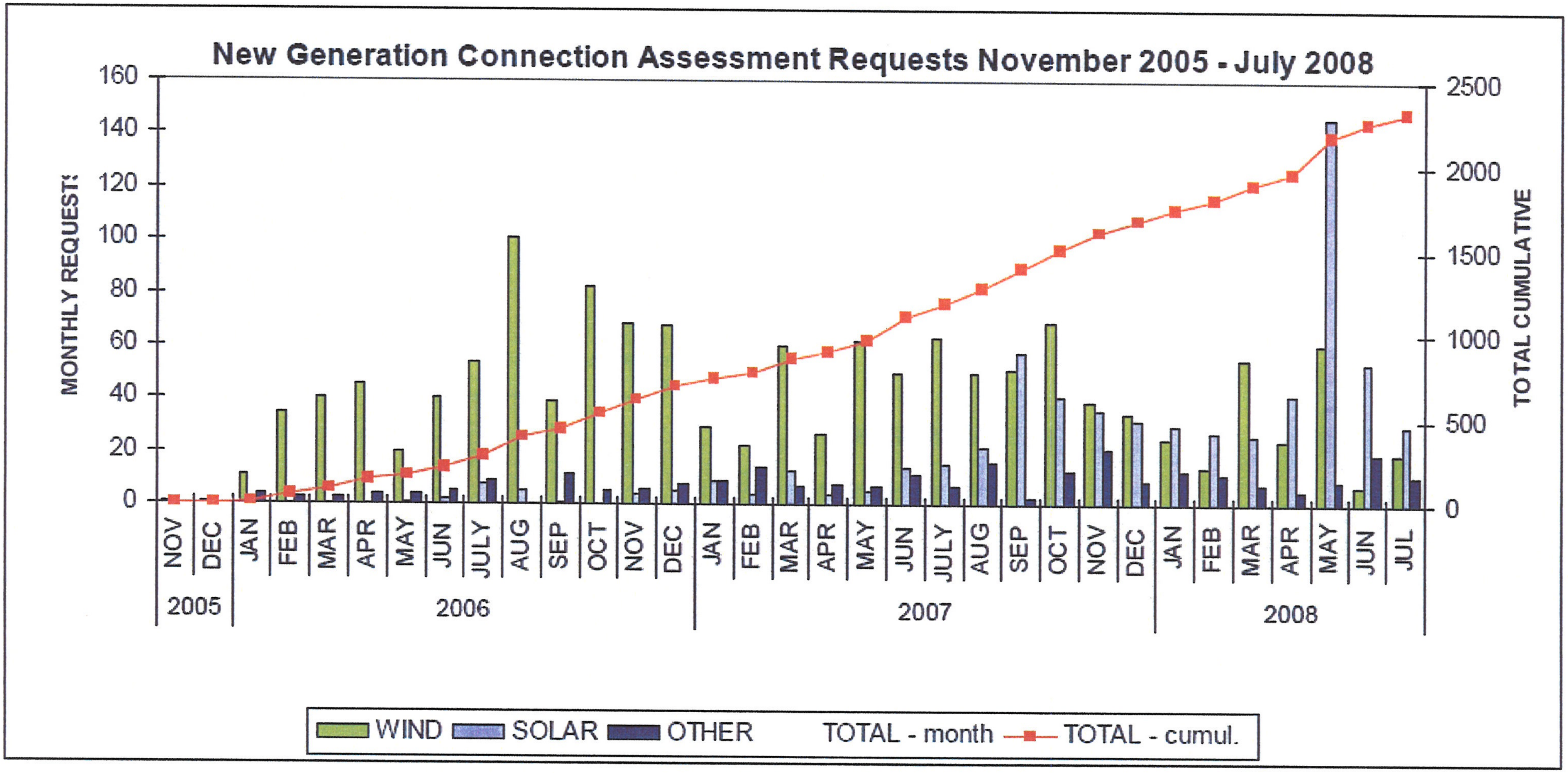
# Smart Grid Mantra

- **Requires <u>transformation of T&D</u>**
  - Break down T&D barriers; Optimize network
  - **Maximize use of low-cost DERs**
  - Enable distributed diagnosis and decision support
- **Objective** – To <u>further improve</u> grid performance
  - Efficiency, Reliability, Power Quality, Safety
  - Faster decision making and isolation/restoration
  - Balancing power delivery and use

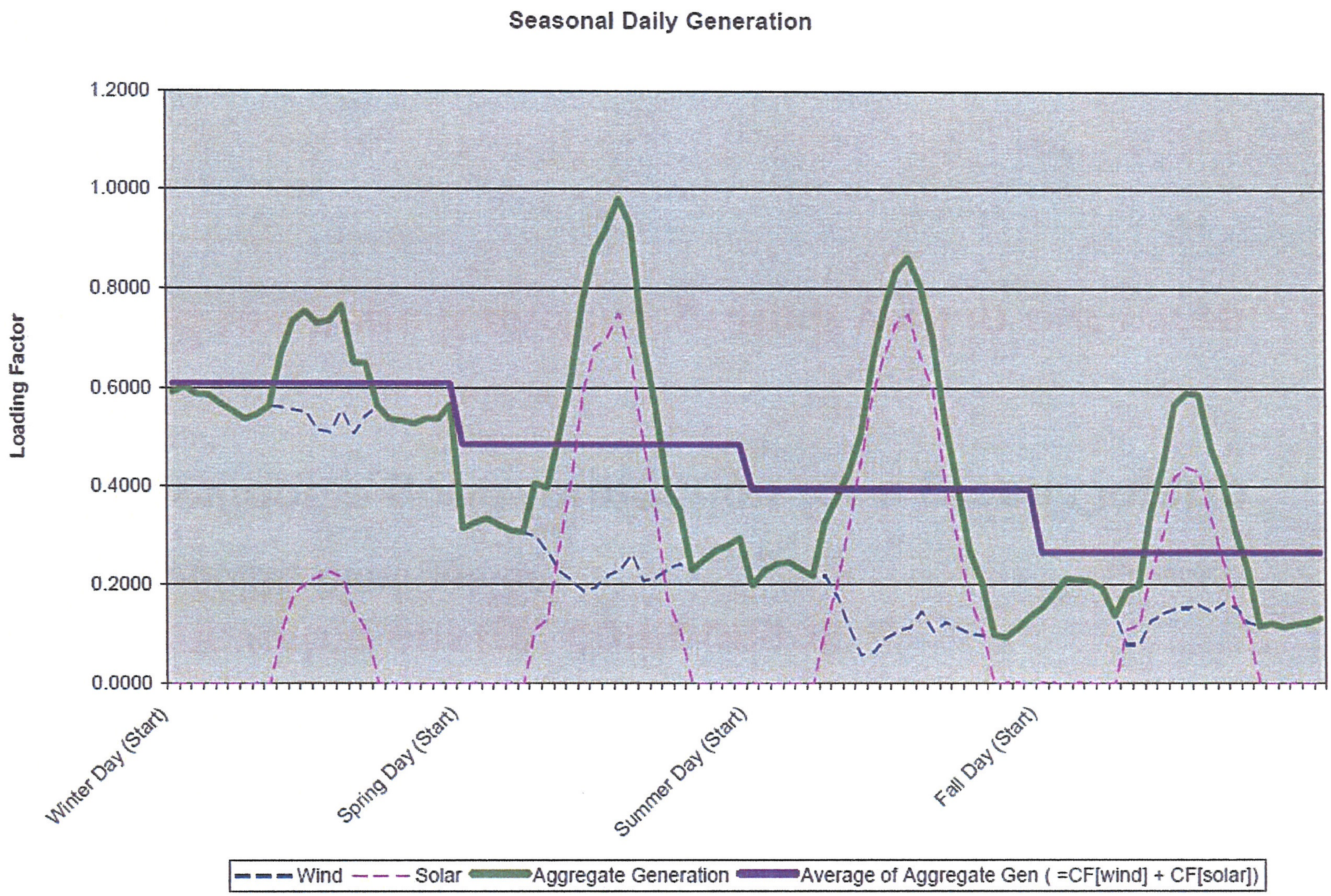
# Smart Grid - Milestones



# Hydro One - Application Request Status



# Benefits of Fuel Mix



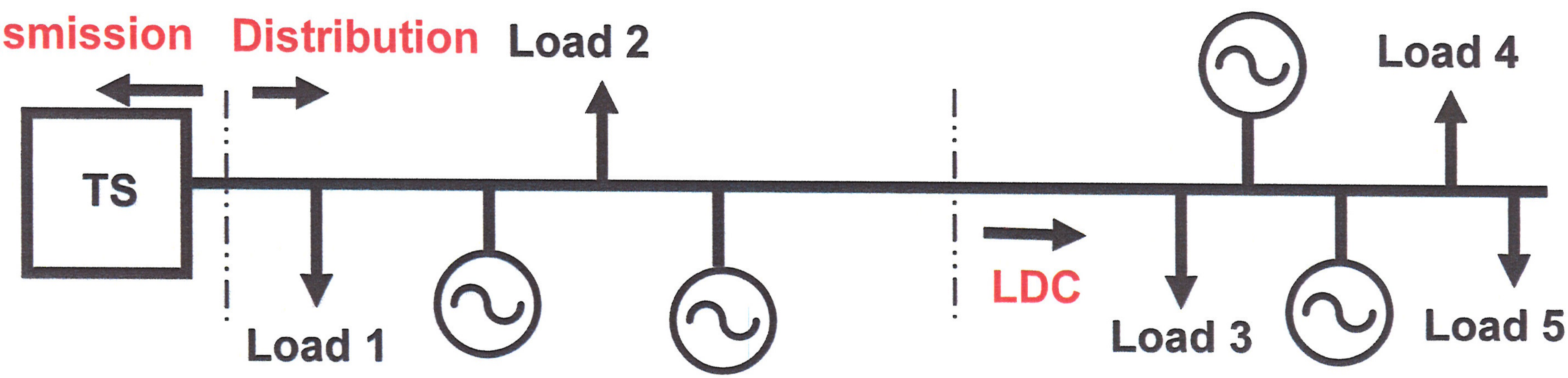
# Ontario's Opportunity to Shape DG growth

- High take interest in applications
  - Across all RFPs
- High Renewable energy component
  - Wind, solar, biodigester

Provides a good foundation for a green Ontario

But we need to shape it and integrate it well in our wires……

# System Aspects to Integrating DGs




| Operations | | Customers | |
|---|---|---|---|
| Op. Control | Personnel Safety | Reliability | Power Quality |
| Voltage Control | ▪Back-feed | ▪Dependability | ▪Voltage |
| Protect Equip. | ▪Isolation / WP | ▪Security | ▪Sys vs DG hunt |
| Thermal/Overload | ▪Safe restoration | ▪Restoration | ▪Harmonics |
| Contingency Mgt | | | ▪Flicker |
| Load following | | | |



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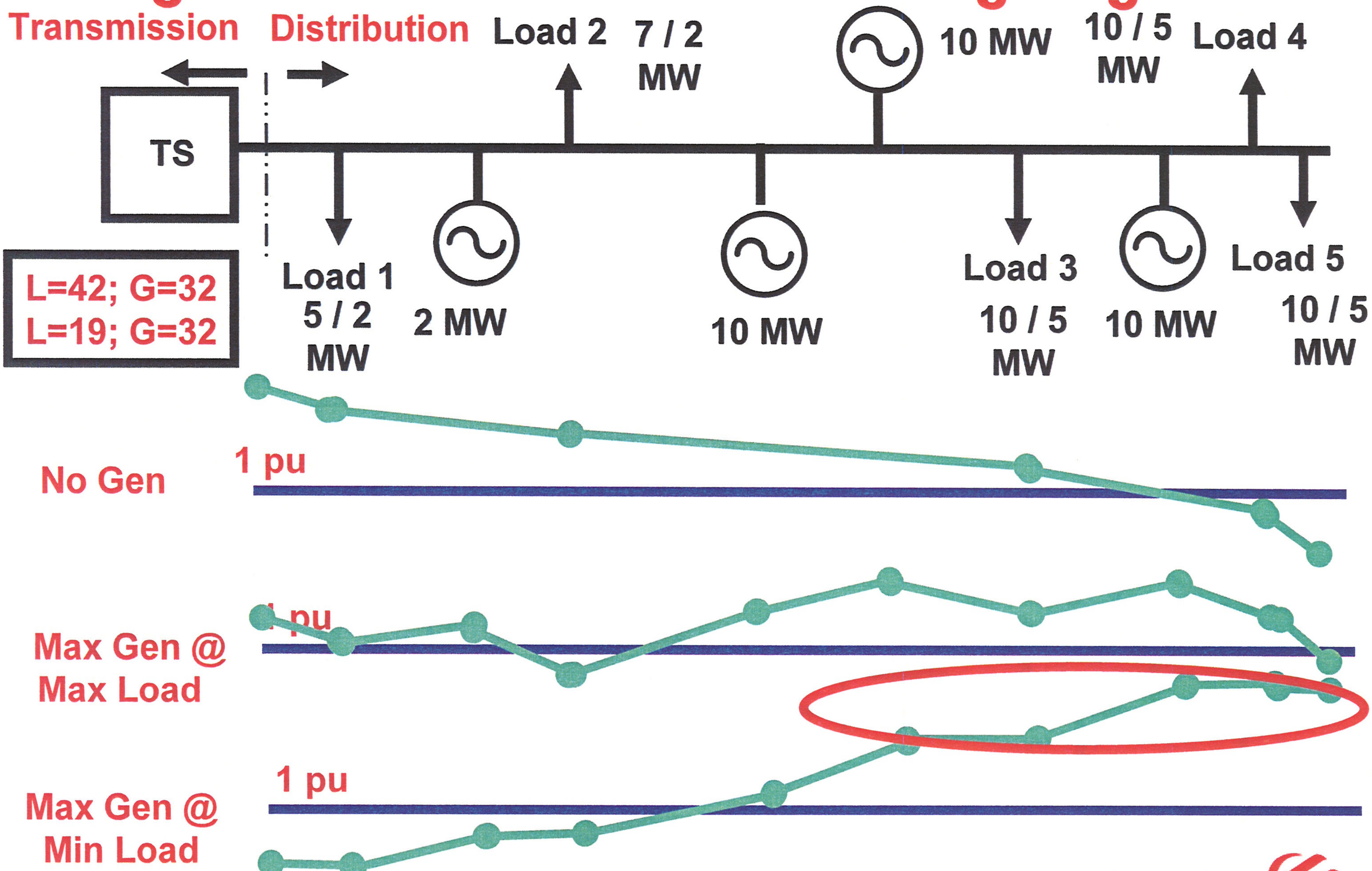
# Mixing Generation With Load – Voltage Mgmt

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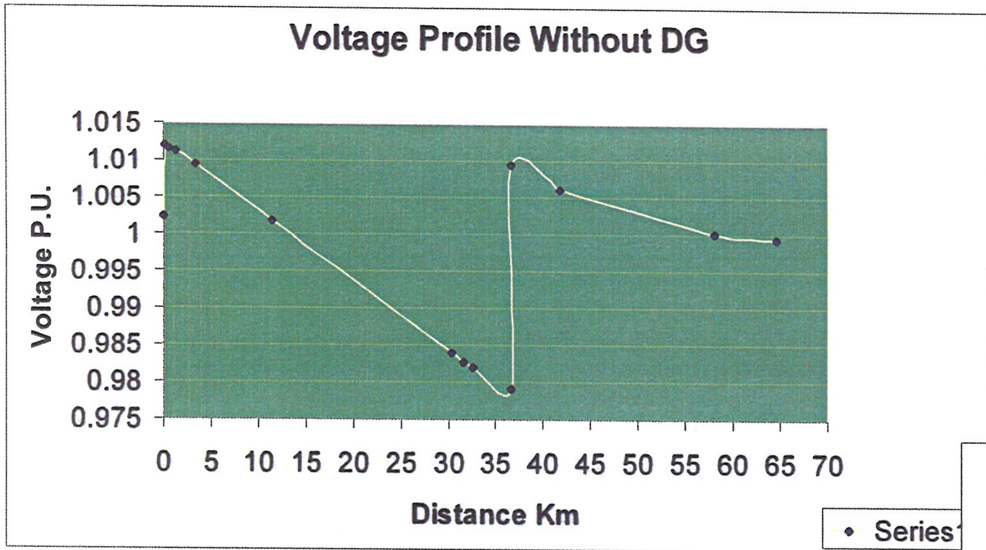
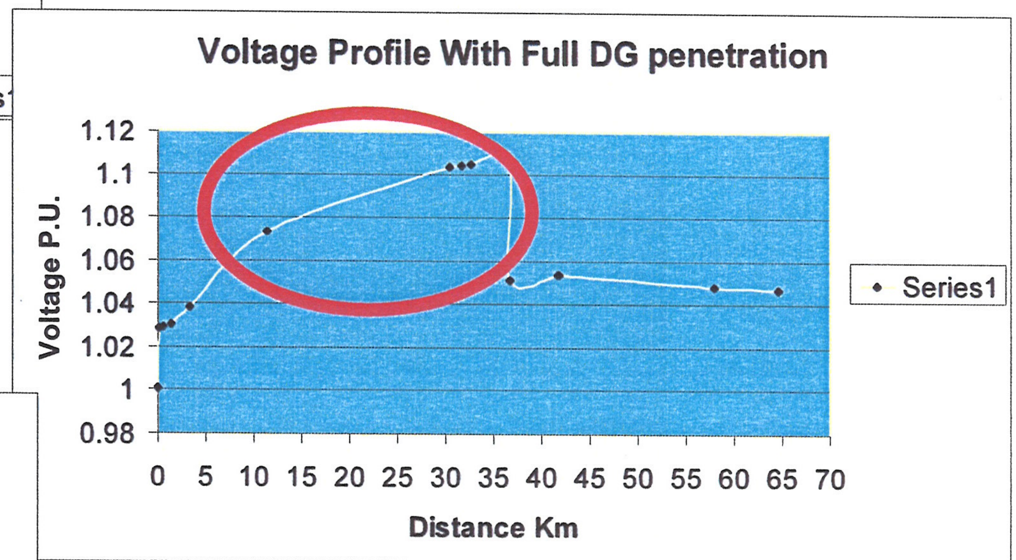
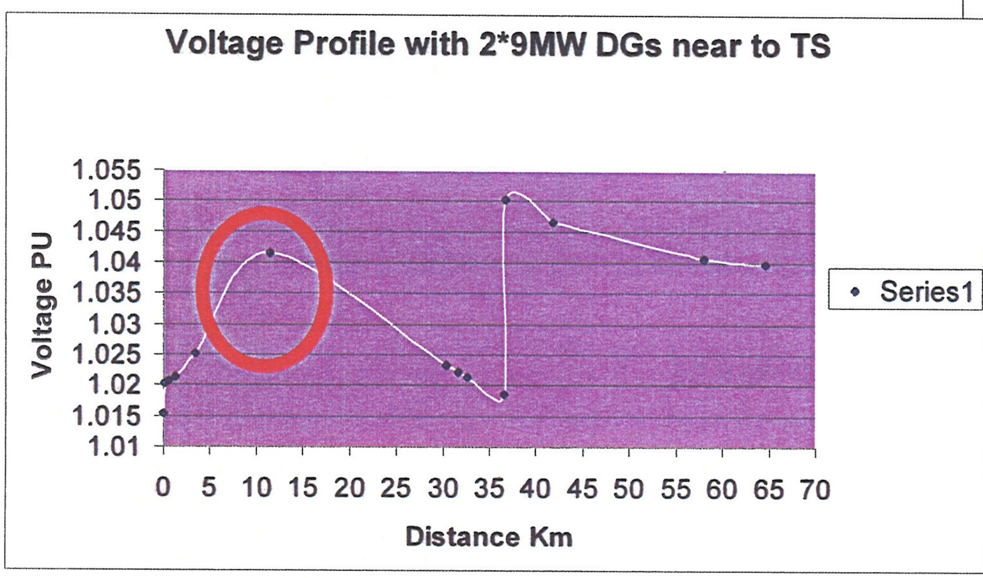
# DG Influence on Feeder Voltage Profiles during light loads

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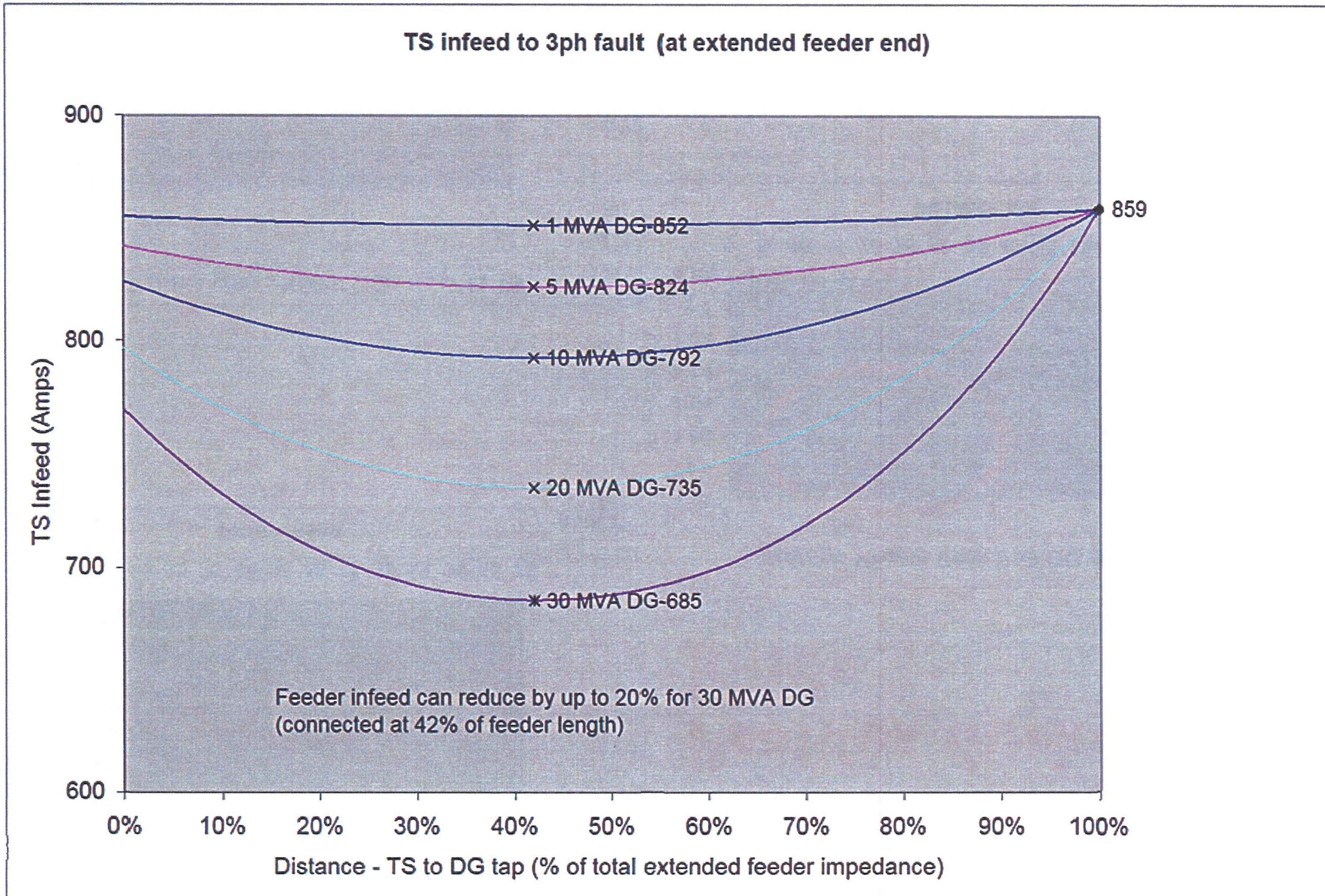
Version 2 hydro one

# Feeder Protections – DG Apparent Impedance on Long Feeders

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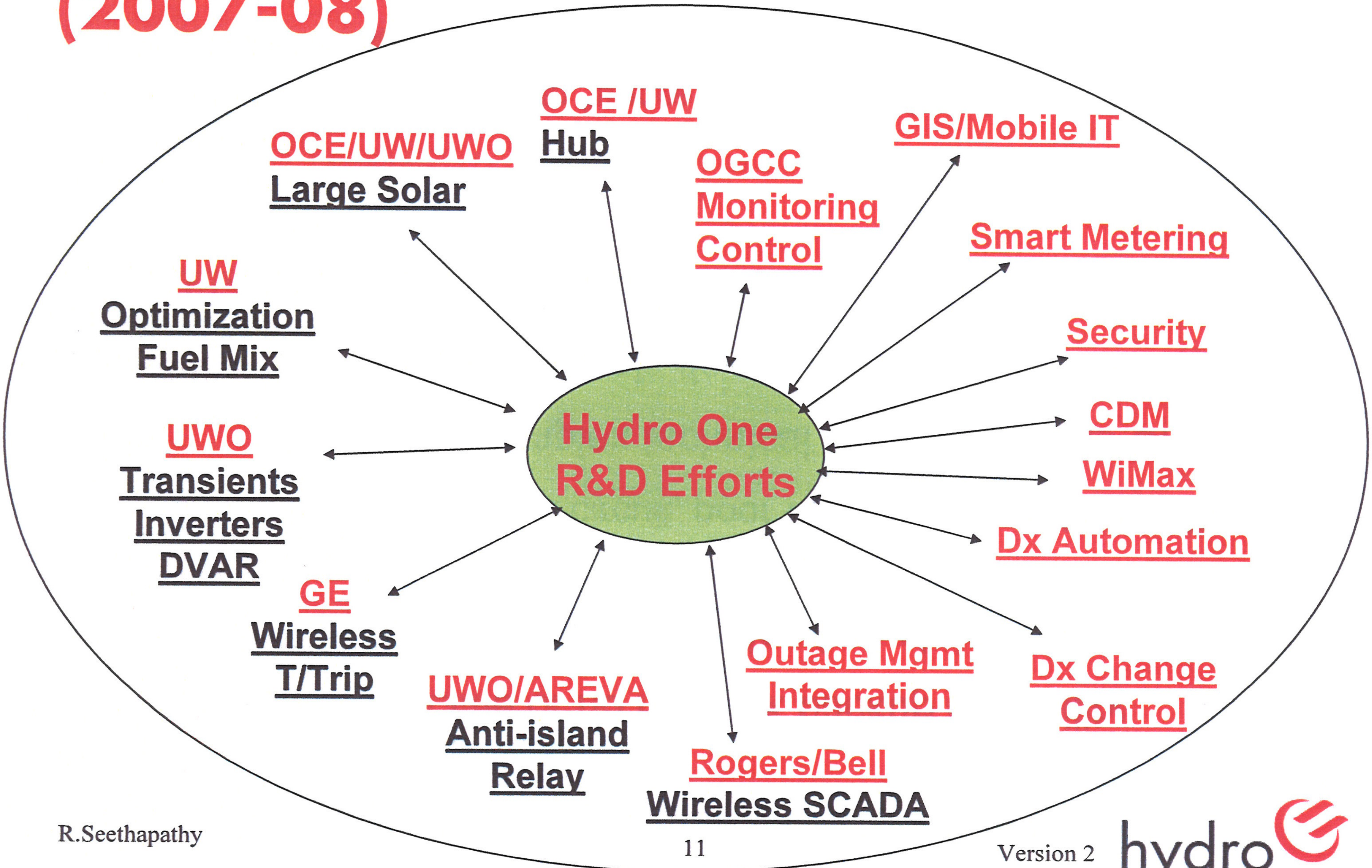
# Hydro One – Studies/Pilots (2007-08)



# Rural Network Challenges

- **Radial system –** Little or no network backup capability
- **Load Factor** - Rural/Farm - Night load much lower than day high
- **Rural Feeders** – "long, weak, light"
  - Low stiffness, low short circuit, poor voltage control; 50% 1-Ph
- **Technical Limits -** Complex technical limits relative to Urban Dx
- **Model & Tools -** Current tools do not have dynamic DG models

**Rural Networks are not ideal for high DG penetration**

- **Future Challenges**
  - Increased investment to "shore" up the weak network
  - Poor power quality – voltage management

# Planning Issues

- **Network optimization**
  - Location, DG size, Fuel Mix, Load Displacement
  - Line Loss Reduction
  - Not impede ability to perform load transfers
  - Otherwise – collect DG power through enabler lines to Tx directly

**All DGs do not provide same value to the network**

- **Future Challenges**
  - Mismatch due to load reductions; DGs have firm contract
  - Restricted ability to perform load transfers with DGs
  - Possible curtailment of DGs based on load levels

# Operations Issues

- **Visibility to Dx network elements**
  - Little or no visibility to network elements except at stations
    - Nodal voltage management
    - Power Quality monitoring
  - Wide daily fluctuations in power factor based on gen-load balance
  - Dynamic management of real-time DG operations

**Need investments in Dx Monitoring & Control**

- **Future Challenges as DG Penetration increases**
  - LDC has no DG output regulating authority
  - Need DVAR support to manage DG dynamics/transients

# Tx-Dx Coupling

- **Transmission Constraints**
  - Back-feed into Tx (likely 27 TS will backfeed)
  - VAR support for DGs
- **Tx/Dx Code overlap**
  - If DGs impact Tx, then both DSC & TSC apply
  - DSC and TSC - different in "socialization" of network costs

**Build Tx enabler lines for High DG cluster areas**

- **Future Challenges**
  - Further Tx-Dx integration as DG penetration increases in Dx
  - All Tx "stiffness" are not same; Regional impact on Dx/DGs
  - Tx ancillary enhancements to support/manage Dx needs

# DG Management

- **Supply Reliability (Firm Power vs Energy)**
  - Intermittent power, possible tandem variability (Wind, Solar)
  - No local backup i.e. CHP or storage
  - Control issues:
    - Non dispatched with little view from the system operator
    - DGs not manned 24/7

  **Need storage devices to smooth intermittent energy**

- **Future Challenges as DG penetration increases**
  - DG management & Regulation Policy/Authority
    - IESO, LDC, Other ??
    - Local Dx based criteria for DG control
    - Also weather related control support
  - Need a DG control center for Ontario

# Enabling DGs - Food for Thought

- **DG size, Location, Fuel Mix - important to Dx architecture**
  - Leverage wires investment - Maximize overall DG capacity factor
  - Emphasize load displacement over pure generation
  - Invest in telecom and electrical storage devices

- **DG Management & Regulation Policy/Authority**
  - IESO, LDC, Other ??
  - Local Dx based criteria for DG control
  - Need a DG control center for Ontario

- **Other**
  - Storage – whose tool is it – Generator or LDC or both?
  - Local Dx based criteria for DG control
  - Need a DG control center for Ontario
  - Need VAR support from Tx

# THANK YOU!