Rapport de la firme ESTA International, LLC

Remplacement du système de conduite du réseau de distribution d'électricité

Assessment Report

20 June 2018

Assessment Report on Hydro-Québec Distribution's Project for the Replacement of their Supervisory Control and Data Acquisition System, Distribution Management System and Outage Management System

Submitted to:

Hydro-Québec Distribution

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1 Introduction

1.1 *Purpose of this Report*

The purpose of this report is to provide an independent assessment of Hydro-Québec Distribution (HQD)'s existing SCADA/OMS/DMS systems, as well as HQD's project to replace these systems, for the Régie de l'énergie du Québec.

1.2 *Methodology*

The methodology followed to perform this assessment included the following steps:

1. Present information on the past and current state of the SCADA/OMS/DMS Industry.
2. Provide a detailed questionnaire to HQD to gather the information about the existing systems.
3. Analyze the information provided by HQD as a basis for the assessment: identify specific issues with the current HQD SCADA/OMS/DMS technologies and compare how HQD's current and projected future needs align with the capabilities of the existing system.
4. Provide our assessment of the functional components, project oversight, procurement strategy, solution providers, evolution strategy, and risk mitigation strategies.

This report concludes with a summary of the key assessment findings, conclusions and recommendations.

1.3 Terminology Used

The following terms are used throughout this report:

- **Distribution Substation** – interconnection between the Transmission network and the Distribution feeders to which customers are connected. The principal devices in a Distribution substation are the step-down transformers which reduce the voltage level and the circuit breakers which determine the flow of power.
- **Distribution Feeder –** The portion of the power system between the distribution substation and the customer meter, including medium voltage power lines and step-down transformers that deliver power to the customers.
- **SCADA – Supervisory Control and Data Acquisition –** These applications collect real-time information from field equipment (for example, currents, voltages, circuit breaker states) and allow HQD operators to remotely control field equipment without the need to send a crew to the field. SCADA applications communicate with field equipment via **Remote Terminal Units (RTUs)**.
- **OMS – Outage Management System** – software tool that assists operators in assessing power outages on the Distribution network, determining their extent, identifying the protective device that operated to cause the outage (e.g. the circuit breaker that tripped or the fuse that blew) and managing the work flow involved in getting power restored, which typically involves sending out a crew to confirm the problem, identify the root cause (such as a line down due to a fallen branch), making repairs as required, and finally restoring power.
- **DMS – Distribution Management System** – provides software applications that analyze the Distribution network in order to:
    - Provide visibility into the system state by calculating flows and voltage (**Distribution State Estimator**), extrapolating from the limited amount of real-time data collected via SCADA
    - Allow the user to determine the impact of a hypothetical fault on the network (**Fault Level Analysis**)

  - Allow the user to verify if a switching operation he/she is about to perform will negatively impact the network (e.g., by causing the voltage to drop below acceptable levels) (**Pre-Switching Validation**)
  - Reduce the extent of an outage by automatically identifying the faulted section of the distribution feeder, isolating the faulted section, and then restoring power to as many customers as possible by re-routing power from a healthy feeder **(Fault Location, Isolation and Service Restoration (FLISR)**.
  - Optimize the operation of the network, for example by reducing total energy consumption or reducing peak demand through remote control of field devices (**Volt-Var Control**).
- **ADMS – Advanced Distribution Management System** –refers to a combined OMS and DMS that shares a common user interface and distribution network model.
- **EMS – Energy Management System** – software tool that assists Operators with assessing the reliability of the transmission power system.
- **"De-Centralized" vs "Centralized" applications** – de-centralized applications are implemented by intelligent devices that are located out in the field and manage a localized area of the network or a substation. Centralized applications run at the Control Center - DMS applications are an example of centralized applications.
- **GIS – Geographic Information Systems** – used by electric utilities to produce and maintain a complete, detailed electric circuit connectivity model of their network with a geographic context.
- **Smart meters** – provide a means of remotely monitoring individual customer power consumption; they can provide real-time indication if the customer has power. Traditional meters provide no communication capability. **Advanced Metering Infrastructure (AMI)** is the name used to refer to the end-to-end solution that provides communication between smart meters and control centers.
- **DTS – Distribution Training Simulator** – replica of the Production system used to provide basic training to new operators and to provide advanced training to more experienced operators.
- **DER - Distributed Energy Resources** – Non-traditional low capacity (typically <10MW) sources of power connected directly to the Distribution grid. DER typically use renewable sources of energy such as solar and wind. Controllable loads, electric vehicles and energy storage devices such as batteries are also considered to be DERs. In the future, electric vehicles may be able to act as batteries, re-injecting power back into the power network during peak load periods.
- **DERMS - DER Management Systems –** Software and communication systems for managing DER; these systems are designed to connect to millions of DER.
- **Microgrids** – refer to small-scale grids that can disconnect from the main electric grid and operate autonomously with generation produced locally within the micro-grid, typically by a combination of renewable and non-renewable DER. Currently, the most common example of micro-grids are college campuses and military bases.
- **"Evergreening"** – The practice of using periodic updates to ensure that systems do not become obsolete and will not require a full system replacement. It requires a commitment to keep these technologies up-to-date with the chosen vendor's products.
- **SCR-D or SCR-D project** – The project to replace HQD's existing SCADA/OMS/DMS systems with a new integrated product.

1.4 About ESTA

ESTA International LLC is a specialized consulting firm providing Intelligence, Strategy, and Technology Advisory Services to the Electric Energy industry worldwide with a focus on Smart Grid and Control Center Technologies including Supervisory Control and Data Acquisition (SCADA), Energy Management Systems (EMS), Generation Management Systems (GMS), Distribution Management Systems (DMS), Outage Management Systems (OMS) and their integration/ interoperation with other utility/non-utility systems.

ESTA International, LLC was established in 2009 and has been serving the electric energy industry worldwide in areas of Smart Grid, Control Center Technologies, and other related areas. ESTA's staff averages over 25 years of experience with these related technologies.

ESTA International, LLC is a US company registered in the Commonwealth of Virginia. Its headquarters are located in Herndon, Virginia, a suburb of Washington D.C.

The personnel that have participated in preparing this report are working with HQD on the replacement project but also have extensive experience assisting other entities with similar types of projects. We have called on that expertise to assess the project as completed thus far as well as the plans for the entire project. Participants include:

Mr. Nader Farah

- President of ESTA International, LLC
- Over 35 years of related experience working with utilities throughout the world

Mr. Joseph Moran

- Executive Consultant
- Over 30 years' experience primarily in North America including Investor Owned Utilities, US Federal Government Entities, Municipal Utilities, and Independent System Operators with the strategy, planning, procurement, implementation and testing of SCADA, EMS, GMS, DMS, MMS, and OMS

Mr. Robert Uluski

- Executive Consultant
- Over 40 years' experience assisting North American and International Utilities including Investor Owned Utilities, Municipal Utilities, and other Distribution Operators with the strategy, business case, planning, procurement, implementation and testing of SCADA, DMS, DA, OMS, and recently DERMS solutions.
- Chair of the IEEE PES Working Group on Distribution Management Systems

Ms. Catherine Murphy

- Executive Consultant
- Over 25 years' experience developing, integrating, delivering and deploying SCADA, EMS, GMS, DMS and OMS software systems to utilities worldwide

2 Evolution of the SCADA/OMS/DMS Industry

This section describes the evolution of the industry over the years in response to changes in the power system, utility needs and regulatory requirements and presents the corresponding evolution of, SCADA/OMS/DMS systems. This is intended to provide the context for the assessment of the existing Hydro-Québec Distribution (HQD) SCADA/OMS/DMS systems presented in Section 3 of this report.

2.1 Level 0 - No remote monitoring and control

The electric distribution networks prior to the 80s had very little complexity compared to today. Power flow was unidirectional (from the primary substation down through the feeders to the customers) and feeders basically always operated in the same configuration so that very simple protection and voltage regulation policies and practices were sufficient. Operations focus was on maintaining “acceptable” electrical conditions at all locations as opposed to “optimal” conditions.

Because the network was operating as designed, electrical conditions were predictable, and an experienced operator always had a good idea of the conditions at all points along the feeder, and there was no real need for continuous monitoring of the assets (i.e., no SCADA).

Utilities developed their own processes and tools for managing power outages, with one of the main tools being paper maps which had been drawn using drafting tools; software tools for managing outages (i.e. OMSs) did not yet exist; customers would call in to report that they had lost power and Distribution operators would direct the crews to the suspected open point (e.g. the circuit breaker that tripped or the fuse that blew) based on the maps.

2.2 Level 1 - Emerging requirements for improved reliability, efficiency, and asset utilization

New requirements (e.g., IEEE standard 1366 – Electric Power Distribution Power Indices), introduced in the 1990s that focused on efficiency and reliability generated a need for monitoring and remote control of Distribution networks and the development of the corresponding SCADA systems. At this stage, monitoring and control were limited to the Distributions substations, i.e. there was not yet any remote monitoring and control of feeders. During this decade, two standard protocols for communication with RTUs were developed: IEC 60870-5-101/104, adopted by European utilities, and DNP3, adopted by North American utilities, with other utilities using one or the other or sometimes both. To this day, these two protocols are in operation at the vast majority of utilities worldwide.

Interfaces to external systems were custom designed as “point to point” interfaces. That is, the interface with each and every external system had to be specifically designed and developed by the vendor for their individual client utility.

The 1990s saw the development of the first commercially available Geographic Information Systems (GIS). These were adopted by electric utilities as a means of recording the physical network (what device is connected to what other devices) and the geographic location of the devices.

The drive toward improved reliability spurred the developed of the first commercially available Outage Management Systems (OMS). Since device inter-connection information is the key to tracing the source of an outage, many of the first commercially available OMSs were developed by GIS vendors. However, since outage management is so closely tied to utility processes, many utilities opted to develop their own OMS.

The very first DMSs were developed during this decade, mostly by the vendors who had developed Energy Management Systems (EMS) for Transmission networks. Those few utilities that did implement a DMS during this period derived little benefit:

- Due to the limited amount of real-time data available from remote monitoring of field devices
- Because the DMS applications required a very detailed model of the Distribution network for use by the applications, and utilities did not typically maintain that level of detailed information about individual devices on their network. While utilities did generally maintain connectivity information (i.e. which device is connected to which other device) which is required by both OMS and DMS, the DMS required a lot of additional information about individual devices (for example, the impedance of each section of line, the core and copper losses across each transformer).
- Because even if the utilities did have the model data, the tools for maintaining the model were poor and extremely inefficient.

One of the challenges vendors faced in developing Distribution network analysis applications, as compared to Transmission network analysis applications, was the sheer size of the models: most Distribution network models comprise easily one hundred (100) times more devices than a Transmission network, so that performance issues for DMS were common.

As an alternative to the DMS offering centralized applications, the first de-centralized applications were developed and installed in substations. These provided automatic reconfiguration of the network to isolate outages and restore customers (Fault Location Isolation and Service Restoration or FLISR) and helped to manage voltage issues through coordinated control of devices (Volt-Var Control). De-centralized applications were much less expensive to implement than a DMS and did not require the same type of detailed device model data.

2.3 Level 2 – Remote monitoring and control of feeders, increasing DMS, important advances in OMS

The 2000s saw an increase in the amount of remote monitoring and control with the corresponding increase in the development and adoption by utilities of Distribution SCADA systems. Utilities that had limited remote monitoring and control focused on adding it to substations, while utilities that had automated a significant proportion of their substations started adding remote monitoring and control of devices on the feeders. One of the challenges with the resulting tsunami of data was the need to filter, consolidate and pre-interpret the data in order to turn it into actionable information that could be used effectively by the Distribution operator.

As internet technologies and standards for transferring data started to mature, vendors adapted their products to use these standard technologies to define and exchange data between systems. In addition, the utility industry developed the initial version of a Common Information Model standard that defined the objects and associated attributes to facilitate exchanging the data (e.g., common definition of attributes for a transformer, bus, etc.), initially targeting Transmission networks but then extending to include Distribution network-specific devices.

A series of widespread outages in North America drove significant advancements in OMS functionality – pressure on operators to improve the accuracy of estimated restoration times dictated needs for better software tools. A significant new development in the late 2000s was the introduction of smart meters and Advanced Metering Infrastructure (AMI). Utilities that implemented smart meters and AMI were notified within seconds or minutes whenever an outage occurred, so that outage detection was faster, and were notified by all of the affected meters, enabling the outage extent to be determined more accurately. OMSs adapted by introducing new functionality to receive and analyze messages from smart meters. Note that smart meters also enabled Time-of-Use Metering; unlike traditional meters, where meter inspectors would record total power consumption over a long period (e.g. once per month), information on consumption could be sampled much more frequently by smart meters and AMI (e.g. 15-minute period) allowing utilities to charge different rates depending on the time of day at which power was consumed. AMI also provided a mechanism that enabled the control center operator to “ping” an individual meter in order to if power was on or off at a particular customer location as a means of confirming the presence of an outage or of confirming that power had been restored.

The rate of adoption of DMS remained relatively slow, for some of the same reasons as during the 1990s, namely the requirement for model data that utilities could not provide without investing in a major field survey. The limitations of de-centralized applications also became more obvious, for example, settings needed to be adapted whenever the physical interconnections changed. This happens relatively frequently in the case of distribution networks and typically these applications could only operate when the network was in its normal state. In contrast, the centralized applications of the DMS (which were based on a real model of the network), could automatically adapt to the state of the network, whether normal or abnormal.

Up until this point, the OMS and the DMS were typically separate systems - different tools, each with its own model and user interface, often from different vendors, even though both were trying to analyze the same network. Some functions were duplicated (e.g. Connectivity Analysis which analyzes the live-dead status throughout the network), while other functions overlapped (e.g. FLISR which tries to reduce the extent of an outage and OMS which tries to manage the outage itself). The concept of an Advanced Distribution Management System (ADMS) which combines OMS and DMS was introduced late in the decade; the key advantages of an ADMS were a single model to maintain, an integrated user interface and integrated applications.

2.4 Level 3 - DMSs become more mature, further advances in OMS, growing penetration of Distributed Energy Resources

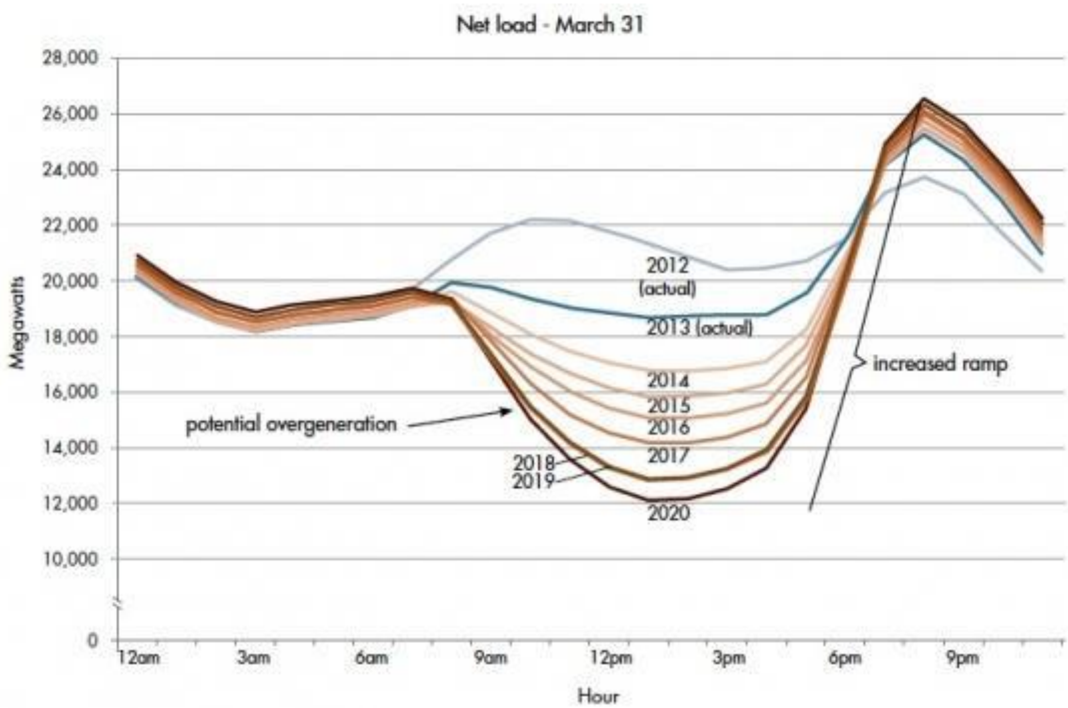
While almost all North American utilities had installed and operated SCADA/EMS systems for many years, very few had embarked on implementing DMS systems until the concept of Intelligent Grids or Smart Grids became a reality within the electric utility industry. Numerous countries invested in Smart Grid programs that facilitated the implementation of these systems, mainly since the beginning of the current decade. Concepts of systems for integration of renewable resources, consumer choice, improved reliability, etc. became the cornerstone of Smart Grid programs. Not only did utilities embark on implementing ADMS, but also governments agencies such as the US Department of Energy provided research funds for the design and testing of modern ADMS systems. As a result, this decade has seen an increased number of utilities installing Distribution Management Systems as products matured and benefited from field experience, in terms of the quality and intelligence of the algorithms and the effectiveness of results presentation. In North

America, according to a Newton-Evans survey of North American utilities for 2017[1], nearly 50% of large utilities (>500,000 customers) surveyed had installed DMS or ADMS.

With the increasing number of utilities installing smart meters, vendors developed algorithms that took advantage of the information available from the meters (such as the message time-stamp) and the ability to ping meters in order to diagnose outages more accurately.

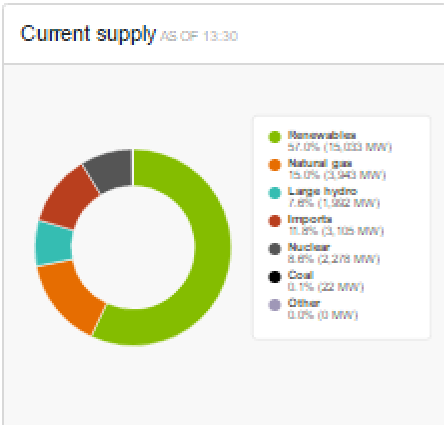
This decade is seeing a substantial increase in the rate of installation by customers of Distributed Energy Resources (such as solar panels), and this has impacted the net load on the network. Historically, load patterns have been fairly predictable with a peak in mid-morning and a peak in early evening. As more and more customers installed DERs in the early 2010s, historical consumption patterns started to fade; a sunny day would dramatically reduce net power consumption in the presence of solar panels, and might, in fact, result in the net injection of power for some customers; on the other hand, a sudden large cloud could significantly increase net power consumption. Similarly for windy days and wind turbines.

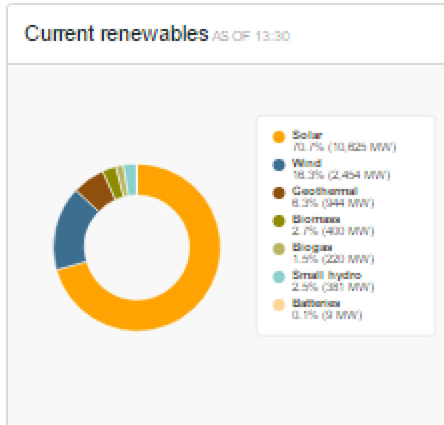
Utilities in California are at the forefront of the paradigm shift cause by DERs. The following diagram (credit California ISO) illustrates the forecasted impact of DER in California and predicts that, by 2019, the load pattern will be completely changed, with potential over-generation. This affects both the Transmission and Distribution of power. Also worth noting is what happens when the sun goes down: the load that must be absorbed by traditional power sources increases at an extremely high rate ("Increased ramp"), which can introduce instability at the transmission level.

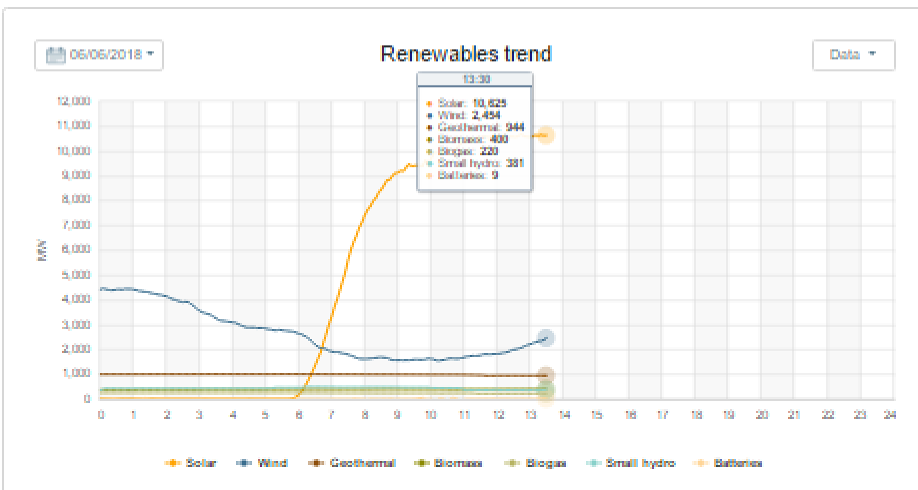


[1] The North American Market Study of SCADA, EMS, DMS and OMS in Electric Utilities: 2017-2019, Newton Evans, March 2017

The following screen capture from the California ISO website, taken at 1:30PM PDT illustrates the real-time generation from DER with over 50% of generation coming from renewables.







While solar energy is unlikely to have the same impact in Québec, Hydro-Québec has implemented pilot projects for both centralized and de-centralized solar power energy production, as a means of developing expertise and preparing for the future. In the more immediate future, HQ will have to contend with the impact of electric vehicles (EVs) - Québec's Ministère de l'énergie et des ressources naturelles's 2030 Energy Policy Action Plan is targeting 100,000 electric vehicles by 2020. In the short term, the growing number of EVs will affect the load pattern and location; eventually, they could also act as batteries, and when they are being discharged, inject power into the network resulting in reverse power flows.

While DER are having a significant effect on load patterns, they also affect operations at a more basic level. As explained in section 2.2, Distribution networks were originally designed for unidirectional power flow: from Distribution substations, along feeders and through to customers. The protection schemes were designed accordingly, so that if a fault current is detected, the current is assumed to be flowing downwards and the upstream protection device will open automatically. In the presence of DER, the fault current may come from the DERs as well as from upstream and protection schemes and DMS applications need to take this into account.

Utilities are responding to the increasing presence of DERs by connecting large energy storage units to the grid and by installing static VAR resources to assist with maintaining voltage within normal limits.

Microgrids are also becoming a reality in Québec and elsewhere, with customers looking for an alternative way of maintaining a stable source of power even if the main grid experiences a major event. Utilities need tools to manage and interface to microgrids.

These factors are resulting in a significant increase in the complexity of managing and operating the distribution power system, which in turn is driving improvements in tools used by Operators, including OMS and DMS.

Vendors have responded to the emergence of DER and Microgrids by developing DER Management Systems (DERMS). These systems need to work cooperatively with DMS applications to forecast and monitor the impacts from DERs. The Common Information Model is being extended to include models of DER to facilitate the exchange of data between these systems.

3 Assessment of the Logiciel CED

3.1 Introduction

The Logiciel CED was a joint venture between HQD and CGI (Cognicase at the time). The objective was to develop a computer system to manage the Distribution network (and more specifically outages and work permits[2]) that would then be commercialized and sold to other utilities. The commercialization never happened with the result that HQD is the sole client and sole source of funding for advancements to the Logiciel CED.

In the case of both OMS and DMS, there is a significant gap between what works in theory and what works in practice, so that field testing is key. Being the only client, HQD is also the only user of the Logiciel CED and it has to do all of the field testing required to harden a new function and make it field-worthy. In contrast, commercially available OMS and DMS systems are effectively field-tested by every utility that deploys them, and vendors bring this experience back into the product, which in turn benefits existing and future clients.

At the time when the Logiciel CED software was initially developed, there was very little in the way of equivalent capability available on the market. This is no longer the case: the SCADA/OMS/DMS software products that are available in 2018 offer rich functionality, much better performance and an increasingly flexible open architecture and are being installed at Distribution utilities world-wide. This is not to say that these systems in their baseline version meet all requirements of all utilities; however the proportion of customizations required to specific utility needs is typically small and growing smaller.

In high-level terms, the more obvious benefits of adopting a third party commercial SCADA/OMS/DMS product center around sharing the cost of new features and the fact that vendors provide basic sustaining capability such as evolving to adapt to new operating systems and hardware platforms, as a matter of course.

More subtle, but equally important, benefits include the opportunity to collaborate with other utilities in driving product developments and to benefit from the experience of other utilities who use the same product.

The following sections identify the strengths and weaknesses of the Logiciel CED compared to what is commercially available.

3.2 Functionality

HQD's Logiciel CED does offer certain features that are not typically available from off-the shelf SCADA/OMS/DMS systems, in particular related to alarms. These very practical features enhance the productivity and effectiveness of HQD operators and would be beneficial to other Distribution utilities. They are included as requirements in the Technical Specification and the strategy will be to encourage vendors to comply with these requirements and introduce the resulting functionality into their standard product offering.

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[2] In French, « Régimes de travail ».

An area where the Logiciel CED offers functionality that is very specific to HQD is related to worker safety; safety rules are currently implemented directly in the Logiciel CED software. While the functionality is hard-coded in the Logiciel CED, it should be possible, through a combination of configuration, scripting (by HQD) and customization (by the vendor) to reproduce this capability in a commercial system.

The following are key areas where the Logiciel CED is lagging the industry:

1) The Logiciel CED is weak in the following basic functions:
   a. Basic display capabilities such as highlighting to indicate that a particular section of network is violating a limit (including both SCADA measurements and application-calculated values)
   b. There is no support for dashboards, which present summary results and which are a key enabler for enhanced situational awareness
   c. There is no support for advanced visualization features which also facilitates enhanced situational awareness
   d. Application results are available only via tabular displays, as opposed to graphical displays which are generally used to improve the interpretation of the results in a much easier manner.
   e. The Calculation package, which is used by utilities to define their own calculations using SCADA data or application results as input, has limited access to data provided by SCADA, DMS and OMS applications and the results cannot be viewed on graphical displays. It is difficult to configure and the capability to add calculations in response to business needs typically requires significant development.
   f. The Sequential Control function, which provides a means of automating sequences of actions on the network and is used extensively by many utilities, offers limited functionality, is difficult to configure, and the capability to add new sequential controls in response to business needs typically requires significant development.
2) Historical Data Collection is very limited:
   a. Measurements information is retained for between 24 and 48 hours. Status changes (e.g., circuit breaker trips) as well as alarms and event logs are retained in the CED for between 15 and 60 days. After the expiry date is reached, the information is exported to an external historical system and access to this system is cumbersome. In comparison, commercial systems typically offer the capability to store historical data for years, with no inherent limitation (i.e. only limited by disk space).
   b. Access to historical application results is limited and unwieldy
   c. There is no ability to take a “snapshot” of the network, comprising the set of all measurements and statuses at a given moment in time; snapshots are useful for conducting an after-the-fact analysis and provide a realistic initial state for performing off-line DMS studies.
   d. There is no ability to “play back” SCADA data, which allows users to replay the sequence of incoming field data on graphical displays, and which is particularly useful for after-the-fact analysis of a major network event.
   e. Very few applications use historical data in support of operations, problem diagnosis, or analytic activities.

3) The Logiciel CED does not support a number of industry-standard DMS applications:
   a. Real-Time Distribution State Estimator, which calculates, in real-time, flows and voltages throughout the Distribution network, taking into consideration available flow and voltage measurements, makes this information available to the operator, and alerts the operator to limit violations, for example by highlighting the sections of network that are experiencing limit violations. While the Logiciel CED does deliver some of this capability (via CYMDIST – see point 4) below), it is missing some key features:
      i. It does not run in real-time
      ii. It does not consider voltage measurements, MW measurements, or MVAR measurements (which reduces the accuracy of its results)
      iii. It does not check for overloads, it does not present results on graphical displays to the operator
      iv. It does not inform the operator of voltage violations or overload conditions
      v. It only runs on a portion of the network.
      vi. Voltage violations are communicated to the engineer via a report sent by email.

      The broader impact of these limitations is that they prevent operators from taking on responsibility for identifying and resolving issues such as voltage violations and overloads. The form in which the Logiciel CED presents information to the operator is too complex for the operator to interpret and analyze the problem or to determine the actions to be taken to correct it.
   b. Pre-Switching Validation, which informs the operator of the impact of a switching operation (e.g. opening or closing a breaker) immediately before he/she performs it. The CED does perform some simple checks but it does not check if a switching action will cause an overload or a voltage violation (for example) and would require significant development to add capability to support HQD's business needs.
   c. Fault Location, Isolation and Service Restoration, which can reduce the duration of an outage for customers outside the immediate vicinity of the faulted section of the network from hours to minutes. HQD's Distribution network has all of the remote monitoring and control required to support this function, which is normally the stumbling block for utilities wanting to implement it, but not the logic.
   d. Study sessions, which mimic a real-time session (i.e., same user interactions) and allow the individual operator to try out what-if scenarios, validate switching plans, see if there will be issues if the current network configuration is maintained, …etc.
4) Most of the DMS applications are not implemented directly in the Logiciel CED but rather by CYMDist, a third-party product which is marketed as an engineering analysis tool used by distribution engineers to perform system planning studies.
5) The Logiciel CED does not include a Load Forecast capability; in commercially available systems, this function is used to simulate the network at a time in the future (e.g., tomorrow during the daily peak or in several months) and typically bases its predictions on a combination of weather forecasts and historical data (see item 6) below). It allows operators to anticipate problems in the near future and serve as a basis for initializing off-line studies at a future moment.
6) Generation (including DER) is not modelled. The Logiciel CED does not include a Generation Forecast capability.

7) The Logiciel CED OMS has some important gaps relative to commercial off-the-shelf OMSs such as the following:
   a) While indications of loss of power or restoration of power received from smart meters data can be viewed via the graphical displays, information about crew location and weather data cannot; if the operator wants to know how far the crew is from the work site or suspected outage location or where the storm is relative to the outages that have been detected, he needs to consult a separate external system.
   b) It is missing certain algorithms which take advantage of the capabilities of smart meters (installed across the province of Québec between 2011 and 2014) to accelerate and improve outage detection.
8) Compared to what is available from off-the-shelf systems, the Logiciel CED Distribution Training Simulator is very primitive. Setting up a training session requires a significant amount of manual effort and results in a training experience that is not realistic, so it provides limited value in preparing the operators for potential real-time events that occur on the Distribution network. Any changes to field data, for example in response to trainee actions, require that an Instructor be standing by to manually enter those changes. There is no way to mimic the loss-of-power messages from smart meters. In contrast, off-the-shelf systems include a simulator which automatically responds to trainee actions, simulates the behavior of smart meters, and includes the capability to produce complex training scenarios that can be used both to train new operators and to refresh training of more experienced operators so that they can better respond during storms that cause widespread outages. In an era of large-scale retirements of more experienced operators, this is one of the more serious and higher impact shortcomings of keeping the Logiciel CED.
9) The Logiciel CED does not support mobile applications so that field crews must always inform operators verbally of actions such as switching of manual breakers so that the operators can then update the state of the network in the Logiciel CED. The reverse is also true in that the crews must ask the operator to verbally confirm that an area is protected, rather than being able to access the information directly. This contributes not only to inefficiency but also to reduced situational awareness for crews.
10) The Logiciel CED monitors larger DER but does not model the increasingly common smaller DERs, and is not aware of their presence on HQD's network so can neither determine their impact on the network nor manage them.

3.3 Architecture

While the industry has moved towards standardizing interfaces between systems, the Logiciel CED currently maintains interfaces to almost 50 systems and all are custom interfaces. The benefit of standards-based interfaces is the reduced cost and complexity of changing out one of the components. If the interface is custom, changing out one component requires re-implementing (i.e. re-developing, re-testing, re-integrating) the custom interface; on the other hand, if the interface is standard, the replacement of one of the systems may requiring some tuning of the interface but the level of effort and complexity is not comparable. This is particularly problematic for the interface with the Geographic Information Systems (one per CED). Changes to the model are forwarded from the GIS to the Logiciel CED in near real-time. The interface is effective but extremely complex and the model exchange format does not follow any standard format so that upgrading or replacing the GIS will be major project in itself.

The CED relies on external systems to interface with substation and feeder RTUs:

1) In the case of the Distribution substations, remote monitoring and control of the Distribution substations is performed by the Hydro-Québec TransÉnergie (HQT) GEN4 SCADA systems. In order to allow the Logiciel CED to receive data and send controls to the GEN4 SCADA, a custom protocol was developed to allow the Logiciel CED to communicate with the HQT GEN4 SCADAs, this despite the existence since the 1990s of a standard protocol for precisely this type of communication. The protocol also supports the exchange of tagging information (mainly related to maintenance) and the management of jurisdiction of devices in a substation (so that HQT and HQD are not both trying to control the same device at the same time).
2) In the case of the distribution feeders, the protocol supported by the RTUs is a world-wide standard (DNP3). Instead of implementing the capability to communicate via DNP in the CED, a third-party vendor was asked to develop a protocol translator that converted the industry standard protocol into the same custom protocol used to communicate with the HQT GEN4 SCADA, with the result that the Logiciel CED has a hard dependency on a third party and cannot operate without it.

As explained in section 3.2, CYMDIST, which provides most of the DMS functionality, is a separate system to which the Logiciel CED interfaces. This two-system approach has a negative impact on performance, even with each Logiciel CED instance covering only a portion of the network. Unlike commercial off-the-shelf DMSs, CYMDIST does not maintain a real-time view of the network. The architecture and resulting mechanisms for presenting results are so different from commercial systems that it becomes difficult to compare, but it can be stated that the existing Logiciel CED architecture would require significant modifications to be able to provide this real-time view with the requisite performance and the resulting situational awareness, assuming it would be feasible at all.

3.4 System Maintenance and Support

There are currently 5 fully operational instances of the Logiciel CED each serving a region of HQD’s territory. A 6th instance, located in Les Îles de la Madeleine, operates only partial functionality. Each of these systems needs to be maintained separately, and connections between adjacent regions require special attention in terms of operations and data maintenance, since, for example, a given feeder may span 2 regions. In contrast, commercial SCADA/OMS/DMS systems are able to manage networks as large as HQD’s in a single system. The multiple instances result in significant duplicate work being required to maintain and update the systems. Additional testing and verification work is required to ensure that each of the five systems is adequately maintained. With a single combined DMS/OMS, the work only needs to be performed once instead of multiple times.

The Logiciel CED supports a Pre-Production environment, which is used to test software changes, in addition to its Production environment. However, there is no capability to route real-time time SCADA data to the Pre-Production environment (referred to as “Listen mode”), which limits the effectiveness and thoroughness of tests that can be conducted prior to putting the changes on-line in the Production environment

3.5 Relation to Hydro-Québec TransÉnergie Replacement Project

As described in section 3.3 Architecture, currently, the HQT and HQD control systems communicate via a proprietary protocol which provides a mechanism for funneling SCADA data related to the Distribution substations collected by the HQT GEN4 system to the CEDs and for the Logiciel CED to send controls to certain Distribution substation devices. The protocol also provides a mechanism for exchanging tagging information (related primarily to maintenance activities) and managing authority over a given substation (between HQT and HQD). Other information that needs to be shared between CED users and GEN4 users is exchanged verbally. The GEN4 CTs and the Logiciel CED each maintain their own separate model of the substations. Processes associated with the same activities (e.g. network maintenance and related field work) have similar objectives but are completely different. The control systems used by the operators look and feel completely different.

While the assessment of the two projects may remain independent, it is important to consider the benefits that would come with a single system:

1) Opportunity to standardize processes between HQT and HQD by having common software for common functions
2) A single standard user interface
3) Opportunity to further standardize processes across HQD by having a single integrated control system (vs the current 6 separate systems).
4) Opportunity to share more information between HQD and HQT control system users and between software functions (e.g. between Load Shedding function at the Transmission level and the Outage Management function at the Distribution level, and between Transmission and Distribution Load Forecast functions)
5) Opportunity to streamline data maintenance and system maintenance
6) Opportunity to eliminate the duplication of data models and interfaces
7) Opportunity to move to a common solution for DER

3.6 Overall Assessment

The current HQD SCADA/OMS/DMS systems can be characterized as Level 2, per the definitions in section 2, with certain reservations. While the OMS would be level 2, the DMS would be level 2 or below with limited functionality and SCADA would be level 2, although, as stated above, it is missing the fundamental ability to communicate with RTUs. The architecture has features of a Level 1 system (lack ofsupport for standard interfaces) but it is up-to-date with regard to operating systems and cybersecurity.

In terms of functionality, the Logiciel CED was ahead of the market for much of its life, but this is no longer the case. Commercial SCADA/OMS/DMSs are now ahead of the Logiciel CED, in terms of functionality, architecture and performance, and the gap will continue to grow especially as the complexities of the distribution network increase.

As network operation becomes even more complex, situational awareness has become a critical requirement. This coupled with an aging workforce where very experienced operators retire, demands tools that quickly identify issues and potential issues to assist operators with determining appropriate resolutions to the problems.

Functions such as FLISR for reducing outage times and a realistic Distribution Training Simulator are needed to deal with current challenges.

DERs need to be managed at the level of Transmission and Distribution and their management needs to be integrated with DMS applications.

Adding all, or even most, of these capabilities to the existing system would be extremely complex.

This type of replacement project will take 4-5 years to execute, so that the decision to proceed should be made now.

4 Evaluation of the Project

4.1 Introduction

Based on the evidence presented in section 3, the HQD project to replace its SCADA/OMS/DMS is necessary because of important and increasing gaps in its functional capability. Alternatives such as adding the missing functionality to the existing Logiciel CED software or bolting it on (i.e., developing it outside the Logiciel CED and adding an interface) are not really practical due to cost and the quality of the result. The functions available from commercial DMSs have been field-tested by other utilities; adopting those functions is an implementation project in the case of a commercial DMS, not a software development project, as in the case of the Logiciel CED. The risks related to software development projects are substantially higher than those associated with implementation projects of commercial products. In the case of DER, which will have an increasing impact on Distribution networks, HQD stands to benefit a lot more from collaborating with Vendors and with other utilities that are already being impacted than by going it alone. The major vendors have annual user group meetings where the users of the vendor's products meet to review upcoming product roadmaps and share experiences with using the products. The feedback provided by the vendor's customers is used to continue to enhance the products.

In light of this, the replacement of these complex systems requires a detailed approach in order to increase the likelihood of meeting the goals of migrating to the new system in the most effective manner.

Projects leading to the full replacement of SCADA/DMS/OMS require long lead times. The complexity of these systems requires utilities to take the time to define their requirements in a detailed specification. This can take a year or more in some cases. The total time for larger utilities to procure, implement, test, and migrate from the old system to the new system can take 4 to 5 years.

While this industry is maturing, external forces impacting utilities and the continued enhancement in underlying technologies drive utilities to ensure that their SCADA/DMS/OMS technologies are kept up to date to ensure that the Operators have the tools required for managing the reliability of power system. The major vendors continually invest in their products to keep them up to date with technology changes and to meet new needs.

4.2 Preparation

Among the first activities initiated in the context of their replacement project was to survey other utilities who had undergone similar types of projects.

While the survey of other utilities focused on Transmission utilities, some of those were vertically integrated utilities like HQD that manage both Transmission and Distribution. The trend among those utilities was to streamline their control systems and either have a single end-to-end system that combined SCADA, EMS, GMS, OMS and DMS, or two systems (one for Transmission and one for Distribution) but from the same vendor.

One of the principal keys to success, in terms of the initial phases of the project, was taking the time to clearly document requirements, and involving all the stakeholders in the process.

In parallel with the utility survey, ESTA also conducted a survey of vendors most commonly selected by utilities to collect general information about baseline vendor capability related principally to SCADA, EMS and GMS but also related to OMS and DMS. The survey of vendors was aimed at collecting general information about each vendor's baseline capability and roadmap.

4.3 Detailed Evaluation

Our opinions stated in the following sections are based on working with HQD in the Planning and Requirements Development phase of the replacement project.

Our opinion includes the following key project areas:

1. Requirements Definition
2. Functional Scope
3. Project Oversight
4. Procurement Strategy
5. Evolution Strategy

4.3.1 Requirements Definition

An important key to success in trying to define requirements in the context of existing off-the-shelf systems is to understand what is available in those off-the-shelf systems.

In mid-2017, HQD and HQT jointly issued an invitation to vendors to pre-qualify for the SCR-D and SCR-T projects; this included vendors' responding to a brief questionnaire. The four vendors who pre-qualified then gave a two-day demonstration of their standard, off-the-shelf products, with the aim of helping HQD to get a clearer and more concrete understanding of the level of advancement of vendor products. The demonstrations were very well attended by HQD, with audience members from operations, system maintenance and solution architecture.

The writing of requirements for the Logiciel CED replacement project began in earnest following the pre-qualification demonstrations. Participants have included:

- Representatives from HQD Operations, including Operators and Engineers
- IT architects

The resulting requirements were published into a formal Request for Proposal released in May 2018.

4.3.2 Functional Scope

The functional scope of the Logiciel CED replacement system combines standard functionality that is available off-the-shelf from all key vendors (including functionality that is not currently available in the Logiciel CED) and will require configuring the system to meet HQD's needs.

The following table compares the existing systems functionality with the requirements for the replacement system (items for this system are in off-the-shelf products):

Functionality	CED	Replacement System
Data Acquisition	X – Data Acquisition is done by 3rd party	Part of standard products
Supervisory Control	X – Supervisory Control is done by 3rd party	Part of standard products
Data Exchange via Standard Protocol	X	Part of standard products
User Interface	√	Part of standard products
Situational Awareness	X	Part of standard products
Distribution Management	√	Part of standard products
Outage Management	√	Part of standard products
Management of DER	X	Part of standard products - evolving
Historian	√ (3-month retention period)	Part of standard products (2+ years retention period)
Switching Management	√	Part of standard products
Distribution Training Simulator	X	Part of standard products
Model Manager	X	Part of standard products

The major functional components of the replacement Distribution and Outage Management System include the following:

- Data Acquisition and Supervisory Control – the new SCADA will communicate directly with feeder RTUs (including pole tops) and other field devices using the existing communication protocols. Communication with substations will depend on the vendor solution but the existing proprietary protocol is expected to be replaced.
- Data Exchange via Standard Protocol – the replacement SCADA system will also include an industry standard protocol for data exchange with other systems.
- User Interface – the replacement system will come with a more modern User Interface that should significantly enhance the User Experience. In an effort to enhance Situational Awareness for Operators and other users, vendors have incorporated the use of advanced visualization techniques to take data and transform it into information that provides for quicker recognition of

system conditions. Users will be able to view the network via geographic maps, not only via schematic displays.

- Outage Management – the replacement system will include outage management functions including Outage Prediction to replace the functions in the older system. In addition, it will also include the ability to present outage information, including crew location, on geographic maps as well as facilitate the use of mobility.
- Distribution Management – the replacement distribution management system will include Network Topology Analysis and Unbalanced Operator Power Flow to replace the functions in the older system. A more complete Distribution State Estimator, that processes not only flows but also voltages, is available as part of the vendor's off-the-shelf product. Commercially available DMS functions offer significantly better robustness and performance than the Logiciel CED. Vendor standard products that are not currently available in the Logiciel CED also include FLISR, integrated Volt-Var control, Pre-Switching Validation, Load Forecast, and Study mode.
- Historian – the new SCADA/DMS/OMS will come with an enhanced Historian. The previous generation of Historian functionality had limitations on the amount of data that could be stored and the duration. The newer versions of Historians available from the vendors include a data recording capability similar to a flight data recorder in that it stores the SCADA data at the rate in which it is received from the field. The capability to play back the data for a previous period greatly enhances after-the-fact analysis. The new Historian will also result in a significant simplification in overall architecture, and improved system security since it will allow for the elimination of a large number of direct interfaces to external software systems.
- Switching Management – the replacement will include the capability to automatically prepare switching orders.
- Distribution Training Simulator (DTS) – all DMS vendors offer, as part of their standard product, a Distribution Training Simulator that provides an environment for utilities to perform cycle training, training of new Operators, training on storm scenarios as well as providing an environment for validating, testing and training Operators on new functionality and changes to business processes. The DTS can also be used as an environment to test new software prior to installing the changes in Production.
- Model Manager – The industry movement towards data exchange using the Common Information Model drove the need for software that manages the creation and maintenance of different network models. Vendors have enhanced these tools to be the basis for managing the Distribution and Outage Management models within one tool including managing data received from the Geographic Information System. The additional capabilities to work on different models reflecting current and future points in time will provide the opportunity to study system changes on the reliability of the network prior to them being commissioned for real-time operation.

It is should be noted that while the vendor's off-the-shelf products can replicate, expand, and improve on most of the Logiciel CED's existing functions and HQD's requirements, some customizations and configurations will be needed to meet HQD's unique needs (these are often through individual modules interfaced with the off-the-shelf systems through interface modules called Application Program Interfaces (API) that allow easy upgrade of the system). This is typical in similar types of replacement projects. HQD has documented the related requirements in terms of the fundamental need driving the requirements in order to provide vendors the opportunity of proposing a way of meeting those requirements that is best adapted to their product and requires the least amount of custom code.

4.3.3 Project Oversight

The implementation of the SCR-D project requires a strong project oversight model adapted to the size and scope of the project including many participants of HQD. Within Hydro-Québec, HQD and IT have implemented a structured governance framework including a Program Management Office which facilitates project information sharing, issue escalation, addressing of risks and decision-making.

Based on ESTA's experience with these types of projects, it is our opinion that the proposed Project Oversight model is appropriate given the size and complexity of the solution being procured.

HQD has established a Risk Identification and Management approach that identifies key risks based on their experience with similar types of projects to the SCR-D project and based on the results of the Market Survey conducted in 2017. HQD has quantified the probability of each risk event occurring, the potential impact on the schedule, budget, and quality of the solution. HQD has identified key issues and defined appropriate mitigation strategies. A detailed risk matrix is currently being monitored.

4.3.4 Procurement Strategy

HQD has a well thought-out and well-planned procurement strategy for its replacement system. The replacement of the SCADA/OMS/DMS will be done using a competitive bidding process. This approach is typical when a full replacement is needed. As a large, major utility, HQD can expect to receive very competitive pricing from the prequalified solution providers.

HQD has developed detailed specifications for the technical, commercial, and service requirements that are required to successfully implement and commission these complex systems. HQD used generic baseline specifications which reflect the features and functions available in the current SCADA/OMS/DMS products and most commonly used by other utilities. HQD enlisted teams that included business and IT personnel to adapt those specifications to the way in which HQD operates its distribution grid. HQD issued the RFP to a pre-qualified set of SCADA/OMS/DMS vendors with the requisite experience and system solutions to meet HQD's requirements.

HQD has developed an evaluation approach that will facilitate selecting the vendor that is best positioned to meet HQD's needs. Since all of the vendors have baseline systems that will meet most of HQD's requirements, it is important to establish an evaluation methodology that allows HQD to focus on the differences between the different vendor offerings. The evaluation will consider both the level of compliance (what is in the products as it relates to HQD's requirements) as well as how the vendor has implemented the requirement. In the case of features or functions where the vendor has complied but does not currently support the feature/function, the specification requires that the vendor indicate whether the resulting capability will be developed as a customization or as part of their product; the latter offers the clear advantage that subsequent software updates would not require re-integration of these new features, and will be ranked accordingly. This will include reviews of the written proposals as well as detailed demonstrations of each vendor's features.

The RFP requests pricing not only for the project itself but also the cost of maintenance; this will allow HQD to estimate the long-term cost of the solution.

4.3.5 Evolution Strategy

HQD plans to adopt an “evergreen” strategy once the new SCADA/DMS/OMS system is deployed to avoid the need to perform a full-scale replacement in the future. This is consistent with the approach that many other utilities have adopted.

While the existing Logiciel CED offers a form of Evergreen system maintenance, the software never evolves unless HQD specifies it and pays for the entire development effort; this includes new functionality as well porting existing functionality to keep ahead of obsolescence of third party software such as Operating Systems.

Commercial vendors maintain roadmaps for their products and are constantly advancing the capability of their products in order to remain competitive. They also keep their product up-to-date with third party software by maintaining compatibility with evolving Operating System versions and with evolving hardware, as a matter of course. HQD will benefit from these advances with minimal disruption of their systems by periodically making incremental upgrades of their software.

5 Conclusions and Recommendations

ESTA's conclusions and recommendations regarding our assessment of HQD's existing Logiciel CED are as follows:

1. The existing system has fallen behind commercial systems and will continue to fall further behind. It is highly dependent on one vendor that is work for hire without a baseline product. Maintenance support and any new features are dependent on a small pool of resources. It lacks modern features proven beneficial by the industry. For example, the lack of critical functions such as a Distribution Training Simulator combined with the increased complexity of Distribution networks increases the risk of having under-trained operators taking over from retiring experienced operators. The growing impact of DER and the absence of any DER function in the Logiciel CED is an issue that needs to be tackled within just a few years. The significant lead time for this type of replacement project requires that HQD continue down its current path of replacement.
2. The existing system should be replaced with commercial off-the-shelf solutions available from major vendors of these products.
3. HQD has defined a detailed set of requirements in which it clearly identifies any requirements that will need to be added to meet its needs.
4. HQD has established a project oversight structure that aligns with similar projects of this size and scope.
5. HQD has developed an evaluation methodology that will facilitate an "apples-to-apples" and unbiased evaluation between the different pre-qualified vendors total offerings.
6. HQD needs to move to adopt an evergreen model for evolution to keep up to date with vendor product changes impacting its power system and technologies.
7. Where possible, through its training and change management, HQD should adjust some of its practices to align more with industry approaches to similar issues (as is being done at other utilities). This will allow HQD to reduce the level of customization of the selected vendor systems and especially the amount of custom code that needs to be developed and maintained.

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