Q. **Reference: Application**

According to the Shenandoah Valley Electric Cooperative (https://odec.myenergysites.com/news/ShenandoahValleyElectric/energy-storage-can-electrify-your-bottom-line?newsletterCampaignSendId=45136&subscriberId=f043515d-6ce0-4f8e-aa88-2748acc61f1f&spaceId=v92ovjhf1w1y), battery energy storage "*offers a cleaner and more eco-friendly storage solution. There's no need to run a generator that emits dangerous gases and requires regular maintenance.*" It goes on to say "*You can have the batteries connected to solar or wind sources on-site to generate your own power, lowering the cost of electricity and your carbon footprint. If you need to pull power from the grid, you can do that during off-peak hours and reduce your energy spend*."

a) Given the remote nature of many of Hydro's customers, is battery energy storage combined with time-of-use rates a valid alternative to meeting load growth and satisfying minimum reliability requirements?

b) How is battery storage in the form of an electric vehicle impacting Hydro's approach to reliability?

c) Is the government, or Hydro, currently offering programs promoting battery storage, customer-owned generation, smart meters or time-of-use rates?

d) What are the benefits of smart meters?

e) What are the unit costs of installation of smart meters and how does it compare to the unit costs of installing AMR?

f) Would smart meters reduce the cost and duration of outages, particularly in the case of remote customers?

g) What are the advantages/disadvantages and challenges associated with implementation of a smart metering program for Hydro's rural customers?

h) Has Hydro undertaken a study quantifying all costs and benefits of smart meters? If so, please file a copy of the report for the record.

i) Please provide copies of all studies Hydro has undertaken or reviewed in relation to smart meters.

A. **a)** Technologies such as battery energy storage and dynamic rate structures provide the opportunity for customers to shift load into periods of lower demand on the grid; neither technology on its own would serve to reduce customer energy requirements and therefore would not be stand-alone solutions to serve load growth in Newfoundland and Labrador Hydro's ("Hydro") service areas. Through its ongoing proceeding seeking approval of the construction of Hydro's Long-Term Supply for Southern Labrador, Hydro has demonstrated that Battery Energy Storage Systems remain cost-prohibitive for the provision of firm capacity on the rural systems which Hydro serves.

b) Hydro continues to study the impact on the electrical system from broad adoption of electric vehicles, as well as industry developments in bidirectional charging or V2X technology (Vehicle to Everything). As this technology matures and electric vehicle adoption grows in Newfoundland and Labrador, Hydro will continue to assess how new technology can be used to serve customers at the lowest possible cost, in an environmentally responsible manner, consistent with reliable service.

c) Hydro currently offers a Net Metering Service Option to its customers. This service option allows customers to install generation on their premises to offset part or all of their electrical energy requirements. Energy generated in excess of their requirements is permitted to be credited against the Customer's energy purchases from Hydro. Hydro also has a number of power purchase agreements with community-owned generation projects in its isolated systems.

d) There are several benefits associated with the implementation of smart meters, including real-time information concerning usage, remote disconnect/reconnect or power limiting, an improved knowledge of the distribution system bettering responses to outages, and the ability to implement dynamic rate structures such as time-of-use rates or critical peak pricing. As with all utility investments, these benefits must be weighed against the cost of implementation.

e) The unit cost of smart meter installation is similar to regular or smart meters. However, the capital and operating costs required to support smart meters are significantly more costly, including the necessary communications infrastructure and interface to the billing system for dynamic rates.

f) To date, Hydro has not assessed whether smart meters would reduce the cost and duration of customer outages.

g) The potential benefits of smart meters are presented in part d) of this response. Capacity-related benefits would require the implementation of dynamic rates combined with changes in customer behavior. In accordance with government direction, rates charged to Hydro's customers on the Island Interconnected System are consistent with Newfoundland Power Inc. ("Newfoundland Power"). Given this direction and that Newfoundland Power serves a majority of customers on the Island Interconnected System, Hydro expects Newfoundland Power to lead the retail rate review process.

With regards to the challenges associated with implementing smart meters on Hydro's rural systems, and given the rugged terrain and large geographic area in which Hydro's Rural customers reside, it is challenging and costly to install and maintain communications infrastructure in these areas.

h) Hydro evaluated the cost of implementation of AMI[1] (smart meters) versus AMR[2] Drive-by technology its 2022 Capital Budget Application. Hydro's analysis determined that the implementation of the AMR Drive-by Solution was the least-cost alternative for the replacement of Hydro's metering system.[3]

i) Hydro's most recent Conservation Potential Study[4] assessed the forecast cost and benefits associated with dynamic rates (i.e., smart meters). This analysis indicated that broad deployment of smart meters would not be cost effective until the mid-2030s.

Through the development of its 2022 Capital Budget Application "Replace Metering System" ("Metering Application"), Hydro commissioned a study on various metering technology

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[1] Advanced Metering Infrastructure ("AMI").
[2] Automatic Meter Reading ("AMR").
[3] Provided as Attachment 1 to Hydro's response to PUB-NLH-016 of the 2022 Capital Budget Application proceeding.
[4] "Newfoundland and Labrador Conservation Potential Study (2020–2034)," Dunsky, filed as "Application for Approvals Required to Execute Programming Identified in the Electrification, Conservation and Demand Management Plan 2021–2025," Newfoundland and Labrador Hydro, rev. July 8, 2021 (originally filed June 16, 2021), sch. 3, sch. C.

alternatives which was prepared by a third party, Util-Assist. The results of this study are consistent with Hydro's Metering Application, that drive-by AMR was the least-cost alternative to address its metering requirements, particularly in the context of the Conservation Potential Study's findings on dynamic rates.[5] A copy of this study is provided as CA-NLH-012, Attachment 1.

[5] Option 3, "Full-scale Drive-by AMR lite" had the highest net present value of all alternatives studied at $17.6 million. This analysis was consistent with Hydro's comparison of alternatives, which found the same technology to have the lowest cumulative net present value.

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June 15, 2020

Business Case Report for Next Generation Metering (NGM) - Newfoundland and Labrador Hydro

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Table of Contents

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Table of Figures

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Table of Tables

Section 1: Executive Summary

The decision to implement next generation metering, whether advanced metering infrastructure (AMI), automated meter reading (AMR), or a hybrid solution, has significant implications for every aspect of a utility's business. Next generation metering is key enabler for modernizing utilities' electric business and can enhance safety and reliability, deliver expanded data to provide customers with enhanced service and choice, as well as enable improved productivity and operational efficiency. When selecting, and implementing a new metering system, it is therefore critical that Newfoundland and Labrador Hydro (NLH) get the information and support it needs to make the best decisions for its operation and customers. This business case report delineates key considerations, outlines the justification to proceed with next-generation metering and provides details on both financial and non-financial drivers and benefits. In addition, it outlines potential deployment option strategies and next steps for the NLH team.

Four options were evaluated from both financial and technical perspectives to arrive at the recommended approach for the utility and they were as follows. First, a full deployment of the utility's partially-deployed Landis+Gyr (L+G) PLX (pronounced Plex), power line carried solution. The second option explored was a full-scale deployment of the Landis+Gyr Mesh AMI with all software and integration required to support most AMI use cases in what would be considered a best practice, and typical AMI deployment. The third option considered potential synergies in a shared-solution with Newfoundland Hydro utilizing their Itron Drive-by system. The final option identified and investigated an AMI-lite solution representing the full deployment of AMI meters and network infrastructure, paired with NLHs current head end software solution, Command Center <u>without</u> the data management software and integration that typically accompanies AMI deployments.

The case for Option 1 (Appendix B) – Full-scale PLC AMR (L+G PLX), returned a positive $10.2M NPV over a 21-year system lifecycle with all meters being deployed in year one. From a technical perspective, there were several concerns with recommending this option to NLH including a higher cost, technology limitations and a potential issue with the viability of the solution through the system lifecycle over which the finances were based.

The second option, Option 2 (Appendix C) – Full-scale AMI (L+G Mesh) AMI deployment over a 22-year system lifecycle was also analyzed, again assuming all meters would be deployed in the first year. This case returned a -$1.2M NPV, on costs of $31M and benefits totalling $28M. While the option would provide the highest benefit value of the analyzed options, it was clear that the AMI big bang approach would not be viable at the utility.

The third case, Option 3 (Appendix D) – Full-scale Drive-by AMR "lite" with NL Power's Itron Drive-by solution over a 21-year system lifecycle was reviewed next. While a viable solution financially ($17.6M NPV), like that with Option 1, the technological limitations to a drive-by solution are too great. As noted in Section 2: Technology and Trends, the trend amongst utilities in Canada and really across North America is toward the deployment of AMI. Drive-by AMR meter reading is something that electric utilities are moving away from and not towards. As the utility industry is searching for ways in which to improve Customer Experience, drive-by metering does the opposite in that it improves the utility's experience while preventing any meaningful impact to the customer. Regardless of technology solution selected, the most significant cost by far to the utility is the replacement of meters, at upwards of 75% of the capital cost. With this in mind, understanding that money is going to have to be spent, NLH must consider what the best investment is for their customers and their utility. Drive-by metering is enticing due to relative cost in comparison to AMI, but when viewed in the current climate of where the industry is with more advanced AMI solutions and the fact that this will be a 20-year investment, the risk to move forward with Drive-by metering is too great and is not recommended.

The final case to be analyzed, Option 4 (Section 4) – Recommended: Full-scale AMI "lite" Cost Benefit involves a full roll out of the L+G RF mesh-based meters and network collection infrastructure while holding back on the deployment of significant components, e.g., Meter Data Management (MDM) software and full system integration, etc. that would enable additional use cases that contribute to the benefit levels in option two. The positive $13.4M NPV along with the protection the utility gets in deploying the most current solution puts NLH in the best position to confidently move forward into the future best-prepared to meet stakeholder requirements as they arise. In particular and with this option, the utility is positioned to take full advantage existing meter and system functionality that enables the support of remote connection and disconnection of service, along with the ability to limit load. Currently the utility is sending two FSRs into the field to perform the disconnect function for safety purposes which given the NLH service territory is a significant waste of effort and labour that would immediately be resolved with this deployment. On the customer side, their experience is increased as NLH would have the ability to remotely reconnect meters, shortening the time to service restoral for the customer. Lastly, with the moratorium on shut-offs during part of the year, NLH has the opportunity to achieve major savings and keep their revenue stream going through the application of load limiting. These are just a few options that this solution provides, not to mention the availability of data to significantly enhance the utility's operational efficiency and customer experience and engagement through the presentment of data.

Recommendations made here seek to address the current problem at NLH which is a mix between current meter reading system challenges including technology obsolescence, and system performance. In addition, a recommendation needs to ensure that NLH is not faced with an obsolescence problem again during the lifecycle of the solution which would lead to expected benefits not being captured. It is recommended then that that NLH move forward with the third option of rolling out meters and network collection infrastructure, while holding back on those aspects of an AMI deployment that while admittedly add benefit, also add a greater cost. In order to mitigate the strategic risks of the PLX solution (limited functionality going forward from a meter perspective, system obsolescence of the system, etc.) an AMI solution should be considered as the primary way forward. The recommended go-forward strategy is one of migration with the current supplier, L+G, taking advantage of out of the box meter/endpoint functionality and benefits as available, and then with additional AMI use cases as they make financial sense. The greatest benefit of this strategy for NLH is that it provides the metering and endpoint platform that will enable the utility to confidently go forward with a solution that provides a level of future-proofing not available from the current power line carrier solution.

Certain limitations, including adequate GPS coordinates of infrastructure and metering locations, along with the ability to create a solid design with firm pricing necessitate the further recommendation for NLH to pursue the best path and value for the utility by going to market for this procurement to ensure the best deal for NLH, whether that be with the current supplier or not.

Detailed evidence supporting the conclusions of the summary follow throughout the remainder of this report.

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Section 2: Technology and Trends

2.1 Technology Prevalence and Market Assessment

Utilities have been deploying AMI on a wide scale for well over a decade, and the technology continues to evolve to provide new benefits. AMI technology has now become the new norm and is widespread across North America. Natural resources Canada has stated that as of December 2018, 82% of electric meters in Canada can be classified as Smart Meters. On the flipside, Drive-by AMR is diminishing in its deployment among electric utilities throughout the country. The figure below shows a diagram outlining the provincial penetration, including AMI, of Smart Grid technologies across Canadian Provinces and Territories.

Figure 1: Smart Grid Deployments in Canada (Dec.2018)

2.2 Emerging AMI and Technology Trends

The tables below describe emerging trends in terms of AMI and utility technology.

AMI Trend	Description
Advanced Metering Infrastructure (AMI)	With the advances in the last ten years in RF communication methodologies, utilities have increasingly moved away from AMR and PLC technologies to take advantage of opportunities that AMI technology presents.
Analytics	Companies that are not investing heavily in analytics by 2020 will quickly fall behind as other businesses leverage analytics to identify problems, opportunities and solutions.
Artificial Intelligence (AI) and machine learning	Companies that invest in analytics are also investing in AI and machine learning in order to navigate new volumes of data and put the information to good use.
Demand Response	Smart meter data can be used to help manage and meet peak demand loads more effectively, by using real-time communication to increase customers' participation and drive changes to their consumption patterns. All categories of customer can now be influenced to help optimize demand management by altering their consumption, not just the current subset of high energy users.
Disaggregation	AI technology has paved the way for platforms (e.g., Grid4C) using granular data to breakdown meter data and determine usage and performance of individual appliances.
Edge computing / Distributed Intelligence	Edge computing is being deployed across industries, placing decision making at the edge (e.g., in meters or network devices) to reduce response time, save bandwidth and deliver feature-rich applications. AMI meter vendors with advanced meter processor and memory achieve functionality through apps in the meter. Greater the level of granularity (i.e., 1 second data), the greater the opportunity for value to the end customer.
Managed Services	Utilities are outsourcing data functions of smart metering projects to vendors. Meter suppliers and third parties are predominantly performing services such as data collection, management and archiving. Utilities seeking flexibility can use this service model and maintain operational involvement as needed for metering projects related to network operation, meter management and asset ownership, all for a recurring fee.
Network as a Service (NaaS)	Instances where the vendor takes responsibility for the performance of network infrastructure and directs third party personnel to fix infrastructure issues in the field as they arise.
Outage management	Distribution utilities are dramatically accelerating outage restoration by using smart metering data to pinpoint the location of a fault, dispatch field crews, notify customers and check the status of all devices afterwards.

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AMI Trend	Description
Renewables	Rising share of generation accounted for by renewables, increases risk of grid instability. To manage, predict and balance pressures on the grid, sensors can be implemented at the edge of the AMI network to collect and communicate relevant data. That network of sensors is precisely what AMI has delivered.
Software as a Service (SaaS)	Applications where the software is licensed on a subscription basis and is centrally hosted.
Security	New technologies create new security vulnerabilities, and IT leaders say their highest risk problems revolve around security threats and data privacy, culminating in the trend of proactively protecting infrastructure.

Table 1: AMI Trends

Technology Trend	Description
Augmented intelligence	Augmented intelligence, like artificial intelligence, is being employed to streamline processes and improve decision-making. The difference is that humans process the information and make the decisions.
Agile Information Technology (IT)	Companies are undertaking more flexible approaches to IT strategy, with the ability to quickly change direction and reprioritize.
Blockchain	Utilities are deploying new transactive business models using blockchain, such as to support energy exchanges (Transactive Energy Processing).
Customer Experience (CX)	Changing expectations of consumers who demanding instant responses and services on demand. Other industries have and continue to shape customer expectations and utilities are finding ways through technology to meet those needs.
Digital twins	Using virtual models of assets is helping utilities gain real-time and predictive insights on performance as well as better integrated distributed energy resources (DERs).
Electric vehicles	Mass take-up of electric vehicles impacting the grid, leading to interest in identifying and monitoring location of EVs. AMI voltage data combined with connectivity modeling within the MDM aid in transformer load monitoring activities for the utility.
Distributed generation	Includes residential rooftop solar—feeding into the grid. Online analytics on energy-usage patterns, based on smart metering data, can be used to model the impact of solar on the network, enabling faster risk assessments of any network impact and more timely responses to customer requests.

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Technology Trend	Description
Process automation	This trend kicked off with robotic process automation (RPA) but will see growth with the combination of process intelligence, content intelligence, AI, Chatbots and other innovative technology.

Table 2: Technology Trends

2.3 AMR & AMI Functionality

The following table was supplied by L+G, the current metering technology supplier of NLH and features functionality differences between their technology solutions. In addition, a column representing the AMR "lite" Drive-by metering option was added by Util-Assist to provide a single view of all evaluated options. Although this represents one supplier's functionality, at the power line carrier and mesh levels, this information can generally be applied to the rest of the leading AMI providers in the marketplace.

Feature	AMR (L+G PLX)	AMR "lite" Drive-by	Full AMI (L+G Mesh)	AMI "lite" (L+G Mesh)
Benefits – Present Value	$20.9M	$18.6M	$26.7M	$20.9M
Costs – Present Value	$14.5M	$10.2M	$31M	$11M
NPV	$6.4M	$8.4M	$4.3M	$9.9M
IRR	11%	14%	N/A	16%

Feature	AMR (L+G PLX)	AMR "lite" Drive-by	Full AMI (L+G Mesh)	AMI "lite" (L+G Mesh)
Deployment / Registration complete	Within 24 hours	No registration process	Within 24 hours. (Typically less than one hour when mesh network is in place and deployed contiguously)	Typically, less than one hour
Data Availability	99% by 8am following day	Monthly or whenever read by mobile device	99% by 8am following day	99% by 8am following day
Reconfiguration (Up to 100K endpoints)	Entire network typically within 24 hours	Network not present	Entire network typically within 24 hours	Entire network typically within 24 hours
Service Disconnect / Reconnect	Less than five minutes, confirmation in 20 minutes. Service limiting support planned.	Not Available	Less than 30 seconds on average.	Less than 30 seconds on average
Alarms	User friendly dashboard and report driven	Collected during monthly read	User friendly dashboard and report driven	User friendly dashboard and report driven
On Demand Request	Less than 5 minutes, packet arrives 4-6 hours later	Not available	Less than 30seconds on average.	Less than 30 seconds on average
Validation of Commands	Within 20 minutes	Not applicable	Virtual real time, typically within five minutes.	Virtual real time, typically within five minutes
Status reports for troubleshooting	Dashboard, standard report, and custom report capable.	Monthly following mobile read download	Dashboard, standard report, and custom report capable.	Dashboard, standard report, and custom report capable

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Feature	AMR (L+G PLX)	AMR "lite" Drive-by	Full AMI (L+G Mesh)	AMI "lite" (L+G Mesh)
Load Profile	One 15-minute value (res) Two 15-minute values (C&I) Built from sampling ANSI meter registers.	Not available	Configurable up to 16 channels of available ANSI meter Load Profile channels (1, 5, 15, 60 minutes). Default configuration is 15 minute intervals.	Configurable up to 16 channels of available ANSI meter Load Profile channels (1, 5, 15, 60 minutes). Default configuration is 15 minute intervals
Landis+Gyr Gyr Box diagnostic registers	Yes – On demand or built within a packet	Not available	Yes – On demand	Yes – On demand
Availability of data	LP data every 15mn, validated hourly. Configurable "daily" packet, data validated hourly as items arrive.	Monthly or whenever read by mobile device	Scheduled data package (Load Profile, voltage etc.) every four hours sent randomly over four hour period.	Scheduled data package (Load Profile, voltage, etc.) every four hours sent randomly over four hour period
Outage notification	15 minutes	Not available	5 minutes	5 minutes
Outage restoration	10 minutes	Not available	5 minutes	5 minutes

Feature	AMR (L+G PLX)	AMR "lite" Drive-by	Full AMI (L+G Mesh)	AMI "lite" (L+G Mesh)
Load Control	Roadmap item	Not available	Yes. Gridstream Dynamic Load Control (DLC) hardware endpoints and software from Landis+Gyr. Includes irrigation, HVAC, and Programmable Thermostats. Also supports ZigBee SEP via Electric FOCUS AXe and S4x endpoint, when using third-party ZigBee hardware and software integration with Command Center.	Yes, Supports ZigBee SEP via Electric FOCUS AXe endpoint, when using third-party ZigBee hardware and software integration with Command Center
Distribution Automation	Roadmap item	Not available	Expanded offering with Gridstream radio installation in various remote sensing and control DA devices device.	Roadmap item
TOU		Not available		
Pre-payment	Yes (via third party integration)	Not available	Yes. Landis+Gyr SmartData Connect Consumer Portal and Prepayment application pre-interfaced with Command Center. Also, several third-party integration options available.	Yes. Landis+Gyr SmartData Connect Consumer Portal and Prepayment application pre-interfaced with Command Center. Also, several third-party integration options available.
Net-Metering	Supported	Not available	Supported	Supported
Web-Presentment	Supported	Not available	Supported	Supported

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Table 3: PLX, Drive-by and RF Mesh Features

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Section 3: Evaluated Options

3.1 Summary of Evaluated Options

Several metering system options were considered and evaluated for the NLH next generation metering system strategy. Options varied from the expansion of one of the in-place metering systems to a full roll out a more advanced AMI solution, as well as Drive-by metering.

3.1.1 Option 1

The first option (Option 1) as referenced in the Executive Summary, looked at extending the deployment of the existing Landis+Gyr (L+G) PLX power line carrier solution across the entire NLH service territory. While this business case was positive, there was another significant component of the evaluation to be considered, and that was the technical component.

When reviewing the Technology and Trends section, one could argue that based on the L+G-provided feature and system comparison matrix (Table 3: PLX, Drive-by and RF Mesh Features), that the technical differences are minimal, at least in what was presented. However, it is important to look beyond and to consider things beyond functionality.

A significant concern from a technical perspective is a potential issue with the viability of the PLX solution through the system lifecycle over which the business case was based. Technology obsolescence with a PLC solution in all likelihood will, by nature of its low level of uptake from the greater utility population, receive fewer R&D dollars meaning that other systems will move forward at a faster pace and PLC will eventually become, practically obsolete. In addition, as R&D dollars are funneled elsewhere, metering and functionality developments will be built into the more popular platforms, such as AMI. Given the current technology obsolescence issue at the utility, the recommendation to move forward with a technology that might lead the utility back to the same place could not be made.

3.1.2 Option 2

The next option (Option 2) that was analyzed looked at the full roll out of a L+G radio frequency (RF) mesh-based AMI solution with the software solutions and integrations required to achieve all use and business case benefits. The analysis again considered both financial and technical factors. A full AMI deployment supported by best practice software and integration strategy produced the highest benefit dollars of all analyzed options. This is to be expected as a full meter data management (MDM) solution combined with the significant investment in a systems integration strategy truly unlock the benefits of AMI. One of the key lessons learned over the last fifteen years of AMI deployments across North America has been the importance of an integration strategy to ensure benefits identified in the business case are achieved and ultimately reconciled back to the business case for presentation to project stakeholders.

While the benefits identified were the highest of the three analyzed options, the costs associated with that were even greater. This produced a multi-million-dollar negative NPV that in large part was a result of project O&M dollars throughout the system lifecycle. As a result of the unfavorable NPV the recommendation to move forward with a solution that was not financially viable did not make sense.

3.1.3 Option 3

A third option (Option 3) was also considered, which involves piggy-backing on to the Newfoundland Power Itron Drive-by system. For the purposes of this report this solution has been termed AMR “lite”. The desire with this option was to explore potential synergies with the utility. Given that NLH and NLP are so closely related, this technical and financial evaluation made sense. The primary concern with this option is the lack of opportunity of the solution to grow with NLH and its customers, not to mention potential regulatory changes over the 20-year lifecycle of the system. Financially the case is positive, however as expressed in the Executive Summary, the technical side of the solution also needs to be addressed. A common refrain from public utility boards when it comes to advanced metering is “what’s in it for the customer?”. Unfortunately, the answer with Drive-by solutions is little to nothing. Electric utilities today take a significant risk in moving forward with a metering technology that at a minimum cannot migrate to full AMI functionality and take advantage of those operational and customer experience-focused opportunities. Twenty years is a long time and a utility needs to look beyond today and what the very near future requirements might be and consider the term nature of this investment and protect themselves and their customers. It is for these technical reasons and impacts along with the lack of meaningful synergies with NL Power that this option has been discounted.

3.1.4 Option 4

The final option (Option 4) considered for evaluation was a pared down version of the second option. This option would consist of a full roll out of AMI meters and network collection infrastructure that takes advantage of the in-place Command Center head end software from L+G. Absent this solution is the MDM software, integration costs, and other related O&M costs attributed to both personnel, and software. This solution has been termed AMI “lite”.

The key benefit of this option is that it protects the utility by enabling a system deployment that does not put NLH at risk of technology obsolescence during the system life cycle. In fact, it provides the opposite. When consideration is given to the percentage of dollars in an AMI system that go towards meters and endpoints, it becomes clear that this is an area requiring special attention. There is only one shot at the meters and endpoints and if the wrong decision is made at that level it sets the utility up for failure in the future because of the limitations of lesser technology. By deploying AMI, even in a “lite” version, NLH will benefit greatly and be protected from landing in the same spot as they are today with a system that can’t support the growth of requirements, whether regulatory, operationally, or customer service.

Add to this the positive NPV of $3.9M and it is clear to see why this is the recommended solution. With Command Center and the billing integration in place, NLH can utilize the system as a meter reading system first and until such point as various use cases make sense and justify the investment in additional software or integrations. The key for NLH is to buy the right endpoint (AMI) to ensure that the full value of the asset can be captured, even if it is a little further down the road.

As indicated, under this solution, the utility can deploy the system that strikes the balance between cost and benefit, while protecting its investment going forward by deploying a solution that can carry NLH through a complete system lifecycle. To capture all the additional benefits, the deployment of an MDM and full integration (~$7M-$8M NPV) will be required. This of course, can and would likely be done over time as well as use case cost/benefit dictate. Benefits anticipated include distribution automation, net metering, load control, and time varying rates. In addition, benefits from web presentment, outage analytics, standard MDM features, HAN programs, edge computing and third-party applications (street lighting) are also available.

Section 4: Option 4 – Recommended: Full-scale AMI "lite" Cost Benefit

4.1 Summary of AMI "lite" Business Case

Util-Assist performed a financial analysis on a full-scale 21-year AMI "lite" deployment. The AMI "lite" analysis is based on a system that would perform the same functionality as the AMR system but would deploy an AMI mesh network. By deploying an AMI mesh network NLH would be able to able to leverage its current L+G head end system and achieve the same functionality as an AMR system but it would give the utility the ability to transition to a full AMI network to meet future use-cases as required. Due to the lack of availability of GIS data to perform a propagation study UA used data from other disparate territories that have implemented AMI and an assumption was made of 350 meters per collector. AMI assets typically have a 20-year life. A proper procurement process and contract negotiations take about a year, so it is not foreseeable for meters to be deployed until about 2023, hence the 2022-2043-time frame. Util-Assist performed a financial analysis from current market data. Although it is valuable in providing a high-level overview, UA recommends validating the numbers through a proper procurement process.

Parameter	Value
Timeline (2020-2041)	21 years
Base Year (discounting to)	2022
Meter Deployment (2023)	32,000 meters (100%)

Table 4: Parameters and Value of AMI "lite"

The current meter reading systems that NLH have are experiencing high failure rates and becoming obsolete. For this reason, Util-Assist recommends a mass meter exchange in order to realign the organization and achieve the available benefits. The AMI "lite" business case uses the same assumptions for the benefits as a full AMI deployment but estimates an FTE reduction of 13 field staff. The following project financial analysis demonstrated that a full AMI "lite" system is cost effective.

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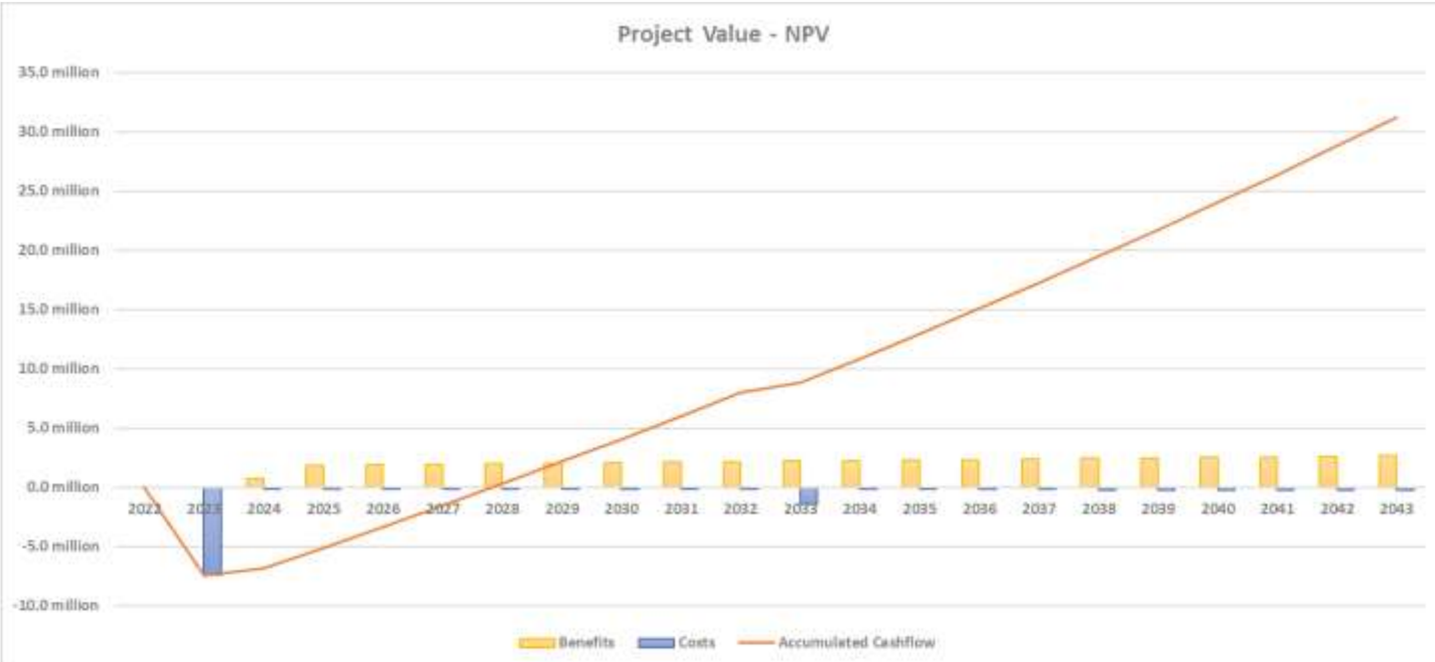

Figure 2: NPV of AMI "lite"

Parameter (NPV)	Value
Benefits ($Millions)	$23.1M
Costs ($Millions)	$9.6M
NPV	$13.4M
IRR	21%
B/C	2.39
Breakeven	6 years

Table 5: Parameters and Values of AMI "lite"

4.1.1 AMI "lite" Benefits

As the AMI "lite" project will provide the same functionality as the AMR project the benefits are identical. In order to maintain a conservative approach, all project benefits are set one year after the mass meter deployment. The project benefits come from reduced field labour needed to perform reads, avoided cost of vehicles and avoided meter replacement costs.

Benefit Component	Present Value ($M)	Share of Benefits
Avoided Costs of Meter Replacements	$13.7M	59%
Reduced Manual Meter Reading	$8.4M	36%
Avoided Cost of Meter Reading Vehicles	$1.0M	4%

Table 6: Benefit Components of AMI "lite"

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4.1.2 AMI “lite” Costs

The following table demonstrates the costs in order to implement, maintain and operate the additional components of an AMI “lite” system. Capital refreshes for all network equipment has been assumed at year ten.

Cost Component	NPV Value	% of Costs
Electric Meters	$3.8M	43%
Installation Costs	$1.9M	18%
Meter Reading System	$1.6M	17%
Yearly Meter Replacement	$0.3M	3%
Project Team	$0.14M	1%
Vendor Travel	$0.036M	<1%
Additional Software (O&M 20 Yrs.)	$4.7K	<1%
Network Costs (O&M 20 Yrs.)	$2.0M	18%

Table 7: Cost Components of AMI “lite”

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Section 5: Deployment Options

Historically NLH has moved forward slowly in the deployment and upgrade of meter reading technology which has contributed to the current position of technology obsolescence at both the handheld and Automated Meter Reading (L+G PLX AMR) level. This has led NLH to investigate near-term steps to mitigate the negative effects to its customers and to the operation as well as to develop a long-term meter-to-cash technology strategy for the utility.

The NLH ask was to identify means by which to address the failing and obsolete metering technology (TS1) infrastructure as well as how tackle the remaining service territory currently not served by AMR. It is recommended that mitigation and long-term remediation activities be separated and pursued concurrently as time is of the essence for NLH, particularly in terms of addressing the failing TS1 system.

In looking at long-term, utility-wide solutions as identified earlier, the recommended approach is to deploy a AMI "lite" solution with the incumbent (L+G) but to go to market through a formal procurement process to ensure the best case for the utility from a technical and financial standpoint that will serve NLH for a 20-year system lifecycle. From the decision to adopt this approach to full deployment NLH would be looking at close to four (4) years, assuming a one (1) year deployment of meters, so it is not a short-term solution. The following section covering Next Steps outlines both timing and tasks to accomplish the procurement.

The recommendation for NLH to move to a formal procurement process is built on the understanding that in order to truly understand the best way forward for NLH that the market will need to dictate what the actual options are. Without an in-depth territory analysis utilizing strong location data, producing multiple propagation study options it will be very difficult to make an informed decision concerning the appropriate solution for NLH.

Given the uniqueness of the utility's service territory, specifically the relatively small number of meters spread over a number of challenging geographies, it is difficult to say what a procurement would yield in terms of an exact solution. However once fully evaluated, a hardened business case could be developed with multiple options for NLH to consider moving forward.

A significant development with vendor solutions today is that many provide multiple communication methodologies within a single meter. The practical outcome of these options is that utilities now have greater opportunities to cover their service territories with a single vendor's solution. This is a significant benefit to NLH in that it will enable a complete solution that will be deployed across the territory that can grow with and support the utility throughout the system lifecycle.

One area where utilities get tripped up in the process of considering their next metering solution is by looking at how things have been done in the past or what is needed today. A prudent process takes into consideration current and more importantly potential future requirements that will enable the solution to grow with the utility over its lifecycle. Additionally, assumptions are often made by utility personnel in terms of what will work in their service territory. It is important to understand that significant technological advancements have been made since NLH first implemented the L+G TS1 and PLX AMR solutions. Therefore, the focus of any procurement needs to be on what the utility needs (now and in the future) in terms of function and not on prescribing what technology the utility thinks will work in their territory.

One way to mitigate the concern about the vendor's proposed solution(s) is to place the onus on the vendor to manage the network and its infrastructure. This option would add O&M cost to the solution over the life of the contract but at the same time would remove the responsibility for system and network performance from the utility and place it on the vendor who is better equipped to manage the complexity of a NLH system.

To summarize the recommendation for dealing with those areas currently not served by AMR, it is strongly recommended that NLH consider a utility-wide metering technology strategy rather than one that simply addresses the immediate remediation needs and puts a potentially separate solution in the non-AMR areas within the utility. Moving forward without a comprehensive plan based on real costs and system benefits will lead NLH back to the current state in a relatively short period of time.

With that said, the current state cannot be ignored. A plan needs to be enacted to mitigate the TS1, and in a small number of cases the PLX, system failures at the meter and communications levels. That plan however must address both cost and efficiency to be successful.

Following a review of available NLH AMR system data, dated December 6, 2019, there is a clear distinction where the primary issue lies (with the TS1 system), however that is complicated by the dispersion of the TS1 meters across the vast service territory. In addition, there are a small number of PLX meters (~0.5%) that are not functioning.

With respect to the PLX meters, the recommendation would be to engage Landis+Gyr (AMR system supplier) to see what if anything can be done within the existing PLX system structure to address the relatively small number of non or intermittently functioning meters. With those meters that cannot be remedied, the suggestion would be the same as for the TS1 meters, outlined in the following paragraphs.

In looking to address the ~15% (1,893) of the installed TS1 meters that are non or intermittently-functioning, the options are limited. Due to the obsolescence of the TS1 system, working with L+G (AMR system supplier) to optimize the solution, is not an option. Therefore, other alternatives need to be considered taking into account efficiency and cost.

Based on discussion with NLH personnel, and a review of the available TS1 system data, broken down by location and performance it became clear that for the most part there was a mix of meter read types and functions within most TS1 areas. We discerned from this data that there was essentially some level of manual meter reading taking place in every area where TS1 is deployed.

If the NLH goal is to minimize the number of estimated reads and increase the level of their customer experience, we would recommend the following approach for addressing the failed and failing TS1 meter population. The proposed strategy involves reading the non and intermittently communicating meters manually either via the handheld metering system or via pen and paper. There is a recognition that this would create additional work however the options are truly limited in this instance. With the earlier recommendation to move into a procurement cycle this strategy would serve to address the current and largest issue related to revenue. There is a further understanding that over the next years that the TS1 meters will need to be replaced due to seal constraints. The suggestion here, since there are no longer TS1 meters to replace them with, that NLH moves to procure the least expensive non-AMR meters for manual meter reading while simultaneously proceeding through the procurement process.

This strategy of addressing non and intermittently-failing TS1 and PLX meters while pursing a procurement strategy appears to be the most cost effective and reliable means by which to address the current meter to cash issues while working towards providing a reliable solution to NLH in the future.

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Section 6: Next Steps

As noted in the prior section, the recommended strategy for NLH is to pursue TS1 mitigation and system-wide procurement activities simultaneously. Following are the action steps through which NLH should proceed:

6.1 TS1 and PLX system mitigation activities

6.1.1 PLX system

1. Engage L+G (AMR system supplier) to see what, if anything, can be done within the existing PLX system structure to address the relatively small number of non or intermittently functioning meters.
2. For those meters that cannot be remedied, the suggestion would be the same as for the TS1 meters, manual meter reading, as outlined below.

6.1.2 TS1 system

1. Read the non and intermittently communicating meters manually either via the handheld metering system or via pen and paper.
2. Determine which reading methodology will be most effective and take steps to implement it.
3. For those TS1 meters that must be removed, procure the least expensive non-AMR meters for manual meter reading while simultaneously proceeding through the procurement process.

6.2 Next Generation Metering Procurement

1. Gather location data for all meters and available infrastructure for network collection equipment
    a. Currently NLH has the location of about 60% of its meters. An immediate effort should be planned with the current meter readers and the available GIS software to gather the coordinates of the remaining 40% of the meters. This will assure that all meters are read on a reliable basis and reduces the risk of pricing increases.

       To ensure the most effective solution for NLH is procured, vendors will require accurate location data both metering and potential network infrastructure assets. So, the first step will be for NLH to collect this location data for the required assets. This can be accomplished during the technical requirements development phase of procurement.

       To mitigate the reliability and uptime risks in the communications network involved with NLH’s complex territory, the utility should shift this risk to vendors. The risk will be shifted to vendors by pursuing a proper procurement process that outlines the network requirements under certain scenarios and assures that these requirements are maintained in the contract. For meter vendors to agree to take on this risk and have the ability to perform a propagation strategy along with a proposed network strategy, they will need a minimum of 90-95% of meters to be geo-coded.

       NLH has agreed to move forward with and complete this effort by the end of 2020, not only for a potential NGM project, but also for the benefit of other areas within the utility.

2. Procurement
    a. Education, Technical Requirements gathering, RFP(s) preparation (3-6 months)
    b. Procurement (6 months)
    c. Contract negotiation (6-9 months)
    d. Phase 1 network and meter deployment – infrastructure deployment, limited business processes development, Phase 1-meter deployment to test basic interfaces (6-9 months)
    e. Mass roll out and project close (12 months)

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Section 7: Conclusion

As a utility, a next generation metering strategy requires an eye on both present-day challenges as well as future-state requirements. As such, Util-Assist's recommendation seeks to mitigate current challenges while best positioning NLH for the future.

Highlighted in Section 6 of this report are the means by which the current state could be managed.

When considering the future state, however, it is critical to understand the importance of meters in the final solution. In order to avoid history repeating itself, NLH must recognize that they only have one opportunity to procure meters which account for 65%-80% of the new system investment and more importantly are the means by which NLH can meet the evolving requirements from the regulatory, customer, and operational perspectives

While it is tempting to move forward with what is known in terms of function within the NLH service territory, i.e., L+G PLX, certain factors have to be taken into consideration to evaluate its viability as a solution that will enable the future functionality that NLH and/or the regulatory body may desire or ultimately require.

Pursuing a Drive-by AMR "lite" or PLX-based solution creates significant risk for NLH and could very well put the utility in the same position as they are currently, with an obsolete metering system that is not capable of meeting future requirements due to its limited function and expected roadmap as of today. Understandably, the chosen strategy must protect the utility from being back in this same position of an obsolete system within the 20-year system life cycle.

Understanding that the business case for full AMI does not pan out, and that proceeding with the currently deployed L+G PLX solution carries too many risks, it is recommended that NLH adopt an AMI "lite" strategy, utilizing the L+G RF mesh AMI solution that has a positive payback but limited in scope, i.e., meters, collectors, and installation, in order to achieve a positive business case. This approach takes advantage of the Command Center software already in place at the utility.

This is a strategy of migration that enables NLH to confidently move forward into the future with a solution that resolves the current system obsolescence challenges while simultaneously protecting their investment by providing the utility with an out of the box solution that provides significantly more value in terms of function and future-proofing, e.g., future AMI use cases, than currently deployed systems.

To support this approach and obtain best value, it is further recommended that an open procurement strategy be pursued to harden business case numbers and network design through a competitive bidding process. This enables the utility to resolve current metering challenges, and best position itself for the future from a technology standpoint to take advantage of other AMI-related use cases as they make sense.

The recommendation is based on it being the better investment, proven out both technically and financially, in both the near and long-terms and it represents the best path forward for Newfoundland and Labrador Hydro.

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Appendix A: Business Case Assumptions

Input Categories	Value	Source
Business Case Evaluation (Years)	20	Industry Standard
Fiscal Year Start (the Project Start)	2022	Based on First Year of Tracking Program Costs
Fiscal Year Start (Mass Deployment Start Date)	2023	Based on First Year of Project Mass Deployment of Capital
Amortization Period AMI (Years)	20	Industry Standard - Current Meters Are 20 to 25 Year Assets
Amortization Period MDM, Collectors, Software (Years)	5	Industry Standard
Amortization Period: AMI Distribution Network Hardware	10	Industry Standard
Net Present Value (NPV) Discount on O&M	5.65%	WACC
Net Present Value (NPV) Discount on Capital	5.65%	WACC
Contingency Percentage Variable	5.00%	UA Recommended
Contingency Percentage Fixed	2.00%	UA Recommended
Contingency Percentage O&M	2.00%	UA Recommended
Meter Base Repair % Assumption	2.0%	Industry Standard
CPI Increase Rate	1.02	Value Provided by Finance
Hourly Rate for Management Staff	76.70	Value Provided by Finance
Hourly Rate for Administrative Staff	41.80	Value Provided by Finance
Employee Burden Rate	1.30	Value Provided by Finance
Corporate Tax Rate	0%	Value Provided by Finance

Appendix B: Option 1 – Full-scale PLC AMR (L+G PLX)

Full-Scale PLC AMR Cost Benefit

Summary of AMR Business Case

Util-Assist performed a financial analysis on a full-scale 21-year AMR deployment which specifically involves rolling out the in-place L+G PLX PLC AMR solution throughout the remainder of the NLH service territory. AMR assets typically have a 20-year life. A proper procurement process and contract negotiations take about a year, so it is not foreseeable for meters to be deployed until about 2023, hence the 2022-2043-time frame. Util-Assist performed a financial analysis from current market data. Although it is valuable in providing a high-level overview, UA recommends validating the numbers through a proper procurement process.

Parameter	Value
Timeline (2022-2043)	21 years
Base Year (discounting to)	2022
Meter Deployment (2023)	32,000 meters (100%)

Table 8: Parameters and Value of AMR

The current meter reading systems that NLH have are experiencing high failure rates and becoming obsolete. For this reason, Util-Assist recommends a mass meter exchange in order to realign the organization and achieve the available benefits. The following project financial analysis demonstrated that a full AMR system is cost effective.

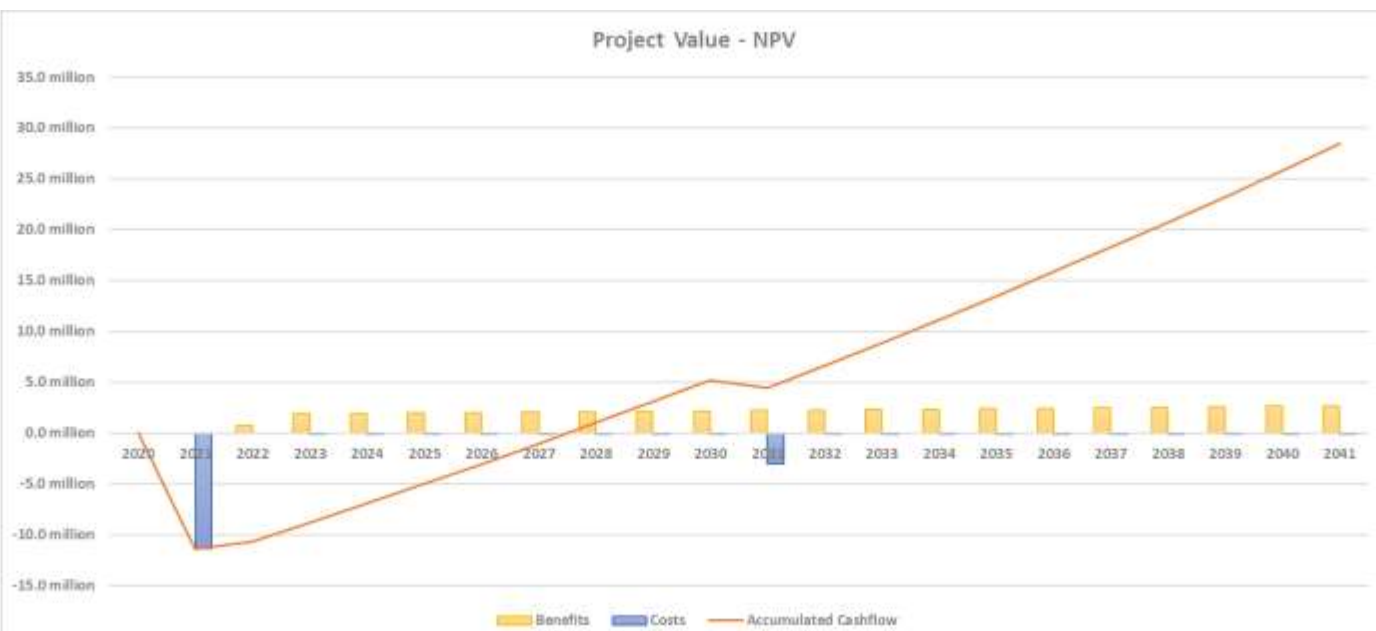

Figure 3: NPV of AMR

Parameter (NPV)	Value
Benefits ($Millions)	$23.1M
Costs ($Millions)	$12.8M
NPV	$10.2M
IRR	14%
B/C	1.8
Breakeven	7.65 years

Table 9: Parameters and Values of AMR

AMR Benefits

The table below demonstrates the typical AMR benefits realized by other utilities who have undertaken an AMR deployment. To maintain a conservative approach, all project benefits are set one year after the mass meter deployment. The project benefits come from reduced field labour needed to perform reads, avoided cost of vehicles and avoided meter replacement costs.

Benefit Component	Present Value ($M)	Share of Benefits
Avoided Costs of Meter Replacements	$13.7M	59%
Reduced Manual Meter Reading	$8.4M	36%
Avoided Cost of Meter Reading Vehicles	$1.0M	4%

Table 10: Benefit Components of AMR

AMR Costs

The following table demonstrates the costs to implement, maintain and operate the additional components of an AMR system. Capital refreshes for all network equipment has been assumed at year ten.

Cost Component	NPV Value	% of Costs
Electric Meters	$6.3M	55%
Installation Costs	$1.9M	14%
Meter Reading System	$3.9M	27%
Yearly Meter Replacement	$0.5M	3%
Project Team	$0.14M	1%
Vendor Travel	$0.036M	<1%

Table 11: Cost Components of AMR

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Benefit Details – AMR

Reduced Manual Meter Reading

Benefit Component Description			
Description	This benefit is achieved by eliminating the need to manually read meters. Not all meter-related field work is reduced and therefore is not accounted for in this benefit.	Present Value Benefit	$8.4M (36% of total benefits)
Benefit Elements	The benefit is calculated by determining how much NLH can save each year by reducing internal meter reading activities. The yearly reduction is calculated by taking the yearly meter reading budget with burden, dividing it by the current number of meter readers (18) and multiplying it by the reduction in meter readers (13)		
Timing	Benefit accrual lags meter deployment by one year, assuming a delay in integration and connection of AMR meter with the AMR headend and provides time for department process changes and staffing re-allocations. The annual available benefit will increase by a CPI adder each year		

Table 12: Meter Reading and Field Services Benefit Component Description

Avoided Meter Replacement Costs

Benefit Component Description			
Description	Even without the AMR project, NLH must maintain its metering assets in the field. These assets traditionally have a 20-year life span and require replacement based on failures and recommended replacement processes. The business case captures net impacts that the AMI project has on NLH so that the "avoided meter replacement" is captured as a benefit, since it is in the current budgeting and work performed by NLH.	Present Value Benefit	$13.7M (59% of total benefits)
Benefit Elements	The business case assumes a balanced replacement window of 5% of the population being replaced. This takes into account the cost for the new meters required plus the labor costs to perform the field meter change work. It was assumed that the all-in rate for residential and commercial meters are $492 and 1,496 respectively.		
Timing	This benefit follows the meter deployment schedule. The calculation takes into account the new meters required plus the labor to perform the field meter change work. The annual available benefit will increase by a CPI adder each year		

Table 13: Avoided Meter Replacement Costs

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Avoided Cost of Meter Reading Vehicles

Benefit Component Description			
Description	The benefit is based on the reduced meter reading vehicles expenses for meter reader and supervisor vehicles. Avoided vehicle purchasing costs are calculated using historic and fleet data and a reduction in vehicles required for meter reading as AMR is deployed.	Present Value Benefit	$1.0M (4% of total benefits)
Benefit Elements	This benefit takes into account the net costs per vehicle and overall forecasted reduction (2).		
Timing	The benefit is calculated by multiplying the net avoided cost per vehicle by the number of vehicles reduced by the percentage of AMR meters installed. The annual available benefit will increase by a CPI adder each year		

Table 14: Avoided Meter Reading Vehicles Benefit Component Description

Non-Quantifiable Benefits of AMR

This section will explore the value of the non-quantifiable benefits associated with the implementation and deployment of the L+G PLX AMR network system.

Customer-Facing Benefits

With AMR, NLH will have the data to deliver enhanced customer service. Customer benefits include the following:

Benefit	Description
Customer Satisfaction	Improve customer satisfaction by: • Providing customers with a broader menu of service options, • Reducing customer complaint calls and equipping customer service representatives with information that can address customer questions faster and more effectively
Service Reliability	Improve service reliability with faster outage notification and restoration verification
Customer Safety	Improve safety for customers through automatic alarms for unsafe conditions (e.g., a hot meter socket).

Table 15: Customer-Facing AMR Benefits

Operational Benefits

L+Gs AMR provides a wealth of data that will enable NLH to achieve the following operational efficiencies:

Benefit	Description
Enhanced Load Research	Deliver data for enhanced load research studies
Transformer Loading	Better manage distribution assets through insight into transformer loading

Benefit	Description
Safety	Improve safety via the following by delivering automatic alarms for unsafe conditions, improving the safety record for meter reading staff and reducing vehicle incidents
Business Processes	Improve business processes by streamlining non-AMR billing processes, enhancing data analytics, enabling service order integration to reduce field visits.
E-Services	Increase participation in e-services (such as online bill payment, self-service customer inquiries etc.) as a result of increased traffic to an AMI Web portal

Table 16: Operational AMI Benefits

Future Benefits

The reference architecture should also allow NLH to make business process changes that result in efficiencies not currently captured in the business case. Architecture decisions should be made with best practices in mind and it should not *prevent* NLH from realizing *additional* smart grid benefits. Below is a non-exhaustive list of potential future benefits.

Potential Benefit	Description
Demand side management programs	Reduce consumer energy consumption via in-home displays/programmable thermostats and home area networks (HAN).
New rate plans	Reduce consumer energy consumption via new rate plans, such as time-of-use or dynamic pricing.
Online rate comparison	Enable customers to compare rate plans and estimate relative savings.
Hosting partners and running third party applications	Host partner data and run third party applications, such street lighting, water, police, air quality, etc.

Table 17: Future AMI Benefits

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Appendix C: Option 2 – Full-scale AMI (L+G Mesh)

Full-scale AMI Cost Benefit

Summary of AMI Business Case

Util-Assist performed a financial analysis on a full-scale 22-year AMI deployment. AMI assets typically have a 20-year life. A proper procurement process, contract negotiations and system integrations take about two years, so it is not foreseeable for meters to be deployed until about 2023, hence the 2023 to 2043 timeframe.

Parameter	Value
Timeline (2020-2042)	22 years
Base Year (discounting to)	2022
Meter Deployment (2023)	40,000 meters (100%)

Table 18: Parameters and Values of AMI overall

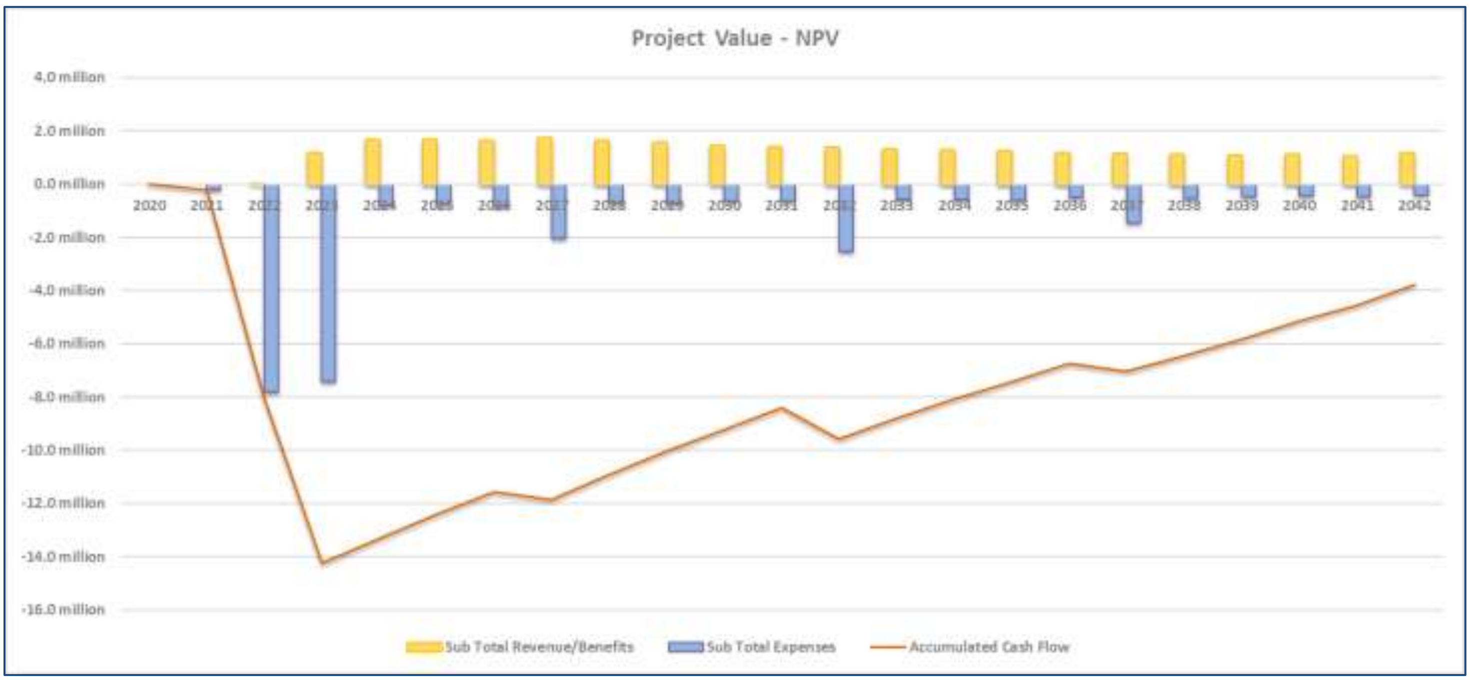

Figure 4: AMI Project Net Present Value

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Parameter	Value
Benefits ($Millions)	$29.7M
Costs ($Millions)	$31M
NPV	-$1.2M
B/C	0.95

Table 19: Parameters and Value of AMI

AMI Benefits

The table below demonstrates the typical AMI benefits realized by other utilities who have undertaken an AMI deployment. In order to maintain a conservative approach, all project benefits are set one year after the mass meter deployment. The largest share of the project benefits come from reduced field labour needed to perform reads and disconnects, reduced distribution losses and the avoided cost or replacing aging meters over the 20-year span.

Benefit Component	Present Value ($M)	Share of Benefits
Reduced Manual Meter Reading and Meter Service Order Benefits	$8.4M	25%
Distribution Network Losses	$1.8M	6%
Avoided Costs of Meter Replacements	$13.7M	53%
Conservation Voltage Reduction	$0.85M	3%
Outage Restoration	$0.48M	2%
Unbillable/Uncollectible Accounts	$0.43M	2%
Reduced Customer Inquiries	$0.61M	2%
Avoided Cost of Handheld System	$0.14M	0.5%
Avoided Cost of Meter Reading Vehicles	$1.1M	4%
Reduced Overtime for Meter Service Orders	$0.076M	0.3%
High Bill Alert	$0.45M	2%
Remaining Book Value	$0.16M	1%

Table 20: AMI Benefits with Present Value and %Share of Benefits

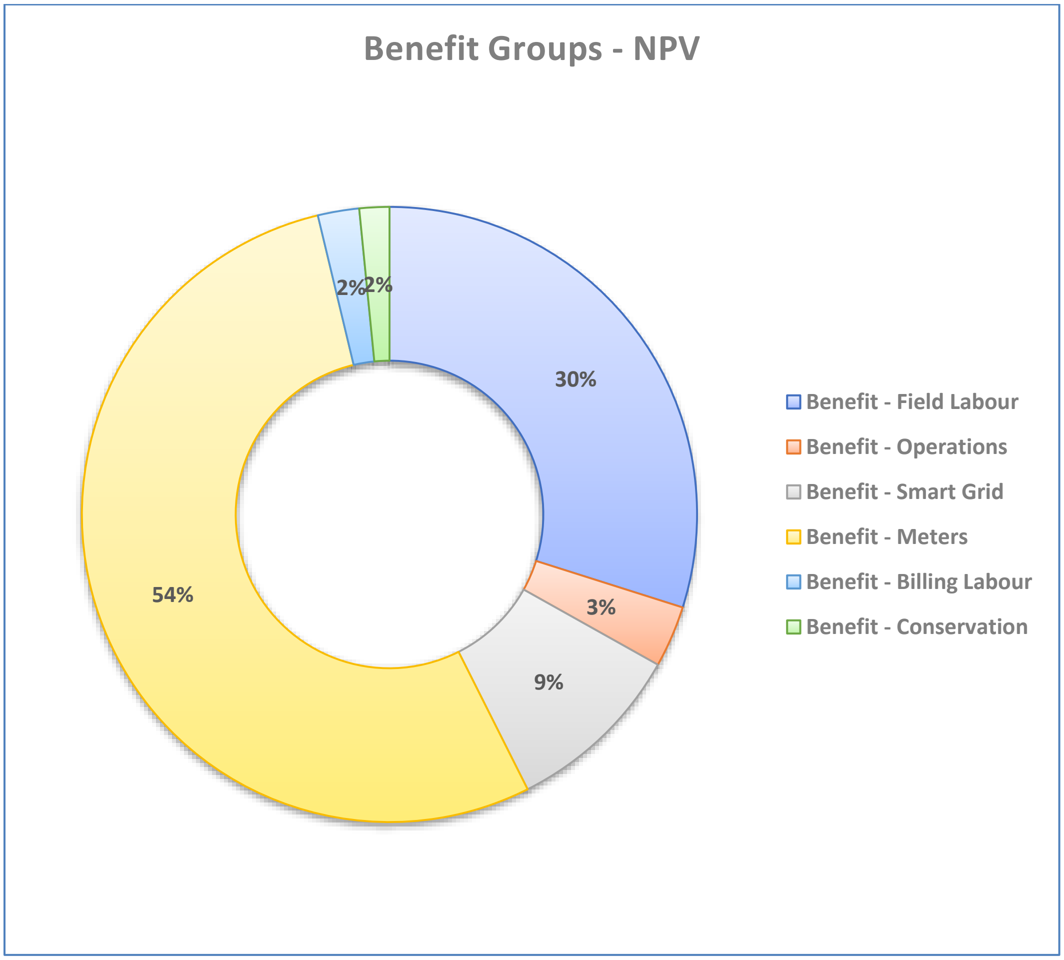

Figure 5: AMI Benefits Distribution Chart

AMI Costs

The following table demonstrates the costs to implement, maintain and operate an AMI system. In today's dollars, $13.9M or roughly 76% of the capital costs are spent in the first 3 years. Seventy percent of the total operation and maintenance (O&M) costs are related to the software and maintenance of the AMI Head End System.

Capital Cost Component	NPV Value	% of Costs
Electric Meters and Modules	$5.4M	29%
Installation Costs	$1.9M	7%
Network Infrastructure	$1.8M	10%
Head end System Infrastructure	$6.1M	33%
Professional Services	$0.5M	3%
MDM System Costs	$0.1M	1%

Capital Cost Component	NPV Value	% of Costs
Project Team	$0.9M	5%
System Integration	$2.4M	12%
Legal	$0.2M	1%

Table 21: Capital Cost Components Table

O&M Cost Component	NPV Value	% of Costs
AMI System O&M	$8.9M	70%
MDM and Labour to run system	$2.6M	20%
Interface Maintenance	$0.7M	5%
Audits	$0.6M	4%

Table 22: Operation and Maintenance (O&M) Cost Components

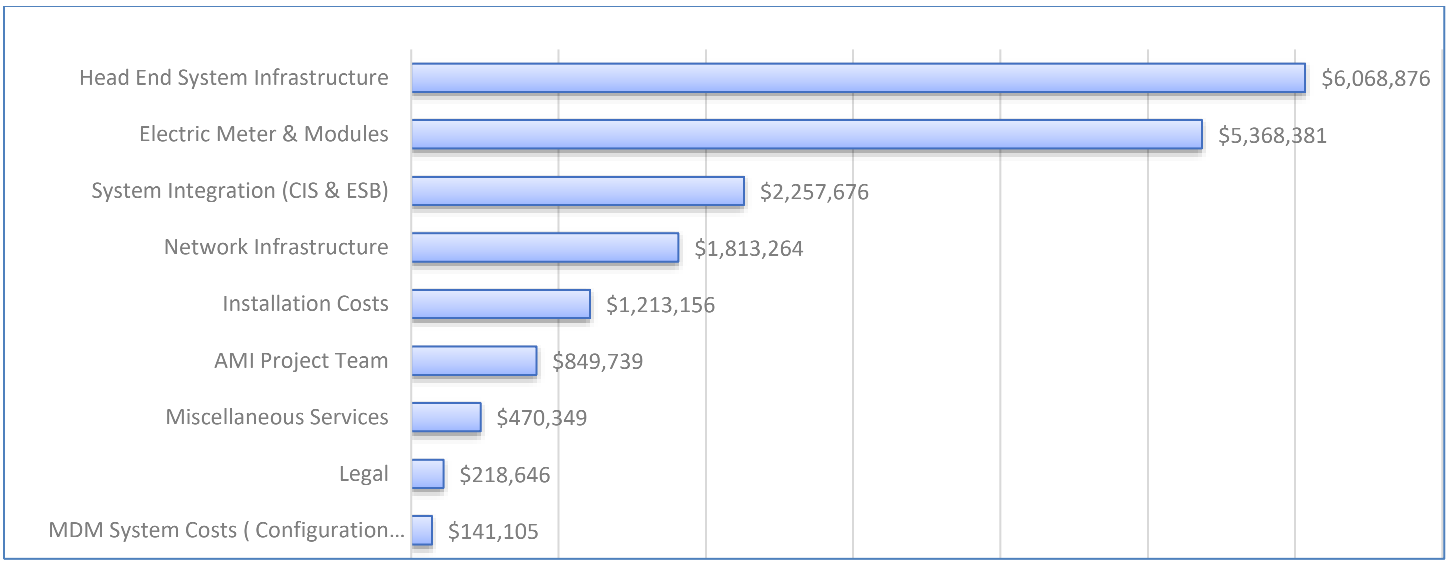

Figure 6: Capital Cost breakdown

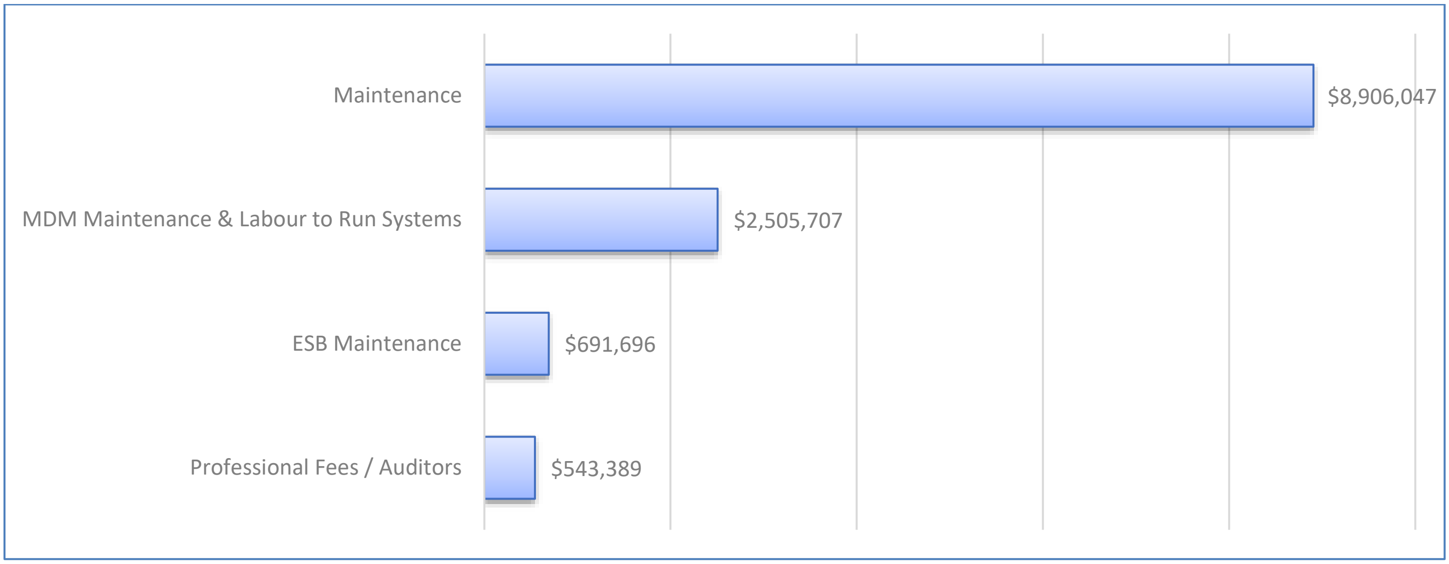

Figure 7: O&M Cost Breakdown

AMI Benefit Details – AMI

Reduced Manual Meter Reading and Meter Service Orders

Benefit Component Description			
Description	This benefit is achieved by eliminating the need to manually read meters. Not all meter-related field work is reduced and therefore is not accounted for in this benefit.	Present Value Benefit	$8.4M (25% of total benefits)
Benefit Elements	The benefit is calculated by determining how much NLH can save each year by reducing internal meter reading activities. The yearly reduction is calculated by taking the yearly meter reading budget with burden, dividing it by the current number of meter readers (18) and multiplying it by the reduction in meter readers (13)		
Timing	Benefit accrual lags meter deployment by one year, assuming a delay in integration and connection of AMR meter with the AMR headend and provides time for department process changes and staffing re-allocations. The annual available benefit will increase by a CPI adder each year		

Table 23: Reduced Manual Meter Reading and Meter Service Orders

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Conservation Voltage Reduction

<table>
<tr><th colspan="4">Benefit Component Description</th></tr>
<tr><td>Description</td><td>Conservation Voltage Reduction (CVR) is a proven technology that reduces energy consumption and demand by dynamically optimizing voltage levels using sophisticated smart grid technologies. Recent CVR pilot projects have delivered excellent results, yielding 1% to 3% reductions in Energy (kWh) and Peak Demand (kW). By optimizing existing distribution automation (DA) equipment, smart grid technologies, and communications with AMI meters and switchable devices, capital purchases can be avoided or delayed.</td><td>Present Value Benefit</td><td>$0.85M
(3% of total benefits)</td></tr>
<tr><td>Benefit Elements</td><td colspan="3">The key elements of a CVR system include primary components (automation equipment installed at the substation), secondary components (field equipment such as AMI meters installed beyond the substation and at the edge of the grid), telecommunications nodes (such as modems, radios, routers, and repeaters), and CVR software. Several other enabling or enhancing components help form the overall CVR cost and benefit structure, including smart meters, backbone communications, grid analytics, and load scheduling analysis.

NLH has estimated that implementing a CVR program will result in a reduction in kWh of 1.25%. The contribution of the AMI is through the added sensors, particularly for end-of-line metering which can contribute to improved information upon which to operate substation feeder voltage regulators. Because AMI is only one part of the program, NLH claims only 20% of the 1.25% as AMI business case benefits. This estimate is considered to be conservative based on various research findings:
• Pacific Northwest National Laboratory prepared a report for the US Department of Energy "Evaluation of Conservation Voltage Reduction (CVR) on a National Level" that finds "CVR provides peak load reduction and annual energy reduction of approximately 0.5%-3% depending on the specific feeder."
• Central Lincoln found an annual energy savings of 1.92%.
• Glendale Water and Power projected an annual savings of between 2% and 4% and eventually realized a 2.95% savings.</td></tr>
<tr><td>Timing</td><td colspan="3">Benefit accrual lags CVR deployment by one year, it is assumed that CVR will be a 3-year deployment (50% - 2027, 25% 2028, 25% 2029). This benefit is calculated per year by multiplying the year's load forecast by the forecasted energy reduction that AMI will grant as part of CVR (020%), and then multiplying this kWh figure by the year's forecasted marginal cost of power. The annual available benefit will increase by a CPI adder each year</td></tr>
</table>

Table 24: Conservation Voltage Reduction Benefit Component Description

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Reduced Distribution Network Losses

Benefit Component Description			
Description	This benefit represents opportunities and programs to use the AMI data to reduce overall distribution system losses, including: • Theft detection from meters (removal and reverse energy flow) • Voltage data and alarms combined with connectivity information identifying potential taps or using transformer metering programs to identify high losses • Better asset management (e.g., transformer monitoring to identify over and under sized assets) Other AMI projects have reduced distribution losses (outside of improved meter accuracy) by 0.25% to 0.5%.	Present Value Benefit	$1.8M (6% of total benefits)
Benefit Elements	• NLH will be able to reduce distribution losses (outside of improved accuracy) by 0.25% • Average marginal cost of power per year is supplied by the Utility Long Term Plan Table • Load forecast for residential, industrial and general services is supplied by Load Forecast		
Timing	This benefit assumes a distribution loss reduction of 0.25% and uses the marginal cost of power in the utility long term plan table and follows the AMI deployment schedule. The annual available benefit will increase by a CPI adder each year		

Table 25: Reduced Distribution Network Losses Benefit Component Description

Avoided Meter Replacement Costs

Benefit Component Description			
Description	Even without the AMI project, NLH must maintain its metering assets in the field. These assets traditionally have a 20-year life span and require replacement based on failures and recommended replacement processes. The business case captures net impacts that the AMI project has on NLH so that the “avoided meter replacement” is captured as a benefit, since it is in the current budgeting and work performed by NLH.	Present Value Benefit	$13.7M (53% of total benefits)
Benefit Elements	The business case assumes a balanced replacement window of 5% of the population being replaced. This takes into account the cost for the new meters required plus the labor costs to perform the field meter change work.		

Benefit Component Description	
Timing	This benefit follows the meter deployment schedule. The calculation takes into account the new meters required plus the labor to perform the field meter change work. The annual available benefit will increase by a CPI adder each year

Table 26: Avoided Meter Replacement Costs Benefit Component Description

Avoided Cost of Meter Reading Vehicles

Benefit Component Description			
Description	The benefit is based on the reduced meter reading vehicles expenses for meter reader and supervisor vehicles. Avoided vehicle purchasing costs are calculated using historic and projected fleet data and a reduction in vehicles required for meter reading as AMI is deployed.	Present Value Benefit	$1.1M (4% of total benefits)
Benefit Elements	This benefit considers the net costs per vehicle and overall forecasted reduction.		
Timing	The benefit is calculated by multiplying the net avoided cost per vehicle by the number of vehicles reduced by the percentage of AMI meters installed. The annual available benefit will increase by a CPI adder each year		

Table 27: Avoided Meter Reading Vehicles Benefit Component Description

Avoided Cost of Handheld System

Benefit Component Description			
Description	This benefit consists of a reduction in existing handheld meter reading system costs. Once AMI is in place, handheld reading equipment and replacement costs will be reduced at the utility. Note that some equipment will be retained to accommodate customers who are not supported by AMI.	Present Value Benefit	$0.14M (0.5% of total benefits)
Benefit Elements and Timing	The benefit is calculated by multiplying the handheld system costs per year by the percentage of AMI meters installed. The annual available benefit will increase by a CPI adder each year.		

Table 28: Avoided Cost of Handheld System Benefit Component Description

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Reduced Customer Inquires

Benefit Component Description			
Description	Today, customer service representatives handle customer calls concerned about estimated bills, wrong readings producing incorrect high bills, and customers not having access to data. With the deployment of AMI, estimated readings will be drastically reduced, helping to minimize estimated and incorrect billing. Ultimately the goal is to help customers trust their bill and reduce specific call types to the ME agents. Daily, the meter data validation team addresses manual meter reading exceptions in order to prepare the data for the customer's end bill. When AMI is fully implemented, this process will be replaced by the Meter Data Management (MDM) system and the staff budgeted to perform the daily reading validation process.	Present Value Benefit	$0.61M (2% of total benefits)
Benefit Elements	This benefit considers the fully burdened cost of half a CSR agent.		
Timing	This benefit is calculated by multiplying the hours of work effort reduced for handling complaints by cost of the labor. The annual available benefit will increase by a CPI adder each year.		

Table 29: Reduced Customer Inquiries

Unbilled/Uncollectable Accounts

Benefit Component Description			
Description	Benefit generated from reduced write-offs from electricity delivered but remaining unpaid due to customers defaulting on bill payment.	Present Value Benefit	$0.43M (2% of total benefits)
Benefit Elements	Benefit assumes that 20% of annual write off can be avoided.		
Timing	A 1-year lag is applied to the accrual of benefits relative to meter deployment. The annual available benefit will increase by a CPI adder each year.		

Table 30: Unbilled/Uncollectable Accounts Benefit Component Description

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Remaining Book Value

Benefit Component Description			
Description	The AMI business case is based on a 20-year project term with the main deployment happening over a three-year window. During the project term, asset refreshes/replacements will occur. This benefit identifies the remaining book value of investments at the end of the project and captures this value as a benefit.	Present Value Benefit	$0.16M (1% of total benefits)
Benefit Elements	This benefit amount is calculated by taking the capital addition and depreciation into account for all of the hardware and software and calculating the book value after 20 years		
Timing	This benefit is captured in year 20 (2042)		

Table 31: Remaining Book Value Benefit Component Description

Outage Restoration (Crew Management)

Benefit Component Description			
Description	This benefit captures the value of service order reduction by reducing the number of truck rolls related to customer-side problems on “no light” calls and load (KVA) problems. AMI meters provide a message when power has been restored to a property and enhanced visibility. The meter also supports two-way communication that provides control room operators and GIS with visibility on the power status of homes in a geographic area. This enhanced visibility enables more effective field crew management. AMI meters offer two-way communication with operators and facilitates more effective outage crew management. This benefit reflects the associated reduction in service orders.	Present Value Benefit	$0.48M (2% of total benefits)
Benefit Elements	The benefit assumed a reduction roughly 9 work orders per month.		
Timing	This benefit tracks the AMI meter deployment. The annual available benefit will increase by a CPI adder each year.		

Table 32: Outage Restoration Benefit Component Description

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Reduced Overtime for Meter Service Orders

Benefit Component Description			
Description	This benefit is associated with the reduced overtime hours needed for reconnects, which will now be done remotely.	Present Value Benefit	$0.076M (<1% of total benefits)
Benefit Elements	This benefit assumes that 95% of the after hour reconnect costs will be done remotely, and overtime labour costs will be avoided.		
Timing	This benefit tracks the AMI meter deployment. The annual available benefit will increase by a CPI adder each year.		

Table 33: Reduced Overtime for Meter Service Orders Benefit Component Description

High-Bill Alert

Benefit Component Description			
Description	This benefit reflects lower consumption of electricity as a result of high bill alerts sent to customers via email once consumption reaches a set point	Present Value Benefit	$0.45M (2% of total benefits)
Benefit Elements	This benefit is generated by reduced end-use electricity consumption that leads to reduced wholesale electricity purchases. The number of customers in the high bill alert program is estimated based on the share of customers with email addresses available to NLH Power and a customer participation rate of 90%, assuming an optout program.		
Timing	This benefit tracks the AMI meter deployment. The annual available benefit will increase by a CPI adder each year.		

Table 34: Reduced Overtime for Meter Service Orders Benefit Component Description

Non-Quantifiable Benefits of AMI

This section will explore the value of the non-quantifiable benefits associated with the implementation and deployment of an AMI network system.

Customer-Facing Benefits

With AMI, NLH will have the data to deliver enhanced customer service. Customer benefits include the following:

Benefit	Description
Customer Satisfaction	Improve customer satisfaction by: • Providing customers with convenience through automation • Providing customers with a broader menu of service options, • Giving customers more control and near real-time intelligence over their energy usage • Reducing customer complaint calls and equipping customer service representatives with information that can address customer questions faster and more effectively
Street Lighting	Enable smart street lighting to give comfort to end customers that streetlight outages are known to the utility and will be acted on in a timely manner
Service Reliability	Improve service reliability with faster outage notification and restoration verification
Electric Vehicles	Support expanded use of electric vehicles
Conservation Voltage Reduction	Reduce energy consumption and demand during peak periods by dynamically optimizing voltage levels
New Rate Plans	Offer new rate plans, such as time-of-use
Customer Safety	Improve safety for customers through automatic alarms for unsafe conditions (e.g., a hot meter socket).
Renewable Generation	Better integrate and accommodate renewable generation using the AMI network and data made available through the AMI
Microgrids	Enable microgrids
Green Button	Leverage the green button initiative which gives consumers the ability to access and share their electricity data with other software applications

Table 35: Customer-Facing AMI Benefits

Operational Benefits

AMIs provide a wealth of data that will enable NLH to achieve the following operational efficiencies:

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Benefit	Description
Enhanced Load Research	Deliver data for enhanced load research studies
Transformer Loading	Better manage distribution assets through insight into transformer loading
Safety	Improve safety via the following by delivering automatic alarms for unsafe conditions, improving the safety record for meter reading staff and reducing vehicle incidents
Business Processes	Improve business processes by streamlining non-AMI billing processes, enhancing data analytics, enabling service order integration to reduce field visits.
E-Services	Increase participation in e-services (such as online bill payment, self-service customer inquiries etc.) as a result of increased traffic to an AMI Web portal

Table 36: Operational AMI Benefits

Future Benefits

The reference architecture should also allow NLH to make business process changes that result in efficiencies not currently captured in the business case. Architecture decisions should be made with best practices in mind and it should not *prevent* NLH from realizing *additional* smart grid benefits. Below is a non-exhaustive list of potential future benefits.

Potential Benefit	Description
Demand side management programs	Reduce consumer energy consumption via in-home displays/programmable thermostats and home area networks (HAN).
New rate plans	Reduce consumer energy consumption via new rate plans, such as time-of-use or dynamic pricing.
Online rate comparison	Enable customers to compare rate plans and estimate relative savings.
Edge computing	Deliver greater actionable insight into the network and added network controls.
Hosting partners and running third party applications	Host partner data and run third party applications, such street lighting, water, police, air quality, etc.

Table 37: Future AMI Benefits

Appendix D: Option 3 – Full-scale Drive-by AMR "lite" with NL Power

Full-scale Drive-by AMR "lite" Cost Benefit

Summary of Drive-by Business Case

Util-Assist performed a financial analysis on a full-scale 21-year Drive-by deployment. Meter assets typically have a 20-year life. A proper procurement process and project planning take about a year, so it is not foreseeable for meters to be deployed until about 2023, hence the 2022-2043-time frame.

Parameter	Value
Timeline (2022-2043)	21 years
Base Year (discounting to)	2022
Meter Deployment (2023)	32,000 meters (100%)

Table 38: Parameters and Value of Drive-by

The current meter reading systems that NLH have are experiencing high failure rates and becoming obsolete. For this reason, Util-Assist recommends a mass meter exchange in order to realign the organization and achieve the available benefits. The following project financial analysis demonstrated that a full Drive-by system is cost effective.

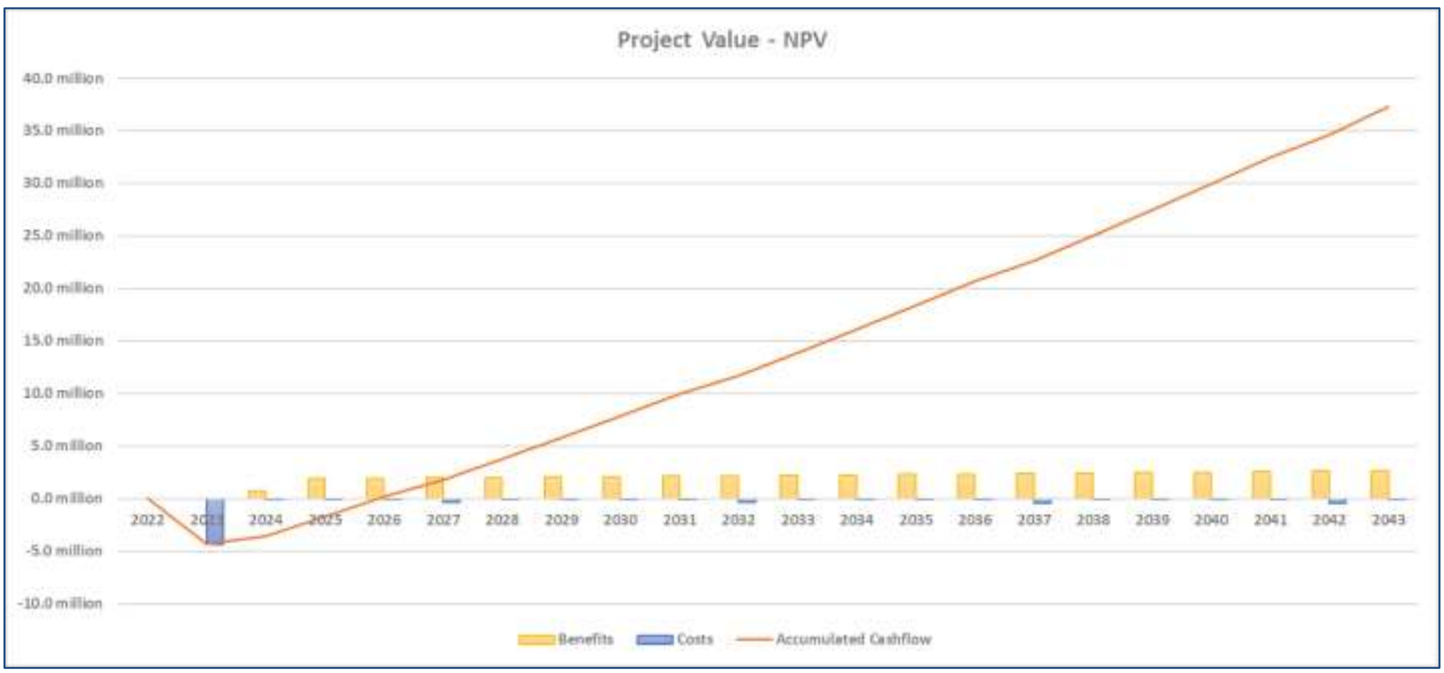

Figure 8: NPV of AMR

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Parameter (NPV)	Value
Benefits ($Millions)	$23.1M
Costs ($Millions)	$5.5M
NPV	$17.6M
IRR	37%
B/C	4.52
Breakeven	4.2 years

Table 39: Parameters and Values of Drive-by

AMR “lite” Benefits

In order to maintain a conservative approach, all project benefits are set one year after the mass meter deployment. The project benefits come from reduced field labour needed to perform reads, avoided cost of vehicles and avoided meter replacement costs.

Benefit Component	Present Value ($M)	Share of Benefits
Avoided Costs of Meter Replacements	$13.7M	59%
Reduced Manual Meter Reading	$8.4M	36%
Avoided Cost of Meter Reading Vehicles	$1.0M	4%

Table 40: Benefit Components of AMI “lite”

AMR “lite” Costs

The following table demonstrates the costs in order to implement, maintain and operate the additional components of an AMI “lite” system. Capital refreshes for all network equipment has been assumed at year ten.

Cost Component	NPV Value	% of Costs
Electric Meters	$1.9M	36%
Installation Costs	$1.9M	36%
Meter Reading System	$1.1M	20%
Yearly Meter Replacement	$0.12M	2%
Project Team	$0.14M	3%
Vendor Travel	$0.036M	1%
Additional Software (O&M 20 Yrs.)	$0.13M	2%

Table 41: Cost Components of AMI “lite”

Appendix E: NLH Metering Overview

Newfoundland and Labrador Hydro has taken various initiatives to enter the world of automated reading. Starting with the Radix handheld system; moving to the Landis+Gyr (L+G) TS1 (2003-2015), and most recently the L+G PLX power line carrier systems (2016-Present). Of the approximately 40,000 meters in NLH's service territory, roughly 23,000 meters are currently read either the TS1 or PLX systems. As these systems have aged NLH has experienced a lack of vendor support and significant communications failures that have not allowed it to achieve the benefits intended. In evaluating the previous meter reading initiatives, it is clear that they have failed due to the lack of a sound business case that reconciles the yearly benefits and accounts for system refreshes, proper change and vendor management.

TS1 System (2003-2015)

L+G used Ultra Narrow Bandwidth (UBN) technology to create the system referred to as TS1. Endpoint transmitters collect information including kWh and demand from the consumer's electric meter and send the data through power lines to the substation. The data is stored in a "collector" located in the substation. From there, data is downloaded to the central server nightly and can be used by the utility for billing, reporting and troubleshooting purposes.

Before its end of life in 2015, the TS1 Command Center supported serval different endpoint types that gave the user many different AMR and metering options. The next table outlines the areas in which TS1s have been deployed.

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Area where TS1 is Deployed	Date Commissioned	Date Upgrade Required (bulk of Meters Due)	Number of Meters	Number of Collectors
Bay D'Espoir	2008	2018	1,285	2
Conne River	2008	2018	418	1
Gaultious	Gaultious has TS1 Meters however the collector is a PLC 300 Collector with a TS1 Card…i.e. PLX meters can go into Gaultious at any time		104	1
St. Anthony	2008	2018	2,418	2
Hawke's Bay	2008	2018	1,209	2
Daniel's Harbour	2008	2018	287	1
Cow Head	2008	2018	465	1
Parsons Pond	2008	2018	270	1
Farewell Head	2010	2020	1,789	1
Wabush	2011	2021	1,261	5
Plum Point	2012	2022	961	2
Bear Cove	2012	2022	943	2
Rocky Harbour	2013	2023	1,173	2
Glenburnie	2013	2023	799	2
Sally's Cove	2014	2024	32	1
Wiltondale	2014	2024	35	1
Roddickton	2014	2024	909	3
Main Brook	2014	2024	251	1
St. Brendan's	2007 (sampled meters in 2013)	2021	146	1
Total			**14,755**	**32**

Table 40: TS1 deployment area

In the areas listed above, the default read time for all meters is 12:00 a.m. Data transmitted in each daily packet contains the reading information taken from 12:00 a.m. through 11:59 p.m. of the previous day (i.e., Monday's packet will be collected at 12:00 a.m. Monday morning, and will consist of Sunday's readings).

The time between the collection of data and transmission to Command Center (CC) is 27.4 hours. These meters are only set up to collect kWh for residential and kWh and kW or kVA demand for general service customers.

The TS1 system consists of the following equipment:

1. Meters with TS1 endpoints
2. Collector in each TS1 area. Depending on the number of distribution lines in the substation, an auxiliary collector is used. It was determined by Engineering that this would be the best way to obtain a good signal-to-noise ratio for the meters to transmit the packets.

3. Communications device – either telephone modem, ethernet connection, cell, or satellite modem

PLX System (2016 – Present)

The L+G PLX system is an "AMI solution that delivers those must have smart grid applications with the capacity to adapt to future market needs".

The system boasts that it is "plug-and-play" with self-healing qualities to avoid loss of data during changing conditions on the distribution system. Once deployed the PLX endpoint transmits packets every 15 minutes in parallel with a longer daily read packet.

- The interval data stream in the system is configured to transmit kWh readings every 15 minutes (starting at midnight) with the data being made available in Command Center within 30 minutes
- There is also the daily packet data stream that delivers custom data (such as scheduled reads, demand reset data, etc.). This data is available at various times throughout the day. The current custom setting gives approximately two 100%-full packets plus one 75%-full packet each day.)

The system can also give you "on-demand" information. The time to retrieve the information will depend on what you request the meter to send back (e.g. 15 minutes to 16 hours.)

The substation requirements have changed with the new PLX system as well. Before with the TS1 system it would only consist of three less expensive components, the PLX system requires pricier equipment:

1. Meters with endpoints
2. Collector
3. Transformer coupler unit (TCU) – the number of TCU units will vary on station size, loading factors etc.
4. Communications device – ethernet connection, cell or satellite modem

The following table outlines the areas in which PLXs have been deployed.

Area where PLX is Deployed	Date Commissioned	Date Upgrade Required	Number of Meters	Number of Collectors
English Harbour West	2016	2026	778	1
Barachoix	2016	2026	1,261	1
HVGB	2017	2027	1,560	2
Lab City (Trailer Park Only, QTZ)	2017	2027	640	1
Total			**2,050**	2

Table 41: PLX deployment area breakdown

Command Center

L+G’s Command Center (CC) is a browser-based application that is at the heart of the AMR system and is the key to managing the operations efficiently. By integrating the meter reading data with the customer information system, outage management systems and engineering analysis applications, Command Center also allows the user a way to increase operational efficiencies and improve customer service. Command Center contains reports that are tailored for use by billing, finance, customer service, operations, distribution planning and engineering departments. The data provided and the analysis of the health of the AMR system (TS1 and PLX) were all produced by Command Center.

AMI Dashboard

The AMI dashboard is a screen in Command Center that provides notification of system events and the status of system processes in a timely basis without user interaction. The AMI dashboard is the main screen used by the administrator, The Meter Shop. It allows the administrator to view system abnormalities without the need to search through views and reports.

Figure 9: AMI dashboard

Command Center uses meter status to help define the state of each meter in the system. Understating each status helps the administrator troubleshoot possible problems.

Endpoint Status	Description
Archive	Inventoried endpoints may be archived if they are no longer to be used
Configure	Endpoints that are going through a configuration update.
Failed	Endpoints that have failed a configuration update.
Find	Endpoints that are actively in the Find process.
Find Pending	Endpoints awaiting the Find process to begin.
Health	Endpoints indicating an error.
Inventory	Initial Status of an endpoint upon import of the Meter Manufacturer File or manual input.
Lost	Loss of signal with the endpoint. Endpoint may be an outage.
Normal	Those that have sent in their first readable packet after being 'found'. Those that have resumed after the loss of signal.
Archive	Inventoried endpoints may be archived if they are no longer to be used.
Configure	Endpoints that are going through a configuration update.
Failed	Endpoints that have failed a configuration update.

Table 42: AMI endpoint statuses

Days in Status displays how many endpoints have been in each status category, listed below in increments of:

- 0 to 1 day
- 2 to 3 days
- 4 to 5 days
- 6 to 10 days
- 11 days or more
- **Not Logging** displays the number of endpoints not delivering the expected packet payload.
- **Low Signal Quality** displays the number of endpoints with a signal quality below the specified threshold.

The most recent reading record is reviewed for the low signal strength threshold. All endpoint statuses, except for Inventory statuses, are reviewed for low signal strength.

To troubleshoot issues that arise within the AMR system the administrator must understand:

- The reports needed to troubleshoot in the field
- Identify geographic trends
- Substation wide
- Isolated to one feed
- Isolated to one entire phase
- Identify and resolve problem areas

Because the endpoint transmits its reading over the power line it is susceptible to issues that arise on a distribution system. These can include:

- Broken or burning lightning arrestors
- Loose hot clamps
- Debris on the line
- Faulty transformers
- Meter base issues – loose lugs, damage to meter base, tampering
- Worn insulation at weather head
- Connection at pole, from service line to pole wire
- Pole ground rod corrosion
- Customer produced harmonics

Because the distribution system can cause numerous readings to fail one would be led to believe that the system is struggling and maybe not worth using, however because the AMR system is integrated with the distribution system itself, the PLC AMR system is ideal for distribution maintenance applications.

Appendix F: Best Practices for Success

Vendor Management

Agnostic of the technology chosen to assure that the system meets the required network performance over its intended life, NLH should shift this risk to the vendors through guaranteed service level agreements (SLAs). The vendor through a propagation study will design a network and system that meets the SLAs which have been clearly specified through the procurement exercise and will become contractual obligations. Internally the project team will need to ensure SLA's are tracked and achieved and contractors are held accountable for meeting theses performance levels.

Business Case

Util-Assist performed a high-level business case of a system wide next generation metering (NGM) system. The financials and the disparate nature of NLH's service territory show that it is likely that the optimal cost-effective solution is a hybrid of solutions. Following a proper procurement process an area by area analysis should be performed to understand the achievable benefits and the support required by the organization. Proper planning and budgeting, a solid business case, and a comprehensive future-proof RFP will unlock the full potential of the next metering solution (see Figure 10).

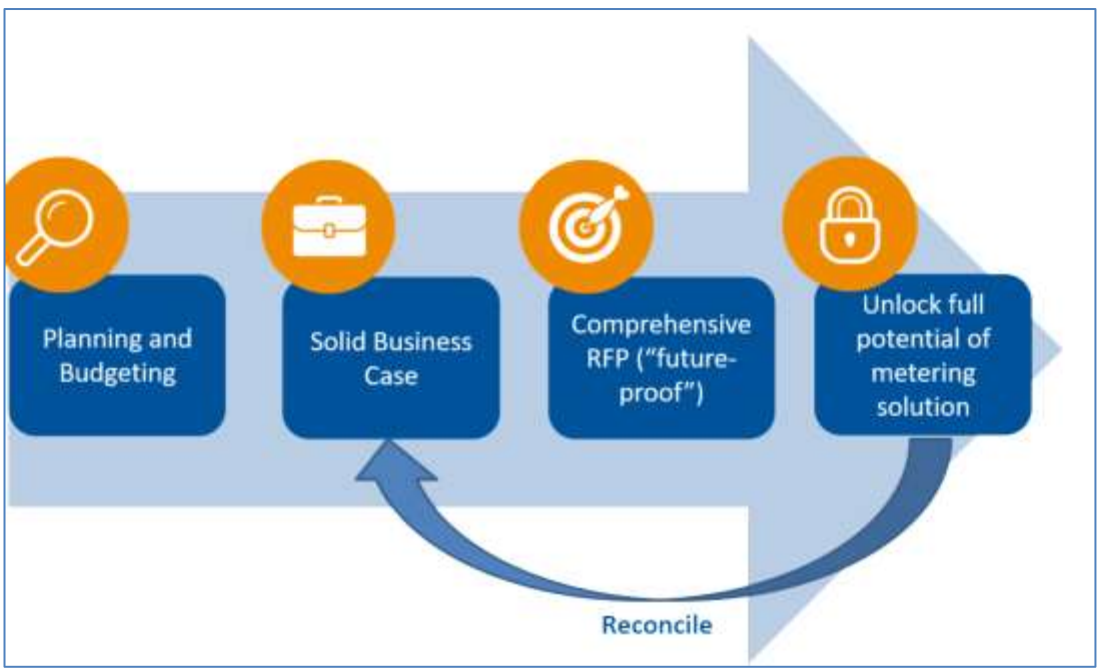

Figure 10: Reconciling to the business case

By reviewing the business case on an annual basis, NLH can ensure that the NGM program is on track with expenditures and benefits, ensuring that the program has been a success.

Customer Safety

To help ensure a positive response from customers, it is best practice to communicate the safety benefits and features of next generation meters. Effective messaging will address potential customer issues, such as concerns related to health (e.g., frequency) and safety (e.g., meter fires). Customer safety issues for electric meters can be mitigated by following these best practices:

- As a form of due diligence, ensure that all next generation meters meet the new UL2735 safety standard. The UL2735 tests cover a full range of conditions, such as temperature, dust, mold, rain and mechanical.
  - UL is an independent safety science company that offers smart meter testing and certification. In response to the absence of safety standards, UL published the *UL 2735, Standard for Safety for Electric Utility Meters* in May 2013. This standard addresses problems reported from field installations of smart meters, including fires, meters ejecting from meter socket bases, and exposed live parts. When electronic components are overstressed, there is a potential for the components to fail.
- Inspect each meter socket before and after the old meter is removed to identify and address any potential safety concerns. An inspection can reveal any corrosion or electrical issues that could lead to unsafe conditions.
- To address customer health concerns regarding radio frequency, communicate the safety of the RF emission levels compared to other household devices. Tests results below show that the average radio-frequency exposure level one metre away from a next-generation meter "is negligible compared to radio-frequency exposure from other devices" as shown in figure 11, below. It can also be pointed out that smart meters fully comply with Federal Communications Commission (FCC) standards and guidelines for environmental exposure to RF and that the World Health Organization has concluded that no adverse health effects have been demonstrated to result from exposure to low-level radio frequency.

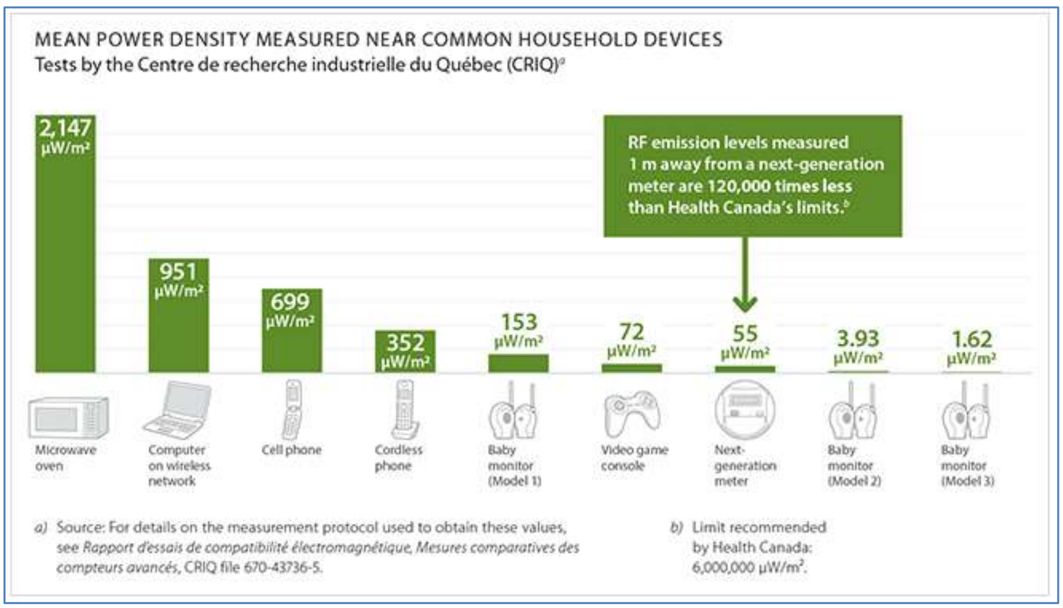

Figure 11: Meter RF emissions compared to other household devices

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Security

There are legal requirements pertaining to the data that the new generation meters will collect: meter data is classified as private. It is best practice to implement policies and procedures to ensure the privacy of information and all data that is sent over the network is encrypted. Note that no identifying customer data (name, address, etc.) is transmitted over an NGM network. Customers should be assured that the utility will have no way of knowing whether a customer is using specific appliances; however, alarms will alert the utility if meter tampering has occurred.

Next Generation Metering Vendor Contract

A solid contract with the NGM vendor provides protection for the utility. In negotiating with the selected vendor, best practices suggest that key clauses be included in the contract:

- A performance service level agreement ensures performance of the network at a certain threshold for the life of the asset.
- Clauses to protect the utility from:
  - Software issues
  - Firmware issues
  - Safety issues
  - Security issues

Asset Management

Best practices to ensure optimal asset management include:

- "Future proofing" the assets through remote firmware upgrades. In this way the utility keeps up to date with security and functional enhancements, ensuring that the investment does not become obsolete.
- Using standard communications protocols: IPv6.
- Following standards published by the American National Standards Institute (ANSI).
- Using existing WAN assets where they are already available.

Standards Compliance

One of the current Smart Grid trends is the move to standards and the move away from propriety protocols. To future-proof the next generation metering network, it is important to buy "right" by considering whether a given solution complies with current standards.

Wi-SUN

NGM vendors are now moving to Wi-SUN standards. The Wi-SUN Alliance was created to provide interoperability standards for smart utility network communications. The alliance consists of more than ninety (90) member companies including utilities, government institutions, product vendors, and software companies.

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The alliance's first initiative was to define a standard radio; the second step (Wi-SUN 1.0 (2015) addressed the speed and behaviour of radios, providing a foundation for different vendor devices on the same network. Wi-SUN FAN 2.0 is yet to be ratified, but it is expected to address:

- Battery-powered devices
- Additional modulations
- Modulation negotiation
- Multi-PHY abstraction (for PLC)
- Peer to peer communications

Choosing vendor solutions that comply with the Wi-SUN standards provides open functionality and more flexibility when choosing network devices. An open standard approach helps to mitigate risks.

Common Information Model (CIM)

The industry is transitioning from MultiSpeak to CIM, a set of standards that enable system integration and information exchanges by providing a model and message/file schemas for information exchanges. CIM standards are based on a Unified Modeling Language (UML) information model. As standards change over time, it will be important that vendors keep pace with standards for information exchanges to downstream systems, such as the GIS, CIS and OMS.

Establish Ownership of Systems

Establishing ownership of systems is another strategy to ensure effective communication practices across departments. System "owners" should be educated to understand their obligations to their internal customers to provide updates on functionality enhancements and other modifications so that other departments understand the impacts. To overcome the "silo" effect, the owners of the systems and data must acknowledge that other utility departments can benefit from the data.

Define System of Record

In addition to establishing system ownership, it is important to define a system of record for each piece of data. A "system of record" is defined as the authoritative source for a set of data in a system that contains multiple sources of the same set of data. To ensure data integrity, there must be only one system of record for a given piece of information. For example, as a best practice, the OMS is defined as the system of record for NGM operational data, such as alarms, and the MDM is defined as the system of record for time-of-use billing data. The identification of the system of record for each piece of data is a component of information architecture and associated data governance practices.

Change Management Strategy

Re-Engineer Business Processes

Utilities often identify business process redesign as their primary management challenge for moving to smart grid. A utility is not able to achieve the full benefits of smart metering without also re-engineering the related processes, with the aim to maximize the value of the product. As new meters are introduced, it is important to follow best practices in updating and re-engineering business processes. Moreover, with an integrated system, utilities need to carefully consider how business processes cross department boundaries.

The high volumes of data ("big data") produced by the next generation meters trigger the need to revise policies and procedures for handling data. For example:

- With meters communicating consumption patterns, privacy concerns will drive new security requirements.
- With the ability to remotely disconnect/reconnect meters, encryption will be required.
- The efficient handling of tamper flags requires more than just the alarm information; service order information is required, illustrating the need for many data elements to be shared across the organization.

It is important that each department understands how to access and how to leverage the data to benefit the department. Business processes should include the following components:

- **Work/data flow diagrams**: diagrams with "swim lanes" to distinguish departmental responsibilities for each process step and milestones to distinguish phases or groups of activities.
- **Supporting documentation:** detailed documentation for each activity in the workflow
- **Entry criteria and inputs**: criteria and information required to start the process.
- **Exceptions**: variations to the primary path.
- **Business rules**: rules to be followed/enforced when executing a process.

It is best practice to continue with existing business processes until the network achieves stability; in other words, previous meter reading methods should continue to be followed. By moving to new processes too quickly, a utility runs the unnecessary risk of bad press or public outcries. Business processes should be identified and prioritized based on reconciling the benefits. Moreover, as the project progresses, and resources change, business processes need to be reviewed and refresher education sessions should be held.

Communicate with Staff and Customers

The common denominator for any successful deployment is a strategic communications plan. The approach to communications should be based on the following principles:

- Learn from other utilities that have implemented the technology and adopt the best practices from those utilities.
- Inform, educate, and foster a sense of ownership among internal staff.
- Communicate benefits to customers, establish open and frequent communication, proactively address concerns, and build support for implementation.

It is key to secure corporate buy-in by delivering workshops that stress the benefits of the shift to the new technology and re-assure staff that the change is positive. Workshops with individual departments should outline exactly how their roles are affected. Employees need to understand the "why" behind business process changes, for example, new considerations in handling next generation meter data and how to manage exception scenarios. The adoption success of a new system is dependent on ensuring all employees have the required skills and information. It is important that project sponsors are authentically dedicated and knowledgeable to set the tone and provide leadership.

Prior to proceeding with educating customers, the utility should prepare the message to be conveyed. Proper communication and positive press are vital to this project. Customers need to understand when changes will occur, why changes are occurring, and specifically how they (the customer) will benefit. Communications should further highlight that the new meter reading technology will better serve customers by gathering accurate meter reads without needing to enter the home. A comprehensive communication plan should incorporate schedule, resources and responsibilities, and estimated costs.

Deliver Comprehensive Training

In order to create subject matter experts within the organization, effective training is not only required when the system or process is initially deployed, but also over the longer-term use of the product/process. Software solutions are rapidly evolving, and it is important that utility resources maintain their level of expertise by engaging with their chosen vendors to understand product roadmaps and how any changes might be integrated into their existing processes. It takes a degree of organizational discipline to continue budgeting time and effort to improving skill sets, but the risk of not retaining expertise—and therefore the possibility that business processes are being managed less effectively—needs to be considered alongside the costs.

Training should be given a high priority. Refresher training helps ensure that employees remain current on the system, and furthermore, follow consistent procedures for completing system tasks.

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Appendix G: About Util-Assist

Util-Assist is based just outside of Toronto, Ontario, but is also incorporated in the United States with its lead consultant for the NLH project based in Minneapolis. Established in 2005, the firm was created at a time when the utility industry was at a juncture of rapid change, with the Ontario government set to mandate smart meters and time-of-use rates. Util-Assist seized the opportunity to use industry experience to support utilities and protect their interests by operating in the middle ground between vendors and customers in the electric, water and gas utility industry.

Util-Assist now applies the knowledge it has gained to projects throughout North America, and in 2016, owing to our success and offerings in the marketplace, Util-Assist was acquired by Alectra Energy Services, which is a branch of the Alectra Utilities family of companies providing non-regulated energy services. Alectra Utilities is the second largest municipally owned electric utility by customer base in North America. It is second only to the Los Angeles Department of Water and Power and serves nearly one million customers in Ontario. The combination of Util-Assist's extensive experience in the advanced metering discipline over the past 13 years and its municipal ownership sets us apart from other interested consultants.

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Appendix H: Acronyms and Definitions

Acronym	Term	Definition
A		
AI	Artificial Intelligence	The simulation of human intelligence processes by machines.
AMI	Advanced Metering Infrastructure	The infrastructure that collects meter read data. The infrastructure consists of three layers: • AMCD (Advanced Metering Communication Device) • AMRC (Advanced Metering Regional Collector) • AMCC (Advanced Metering Control Computer)
AMR	Automatic Meter Reading	A system where aggregated kWh usage, and in some cases demand, is retrieved via an automatic means, such as a drive-by vehicle or walk-by handheld system. In the case of NLH and for the purposes of this document, AMR is understood to mean the PLX power line carrier meter reading solution from the NLH metering technology provider, Landis+Gyr.
ANSI	American National Standards Institute	
B		
	Bandwidth	The rate of data transfer or throughput.
C		
C&I	Cost and Investment?	
CIM	Common Information Model	A standard that defines common language for data elements exchanged between back-office systems (e.g., metering data, price, demand response events, outage and other system data).
CIS	Customer Information System	A system used to manage customer accounts, consumption and billing data.
CPI	Consumer Price Index	
CSR	Customer Service Representative	Interacts with customers to handle inquiries, complaints, and provide information about a utility or service.
CVR	Conservation Voltage Reduction	Uses smart grid technology to reduce energy consumption and demand during peak periods by dynamically optimizing voltage levels.
CX	Customer Experience	The product of an interaction between a utility and customer over the duration of their relationship.

Acronym	Term	Definition
D		
DA	Distribution Automation	Real-time adjustment to changing loads, generation, and failure conditions of the distribution system, usually without operator intervention.
DLC	Dynamic Load Control	
DR	Demand Response	The ability to respond to changes in the electricity market, such as when demand and prices are high. Consumers may choose to reduce their consumption to save money.
E		
ESB	Enterprise Service Bus	A high-level protocol communication system between mutually interacting software applications in a service-oriented architecture (SOA).
F		
FAN	Field Area Network	Provides connectivity to a large number of metering and sensor devices spread throughout a given geographic area, e.g., Collectors, Gateways
G		
GIS	Geographic Information System	A system designed to capture, store, manipulate, analyze, manage, and present geographically referenced data.
GPS	Global Positioning System	A satellite navigation system used to determine the ground position of an object.
H		
HAN	Home Area Network	A LAN for digital devices used in the home.
I		
IHD	In-Home Display	HAN in-home displays help customers track energy usage. The displays monitor and control thermostats and other appliances to change consumption patterns and realize improved energy efficiency. IHDs may be portable or installed on a wall.
IT	Information Technology	The use of systems for storing, retrieving, and sending information.
L		
L+G	Landis and Gyr	
LP	Load profile	Data recorded at set intervals that when taken together provide a profile of data demonstrating electricity consumption over time. Load profile information can be recorded for different units of measure.

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Acronym	Term	Definition
M		
MDM (MDMS)	Meter Data Management System	Performs storage and processing of data delivered by a smart metering system: • Monitors the performance of the AMI network • Helps the troubleshoot problem meters • Receives the meter read data: register reads and interval data • Can receive and analyze operational data from the meters, such as tamper alerts, outages, voltage alarms (Also referred to as ODS in Ontario.)
N		
NaaS	Network as a Service	Instances where the vendor takes responsibility for the performance of network infrastructure and directs third party personnel to fix infrastructure issues in the field as they arise.
NGM	Next Generation Metering	AMI or AMR metering solutions referring to non-manually read meters.
NIC	Network Interface Card	A hardware component, without which a computer cannot be connected over a network.
NPV	Net Present Value	Difference between the present value of cash inflows and the present value of cash outflows over a period of time.
O		
O&M	Operations and Maintenance	
OMS	Outage Management System	Used by operators of electric distribution systems to assist in restoration of power through the following functions: • Fault location prediction • Prioritizing restoration • Providing outage to stakeholders • Calculating estimation time of restoration (ETR) Scheduling and management of crews assisting in restoration
OT	Operational Technology	Hardware and software that monitors and controls how physical devices perform.
P		
PLC	Power Line Communication	A communication technology that enables carrying data on a conductor that is also used for electric power transmission.

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Acronym	Term	Definition
PLX		A Power Line Carrier Solution designed by L+G
PMO	Project Management Office	
R		
RF	Radio Frequency	Any frequency within the electromagnetic spectrum associated with radio wave propagation. Smart meters transmit via radio frequency.
RFP	Request for Proposal	As part of procurement, an RFP is a formal request issued to suppliers to submit a proposal for a commodity or service.
RPA	Robotic Process Automation	An emerging form of business process automation technology based on the notion of metaphorical software robots of AI workers.
S		
SaaS	Software as a Service	A third-party hosted application service.
SAT	System Acceptance Testing	Used to assess a system's compliance with the determined business requirements.
SLA	Service Level Agreement	Contract in which levels of service are defined.
T		
TS1	Turtle System 1	Originally developed by Hunt Technologies and later acquired by L+G, TS1 represents the in-place, now obsolete power line carrier meter reading solution that accounts for the largest number of AMR meters in the field and is in need of replacement.
U		
UML	Unified Modelling Language	
V		
VEE	Validation, Estimation and Editing	Validation, Estimating and Editing of meter reads to identify and account for missed and inaccurate meter reads to derive billing data. The algorithm to complete VEE identifies gaps in meter reads and rebuilds consumption based on historical trending and averaging.
W		
WAN	Wide Area Network	The communication network that transmits meter reads from the AMRC to the AMCC or, in some systems, from the AMCD directly to the AMCC. The WAN can be either public network options (such as cellular, spread spectrum) or private (including utility fiber, licensed radio frequency, etc.).

Table 43: Acronyms and Definitions