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Metering Technology

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Metering Technology

The market for electricity meters is shifting away from kilowatt-hour only devices to those containing advanced features and functions. The catalyst for this change is the suite of requirements enumerated in the US federal legislation commonly referred to as EPAct2005, and distilled into concrete requirements at the utility level by the UtilityAMI organization.

Since the publication of the UtilityAMI requirements, as well as formal requests by a handful of utilities, vendors have responded by broadening their product offering to match.

This paper focuses on metering technology available today (or in the near future in production volumes) and the features relevant to the future generation of solid-state devices. Critical elements such as meter type (forms), class (current and accuracy), service switches and attributes related to data measurement and transport are presented. In addition to metering technology, a high-level overview of wired and wireless communications technologies used in the metering industry is provided.

Background

For many years, utilities have been automating business processes whenever and wherever possible to streamline their operations and maintain internal earnings targets. One way to preserve earnings is to automate the meter reading system in some manner and integrate with a meter data management system (MDMS) where necessary. Automating meter reading systems reduces personnel labor requirements, insurance costs, liability issues, and inaccuracies inherent to non-automated processes, while a MDMS allows the utility to better handle the larger volume of metering data. One possible negative aspect of this automation is that utilities lose "eyes on the meter" every month, leading to cases where revenue assurance activities must actually increase.

Automation in the early days involved pairing an all-electronic "register" with an electro-mechanical "metrology," both for single and polyphase meters. This meter/communications pair allowed the utility to stay with their preferred meter technology vendor while installing whichever communications technology met their business and operations needs at the time. A downside to this pairing approach is potential incompatibilities. Often different "meter" vendors do not offer the same communications technologies, prohibiting utilities from meeting their goal of a multi-vendor solution. In fact, most utilities have multiple "metering" technologies, multiple "communications" technologies, and one or more meter reading systems. They may also have a distinct meter data management system provided by a different vendor.

Metering Technologies

Metering Technology Introduction

Smart meters are a combination of a meter (for this paper, defined as a "metrology" and a display) and an integrated communications module that can enable communications with both the home area network and utility company. This module (or modules) effectively implements the utility/consumer portal function, which could also be implemented in a separate, purpose-built device. The communications module can be purchased sepa-

rately from the meter, often from a vendor other than the meter manufacturer – but usually under a specific agreement between the two vendors. It is becoming increasingly common however for the communications capability to be fully integrated with the meter to minimize cost.

Selection of the communications vendor determines the capabilities of the meter including not only the communication protocols (wired or wireless), but the data storage capacity and features available to the home network. For example, the communications module's compatibility determines the ability to collect information from other meters in the home or the ability to control devices that reside in the home. Similar to a computer, this module is often a multi-purpose device that provides intelligence to the meter. Like a computer, the module may need to be updated with new firmware or replaced more often than a traditional mechanical meter. It is therefore important to choose a smart meter that can have its software components reliably and securely upgraded via remote commands through the communications network.

Meter Technology Design Constraints

While the external interface from an electric meter to the outside world is well-standardized for both the meter and communications, the interface "under the glass" has been considered the meter manufacturer's domain. At the present time, no recognized standard for this interface exists. As such, neither the electrical nor the physical nor even the protocol characteristics of this interface are the same from meter vendor to meter vendor. Instead, the communication module vendors are left to negotiate, discuss, or take interface requirements on a vendor-by-vendor basis. Typically the communications vendors will attempt to balance requirements and time-to-market for the combined solution based on the size of purchase orders.

On the other hand, the external meter interfaces are governed by standards such as American National Standards Institute (ANSI) standard ANSI C12.10, which defines the electrical interface between a meter and a meter mounting device (socket). The communications interface is governed by standards such as ANSI C12.18, Recommended Standards (RS) RS-232, Distributed Network Protocol (DNP) version 3.0, Ethernet and other connector and protocol standards. Major components of meter design, manufacturability, performance, and safety are the electrical and physical interfaces determined by the meter vendor, which are seldom negotiable. Performance and safety of the integrated meter and communications technology is governed by the type testing standards such as ANSI C12.1 and C12.20, which have a rich history of participation by the vendors and utilities and little to no participation by the module vendors. Established meter manufacturers rarely trust the integrated product testing and certification to the communications vendor due to contractual, warranty and liability concerns. The market share for a successful meter product may run into the tens of millions of units. Whereas the market share for a successful communications product is in the hundreds of thousands, leading to a disparity in the reputation and risk for those vendors.

One industry group, OpenAMI (http://www.openami.org), has formed to address advanced metering infrastructure (AMI) developments and is attempting to surmount traditional business and technical paradigms. This group seeks to solve the under-glass dilemma by investigating a common three-dimensional physical space, physical connector, electrical and protocol interface. However, the OpenAMI group has achieved little to date due to the different metering device and communications vendors working to address the much bigger problem of building the core two-way AMI system. Finally, it is worth mentioning that an Institute of Electrical and Electronics Engineers (IEEE) standards group, Standards Coordinating Committee 31, has started a similar project in coordination with a sister ANSI standards group, ANSI C12 Subcommittee 17.

Feature-Driven Technology or Technology-Driven Features

Interval Metering

The ability to manage the grid intelligently is improved by the timely capture of consumption and demand data for individual loads. Interval metering records energy consumption and demand throughout the day in interval chunks, or "buckets" providing support for time-based rates. Typical divisions are 15-minute intervals, or multiples of 15 (e.g., 30 or 60-minute intervals), and down to 5-minute intervals for both energy and demand. Smart meters are also anticipated to provide the same granularity for other measurements such as voltage, power factor, volt-amperes

reactive (VARs) and volt-amperes (VA). Accurate time-keeping and enough on-board memory to store measurements up to sixty days or more for each desired value is required. Time-keeping and memory storage cannot be accomplished without some sort of solid-state register and communications. Though there is no standard for defining data intervals, there are standards for communicating meter data such as ANSI C12.19 and Device Language Message Specification (DLMS)[1], also published as Commission Electrotechnique Internationale (International Electrotechnical Commission, "IEC" in English) standard IEC 62056.

Data (Battery) Back-up

A backup is required to alleviate loss of data in the case where the register memory is volatile. This is accomplished by batteries or storage capacitors. Both technologies can supply the register microprocessor with energy to store the last bit of data when line power is lost. Batteries either require a recharge circuit or must be designed for a long discharge lifetime and are often an option for the register. They also create disposal problems due to their chemical composition. Storage capacitors require a recharge circuit, and are technologically more difficult to implement due to their energy delivery characteristics. Most vendors either offer a back-up device or use non-volatile (flash) memory. Application of the latter however is limited by a fixed "lifetime" of read/write operations. No open standard for data backup, batteries, or storage capacitors exists.

Meter Classes

ANSI meter class is defined by the maximum current the meter is expected to encounter for a particular service, while IEC meter class is more often defined by its accuracy designation. ANSI socket meters are rated for 100A, 200A and 320A services, and are typically residential (single-phase) and small commercial (single-phase or polyphase) meters. Large commercial and industrial meters are known as ANSI transformer-rated meters and are available in 2A, 10A, and 20A ANSI class ratings. These meters use voltage and current instrument transformers together with a meter to measure the energy and demand and may not be connected in-line with the service. The ANSI class ratings are defined in the ANSI C12.1 and C12.20 standards and these standards include tests to determine meter accuracy as well. There are parallel IEC standards for meter current limits and accuracy ratings, such as the IEC 62052 and 62053 series of standards.[2]

Meter Form Configurations

ANSI C12.10 defines thirty socket-based forms for electricity meters and twenty-four bottom fed, or "A" base, forms. For single-phase socket-based meters there are only four defined configurations of terminals, whereas three-phase meters have two terminal configurations.[3] The different terminal configurations and form designations can be attributed to the internal current and voltage sensing circuit configurations that have been developed over time. Despite these differences, meters with the same ANSI form designation number are interchangeable. In certain markets, clear preference is given to the four-terminal, 2S ANSI C12.10 form for single-phase connections, and 12S, 9S and 16S ANSI C12.10 forms for two and three-phase connections.

National standard forms such as those applied in Brazil, Japan and Australia and utility-standard forms are more commonly specified and used outside of the ANSI-accepted market. Some utilities use a form factor defined by the German Standards Institute.[4] The form-factor variety is one of the reasons why it is practically impossible to build a single meter to serve all markets.

Most meter manufacturers leverage their technology across as many form configurations as possible, beginning with the most common (highest production volume) and then expanding their manufacturing base as customer demand dictates. The advent of smart grids and smart meters may help reduce the variety of meter configurations demanded.

Data Channels

Data channels typically refers to a collection of time-series interval-based register (measured) quantities for display or transmission. The number of registers and channels selected by the user combined with the memory on the meter then determines the

1 Device Language Message Specification, see more at http://www.dlms.com/

2 IEC 62052-11 is one of them

3 See the Pocket Guide for Watthour Meters, p. 21

4 Commonly stated as "DIN meters," where DIN stands for "Deutsches Institut für Normung" in German

amount of data the meter is able to store before needing to be read and refreshed. There is no standard method of defining data channel capabilities of meters since implementation differs from vendor to vendor.

Non-Kilowatt-Hour Calculation Methods

Other than the kilowatt-hour calculation, there are no standard accuracy type tests for other desired values such as voltage, current, power factor, VARs and volt-amperes (VA). In particular, there are three recognized mathematical definitions of VA: arithmetic, vectorial, and as defined by IEEE 1459. There is a cross-industry and multi-national effort that recognizes the numerous variations known as the ANSI C12 Subcommittee 24. This subcommittee will catalog the plethora of algorithms in the form of a standard. Once this catalog standard has been completed, utilities will be able to specify a particular algorithm and level of accuracy in addition to requiring vendors to provide meters that match the specification. The reason for the variation in calculation methods stems from differences in treatment of voltage and current harmonics at the point of service. The utility typically generates pure fundamental frequency power, but that form of power is not usually measured at the point of service. Algorithms that favor voltage harmonics are seen to penalize the utility, while algorithms that favor current harmonics are seen to penalize the customer. Application of such algorithms to calculate demand (kW) at any given time will skew benefits for one of the two stakeholders. Therefore, an industry need is to coalesce on a measurement approach that delivers proper balance between "correctness" and "fairness."

Time (Synchronization, Daylight Saving Time, etc.)

Most meters use either a crystal clock or a line syncing algorithm to maintain accurate on-board time keeping. This is an absolutely critical design consideration in taking revenue measurements, especially for interval metering under time-based rates. All meters should allow daylight saving time to be locally applied, as well as specification of a time-zone setting. This will allow for simple interpretation by customers and field service personnel. Advanced meters may have GPS capability for both time and position determination, yielding extremely tight tolerances for clock synchronization.

Service Switches

The requirement for service switches, also known as "disconnect," "connect," or "reconnect" switches, to be a functional element of the metering device is new to the industry. The broad deployment of communication technologies to every service point will allow the utility to perform "soft" and "hard" service connections remotely, saving on utility personnel trips. Soft connections are accomplished by the meter software and firmware in conjunction with rules and policies developed by the utility for each customer. This soft switching can be used for stability reasons (limit available current), revenue reasons (non-payment), and safety reasons. Hard connections are those where the software/firmware manipulate a physical switch to connect/disconnect the customer's electric service. This type of switching is useful for widespread outage restoration, service changes (customer changes), and other stability and safety reasons. These types of actions are coordinated based on utility rules and policies.

Tamper Detection, Net Metering, Reverse Flow Detection

Tamper detection and mitigation is accomplished by several different methods. Some solid-state meters have a hardware tilt detection switch. When the meter is removed from the socket, this hardware switch causes a flag to be set in the meter firmware that is transmitted to the utility the next time the meter is read. When this flag has been triggered several times without a corresponding utility-known reason, this is a clear tampering indication. Another method for handling this situation is to create a meter that always counts energy being consumed despite the apparent current flow direction sensed by the metrology. Net metering, or allowing for and accounting for current flow in either direction (from utility to customer or customer to utility), is a metering method used for on-site generation, and may be used to detect tampering attempts when there is no known on-site generation. Meters that can provide measurements for net metering can also provide reverse flow detection. Another tamper-indicating measurement is the "blink," or loss of voltage. This can be captured by the meter and communicated to the utility, and used as a quality of service indicator as well.

Power Quality - Features, Options, Cost

Power quality (PQ) is a prevalent topic in the metering industry. The measurements that are used to perform PQ calculations are starting to be specified for residential meters as part of smart grid rollouts. These measurements include voltage, voltage profile, current, and power factor, in addition to energy (kilowatt-hour) and demand (kilowatt). PQ performance measures such as total harmonic distortion (THD) and total demand distortion (TDD) can be calculated in the meter or in the utility back-office application for use in service assessments and complaint resolution. IEEE has standards for power quality characterization and power quality data transmission, such as IEEE 519 and the IEEE 1159 series.

Diagnostics, Alarms, Logs and Events

Diagnostics, alarms, logs and events are a set of features that complement the ability of a meter to perform its revenue function properly. Typical events or flags a meter may offer to alert the utility include power outages, number of demand resets, number of times programmed, number of minutes on battery carryover, and direct tamper indicators. Tamper indicators include inversions, removals, reprogramming attempts (bad passwords), power losses, reverse rotations, physical changes (tilt), encoder (electronic registers for electromechanical meters), and firmware issues such as watchdog timeouts and recoveries the meter has encountered. Most meters can be configured to record diagnostics, logs or alarms, with prioritized rules on how and when the events are reported. Some meters may store a daily "snapshot" of their configuration and self-test program, allowing the utility to monitor the evolution of the meter during its installed lifetime.

The number and types of diagnostics, alarms, logs and events is driven by the meter vendor's choice of on-board storage size. Most North American vendors are implementing the data model specified by ANSI C12.19, which is extremely rich in the standard-defined information ("tables") that can be stored for retrieval by the utility (required in Canada).

Remote Settings

Another new requirement in the metering marketplace is the concept of remote configuration (also known as programming) and updating (also known as over-the-air firmware updating). Most solid-state meters in the field at the present time are programmable via their optical port or modem. Several vendors have recently offered networkable meters with Internet technology to accomplish the same tasks. This capability is driven by the desire of utilities to determine their business case on as few visits to each service point as possible. The ability for meters to be reworked from a central point eliminates having multiple personnel with multiple computers and multiple accounts in circulation – an information technology management nightmare.

Reliability - What are the Key Parameters and Standards?

Meter reliability is driven by utility business-case requirements and vendor warranty periods. Most United States (US) and Canadian utilities require an installed lifetime of 20+ years. Utilities test and verify reliability through "in-service" testing programs, for which guidance is defined by ANSI C12.1,[5] and their own internally-defined meter testing programs. For these programs, a certain percentage of meters from defined populations are tested every year for kilowatt-hour accuracy drift to ensure that the overall customer base averages to a proper accuracy point.

Most, if not all, vendors are Organisation nationale de normalisation (International Organisation for Standardisation, or "ISO" in English) certified facilities,[6] meaning that there are auditable procedures and plans in place that provide for a certain level of quality confidence.

Displays

The requirements on meter displays, and in particular the information that is displayed, varies from the core kilowatt-hour reading for all customers to most any value a meter is capable of measuring. Most solid-state meter vendors replicate the mechanical dial and cyclometer registers with a liquid crystal display (LCD)-based display register. In the most simple, fixed-segment manifestation of the display register, energy, demand, voltage presence, watthour disk emulator and meter mode are displayed. If meters are capable of being put into alternate and test modes, this is also visually

5 An international parallel is provided through IEC 62059-41, Electricity metering equipment-Dependability-Part 41: Reliability prediction

6 Either ISO 9000 or ISO 14000 facilities

indicated. Most vendors offer the ability to put other values in the pre-defined segment space.

More meter capability requires more advanced displaying technology. A meter capable of performing net measurements, being detented, displaying per-phase voltage presence, and so forth usually indicates readings visually on the display. Extremely advanced meters have bitmap displays similar to computer monitors that allow graphing, phasor diagrams, or other definable objects to be presented to the customer. However, this technology is typically unnecessary for mass-market meters.

Security

Most electricity meters that are all solid-state devices with communications rely on several (up to four) passwords. As an example, these may be defined as read-only, read and test, meter shop (read, program and test) and manufacturer (anything is possible). Each password relates to a role with permission to perform a given set of actions. Meters that support point-to-point communications over either an optical port or telephone modem are relatively secure under this methodology if "default" passwords are not employed.

The forthcoming ANSI network standard, C12.22, allows for application layer use of Data Encryption Standard (DES), triple DES and Advanced Encryption Standard (AES) algorithms for communications encryption. Other measures will be needed once meters are "networked" and deployed with control switches inside. While the meter measurements are certainly a major privacy concern for utilities, the control of such features as over-the-air firmware modifications, control switch actions and possible commands being sent into the customer home represent significant security concerns. It would certainly be unacceptable for a rogue agent to program the switches to cycle periodically and then lockout access to the meter to those able to correct that issue.

Recently, an industry group was formed to look at the security issues in the advanced metering infrastructure context. Formed under the UCA International Users Group, it is known as AMI-SEC, where the "SEC" stands for "security."

Summary

The change from simple kilowatt-hour only electromechanical meters to fully solid-state "smart" meters represents a major shift in utility industry practice. Each feature and technology adds complexity (i.e., cost) to the metering device, as well as additional points of failure. Though metering testing standards and programs have evolved over time, it may be the case that the expected installed lifetime of the meters will have to be reduced to allow for the rapid technological progress and desired feature sets to be deployed.

While the price of solid-state equivalents of the simple kilowatt-hour only electromechanical residential meter is comparable, the expectation that a robust, feature-laden advanced meter with multiple data point recording and logging capabilities, integrated home-area network (HAN) communications, wide-area network (WAN) communications, local communications port and an integrated connect/disconnect switch to be comparable is unfounded by reality. Second or third-generation devices in quantity may attain a similar price point, but not for several years of actual manufacturing and deployments.

Meter Communications Overview

This chapter is a high-level overview of the challenges facing communications technology designers and includes a review of the types of systems that are commonly used in utility metering.

Meter Communications Technology

Metering communications technology has been traditionally focused on getting the least amount of information in the quickest and simplest manner (ignoring manual reading). Originally, technology centered on recording technologies such as magnetic plastic and stamped paper tapes. These were installed on high revenue service points, and usually collected monthly. Each vendor had a proprietary means of recording readings (usually the so-called "pulses" from the rotating disc) and related decoding equipment. This eventually evolved into solid-state "registers" that recorded the pulses and could also convert those into an energy reading on-site. More often, the pulse counts were brought back into the utility for processing into energy and demand readings. Work began on metering data protocol standards in the early 1990s, culminating in three standards known as ANSI C12.19, ANSI C12.18, and ANSI C12.21. A data model is defined in the ANSI C12.19 and is applicable to electric, water and gas meters. C12.18 is a stan-

dard for a protocol (Protocol Specification for Electric Metering, or PSEM) for point-to-point communications over a serial optical link (ANSI Type 2 Optical Port), while C12.21 defines a set of services to allow the metering data to be retrieved in a standard manner over the public telephone network.

These standards represented a step forward, but still required significant effort to employ: ANSI C12.18 requires visiting and "probing" each meter to get the full data set, while ANSI C12.21 involves placing modems, phone lines and dedicated modems pool to perform monthly data-harvesting calls. Neither technology is easily justifiable for performing frequent meter interrogations or returning energy and demand readings from the business case standpoint.

Communications devices installed with water and gas meters have very little power available presenting another limitation, necessitating advanced battery designs and extremely optimized circuits. Almost all communications devices presently deployed for these types of meters are one way (intermittent or continual broadcast of the reading) or one and a half ways (respond to a wake-up signal then broadcast the reading). The standards mentioned here are not extremely applicable to the water and gas meter side of the system as the communications protocol overhead or physical connection exceeds its value as a reading tool. However, having the data model for those meters pre-coded as part of a standard allows back-office processing to treat them in a consistent manner.

Metering Communications Design Constraints

Data flowing from or to the meters can be over numerous types of communication links including both wired and wireless connections. Wireless radio frequency (RF) connections can be either fixed or meshed networks. A meshed network allows for multiple communication paths in the event that one path is blocked or has failed. The architecture for both wired and wireless approaches is similar: the data from the meter normally flows into a concentrator or aggregator, which may be just another meter. The concentrator gathers data from multiple meters via a communications link and then transports it back to the data center through a more robust communications network. The 'hop' from the meter to the concentrator/aggregator is usually wired or wireless, while the 'hop' from the concentrator/aggregator to the data center is normally over a high-speed, wired connection. Some utilities leverage spare bandwidth in their substation communications network to get the data from the field to the data center.

Meters can be connected through wired approaches like Power Line Carrier (PLC), Broadband over Power Lines (BPL), or telephone lines. Wireless approaches include cell phone technologies such as Code Division Multiple Access (CDMA), Groupe Spécial Mobile, now Global System for Mobile communications (GSM), Enhanced Data GSM Environment (EDGE) and Evolution-Data Optimized (EvDO), satellite or wireless fidelity (Wi-Fi) and World Interoperability for Microwave Access (WiMAX) communications. The number of meters connected to a single concentrator/aggregator varies widely, but the normal range is from one hundred to eight hundred meters per device. Due to the large geographical coverage of most medium and large utilities, it is expected that multiple types of communication networks with both wired/wireless configurations will need to be deployed to match the varying customer densities within their service territory.

Important issues to consider when selecting the meter communications network are:

- The network must be able to handle large data flows resulting from wide area outages/restorations and firmware upgrades in a secure manner.
- Meshed networks, while offering redundant data paths, may make local problem isolation more difficult.
- Communication network costs can be high and the network is an additional point of possible failure for the company.
- Open communication standards are necessary to avoid vendor lock-in.
- Requirements for use in applications other than supporting the customer interface (e.g., distribution automation, asset management, remote sensing, etc.) must be considered for the business case.

Power Line Carrier

Power Line Carrier (PLC) refers to technologies that use the existing power delivery infrastructure (wires) as the communications channel. There are two common methods, characterized by frequency of the injected signal, intended for different applications.

Low-Frequency PLC

Low frequency PLC refers to PLC technology that provides a lower data rate, longer propagation capability over the electric distribution infrastructure. The hundreds to several kilo-hertz communications signal does not require special equipment to bypass power transformers, which act as low-pass filters for communications signals. Another advantage of low-frequency PLC is that the signal can travel many miles before requiring boosting equipment. This technology is most often used by utilities to perform switching or control operations such as relay tripping and water heater management, as well as by some vendors to perform meter reading applications. While a robust technology, the low bandwidth tends to limit the realm of data intensive applications.

High-Frequency PLC

Broadband over Power Line (BPL)[7] refers to PLC technology that provides "last mile" digital broadband capabilities over electric distribution infrastructure. This "last mile" capability is technically constrained by the ability to propagate the signal through the power transformers in the distribution system (those act as low-pass filters and attenuate the high-frequency PLC signals) and the ability for the signal to travel longer distances, which is a function of both the natural attenuation of the power wires and the signal power limits imposed by the FCC.

In addition to utility applications, BPL supports commercial applications such as high-speed internet access, video on demand and streaming audio. As governed by the FCC, the frequency of transmission is set from 1.6 MHz to 80MHz, partitioned into a so-called "access" band of 1.6MHz to 10MHz (over MV distribution lines) and an "in-house" band of 10MHz to 30MHz.

"In-house" BPL is a home networking technology that uses the transmission standards developed by consumer groups such as the HomePlug Alliance. Products for in-home networking use the electric outlets and wiring within premises as the communications path.

"Access" BPL is the term for technology that carries broadband traffic over medium and low-voltage power lines. This is accomplished by overlaying digital communications equipment at certain points along the electric power distribution network. Three components of the electric power distribution network are directly involved. The first is the medium voltage (1 to 40kV) line over which an electric utility brings power from a substation to a residential neighborhood. The second component is equipment used to bypass the low-voltage transformers, that is, those that step the line voltage down to the residential 240V service level. The third component is the low voltage distribution network (in some cases a single line) from the pole-top step-down transformer to residential service panel and on into premises.

There are three commercialized methods of bypassing transformers for communications: using a special wire to carry the data, using a packet-chopping technology to communicate through the transformer, and using wireless technology to get the signal from the high side of the transformer directly into the home.

The main technological challenges surrounding transformer bypass are benign compared to the political challenges raised by groups such as the American Radio Relay League (ARRL), due to concerns about some BPL implementations generating interference in bands previously reserved for other purposes.

Wireless Radio Frequency (RF)

Unlicensed Fixed/Mobile

Unlicensed Fixed/Mobile for wireless radio frequency nomenclature refers to using one of the frequency bands reserved by the FCC for 'unlicensed,' or free use. These are commonly referred to by their core frequency of 900MHz, 2.4 GHz and 5.8 GHz, though the actual operating frequency differs from this value. Advantages of this approach include the lack of licensing and country-wide availability. Disadvantages include a multitude of interfering devices such as wireless phones, baby monitors, security camera systems and the like, as well as a non-existent arbitration stance from the FCC. Vendors operating in these bands trade off speed with bandwidth according to which part of the spectrum they choose for their particular technology.

7 The subject of an IEEE working group: http://standards.ieee.org/announcements/pr_p1675.html

Licensed Fixed/Mobile

The use of a licensed frequency, in contrast to the unlicensed spectrum, guarantees availability of the communication channel to the licensee, with clear arbitration rules set forth by the FCC. The major disadvantage is that a specific operating frequency may not be available in all desired service territories.

Summary

No single wired or wireless communication technology meets all needs in the utility, especially for performing metering functions. Service point density, topology and weather are all factors in the selection of the proper technology for the application. Automating the meter reading function requires relatively low bandwidth one-way technology. Allowing two-way communications, control functions, over-the-air firmware updates and interaction with networks and equipment at customer premises requires higher bandwidth technologies. Many vendors are developing solutions to meet the rapidly evolving market needs.

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Appendix A
Metering Communications

This section associates meter and communication technologies through matrices. A meter versus communications technology matrix is presented, followed by a "technology" versus features matrix.

Meter and Communications Matrix

This matrix identifies meters (i.e., metrology devices) and communications technology options available for those meters. A check within the matrix indicates the meters (rows) for which the communications technologies (columns) have been integrated.

Meter Technology		Communication Technology Options									
Manufacturer	Model	Itron	Aclara	Hunt	Cellnet	Cannon	Elster	Sensus	Smart-Synch	Silver-Spring	Trilliant
AMPY	Type 5211	AMPY has their own PLC communications									
Echelon	EM-502xx-ANSI	Echelon has their own PLC communications									
Elster	AB1	ERT	EMT	TS1, TS2	X						
	REX						Energy Axis				
	REX2-EA						Energy Axis				
	ALPHA Plus				X						
	A3 ALPHA	50ESS ERT	UMT-C-A3		X		Energy Axis		SSI		
	ABS	ERT	EMT	TS1, TS2	X						
GE	kV				X						
	kV2				X						
	kV2c	53ESS ERT	UMT-C	TS1, TS2	UtiliNet				SSI	Power-Point	
	kV2c+	53ESS ERT									Cell-Reader
	I-210	52ESS ERT	EMT-3G	TS1							
	I-210+		UMT-R						NIC		
	I-70			TS1, TS2							
Itron	CENTRON	R300, HP	EMT	TS1, TS2	X	MCT-410cL			SSI		
	CENTRON Polyphase	R300									
	CENTRON OpenWay	OpenWay									
	SENTINEL	R300	CMT		X				SSI		Cell-Reader
Landis+Gyr	DEMX	Sensus TouchRead									
	OMRMX	Genesis									
	DCSIMX		IMT								
	HuntMX			TS1, TS2							
	CellnetMX				BAMM						
	ALTIMUS		EMT								
	FOCUS		EMT, UMT	TS1, TS2, StatSignal	Inter-leave			FlexNet			
	S4		CMT	TS2, StatSignal	X			FlexNet			
Sensus	iCON	51ESS ERT		TS2	X	MCT-410		FlexNet, RadioRead			

Technology and Features Matrix

This matrix shows a relative comparison of metering and communications technologies with respect to features such as cost, memory, remote firmware upgrades, number of registers (values), integrated disconnect devices and HAN support.

Meter Technology		Features					
Manufacturer	Model	Expansion	Technology	Firmware	Disconnect	HAN	Memory (Expanded)
AMPY	Type 5211		Solid-state	ANSI			
Echelon	EM-502xx-ANSI		Solid-state	ANSI	200A		
Elster	AB1	module	Electro-mechanical				
	REX		Solid-state	ANSI			
	REX2-EA		Solid-state	ANSI	200A	ZigBee	
	ALPHA Plus		Solid-state				
	A3 ALPHA		Solid-state	ANSI			40kB (1MB)
	ABS	module	Electro-mechanical				
GE	kV		Electro-mechanical				
	kV2		Solid-state	ANSI			
	kV2c		Solid-state	ANSI			
	kV2c+		Solid-state	ANSI			
	I-210		Solid-state	ANSI			
	I-210+		Solid-state	ANSI	200A		
	I-70		Electro-mechanical				
Itron	CENTRON	board	Solid-state				
	CENTRON Polyphase	board	Solid-state	ANSI			
	CENTRON OpenWay	board	Solid-state	ANSI	200A	ZigBee	
	SENTINEL	board	Solid-state	ANSI			
Landis+Gyr	DEMX	module	Electro-mechanical				
	OMRMX	module	Electro-mechanical				
	DCSIMX	module	Electro-mechanical				
	HuntMX	module	Electro-mechanical				
	CellnetMX	module	Electro-mechanical				
	ALTIMUS		Solid-state	ANSI	200A		
	FOCUS		Solid-state	ANSI	200A		
	S4		Solid-state				
Sensus	iCON		Solid-state	ANSI			

Appendix B
Vendor Web links

Power Line Carrier (PLC) Vendors

Cannon Technologies: http://www.cannontech.com/

Comverge: http://www.comverge.com/

DCSI: http://www.twacs.com/

Hunt: http://www.hunttechnologies.com/

Broadband Over Power Line (BPL) Vendors

Ambient Corporation: http://www.ambientcorp.com/

Amperion, Inc.: http://www.amperion.com/

Corinex Communications Group: http://www.corinex.com/

Current Technologies Group: http://www.currenttechnologies.com/

MainNet: http://www.mainnet-plc.com/

Radio Frequency (RF) Vendors

Cellnet Technology, Inc.: http://www.cellnet.com/

Datamatic, Inc.: http://www.datamatic.com/

EKA Systems: http://www.ekasystems.com/

Grid Net: http://www.grid-net.com/

Itron, Inc.: http://www.itron.com/

SensusMetering: http://www.sensus.com/

Silver Spring Networks: http://www.silverspringnetworks.com/

SmartSynch: http://www.smartsynch.com/

Tantalus: http://www.tantalus.com/

Trilliant Networks: http://www.trilliantnetworks.com/

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