



Smart Grid Plan for the Public Utility Commission of Oregon

Smart Grid Team

October 2011

© 2011 Idaho Power

TABLE OF CONTENTS

Table of Contents	i
List of Figures	iii
List of Appendices	iii
I. Executive Summary	1
II. Introduction	3
A. American Reinvestment and Recovery Act Smart Grid Investment Grant	3
B. Beyond the grant	3
III. Current Smart Grid Investments	4
A. Customer Information and Energy Management	4
Advanced Metering Infrastructure	4
Meter Data Management System	4
Meter Data Warehouse	5
Energy Use Advising Tool	5
Direct Load Control	5
A/C Cool Credit	5
Irrigation Load Control	6
Irrigation Peak Rewards	6
FlexPeak Management	6
B. Operations Control, Measurement, and Monitoring	7
Transmission Situational Awareness Project	7
Renewable Integration Tools	7
C. Communications and Supporting Systems	7
Substation communications	7
Advanced Metering Infrastructure	7
Transmission Situational Awareness	8
Information Technology	8
Customer Information System Replacement	8

Outage Management System Replacement	8
Enterprise Data Warehouse.....	8
D. Customer Outreach and Education	8
General Customer Outreach and Education.....	8
Overview	8
Events	9
Communications	9
Electric Vehicles	9
Summary	9
E. Privacy	9
F. Cyber Security	10
Smart Grid Plans that do not Conform to Standards.....	10
G. Interoperability Standards	11
Systems Integration and Interoperability	11
Legacy System Integration into the Smart Grid	11
Interoperability Roadmap	11
Interoperability within Back-Office (IT) Systems.....	11
Interoperability between IT and Operations	12
IV. Smart Grid Planning Organization	13
A. Planning and Development Responsibilities.....	13
B. Ensuring Consistency between Assessing Smart Grid Investments and Integrated Resource Planning.....	15
V. Smart Grid Plans under Consideration: Three to Five Years.....	15
A. Evaluations of Potential Investments.....	15
Dynamic Line Rating.....	15
Fiber in the Substation (IEC 61850)	15
B. Customer Relationship Management	16
VI. Smart Grid Evaluations and Decisions	16
A. Distribution Automation	16

Self-Healing Network	16
Distribution Management System.....	17
B. Home Energy Network.....	17
VII. Conclusion.....	18

LIST OF FIGURES

Figure 1	
SGIG objectives	2
Figure 2	
Use of CIM model (IEC 61968) to enable interoperability between IT and operations systems	12
Figure 3	
Idea processing process.....	13
Figure 4	
Smart Grid project evaluation, piloting, and deployment process	14

LIST OF APPENDICES

Appendix 1	
Idaho Power Company (IPC) Active Smart Grid Projects	19

This page left blank intentionally.

I. EXECUTIVE SUMMARY

A team of Idaho Power Company (IPC) senior managers developed a Smart Grid vision in June 2009. Those Smart Grid concepts were later developed into an application for an American Reinvestment and Recovery Act (ARRA) Smart Grid Investment Grant (SGIG). As defined by the team, the IPC Smart Grid has seven major characteristics:

1. Customer participation
2. Accommodate generation/storage
3. Enable new products/services/markets
4. Power quality
5. Optimize asset efficiency
6. Anticipate/respond to disturbances
7. Resilient operation/robustness

The Advanced Metering Infrastructure (AMI) being deployed today represents the foundation for establishing IPC's Smart Grid. The Smart Grid team also identified the following priorities:

- A major revision to the current customer information system,
- Customer communications and education,
- Remote or automated switching of distribution devices,
- Increase system capacity,
- Installation of additional distribution sensing equipment,
- Additional Information Technology (IT) and communications capabilities,
- Development of interoperability standards.

All of these priorities are addressed at some level in the SGIG project that began in 2010 and will continue until April 2013. Ten projects are currently in progress. Two projects were deferred for future consideration.



Figure 1
SGIG objectives

II. INTRODUCTION

A. American Reinvestment and Recovery Act Smart Grid Investment Grant

Idaho Power Company's (IPC) Smart Grid program represents the integration of three systems: 1) Advanced Metering Infrastructure (AMI), 2) Customer Systems, and 3) Operations Systems with functionality provided by ten interdependent projects that will move toward achieving a smart grid that is reliable, efficient, secure, and customer empowered.

IPC will implement an AMI solution that will allow customer access to smart meter information and programs enabled by the smart grid, as well as modernize the electric transmission and distribution (T&D) infrastructure. The projects will accomplish the following:

- Implement smart meters throughout IPC's service area
- Increase customer access to energy-usage information
 - Enable time-variant pricing (TVP) options via interval meter data (initially in Idaho only)
 - Enable customers to access usage information gained via smart meters
 - Allow customers to make informed choices regarding energy consumption
- Implement a customer information system (CIS) and enterprise data warehouse (EDW)
 - Enable TVP options throughout IPC's service area
 - Help customers interpret energy use and find programs and options to reduce use and cost
 - Implement an interface with the outage management system (OMS) that communicates with the AMI to determine the extent of outages and validate service restoration
- Improve electrical infrastructure
 - Add transmission system tools that enhance reliability
 - Install Renewable Integration Tools (RIT) that allow efficient integration of wind generation
 - Investigate a Self-Healing Network (SHN)

B. Beyond the grant

There are two projects proposed for the 2012 capital budget that are not part of the American Reinvestment and Recovery Act (ARRA) grant. More information can be found in VI. Smart Grid Plans under Consideration.

III. CURRENT SMART GRID INVESTMENTS

A. Customer Information and Energy Management

Advanced Metering Infrastructure

The scope of the AMI project entails transitioning from traditional meters to smart meters, installing Aclara's powerline carrier (PLC) Two-Way Automated Communication System (TWACS®), installing broadband communications from substation to the Information Technology (IT) data center, and upgrading Itron, Inc.'s Meter Data Management System (MDMS). IPC has backhaul communications in place for 445,000 customer meters, with 405,000 AMI meters installed. IPC will complete the installation of meters and backhaul communications in December 2011. There are currently a limited number of customers on voluntary time-variant rates, based on hourly energy consumption data. The objectives of this growing infrastructure are to collect hourly energy consumption data from all retail service endpoints; implement data collection and billing from the automated system; reduce operational and maintenance costs; and provide the base for expansion of time-variant rates, enhancement of outage management and restoration processes, and expansion of demand-side management (DSM) programs through the use of TWACS backhaul communications.

As of August 31, 2011, IPC has deployed Aclara's TWACS AMI system for 90 percent of IPC's metered retail customers. TWACS Substation Control Equipment (SCE) is installed in 132 distribution substations, enabling two-way communications with 448,289 smart meters installed on IPC's electrical distribution system. TWACS is currently collecting hourly energy consumption data and, daily kilowatt-hour (kWh) and kilowatt (kW) readings for all smart meters deployed in Idaho and Oregon.

IPC will complete the deployment of TWACS AMI in December 2011, deploying TWACS SCE equipment in an additional seven substations and installing 47,700 more smart meters. Once completed, the AMI system will provide two-way communications to 99 percent of IPC's metered retail service customers. The remaining 1 percent of retail service customers did not meet IPC's business case requirements at the time the implementation plan was initiated.

In the next few years, IPC plans to evaluate potential AMI solutions for the remaining 1 percent of IPC's retail service customers. In addition, IPC will evaluate the targeted use of remote connect/disconnect switches using the TWACS system. Finally, IPC plans to integrate the AMI system with a new outage management system that is currently in development.

Meter Data Management System

IPC has implemented the Itron Enterprise Edition (IEE 7.0) MDMS. IPC is collecting hourly energy consumption data and daily kWh and kW data from all AMI/smart meters on a daily schedule. The system validates the data, estimates the profile for any missing hourly data, and allows for manual editing. The system also processes data for billing, including the calculations for time-variant rates from hourly consumption data.

In the near future IPC plans to integrate the MDMS with a OMS currently in development.

Meter Data Warehouse

The Meter Data Warehouse (MDW) will create an analytic database to store meter data. The MDW will be a subset of an EDW that will provide data for presentation and analytic needs that are not directly related to the operational processes of the source systems. The project will remove connections to the production MDMS system to reduce performance impacts and will eliminate copies of meter data in other departments.

IPC is currently using the IEE production data base to provide customers with smart-meter access to their hourly energy use data through a secure website. The data access is limited to the most recent 65 days of data to limit the burden on the IEE 7.0 production system. In October 2011, IPC will implement the first phase of a separate MDW, relieve the burden on the IEE 7.0 production system, and enable customers to access more of their historic energy-consumption data. This MDW will support the upgrade of IPC's Energy Use Advisory Tools (EUAT).

Other than possible expansion of reporting and analytics, no additional investments in the data warehouse are planned.

Energy Use Advising Tool

The main component of EUAT is Aclara's Energy Prism[®] application with several modules. The first module is the Customer Bill Prism tool to allow customers access to their detailed AMI usage information via the Web. The tool provides customers with up-to-date energy usage information that supports better-informed decisions about energy usage and its financial impacts. The second module is the Customer Service Representative (CSR) Bill Prism tool which provides CSRs the ability to access the detailed AMI usage information for each customer. There is up to a two-day lag due to the data-validation process.

Direct Load Control

A/C Cool Credit

A/C Cool Credit is a voluntary, dispatchable demand response program for residential customers. Using communication hardware and software, IPC cycles participants' central air conditioners (A/C) or heat pumps on and off via a direct-load control device installed on the A/C unit. Participants receive a monthly monetary incentive for participating in the program during the summer season. This program enables IPC to reduce system peaking requirements during times when summer peak load is high.

Individual radio-controlled or PLC switches are installed on customers' A/C units. These switches allow IPC to cycle customers' A/Cs during a cycling event. As IPC's smart meter project expands across its service area, newly installed switches will be PLC switches which will allow broader participation. Any radio-controlled switches that need replaced will be replaced with the PLC switch. Under this program, IPC may cycle participants' A/Cs for up to 40 hours each month in June, July, and August; and participants receive a \$7 per-month credit on their

IPC bill during July, August, and September. Under IPC's A/C Cool Credit program, there are 24,670 radio-controlled and 13,725 PLC switches installed on customers' A/C units.

Irrigation Load Control

The objective of the Irrigation Load Control (ILC) project is to use grid-enabled communication to activate load control devices on agricultural irrigation service locations for the purpose of turning off irrigation pumps during times of peak power usage. IPC presently uses cell phone and Web-based technology, as well as simple timers, as the basis for the company's Irrigation Peak Rewards Program. Using grid-enabled communication would provide a more secure and reliable environment for communication.

Irrigation Peak Rewards

IPC's Irrigation Peak Rewards program is a voluntary program available to all Idaho and Oregon agricultural irrigation customers. The purpose of the program is to produce a decrease in the company's system summer peak by turning off specified irrigation pumps with the use of one or more load-control devices during the program season June 15 through August 15.

Participants chose between three options: 1) the electric timer option; 2) an automatic dispatch option that allows IPC to remotely turn participants' pumps off; or 3) a manual dispatch option designed for large-service locations with 1,000 horsepower (hp) or greater that allows participating customers, after being notified by IPC, to choose which pumps to manually turn off during summer peak hours. For customers participating in the dispatch options, load-control events could occur up to 4 hours per day, up to 15 hours per week, but no more than 60 hours per season. Dispatchable load-control events could happen between 1:00 p.m. and 9:00 p.m. on weekdays and Saturdays. A control device attached to the customer's individual pump electrical panels allows IPC to remotely control the pumps. In 2011, IPC had 2,344 service points participating, accounting for approximately 323 MW of load reduction. The majority of installed devices use cell-phone technology to control participants' pumps; however in 2011, the company had 58 PLC devices installed using the AMI system.

FlexPeak Management

FlexPeak Management is a voluntary demand response program targeting IPC's industrial and large commercial customers that are capable of reducing their electrical energy loads for short periods during summer peak days. The program objective is to reduce the demand on IPC's system during peak times through customers' voluntary electrical-use reduction. IPC contracts with a third party, EnerNOC, Inc., to help implement and facilitate the program. EnerNOC, Inc., is responsible for developing and implementing all marketing plans, securing all participants, installing and maintaining all equipment behind IPC's meter used to reduce demand, tracking participation, and reporting results to IPC. IPC initiates demand response events by notifying EnerNOC, Inc., who then supplies the requested load reduction to the IPC system. Customers enroll in the program by entering into a contract with EnerNOC, Inc. Then, EnerNOC, Inc., installs energy monitoring equipment at the customer site and enrolls the facility in the program.

Contractually, EnerNOC, Inc., has agreed to a target annual demand reduction amount for the five-year contract length. Each week, EnerNOC, Inc., commits a demand reduction level in MWs to IPC that EnerNOC, Inc., is obligated to meet in a demand reduction event. When IPC

anticipates the need for capacity, it schedules the date and time of the event and notifies EnerNOC, Inc. IPC has access to an EnerNOC, Inc., website that shows near real-time energy usage data of the aggregated load and can continually monitor the success of the demand reduction event. Customers can also continuously monitor their demand-reduction performance using their individual near real-time energy usage data available to them through the EnerNOC, Inc., website. The program is active June 1 to August 31, between the hours of 2:00 p.m. to 8:00 p.m. on non-holiday weekdays. Customers receive notification of a demand reduction event two hours prior to the start of the event, and events will last anywhere between two to four hours, with a maximum of 60 hours per season.

B. Operations Control, Measurement, and Monitoring

Transmission Situational Awareness Project

The Transmission Situational Awareness (TSA) project will enable Phasor Measurement Unit (PMU) data availability from system grid-level substation buses operating above 200 kilovolt (kV) to be sent to a central phasor data concentrator located in Boise, Idaho. Data from the company's PMUs will be combined with data from regional PMUs to provide extensive coverage of IPC's backbone transmission grid and information for the regional grid transmission system. IPC will send PMU data to the Energy Management System (EMS) system and system-state estimator, along with proper dispatch and planning data displays. The PMU installation will enhance IPC and regional electric-grid situational awareness, operations, system protection, and system efficiency and reliability.

The first phase of the project will install and enable hardware to measure the synchronized phasor information. Digital communication infrastructure will be added at three locations to provide PMU data transport capabilities, along with communication circuits to PMUs. The PMU data concentration and archive system will be designed to process and store the PMU data.

Renewable Integration Tools

As larger amounts of wind and other various variable renewable sources are developed and integrated into the grid, the task of continuously balancing electricity supply and demand becomes more challenging. The RIT project will develop a Wind Generation Megawatt (MW) Forecasting Tool, improve the existing load forecast, and ultimately provide better situational awareness to the grid operators and wholesale electricity marketers to allow them to efficiently and reliably integrate variable renewable resources with traditional generation resources.

C. Communications and Supporting Systems

Substation communications

Advanced Metering Infrastructure

IPC communicates with each of its AMI meters with powerline carrier technology. This technology has a narrow bandwidth and it allows IPC to collect the customers hourly meter data, reset demand, and operate limited demand response devices, i.e. on/off switches for air

conditioner compressors. For the majority of the substations, commercial third-party broadband communications was installed from the substation to the IT data center for backhaul communications.

Transmission Situational Awareness

High-speed, high-bandwidth digital communications from the substations to IPC's Grid Operations Center and Western Electrical Coordinating Council (WECC) were installed to meet data transfer requirements of the synchrophasor units.

Information Technology

Customer Information System Replacement

Implementation of the CIS will enable smart-grid functionality for dynamic and TVP capabilities and interoperability through its open systems architecture. Using middleware technology, the new CIS will be integrated with the AMI system, the other customer systems, and the OMS. Implementation of the CIS will enable IPC to offer TVP to all residential customers, instead of a limited number of customers as is the case with the current CIS. Peak demand is expected to be measurably reduced as a result of customers participating in TVP programs.

Outage Management System Replacement

The OMS will enable a direct interface to the customer's meter to validate outage scope and restoration. Through the OMS application, OMS operators will query specific meters in suspected outage areas. The OMS application will provide outage data presentation through direct communications with AMI meters, verify the scope of customer-reported outages, and provide confirmation of power restoration. Verification of an outage prior to dispatching resources to repair the outage will allow the repair crew to be more efficient in terms of customer-restoration times, and confirming restoration will eliminate the chance of repair crews leaving the area before service is restored to all customers.

Enterprise Data Warehouse

The EDW project will create an analytic database to store meter and customer data. The EDW will provide data for presentation and analytic needs that are not directly related to the operational processes of the source systems. The smart-grid phases of the project will provide a data repository for customer and meter data for reporting and analytics.

D. Customer Outreach and Education

General Customer Outreach and Education

Overview

Over the past five years, IPC has provided residential and small commercial customers self-service options at www.idahopower.com. The self-service options help customers learn about energy, how they are using it, and how they can save money on their monthly bills. This technology gives customers the ability to view their meter data with additional energy tools and analytics technology. AMI-/smart meter-supported rate classes can also view their meter

data at www.idahopower.com and use self-service features and information 24 hours a day, 7 days a week.

Starting mid-December 2011, IPC employees will have the ability to answer residential and small commercial customers' questions about detailed energy usage provided the customer have the AMI, smart metering infrastructure. This specific data is available for TVP rate structure (residential), while using features in the CSR tool, the Meter Highlights tool (with bill-to-date functionality), and the Rate Comparison tool for residential customers. The CSR tool will allow authorized, internal employees to see the same data as the Internet self-serve customer.

Events

The company participates in numerous home and garden shows, energy fairs, parade of homes and other public events. At these events, IPC employees cover a wide range of information and answer customer questions. The company also promotes www.idahopower.com, using the Account Manager tool to learn more about using energy, tips and ideas to save energy, energy efficiency program information, information about smart meters, payment options, and general company information.

Communications

IPC communicates frequently with customers through a variety of channels, including but not limited to billing statements, bill messages, bill inserts, *Customer Connection* articles, customer letters, doorknockers, postcards, brochures, Web content at www.idahopower.com, hold messaging on IPC's 1-800-488-6151, social media using Facebook, public events, customer visits, etc.

Electric Vehicles

IPC customer representatives are meeting with auto dealerships about electric vehicles. The purpose of these visits is to establish a point of contact, build a relationship, gather information, and identify partnership opportunities with IPC's mutual customers on the best ways to use electricity.

Summary

Through events and different communication channels, customers are provided relevant information on a frequent basis about energy efficiency, company and program information, and updates about smart metering. IPC also sends a new customer welcome letter inviting customers to visit www.idahopower.com to learn more about their energy usage and to register as account managers.

E. Privacy

IPC is committed to protecting the company's systems and the data within them as stated in IPC's *Corporate Security Policy* and evidenced by the company's Corporate Security program. For confidential data, such as customer information and energy usage data, IPC limits access using a need-to-know approach enforced by role-based access controls for employees and

contractors. The policies and controls undergo periodic reviews to ensure they support applicable mandates and guidance.

IPC recognizes new risks are emerging from smart-grid technologies, both from the increase in data and the increasing interconnectivity of systems. To stay current on these, IPC has joined collaborative public-private partnerships such as the National Institute of Standards and Technology Smart Grid Interoperability Panel Cyber Security Working Group (NIST SGIP CSWG).

IPC customers can access their energy usage data electronically via a registered and password protected login (account manager) on IPC's website. Customers can also request for IPC to provide hard-copy usage information via fax, email, or mail.

IPC can only provide customer usage data to entities other than the customer under the following conditions:

- Receipt by IPC of a court-ordered subpoena
- Presentation by a third party of legal documentation substantiating power of attorney for the customer of record
- Receipt by IPC of written authorization from the customer of record identifying the third party to whom information is to be released and specifying the information to be released
- Notification by a public utility commission that the customer of record has filed a complaint

In addition to the above conditions, under which information for an individual customer may be provided, IPC has several contractual business relationships with third parties for the procurement of services essential to the operation of the business (e.g., bill print services).

F. Cyber Security

IPC recognizes new risks are emerging from smart-grid technologies, both from the increase in data and the increasing interconnectivity of systems. To stay current on these, IPC has increased its participation beyond industry-specific groups, such as North American Electric Reliability Corporation (NERC) and has joined collaborative public-private partnerships, such as the NIST SGIP CSWG.

IPC is committed to protecting Company data and systems as evidenced by a strong *Corporate Security Policy* and Corporate Security program. For confidential data, such as customer-related information, IPC limits access using a need-to-know approach enforced by role-based access controls. The policies and controls undergo periodic reviews to ensure they support applicable mandates and guidance.

Smart Grid Plans that do not Conform to Standards

There are no Smart Grid projects or plans that do not conform to IPC security standards.

G. Interoperability Standards

Systems Integration and Interoperability

The large-scale adoption of smart-grid technology brings a renewed focus within IPC on interoperability between all utility systems. IPC will ensure new smart-grid technologies work with existing systems through continued use of industry communication standards and technologies and IPC's own integration expertise. IPC will continue to use system life-cycle management and system methodology for interface identification, specification, design, testing, and implementation to ensure system interoperability. IPC will ensure information exchanges involving automated-component interfaces and existing infrastructure meet all cyber security standards and operate using industry-standard protocols.

Legacy System Integration into the Smart Grid

An important aspect of the NIST Roadmap is the integration of systems. The IPC Smart Grid will be a system-of-systems. As such, using open-industry standard protocols at the automated-component interface points is critical to reliable operation and integration of present and future smart grid technologies.

The manufacturer of IPC's AMI participates in efforts by NIST, the Electric Power Research Institute (EPRI), and other standards agencies to develop the Smart Interoperability Roadmap.

Interoperability Roadmap

The new smart-grid standards will be incorporated within Operations as those standards emerge and are adopted by multiple equipment manufacturers. IPC will integrate adequately performing legacy systems into the enterprise environment, whenever such automated component interfaces are practical and appropriate. When legacy systems cannot be incorporated, new equipment featuring automated-component interfaces that meet all present communication and security standards will be installed. Continued use of industry-standard protocols at automated-component interfaces will limit the stranding of legacy assets already deployed in the field. Non-standard automated-component interfaces, communication protocols, and systems will be converted to enterprise-standard interfaces as new equipment becomes available. Using industry-standard communication systems and protocols ensures that several equipment manufacturers may be used without interoperability problems.

Interoperability within Back-Office (IT) Systems

The interoperability of IT systems at IPC is based on open standard application programming interfaces (APIs) such as XML and Web Services, which enable ease of integration to IPC's other applications and to the external web. The architecture enables very flexible interoperability within the intended IPC Smart Grid-enabled applications like the OMS, EDW, Customer Relationship and Billing System (CR&B), AMI systems, and IPC's website.

IPC is currently implementing a Service-Oriented Architecture (SOA) using TIBCO® integration technologies, including an Enterprise Service Bus (ESB). The ESB will be the backbone for most

IT smart grid applications and systems, and will provide true interoperability between the new IT and Operations applications. By loosely coupling these systems using the ESB and employing Web services for integration, IPC will achieve a higher level of agility as new applications and systems emerge as smart-grid technology evolves. In addition, the EDW will improve IT system interoperability by enforcing a common data model across systems for analytics use. This will lead to improved data accuracy and alignment throughout the company. As with Operations, a key component of IT system interoperability is the adoption of standards, such as the Common Information Model (CIM) for utilities. The ESB extends off-the-shelf Enterprise Application Integration (EAI) middleware with utility-specific extensions for support of distributed power system models and standards-based API using XML messaging per the IEC61970 and IEC61968 standards. The ESB and CIM enable IPC to build a flexible, model-driven architecture for application integration and data warehousing to leverage existing power-system-related application investments.

Interoperability between IT and Operations

IT and Operations refined their methods to become substantially different architectures provided by different classes of vendors. AMI and the smart grid programs are now driving a technological convergence of IT and Operations. Operations systems are starting to have IT architectures, with all the benefits and complications that come with that change. Additionally, most smart grid performance-improvement projects are joint activities that require IT and Operations to be closely aligned. An example of this is the requirement to closely integrate the AMI and the interval meter data it provides (an Operations system) with the CR&B system (an IT system) in order to provide billing services for IPC customers.

The interchange of data cannot be inhibited by vendor-specific implementations. Data integrations must leverage industry-standard communication models to ensure interoperability and smart grid system integrity. Within Operations, IPC uses standard communication protocols, such as the NIST Smart Grid Roadmap, DNP-3 (Supervisory Control and Data Acquisition [SCADA] systems), and IEC-61968 (distribution management systems). Substation data and control systems may use IEC-61850 (substation automation). Data transfers may use CIM and other approved standards. Currently within IT, IPC uses point-to-point integrations based upon XML and other open-standards-based protocols. IPC is implementing SOA to enable further adoption of service-enabled interoperability via EMD models, such as the CIM model, and others shown in Figure 2.

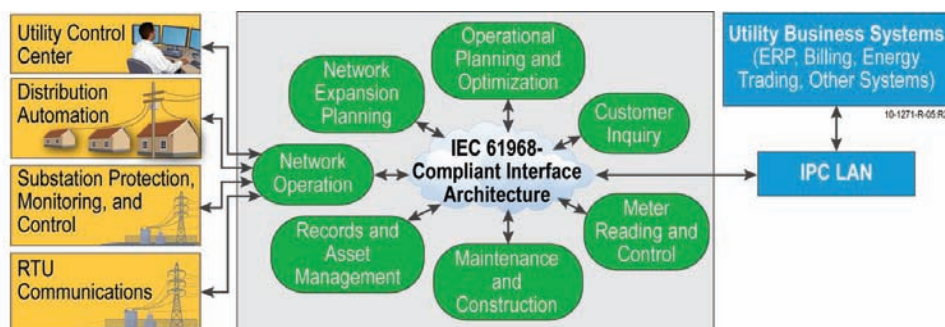


Figure 2

Use of CIM model (IEC 61968) to enable interoperability between IT and operations systems

IPC will employ its Enterprise Architecture (EA) Program, IT Infrastructure Library (ITIL) Change Management, Project Management Office, and Project Management standards and best practices to ensure interoperability standards mentioned will be leveraged to the fullest. IPC is a member of the CIM User Group and will continue to adopt emerging improvements to CIM and NIST standards.

IV. SMART GRID PLANNING ORGANIZATION

A. Planning and Development Responsibilities

The Research, Development and Deployment department (RD&D) is responsible for the assessment of new grid technologies, including smart grid opportunities. The RD&D Engineering project leaders are responsible for tracking industry technologies, evaluating technologies, managing technology pilots, and assessing pilot-project outcomes. The leaders plan the utility-wide deployment of successful technologies and submit these plans for capital funding. Smart-grid technologies are collected and evaluated with all other ideas. The high-level process is shown in Figure 3.

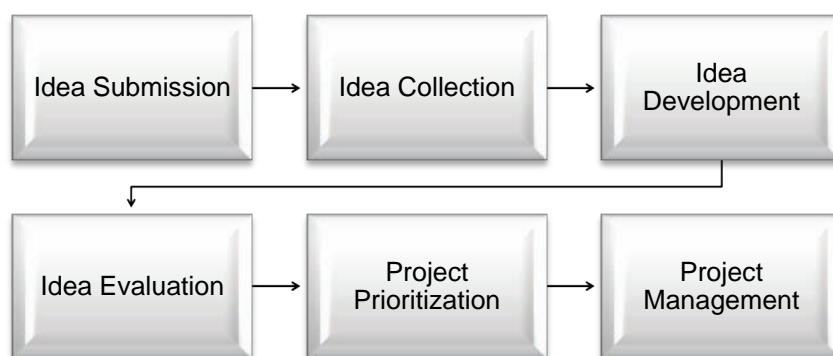


Figure 3
Idea processing

Smart Grid ideas are analyzed to determine if they solve an existing problem or improve efficiency. The RD&D leaders also develop smart-grid ideas into a deployable pilot project and evaluate the cost benefit of the project. The pilot project is submitted to a review team to ensure all aspects of the project have been included in the initial design and evaluate external impacts of the project (e.g., communication infrastructure and operating capabilities). The project is then evaluated for funding against all other projects. Once the pilot project is funded and deployed, it is evaluated against the projected costs and proposed benefits determined in the initial evaluation stage. If the pilot project meets the expectations, then a project plan is developed for utility wide deployment and submitted for funding. This process is shown in Figure 4.

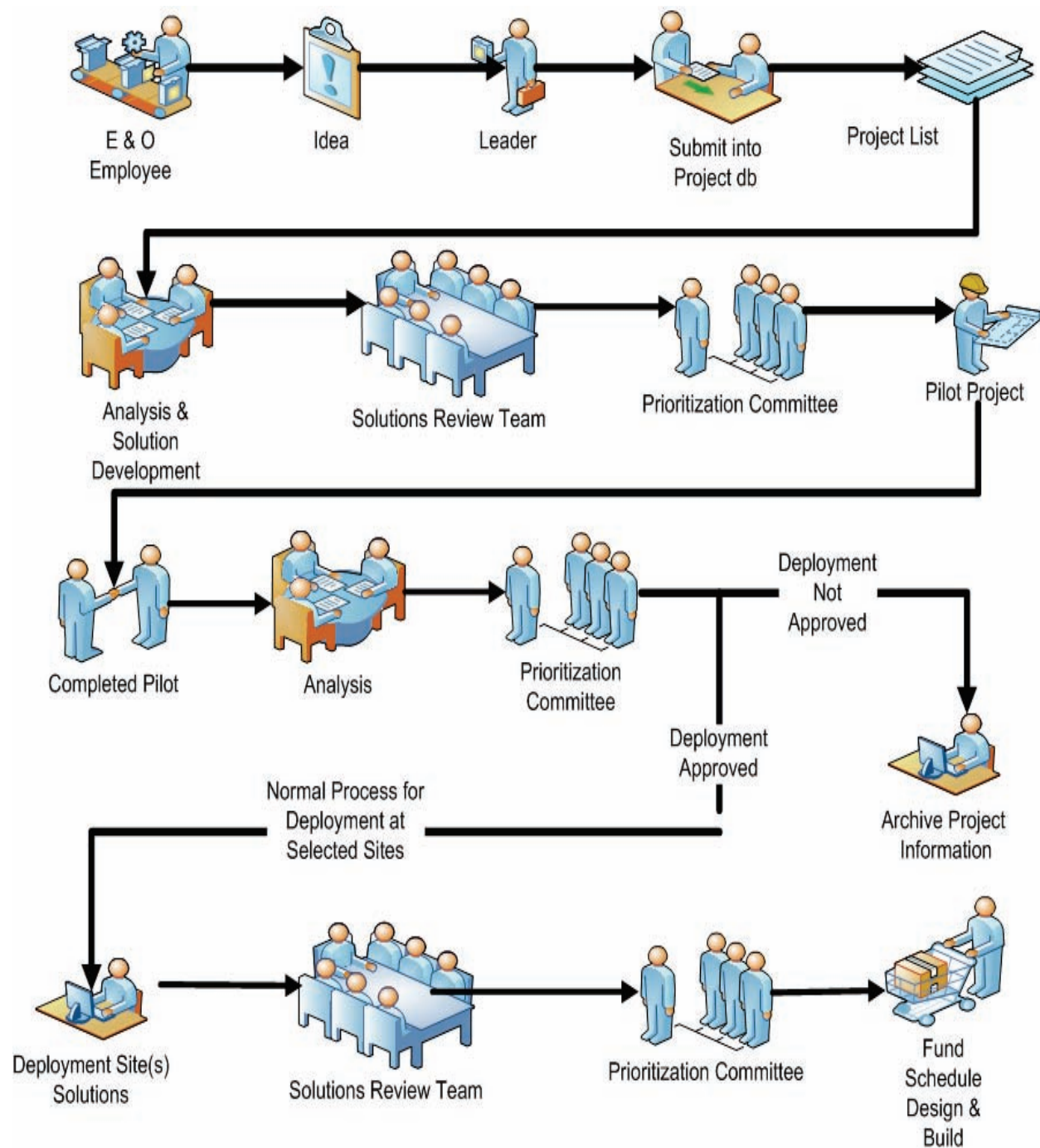


Figure 4
Smart Grid project evaluation, piloting, and deployment process

B. Ensuring Consistency between Assessing Smart Grid Investments and Integrated Resource Planning

IPC has integrated the capital budget and approval process for the Operations business unit which includes the production, power supply, delivery, and T&D of energy. The capital funding of power supply resources and Smart Grid projects are evaluated using common criteria.

V. SMART GRID PLANS UNDER CONSIDERATION: THREE TO FIVE YEARS

A. Evaluations of Potential Investments

Dynamic Line Rating

IPC is working with the Idaho National Laboratory (INL) and Boise State University to develop a meteorological-based, dynamic-line rating system. With this system, meteorological sensors are installed at various intervals along a transmission line or transmission corridor to measure meteorological conditions. This information is then fed into a software model where the conditions at all points along a line can be calculated. This information, when used with the current load information, can then be used to calculate a dynamic-line load limit. The objective is to increase the line rating 20 percent above the present static line rating.

A pilot Dynamic Line Rating (DLR) project has been monitoring three lines in southern Idaho for approximately one year. The RD&D department has submitted a three-year DLR project to deploy the system to several of IPC transmission paths. This deployment project has been recommended for capital funding in 2012 and is awaiting final 2012 budget approval.

Fiber in the Substation (IEC 61850)

IPC has been researching the future of communications within the substation. Although present communications already employ intelligent communication protocols to Intelligent Electronic Devices (IED), additional efficiencies can be had by implementing a standard platform for designing, implementing, and operating substation-automation systems. IEC 61850 is such a standard. IPC is working with vendors to pilot an IEC 61850 project. Benefits of IEC 61850 include a more modern approach to communications and substation networks. For instance, most of the copper wire to substation equipment and components can be replaced with fiber-optic cable. This alone can constitute a substantial savings in the construction of a large substation. Additionally, although IEC 61850 is focused on substation automation systems, it also provides network options to traditional SCADA applications, high-speed protection, and analog wave form data. IEC 61850 is based on more modern information technology concepts and features which can lead to faster design, configuration, and implementation. It will also allow easier access to substation data while maintaining a more secure and reliable system.

The RD&D department has submitted a project to pilot the IEC 61850 system at an IPC substation. This pilot project has been recommended for capital funding in 2012 and is awaiting final 2012 budget approval.

B. Customer Relationship Management

A Customer Relationship Management (CRM) system will allow IPC to manage and track customer interactions related to Energy Efficiency and Customer Relations with the ultimate goal of increasing the effectiveness of IPC's energy efficiency efforts.

In addition to supporting energy efficiency marketing campaigns, the system should support the customer engagement for those campaigns. This customer engagement could be through a mix of push channels (direct mail, email, Web, etc.) or through direct-customer interaction (the customer service center or a field representative at a customer's location).

Ultimately, this solution will allow the company to better interact with customers, meet customer needs, and accelerate program participation.

VI. SMART GRID EVALUATIONS AND DECISIONS

A. Distribution Automation

Self-Healing Network

IPC investigated the creation of a SHN. Existing manual distribution tie switches would be replaced with smart switches.. The original project proposal included the following attributes:

- Additional smart switches to divide circuits into sections serving about 500 customers
- Digital control and data for each switch to accumulate at the substation level using hard-wire, fiber, and secured-radio systems.
- At the distribution substation level, distribution circuits equipped with microprocessor control, protection, and data systems
- Data from the distribution equipment and the substations to be combined in a control computer that will monitor all load levels and distribution configurations and supply the intelligence for determining equipment commands that will implement the SHN
- Data and operational information sent to the EMS using broadband communications
- Dispatcher interface to be integrated into the EMS system. Dispatchers to have normal control capabilities, including the ability to override the SHN automatic functions

After extensive research and analysis of existing SHN tools and the project area, the team determined that IPC would not achieve significant reliability gains with this project at this time. Budget constraints on the IPC Smart Grid Project caused the deferral of this project until it can be prioritized and funded

In addition to the SHN project, upgrades to digital relaying systems were proposed for some existing subtransmission (69 and 46 kV) and feeders relaying systems. In several areas that are served by an extended subtransmission system, over 50 percent of customer outages are due to failures in the supplying subtransmission system. This project intended to include the following:

- Install line switches with microprocessor-based protection, control, and telemetry at the sub-transmission level to develop a near-self-healing, sub-transmission system.
- Install smart-line switches with smart-station switches to implement auto restoration and reduce the size of subtransmission-caused customer outages. IPC anticipated a 30–70 percent improvement for customers supplied by a System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI).
- Distribution substations in high load-density areas that are candidates for an SHN to be equipped with microprocessor-based protection, control, and telemetry systems to prepare the system for self-healing and other enhanced-reliability operation.
- Limited pilot project to be equip three substations with the new systems.
- As the SHN expands, additional substations will be equipped to support the self-healing concept. In addition, 100 line-recloser controllers will be installed with microprocessor-based controllers; these smart controllers will allow remote arming of the recloser for fuse-saving in storm situations. The data will be used to determine fault characteristics, and reduced outage restoration time.

Some of the projects outlined above may be pursued in the future; however, no wholesale upgrades of subtransmission and distribution systems will be done.

IPC will continue to develop and implement small contained areas of distribution automation as the need to improve reliability is identified in specific areas and the improvements can be justified with a strong business case.

Distribution Management System

While investigating systems that could manage the controls of a SHN, IPC became aware of the features and functionality of Distribution Management Systems (DMS). These systems are just beginning to be developed and deployed to manage the more advanced needs and requirements of a distribution system; such as volt/var control, distributed generation, etc. IPC will continue to monitor the development of these systems and determine whether a DMS would meet IPC's future needs.

B. Home Energy Network

At the present time, IPC does not plan to offer home area network (HAN) solutions for IPC's retail customers. IPC's preference is for third-party organizations to offer these in-the-home services. IPC has been monitoring this fledgling industry. The lack of interoperability standards and communications protocols greatly hinders the development of this market. It is important to note that both Google and Microsoft plan to exit this business citing slower than anticipated growth.

IPC's AMI system is a PLC-based system. The system can communicate directly to devices on the electrical system beyond the meter and independently of the meter. IPC is using IPC's AMI system for direct communication to load control transponders on customer air conditioners and irrigation pumps to facilitate IPC's demand response programs. The AMI system is capable of two-way communications with any TWACS device installed on a 240-volt, 20-amp circuits and can provide much of what could be gained by a HAN with minimal additional investment by the customer.

IPC has supported customers desiring in-home displays or energy management systems by providing pulse outputs from IPC's meter or allowing customers to attach compatible, commercially available devices to IPC's meters. Over the years the demand for this service has been very small and as IPC deployed AMI, IPC discovered customers with in-home display devices were not interested in maintaining their system post AMI deployment. They were satisfied with the AMI data available on IPC's website.

VII. CONCLUSION

IPC developed a strong internal vision for moving forward with a smart grid program. The company developed a complete vision and a process for evaluating and planning for future opportunities. IPC took advantage of the ARRA SGIG opportunity to fund many of the priorities that were identified.

IPC will continue to monitor and investigate smart grid projects and results at other utilities. As always, IPC will weigh the costs, benefits, and risks involved with any technologies under consideration in the future.

Appendix 1

Idaho Power Company (IPC) Active Smart Grid Projects

This page left blank intentionally.

ID	Task Name	Cost	Work	2010				Half 2, 2010				Half 1, 2011				Half 2, 2011				Half 1, 2012				Half 2, 2012				Half 1, 2013				Half 2, 2013																			
				M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O				
1	Idaho Power Smart Grid Investment Grant Program	\$98,270,536	33,579,348.53 hrs																																																
2	DOE Signs Idaho Power Grant	\$0	0 hrs																																																
3	Program Management Support	\$8,168,183	5,444,942.32 hrs																																																
73	Customer Systems	\$43,549,662	21,992,414.37 hrs																																																
74	Enterprise Data Warehouse (EDW)	\$5,766,359	2,401,333.2 hrs																																																
76	Customer Relationship Manager (CRM)	\$180,297	3,753.28 hrs																																																
78	SGIG - Energy Use Advising Tool (EUAT)	\$480,493	77,128.17 hrs																																																
80	Customer Information System (CIS)	\$31,080,798	19,394,546.28 hrs																																																
82	Network Management System (NMS) Upgrade v6	\$781,373	10,243.5 hrs																																																
84	Integrations	\$5,260,343	105,409.93 hrs																																																
86	Complete Customer Systems	\$0	0 hrs																																																
87	Advanced Metering Infrastructure	\$44,470,277	6,002,477.2 hrs																																																
88	Meter Data Management System (MDMS) - IEE v7 Implem	\$1,215,998	75,493.4 hrs																																																
90	Backhaul (Station) Communications	\$7,530,678	1,346,329 hrs																																																
120	Smart Meters	\$35,481,725	4,357,261.03 hrs																																																
147	Irrigation Load Control	\$241,876	223,393.77 hrs																																																
199	Complete AMI	\$0	0 hrs																																																
200	Transmission & Distribution Systems	\$2,082,415	139,514.65 hrs																																																
201	Transmission Situational Awareness (TSA)	\$1,337,416	38,772.63 hrs																																																
203	Renewable Integration Tools (RIT)	\$576,786	97,009.28 hrs																																																
205	Self Healing Network (SHN)	\$168,213	3,732.73 hrs																																																
207	Complete Transmission & Distribution Systems	\$0	0 hrs																																																
208	End of Project	\$0	0 hrs																																																

This page left blank intentionally.