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IDAHO PUBLIC
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December 30, 2005

IPC-E-02-12

Ms. Jean Jewell
Commission Secretary
Idaho Public Utilities Commission
472 West Washington Street
PO Box 83720
Boise, Idaho 83720-0074

RE: Phase One AMR Implementation Status Report

Dear Ms. Jewell:

Enclosed please find seven copies of Idaho Power's Phase One AMR Implementation Status Report. This report is filed in compliance with Idaho Public Utilities Commission Order No. 29362.

The Company has previewed the report's findings with the Commission's Staff and stands ready to follow up with further information in any manner that the Commission deems appropriate.

If you have any questions regarding this report, please direct them to Maggie Brilz at 388-2848 or me at 388-2887.

Cordially,

John R Gale

John R. Gale

JRG:ma

Phase One
AMR Implementation Status Report

Presented by Idaho Power Company
to the Idaho Public Utilities Commission

December 30, 2005

Acronyms and Definitions

Due to the technical nature of this document, many abbreviations are used throughout to enhance readability. To avoid any confusion, use the table below as a guide to the acronyms and definitions of the terms used in this report.

Acronym	Description	Definition
AMR	Advanced Meter Reading	The components necessary to read a meter remotely using technology to retrieve meter reading data through a communication network.
CAMC	Customer Account Management Center	The group of employees in the Idaho Power Customer Service Department that conduct billing and collections evaluations on customer accounts.
CIS	Customer Information System	Idaho Power's billing and customer system that contains all customer data utilized by Idaho Power employees to provide functionality for customer-related events such as billing, rates, service orders, and meter reading.
CSR	Customer Service Representative	The Customer Service Department employee titles for those employees who assist customers with service requests or inquiries. CSRs exist both in the Idaho Power Call Center and CAMC.
DCSI	Distribution Control Systems, Inc	The vendor who sells the AMR power-line-carrier system Idaho Power implemented during the Phase One project.
EMS	Energy Management System	A software system used to monitor and control switching of the distribution and transmission system at Idaho Power.
EW	Energy Watch	The Critical Peak pricing program Idaho Power implemented in the Emmett area in 2005.
IEE	Itron Enterprise Edition®	The Itron product name of the Meter Data Management System Idaho Power purchased for the Phase One project.
IPC	Idaho Power Company	
IPUC	Idaho Public Utilities Commission	
LCT	Load Control Transponder	A power-line-carrier device that can open or close a circuit at the home, allowing a utility to control devices at the premises from the TNS system.

Acronym	Description	Definition
MDMS	Meter Data Management System	A system that manages meter reading data intended to validate the accuracy and completeness of the data, and provide estimating routines to create billing quality data. The system is also intended to compile the data to billing intervals for time-of-use programs.
MVRS	Manual Meter Reading System	The software package and equipment Idaho Power purchased from Itron that facilitates the current manual meter reading process. This consists of the handheld devices that are used to collect the existing meter reading data and the software to feed the information to the CIS.
MV90	MV90	A software system purchased by Idaho Power from Itron that manages 15-minute interval data for large primary meter customers that converts pulse data to usable quantities.
MWM	Mobile Workforce Management	A project under evaluation at Idaho Power that would assign and distribute service order type work over a wireless network to field employees.
OASys	Outage Assessment System	A separate software program sold by DCSI to enable the collection of meter outputs that can indicate outage events at the meter location.
Nexus	Nexus Energy Software	A hosted internet based tool that Idaho Power contracted with Nexus Energy to provide customers with access to their hourly energy usage via the Idaho Power Website.
O&M	Operating & Maintenance	The costs associated with operating the Company after implementation of capital-related expenditures.
OMS	Outage Management System	The software system Idaho Power implemented separately from the Phase One project that is used to manage outage information, crew assignment, customer to transformer alignment in the distribution system that uses algorithms to identify and track distribution outages to control devices.
PLC	Power Line Carrier	The AMR technology used during the Phase One AMR Project that uses the electrical distribution system as the communication medium between the meter and the controlling software.
RCE	Remote Communication Equipment	The modules installed in the meters that coordinate the meter information to be communicated over the electrical distribution alternating cycle.
SCE	Substation Communication Equipment	The equipment placed in an electrical distribution substation that converts communication data from the electrical distribution alternating cycle to another type of medium that can be communicated over a network to the host servers.

Acronym	Description	Definition
TNS	TWACS® Network Server	This is the host software sold by DCSI that controls the signaling of information between the meter through power-line-carrier.
TOD	Time of Day	The Time-of-Use pricing program Idaho Power implemented in the Emmett area in 2005.
TWACS®	Two-Way Automatic Communication System	The DCSI AMR system Idaho Power installed during Phase One. The system uses power-line-carrier technology to communicate with the meter.
VEE	Validate, Estimate, Edit	A primary functional requirement of the MDMS system to validate meter data for accuracy and completeness, and provide estimates for any missing interval data. This function also provides validation of any anomalies in the data and edits the data accordingly to achieve billing quality data.
VSD	Variable Speed Drives	Customer equipment at the meter location that allows the customer to change the load of energy required to operate a piece of equipment.
XM	Extended Memory	A new meter module proposed for development for TWACS® that will have 7 days of memory.

Table of Contents

Part 1—Executive Summary

1. Project Overview

Idaho Power Company (IPC) implemented a Phase One Advanced Meter Reading (AMR) Project in 2004 and 2005 pursuant to Order No. 29362 issued by the Idaho Public Utilities Commission (IPUC). Order No. 29362 required IPC to file an AMR Phase One status report by the end of 2005.

The Phase One AMR Project consisted of the implementation and evaluation of AMR technology for approximately 23,500 customers in IPC's Emmett and McCall operating areas. The power line carrier based AMR system has operated successfully since its completed installation in November of 2004. In addition to the AMR technology and infrastructure that included the meters, substation technology, and AMR software, IPC installed a Meter Data Management System (MDMS), which is required for validating the data and providing the data for billing purposes, and an Internet-based data presentment software system, which makes usage data available to customers via the IPC Web site. Customer programs offered during the summer of 2005 included:

1. Time-variant pricing programs for residential AMR customers in the Emmett area (Time-of-Day and Energy Watch pilot programs), and
2. A/C Cool Credit program for residential AMR customers in the Emmett area utilizing the load control functionality of the AMR technology.

2. Project Scope and Exclusions

AMR was installed in IPC's Emmett and McCall operating areas. AMR installation in the Emmett operating area included the communities of Emmett, Sweet, Montour, Horseshoe Bend, Banks, Crouch, Garden Valley, Lowman, and the surrounding rural areas of each of these communities. AMR installation in the McCall operating area included the communities of McCall, Lake Fork, Donnelly, Cascade, New Meadows, Riggins, and the surrounding rural areas of each of these communities.

AMR was installed for residential, small and large general service, and irrigation customers taking service under Schedules 01, 07, 09, and 24. A total of 23,474 AMR meters were installed with 10,742 AMR meters installed in the Emmett operating area and 12,732 meters installed in the McCall operating area.

Certain exclusions were made when installing the AMR meters. These exclusions included the following: primary service level accounts, dairies, accounts with load research meters, Tamarack substation customers, and single-phase substation customers. In total, these exclusions equal approximately 650 customers.

3. Major Systems Installed

The Phase One AMR Project included the installation of three separate, but related, systems. No single system or vendor was able to provide all the functionality to meet the objective of the Phase One project. This required IPC to evaluate multiple vendors and build the necessary interfaces between systems to meet the functionality requirements.

a. TWACS® AMR Power Line Carrier System

The Two-Way Automated Communication System (TWACS®)AMR system, consisting of software and physical equipment in the field, is the meter data collection system. TWACS® uses two-way communications via power line carrier technology to retrieve meter reading data. The TWACS® system is a multi-tiered technology that uses specific TWACS® meter modules, substation equipment, a communication network, and software to operate the system. The TWACS® system was chosen as the best match for the IPC service territory to achieve mass meter coverage of the geographical areas.

The installation of the single-phase AMR meters for residential and small commercial customers was contracted to Terasen Utility Service Inc. of Milwaukee, Wisconsin. Terasen was responsible for providing the supervision and resources necessary to install the single-phase AMR meters. IPC provided meters that were purchased from Itron that included the TWACS® meter modules installed at the factory during manufacturing. Terasen conducted meter exchanges and provided data collection of exchange readings from old to new meters. Teresen also provided IPC with electronic data to enable the record keeping of the meter exchanges within IPC's systems. IPC meter technicians completed approximately 1,200 meter exchanges of Current Transformer Rated and Poly-phase applications. The TWACS® substation equipment was installed by IPC personnel. The communication infrastructure was a combination of local phone service provider equipment and IPC infrastructure. The TWACS® Network Server (TNS) software application was installed by Distribution Control Systems, Inc. (DCSI) and jointly tested with IPC.

b. Itron EE® Meter Data Management System

The TWACS® system is not designed to validate the meter data or accumulate it into time-variant billing determinants. To provide billing quality data for time-variant pricing programs requires a secondary system beyond the AMR system. The Itron EE Meter Data Management System (MDMS) was implemented in order to provide the Validating, Editing, and Estimating (VEE) function for the hourly interval consumption data retrieved by TWACS® and converting this interval data into billing data for time-variant pricing programs.

The intended system operation for MDMS is to receive hourly interval data and daily meter reading data from the TNS software. The MDMS is then intended to run the appropriate VEE routines and algorithms on each day's data. Depending on the quality of the data provided, this VEE process can take several hours each day.

For those customers on a time-variant pricing program, MDMS was intended to aggregate the interval data into the appropriate billing determinants and pass this accumulated kWh data to IPC's customer information system for customer billing. For customers not on the time-variant pricing programs, the MDMS was intended to VEE the data for customer inquiry through the Nexus Energy Software system.

c. Nexus Energy Software

Nexus Energy Software is an Internet-based software system used for data presentment in which customers can access their AMR hourly energy use data through a Web site. The Nexus Energy Software system is a vendor-hosted Web application accessible via links on Idahopower.com. Services are provided to residential and business customers with expanded options for customers with AMR meters. Information from CIS *PL*US® (IPC's current customer information system, or CIS) and MDMS is compiled and transmitted via the Internet to the Nexus Web site for customer presentation and analysis.

Figure 1 below illustrates how each of these three systems interrelates within IPC's overall AMR system:

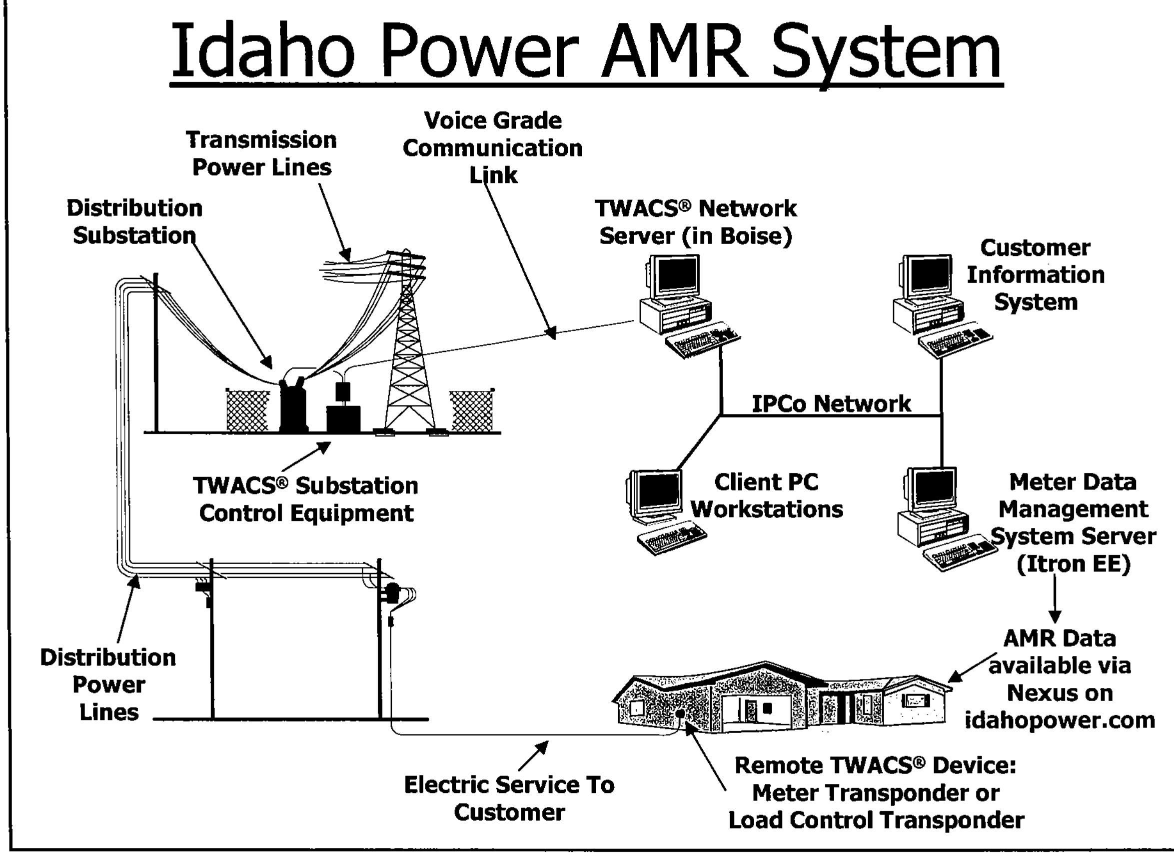


Figure 1 IPC's AMR System

4. System Performance

a. TWACS® AMR Power Line Carrier System

IPC has a near 100 percent success rate in collecting daily reads through the TWACS® system. It has an approximately 98 percent success rate in collecting hourly usage information. The meter modules used in Phase One have a 24-hour memory that is used in 8-hour blocks. Any problems with the electrical system, phone lines, software or the servers can usually be resolved in time to capture the daily readings that are stored in the meter for 24 hours. To ensure accurate data collection, it is necessary to communicate with the meter in no greater than 16 hours timeframes prior to the data being over-written in thememory. Individual meter failures or problems that cannot be fixed within 16 hours are rare, but do result in the loss of daily readings and hourly data.

The system does have limitations in its bandwidth capabilities. This limitation presently exists at the substation equipment level in which the equipment is not able to listen to multiple substation bus, feeder, and phase configurations. For the Phase One Project, IPC placed an emphasis on collecting the meter usage information at the hourly level, which required IPC to contact each meter a minimum of three times daily to obtain the information in the 8-hour time blocks. The bandwidth limitation causes concern when other services may be used on top of meter data collection, such as load control signaling or polling for outage verification, in which the communication network may become over burdened creating conflicts in functionality. IPC also upgraded its own communication network at the Crane Creek substation to enable increased communication capacity to improve reliability of data gathering.

IPC consistently experienced meter failures on irrigation pump locations using variable speed drives (VSD). To date, nine meters installed at service points with VSD have failed. As of this status report, DCSI has not diagnosed the problem which causes this failure or provided a resolution to the issue. During the Phase One project, IPC was required to reinstall standard meters on these installations and manually read them to obtain usage data.

On November 18, 2005, IPC received a service announcement from DCSI to immediately discontinue the use of 480-volt meter operation and installations due to safety concerns of thermal overheating. This directive raises a serious concern regarding the viability of the AMR technology for irrigation and commercial installations where the collection of interval usage data is required or desired. In the IPC Phase One project, this issue impacts approximately 330 meters. IPC is continuing to work with the vendor to understand the problem and potential options for resolution. In the mean time, IPC is not collecting hourly or daily reads from the 480-volt AMR meters and is limiting its operation to the collection of monthly reads only.

b. Itron EE Meter Data Management System

IPC's criteria for VEE required some very complex calculations and algorithms for hourly interval data for the 23,474 meters. When the MDMS request for proposal was issued in early 2004, there were no identified vendors providing MDMS systems currently in a production status that had the functionality and volume requirements for hourly interval data management that IPC specified. Given this, IPC contracted with Itron, to implement an existing product that they believed could be modified to meet IPC's criteria. Actual modification of the Itron Enterprise Edition product to fit IPC's criteria proved to be much more difficult than anticipated and Itron experienced significant difficulty meeting IPC's acceptance test criteria for VEE. Itron has not been able to deliver acceptable VEE functionality for the MDMS product installed, IEE version 4. While Itron has diligently worked with IPC during this time, this vendor delay has prevented IPC from utilizing the MDMS functionality during the Phase One project period. The two time-variant pricing programs offered in the Emmett area required hourly data to be VEE'd for billing purposes. Because of the Itron MDMS failure, all billings for these two pricing programs for the months of June, July, and August were manually extracted, reviewed, and entered into IPC's billing system. The manual process was manageable due to the small scale of the two pricing programs, but any expansion of the pricing programs is not recommended until a MDMS solution is tested and in production.

A major upgrade (version 5.0) of the MDMS VEE functionality was released by Itron in November 2005. This new release requires a new implementation, testing, and acceptance process prior to its being placed in production. The final assessments and evaluations of the MDMS technology are not expected to be complete until April 2006.

c. Nexus Energy Software

The Nexus Energy tools were implemented in phases. Beginning on April 4, 2005, AMR customers were able to use the Nexus system to view hourly usage information, and on July 11, 2005, all residential and small commercial customers were able to access usage data and receive information on energy savings tips.

Customer interest in viewing and examining AMR provided hourly data was minimal during the time-variant program period in Emmett in 2005. During the solicitation period for the time-variant pricing programs in April and May, IPC sent out direct mailing pieces to approximately 5,000 targeted customers. These mailings provided the Internet address where customers could log-in to review their previous summer's hourly data and load profiles and also use the Nexus calculator to help them see if there were potential savings by participating in the program. Of the 5,000 targeted customers, only 35 accessed their data using Nexus. Of the 170 eventual program participants, 24 looked at their previous summer's usage prior to signing up for a program. IPC was able to track specific AMR customer Web site traffic to those who viewed portions of the Web site that contained hourly AMR data; in total only 58, or .25 percent of all AMR customers, viewed 93 reports and 481 charts containing hourly data.

5. Programs Offered

IPC offered two different time-variant pricing programs and one demand response program in the Emmett AMR area during 2005. IPC solicited approximately 5,000 Emmett Valley customers simultaneously for participation in the three programs: the Time-of-Day (TOD), the Energy Watch (EW), and the A/C Cool Credit programs. The

TOD program had 97 customers apply to participate and the EW program had 80 customers apply to participate. Customers were restricted to participation in only one of the three programs offered to Emmett Valley residents during the summer of 2005.

a. Result of Time-of-Day and Energy Watch Programs

The Company has contracted with RLW Analytics to evaluate participants' peak impacts, energy impacts, and bill impacts for the Energy Watch and Time-of-Day participants.

RLW Analytic's preliminary analysis results of the TOD program indicate that for all three months and the summer season in aggregate, there was not a statistically significant change in the usage patterns of the TOD participants when compared to the control group. However, there was some indication that there was some reduction of load during the on-peak periods and an increase in load during the off-peak periods. Preliminary bill comparisons for the TOD participants indicate that participants' average bill might have been slightly less for the summer season when compared to the control group's average bill under the standard residential rate.

The preliminary results of the analysis of the EW group by RLW Analytics indicate that on average a statistically significant level of peak load reduction was realized from the EW participants during the nine EW Events. The preliminary bill analysis indicates that for both the control group and the participant group the average bill at standard residential rates was slightly higher than the average bill under EW rates.

Overall, the preliminary analysis of the TOD and EW pilot programs demonstrates that these programs were reasonably successful for both the participants and the Company. As required by the Commission in Order No. 29737, the Company will submit a final report upon the completion of the programs in April, 2006.

b. A/C Cool Credit using AMR Technology

The TWACS® Load Control Transponder (LCT) is a device that can be installed at service points and used as a switch for load control applications. The LCT is a completely separate and independent device from the AMR enhanced meters. It is controlled by TWACS® software and is capable of two-way power line carrier based communications as are the AMR meters. Each LCT has the ability to cycle two appliances at the installation location. Approximately 170 Emmett customers enrolled in the A/C Cool Credit program in the Emmett area.

IPC used the same contractor to install the LCTs for its Emmett AMR customers as it did to install the radio pager technology in other A/C cycling areas. During the data evaluation period, IPC discovered that the LCTs were wired to the low-voltage connection, which is the normal procedure for radio-controlled switches, not the high-voltage connection, which is the normal procedure for the LCTs. This wiring configuration gave IPC a false impression that the air conditioners were being cycled through the AMR technology, when in fact they were not being physically cycled on and off. Further testing is currently underway to correct the switching issue for the 2006 season. Despite this error, all indications from industry and vendor sources are that the AMR technology and LCTs can effectively conduct load control of appliances using on-demand technology.

6. Programs Evaluated

IPC evaluated, or is continuing to experiment with, other AMR-related services, functions, and benefits.

a. Account Aggregation and Customer Choice of Reading Dates

Account aggregation, also known as summary billing, has been offered by IPC since 1997. AMR technology would enable customers with multiple meter points to change their current monthly meter reading date so that all meters would be read on the same date regardless of their geographical location. In addition, customer choice for reading and billing dates could also be implemented with AMR. A concern exists for both the aggregate and customer choice of reading dates in relation to AMR and other processes. IPC prepares approximately 450,000 bills balanced over 21 billing cycles each month. This process of using billing cycles spreads the workload into manageable allotments. If customer choice or bill aggregation were to create unbalanced cycle volumes, the processes, systems, and employee scheduling could lead to inefficiencies that outweigh the benefits.

b. Remote Connect/Disconnect

The TWACS® remote connect/disconnect device is a single-phase 200-amp switch mounted in a socket meter base extension. The device is installed between the meter and the customer's meter base; it is totally separate and independent from the AMR-enhanced meter.

IPC did not install any of the remote connect/disconnect switches. There were only 15 residential service points company-wide with four or more actual connects or disconnects in 2004. Over 70 percent of customer requests for service establishment or service disconnection do not require the physical connection or disconnection of the meter, but only a reading to transition the customer responsibility. The TWACS® remote connect/disconnect devices cost approximately $200 each. IPC's average cost for the field work associated with a site visit within the Emmett and McCall operating areas to perform a disconnect or connect is $18. Given these costs, any remote connect/disconnect device installed on an average service would have to be operated more than 10 times to break even on the purchase of the device.

Although IPC did not install remote connect/disconnect switches, it did use the AMR system to avoid trips to AMR related accounts to obtain transition readings between customers when a physical connect or disconnect was not necessary. IPC was successful in building interfaces between its CIS and AMR systems to capture the readings while reducing the cost of labor and mileage in these cases.

c. Theft Detection

The AMR system provides three different pieces of information that can be analyzed to identify possible energy theft. The Phase One project allowed IPC to collect data on all three elements of information.

The volume of information collected from these primary theft detection elements has not led IPC to identify any theft detection in the Emmett or McCall operating areas. Software products to assist in evaluating this type of information to identify possible theft situations have not been made commercially available or were not evaluated during this phase of the project.

d. Outage Confirmation

IPC is continuing to evaluate a secondary DCSI software package that is designed as an outage assessment tool named the Outage Assessment System (OASys) (). The features provided by OASys include: a) The ability to report meters that do not reply to the automated meter polling; b) Blink Count, an outage accumulator within each meter; and c) the ability for a meter system operator to select a meter (or group of meters) to initiate a polling of the meter(s).

e. Voltage Monitoring

The three-phase AMR enhanced meters provide a revenue-accurate voltage reading. However, the single-phase residential AMR enhanced meter provides a voltage measurement within the communications module. This voltage is specified to have an accuracy of +/-five percent. For our evaluation, 30 meters were selected near each regulating device and along each branch of the feeder. Four of the 30 meters indicated 26 voltage readings outside of the given ANSI C84.1 standard of 114 and 126 volts.

7. Costs

Projected final capital costs, including all vendor costs, contract costs, IPC labor and costs, loadings, overheads, and AFUDC for each of the three major project components of the Phase One AMR Project are as follows:

TWACS® AMR System	Projected Cost
Installed Cost of Meters, Substation, Software, Servers, including labor	$5,855,144
Installed Cost of Itron EE MDMS System Software & Servers including labor	$ 770,000 (Still in Progress)
Installed Cost of Nexus Energy Software including labor	$ 234,280
Total Projected Phase One Project Cost	**$6,859,424**

These costs result in an average cost of $292 per installed meter point for the Phase One project.

8. Benefits

IPC evaluated the benefits provided by AMR in relation to both real cost savings and service related results.

IPC realized a $303,000 annual savings in manpower in the Emmett and McCall operating areas. IPC reduced its manpower for meter reading and service orders by four employees as a result of the Phase One project. This savings includes loaded labor and reductions in travel costs associated with meter reading and service order work that were replaced with AMR functionality.

IPC also identified benefits associated with billing accuracy related to AMR. Specifically, estimated readings were reduced 92 percent from 2003 levels, while corrected billings in the same areas were reduced by 45 percent. Because the overall volume of AMR meter readings in Phase One was five percent of the meter readings in the IPC operating area as a whole, no cost savings were obtained in labor reductions in the customer service area as the described benefit was not significant enough as a whole to reduce labor. IPC could not statistically ascertain that any call volume reductions were contributable to AMR directly. IPC did evaluate customer contact rates in the AMR areas versus the remainder of the Company. This information did show a decrease in overall customer contacts for AMR areas, but as noted, IPC could not statistically ascertain that the decrease was directly tied to AMR improvements.

9. Customer Feedback

IPC contracted with Northwest Research Group, Inc. to conduct a survey with Emmett area customers to determine awareness and perceptions of IPC's service since installing AMR technology. A telephone survey was conducted with 533 of IPC's Emmett area customers.

Objectives of the study were to help IPC understand the perceptions of these customers with regard to service and the customer's ability to gather relevant energy usage information from IPC. Customers who participated in one of the two pricing programs offered in the Emmett area during the summer of 2005 were asked an additional battery of questions. Information from this portion of the research will be included with the final program report to be filed in April 2006.

Overall satisfaction with the level of service received from IPC was high with 61 percent of customers in this study stating they were "very satisfied" and 33 percent stating "somewhat satisfied." When asked if their level of satisfaction with IPC had changed within the past twelve months, 84 percent of these customers indicated their satisfaction level had stayed the same. Survey respondents indicated that IPC does a good job of providing information to customers about how and when to use electricity (mean score of 4.33 on scale of "1" to "5").

Most of the customers interviewed in the survey were aware that an AMR meter had been installed at their residence and that they no longer have a meter reader coming on to their property monthly. When asked if they had a need or interest in knowing daily or hourly electricity usage, 43 percent of those surveyed said they were interested in knowing their daily usage and 37 percent said they were interested in knowing hourly usage.

Only nine percent of the customers included in this study said they had ever gone to IPC's Web site for electricity usage information. The majority of survey participants who had gone to IPC's Web site for energy usage information indicated they found the information useful and it met their needs. When asked where they would prefer to get electricity usage information, 87 percent of the customers involved in this research said they would prefer to see it on their power bill rather than on the IPC Web site.

General conclusions of the research are that customers in the Emmett area are satisfied with the level of service they receive from IPC and that Emmett customers' satisfaction level has stayed constant within the past 12 months. Customers are generally aware that they have AMR meters but most aren't aware of the amount and type of usage information available to them.

10. Conclusions

The AMR project has shown potential benefits, but before any decisions can be made about expanding this program more work is needed with respect to economic analysis, business requirement definition and planning, monitoring of the maturity of AMR technologies, an AMR industry analysis, and defining and understanding customer needs and behaviors. This work should acknowledge the following conclusions reached as a result of the Phase One project:

- The cost of the Phase One project was $6.8 million, or $292 per meter point. The associated realized benefits are $303,000 annually. In combination, these values do not reflect a positive cost benefit analysis. AMR will require time to mature in its technology lifecycle; IPC will continue to analyze increased and other realizable benefits, along with further evaluation of implementation cost options. By continuing to monitor and develop these items in combination, IPC will be able to monitor any change in the balance between costs and benefits.

- The TWACS® system performs well when asked to provide monthly or daily reads. The system and its limited bandwidth of communication start to show limitations in the collection of hourly reads. This limitation required dedicated manual oversight to collect hourly reads.

- Meter reading accuracy has increased and estimated readings are significantly reduced. This demonstrates that AMR can improve bill quality. IPC was not able to translate these soft benefits into a hard dollar savings during the Phase One project.

- The AMR system provides an abundance of data to evaluate for theft detection and outage events. The volume of data will require either advanced software, or added labor costs to evaluate the data for effective determination of any benefit.

- Upgrades to the TWACS® system such as new meters and substation equipment require version coordination of hardware and software. In the future, this will require IPC to consider upgrades and costs to both software and hardware to evaluate new functionality made available by the vendors.

- The current service advisory from DCSI regarding the 480-volt meters, meter issues associated with the use of variable speed drives, and single-phase substation limitations leave a portion of IPC's meter population without an AMR solution, or at a minimum without the ability to collect time-variant daily or hourly data.

- The TWACS® system has effective add-on components such as the load control devices used to cycle air conditioners. Even though IPC-related implementation issues with the air conditioning cycling in the Emmett area resulted in the program not working as intended, the technology worked as designed.

- The Itron MDMS system failed, requiring manual intervention for the bill processing of all interval data used for the two time-variant pricing programs. As of this status report, IPC and Itron continue to work with the new version 5.0 MDMS to evaluate its effectiveness. No definitive conclusion can be reached until testing is completed in 2006.

- A workable MDMS solution is required to expand time-variant pricing programs.

- Customers showed limited interest in obtaining hourly data via the Nexus software accessed via IPC's Web site. Only 58 customers in the Emmett and McCall areas viewed their hourly data. Of the customers surveyed by Northwest Research Group, Inc., 87 percent stated they would rather see usage information on their bill.

- The recent announcements that large investor-owned utilities may sign sizeable AMR contracts in the near future may provide industry vendor incentives and opportunities to improve the technology, along with lowering the cost through increased production.

11. Next Steps

During the Phase One AMR Project, IPC has gathered valuable information on the operation of its AMR system and the interaction between various systems needed to fully utilize and implement AMR-related features and capabilities. In order to facilitate our in-depth evaluation of AMR and potential future options and strategies, IPC contracted with MW Consulting, a leading consulting firm with extensive experience in the AMR field. Based on the guidance provided by MW Consulting, the company has adopted the following 12- to 24-month strategy for determining its future AMR policy.

- Allow the AMR technology to mature for a minimum of one year. It is expected, as with most technology lifecycles, that the technology functionality with memory, bandwidth, and reliability will improve. IPC plans to continue testing and evaluating new TWACS® products in 2006 with regard to substation equipment improvements and new meters with expanded memory, in addition to software upgrades. These items are not presently available for testing or evaluation.

- Allow the MDMS technology to mature for a minimum of one year. IPC and Itron have agreed to a testing plan for version 5.0 of the MDMS that is targeted to be completed in April 2006. This is a critical technology link to enable time-variant pricing programs such as TOD or EW on a larger scale.
- Conduct further investigation to identify and quantify other realizable hard benefits that may be available from AMR. Any identified benefits would be used to update the ongoing financial assessment.
- Define the specific business requirements and associated functionality needs that require AMR implementation.
- Evaluate possible implementation models using a measured approach to geographical implementation of AMR in defined areas of the company's service territory that provide the greatest economic value and use of the AMR systems.
- Evaluate other AMR technologies with the possibility of a mixed AMR approach using varied technologies.
- Conduct a competitive bidding process during the first half of 2007 that includes new Request for Proposals to multiple vendors. The intent is to achieve the maximum value for customers and the company, as well as provide updated information to the financial analysis while considering updates in technology. IPC must evaluate the market for technology solutions that meet business requirements in the most cost effective manner.
- Conduct an in-depth financial analysis of AMR during the second half of 2007 using varied scenarios of cost options and benefit possibilities. IPC recognized tangible results from the Phase One Project; further evaluation is necessary to construct a business case that fully compares the cost options to other realizable benefits.

IPC believes this strategy will allow it to fully understand the costs, benefits, and customer impacts of AMR prior to determining its future AMR policy.

Part 2—Implementation Status of Phase One AMR Project

1. Background & Procedural History

The IPUC's Order No. 29362, dated October 24, 2003, directed IPC to install a Phase One AMR system in selected service areas. This Order required IPC to complete the following activities:

- File a Phase One AMR Implementation Plan within 60 days of the order date. An implementation plan was subsequently filed with the Commission on December 23, 2003.
- Complete the Phase One AMR installation by December 31, 2004. The Phase One AMR meter installation was completed by November 2004 and has operated successfully since that time.
- File a Phase One AMR Implementation Status Report by the end of 2005. This document fulfills this requirement.

2. Scope of Phase One AMR Implementation

a. Geographic Location

AMR was installed in IPC's Emmett and McCall operating areas. AMR installation in the Emmett operating area included the communities of Emmett, Sweet, Montour, Horseshoe Bend, Banks, Crouch, Garden Valley, Lowman, and the surrounding rural areas of these communities. AMR installation in the McCall operating area included the communities of McCall, Lake Fork, Donnelly, Cascade, New Meadows, Riggins, and the surrounding rural areas of these communities. A map showing AMR installation coverage areas is attached as Appendix A.

b. Customers Included and Excluded

AMR was installed for residential, small and large general service. A total of 23,474 AMR meters were installed with 10,742 AMR meters installed in the Emmett operating area and 12,732 meters installed in the McCall operating area.

Some customers did not have AMR meters installed for various reasons, as follows:

- **Primary service level accounts:** All primary service level accounts having primary service billing data requirements are on an existing telephone-based automated meter reading system and were left as is (approximately seven in the Emmett and McCall area).
- **Dairies:** Meters at dairies (approximately 13) did not have AMR installed pending further clarification of stray voltage issues. These meters continue to be manually read.
- **Load research meters:** Load research meters (approximately 33) were left as is. The 15-minute data these meters record is more granular than the hourly data

retrieved by the AMR meters. The survey meters store 90 days of data, ensuring sample and data integrity. These meters continue to be manually read.

- **Tamarack substation customers:** AMR equipment was not installed at Tamarack substation south of New Meadows due to the small number of customers (approximately 70) served by this substation and the high cost ($90,000) of installing the AMR substation equipment at this location. These meters continue to be manually read.
- **Single-phase substation customers:** The power-line carrier AMR technology used for the Phase One project is not currently functional with single-phase substations. Hence, those customers (approximately 520) served by the following single-phase substations did not have AMR installed:

Single-Phase Station	General Location	Approximate Number of Meters*
Ola	North between Emmett and Horseshoe Bend	115
Hidden Lake	Between Ola and Smith's Ferry	83
Smith's Ferry	North of Banks and south of Cascade	118
Scott Valley	East of Cascade	1
Warm Lake	Thirty miles east of Cascade	197
Joyce	South of Tamarack and north of Council	6

*These meters continue to be manually read.

c. Systems Installed

The Phase One AMR Project included the installation of three separate, but related, systems. The collection, management, and presentment systems are as follows:

1. **TWACS® AMR System:** This system, consisting of software and physical equipment in the field, is the meter data collection system. TWACS® uses two-way communications via power line carrier technology to retrieve meter reading data. This system is discussed in detail in Section 3.
2. **Itron EE® MDMS:** This software system is the data management system for validating, editing, and estimating hourly interval consumption data retrieved by TWACS® and converting this interval data into billing data for time-variant pricing programs. This system is discussed in detail in Section 4.
3. **Nexus Energy Software:** This Internet-based software system is the data presentment system through which customers can access their energy use data

using the www.Idahopower.com Web site. This system is discussed in detail in section 5.

Figure1, repeated below, illustrates how each of these three systems interrelates within IPC's overall AMR system.

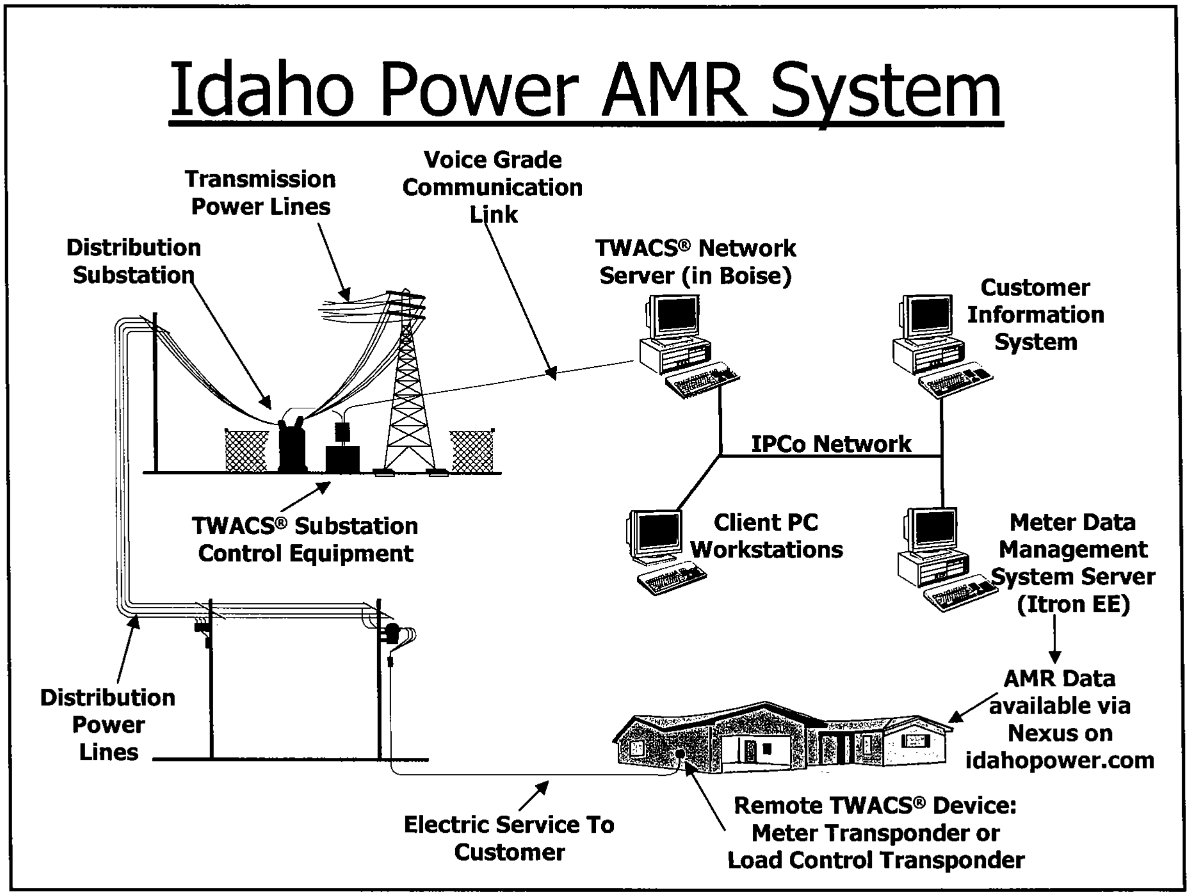


Figure 1 IPC's AMR System

d. Implementation Timeline

The implementation timeline for the TWACS® AMR system was as follows:

Date	Event
October 24, 2003	IPUC issued AMR Order No. 29362
December 2, 2003	AMR workshop conducted with IPUC
December 23, 2003	IPC submittal of Phase One AMR Implementation Plan to IPUC
March 15, 2004	Installation of TWACS® equipment in substations begins in Emmett
April 20, 2004	AMR meter installation begins in Emmett
April 28, 2004	Hourly data collection by TWACS® begins as meters are installed
May 28, 2004	All Emmett operating area commercial AMR meters are installed
June 14, 2004	All Emmett valley residential AMR meters installed
June 14, 2004	TWACS® is retrieving daily and hourly data for all Emmett valley customers
October 2004	TWACS® equipment installation in substations in McCall is complete
October 29, 2004	AMR meter installation is complete in McCall
November 2004	TWACS® is retrieving daily and hourly data for all McCall customers
November 2004	Phase One meter implementation is complete

e. Implementation Process

The implementation of the three systems was completed using varied resources from IPC, the vendors, and contractors.

1. The installation of the single-phase AMR meters for residential and small commercial customers was contracted to Terasen Utility Services Inc. of Milwaukee, Wisconsin. Terasen was responsible for providing the supervision and resources necessary to install the single-phase AMR meters. They managed the materials (meters) as provided by IPC, data collection of exchange readings from old to new meters, and provided IPC with electronic data to enable the record keeping of the meter exchanges within IPC's systems.

2. IPC meter technicians completed approximately 1,200 meter exchanges of current transformer-rated and poly-phase applications.

3. The TWACS® substation equipment was installed by IPC resources. DSCI provided IPC with the training for the installation process.

4. The communication infrastructure was a combination of local phone service provider equipment and IPC infrastructure.

5. The TWACS® Network Server software application was installed by DCSI and jointly tested with IPC.

6. The MDMS was installed in combination using both Itron and IPC resources. Itron provided training and testing resources to assist IPC in understanding the functionality and operation of the system. IPC provided Itron with the functional requirements expected for the system to perform.

7. The Nexus system is a hosted system. IPC and Nexus evaluated and modified the Nexus implementation templates to map IPC data to the Nexus system. Although this is a hosted system, the planning process was intensive on IPC resources to define and test the data presentation, the data security requirements, and incorporation into the IPC Web site.

3. Assessment of TWACS® AMR System

a. Description of System

The AMR technology platform used is the TWACS® fixed network power line carrier communication system provided by DCSI. TWACS® consists of the following major components:

- **TWACS® Net Server:** The TNS is the highest level of the TWACS® network. The TNS consists of an application server and associated software that is located in IPC's computer Data Center in Boise. IPC users access the system via their client workstations. The primary TNS functions are management of the TWACS® communication network, origination of meter reading and load control applications, and collection of remote meter reading data for the TWACS® database server.
- **Substation Communication Equipment (SCE):** Each substation serving AMR meters required the TWACS® SCE be installed. This equipment sends and receives data over IPC's existing distribution lines. SCE was installed in IPC's Emmett, Crane Creek, Horseshoe Bend, Cascade, Donnelly, McCall, and New Meadows substations.
- **Remote Communication Equipment:** This is either the AMR-enhanced meter for meter reading or the TWACS® LCT for load control/demand response applications. Following is a short description of each piece of equipment:
    - **AMR-Enhanced Meters:** All existing meters were removed and replaced with new AMR-enhanced solid state electronic meters that contained a TWACS® electronic metering transponder. Meters used included the Itron

Centron® meter for single-phase installations and the Landis+Gyr S4 meter for poly-phase installations. The TWACS® metering transponder was installed in these meters at the respective meter manufacturer's facility and the integral meter units were then shipped to IPC.

- **Load Control Transponder:** The TWACS® LCTs are completely separate, independent, and stand-alone devices from the AMR enhanced meters. These devices can open and close remotely either the power circuit or the control circuit to the customer's equipment. As part of the Phase One AMR Project, IPC deployed the LCTs for Emmett customers participating in IPC's A/C Cool Credit program.

- **Communication Link from Substations to TNS:** A voice grade communication circuit is required between each substation containing the SCE and the TNS in Boise. This circuit can be a dial-up telephone line, a frame relay circuit, or other comparable communication method. The following types of communication links were used.

Substation	Type of Communication Circuit Used
Emmett	Frame relay to Boise
Horseshoe Bend	Dial-up to Boise
Donnelly	Dial-up to McCall and then IPC network to Boise
Cascade	Dial-up to McCall and then IPC network to Boise
New Meadows	Dial-up to McCall and then IPC network to Boise
Crane Creek (NW of Emmett)	Frame relay to Boise (was originally installed as dial-up)
McCall	IPC network to Boise (substation is adjacent to IPC McCall office where IPC network service was available)

These basic TWACS® system components are illustrated in Figure 2:

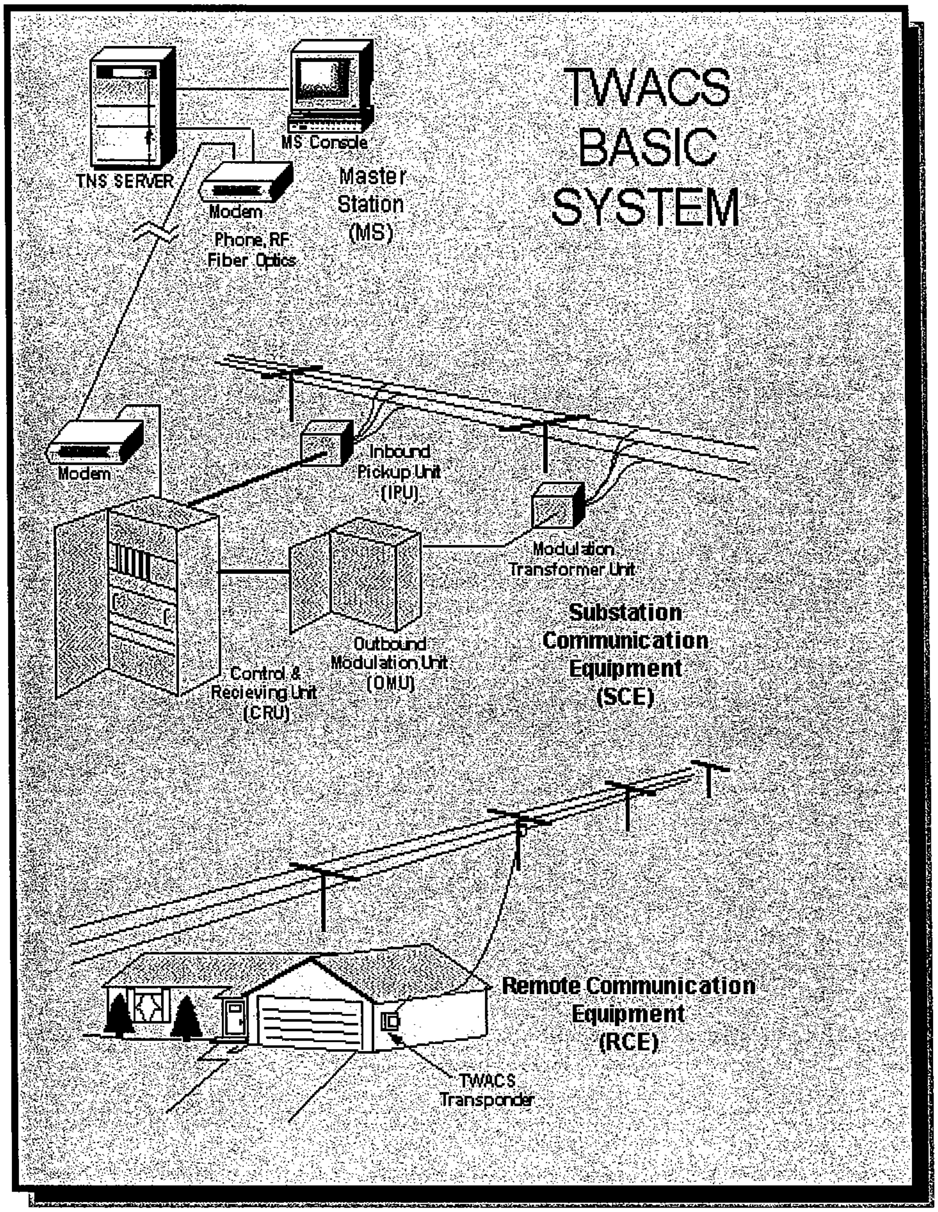


Figure 2 TWACS® Components

b. System Operation

The following summarizes the operations and functions of the TWACS® AMR system.

Transponder installation: Equipment, such as meters containing an internal TWACS® electronic metering transponder and LCTs, are installed in the field and the device information and transponder ID are entered into the TNS system. The device is assigned to its associated substation in TNS. The system is then tasked with "searching in" the device and determining the best communication path (i.e., station bus, feeder, and phase). Once the system determines the best communication path, the path is accepted as the address of the device and the system automatically uses that path for future scheduled communications. The initial "search in" process can take several hours per meter. Difficulties were experienced while trying to collect meter data on previously installed meters while searching in large numbers of new meters. For future deployments, it is recommended that all meters be "searched in" on a substation prior to instituting the collection of meter data on that particular substation.

Meter communication scheduling: Once the meter is "searched in," it is put on a schedule to retrieve data. The following types of meter data are retrieved:

- **Daily Meter Register Readings:** The meter performs a self-read of the accumulated register at midnight each day; the reading is stored in the meter for 24 hours until it is written over with the next midnight read. The reading is the same as the kWh value displayed on the meter at midnight. This value is then retrieved from the meter by TNS on a daily basis and is stored in TNS as the daily reading. The readings from the above process are used to complete customer movement orders and to provide a reading for normal monthly billing. They are also used for billing questions or service order completion.
- **Monthly Demand Register Readings:** A very similar process is used once a month on the billing read day; the difference is that a peak demand read (in kW) is also retrieved from the meter, and the displayed kW demand on the meter is reset to zero. The peak demand value in kW is displayed on the meter. The kW value displayed on the meter automatically toggles back and forth between it and the current kWh reading.
- **Hourly Consumption:** The meter also records hourly kWh consumption internally. This data is retrievable for 16 hours, after which time the meter begins to write over the oldest data. Hourly data is retrieved by TNS three times a day at scheduled intervals. Retrieving each 8-hour block of consumption values can take several hours. These hourly kWh consumption values are <u>not</u> displayed on the meter face.

On-Demand Readings: IPC can communicate with the meters and load control devices individually by selecting the appropriate transponder ID in TNS and initiating the desired communication. This manual process is used for troubleshooting and maintenance only; the process of individual reading is too inefficient to be used for routine execution because of the limitations on bandwidth communication, licensing the software, and the fact that it requires manual intervention.

- **Blink Count:** The TWACS® metering transponder records an ongoing cumulative count of outage "blinks." This cumulative "blink count" is not retrieved as part of the normal meter data retrieval processes discussed above; rather, the cumulative blink count is retrieved by executing a special on-demand command in TNS.
- **Voltage Data:** Detailed functionality of the voltage-monitoring capability of the TWACS® metering transponders is discussed in section 10g of this report. Voltage data is not retrieved as part of the normal daily or hourly meter data retrieval processes discussed above. Rather, the current voltage data is retrieved by executing a special on-demand command in TNS using the add-on modular software from DCSI, OASys.
- **Load Control Transponder Communication Scheduling:** Load-control cycling schedules are built in TNS. These schedules are then transmitted to the field LCT devices via TWACS® and are implemented as desired. Further discussion of the TWACS® load control functionality is included in section 9.

c. Meter Reading Performance

Since the daily meter readings are held in the meter for 24 hours from midnight to midnight, the system is virtually 100 percent successful in retrieval of those readings. Any problems with the electrical system, phone lines, TNS or the servers can usually be resolved in time to capture the daily readings that are stored in the meter for 24 hours. Individual meter failures or problems that cannot be fixed within 24 hours are rare, but do result in the loss of daily readings and hourly data. Because daily readings are accumulative reads, the loss of a daily reading is not a major problem. In those cases, the read from the previous day or the next day can probably be used to fulfill any need for the kWh data.

IPC is able to achieve a 98 percent successful read rate on hourly consumption reads. Hourly consumption reads are more susceptible to being lost because they are stored for only 16 hours before they are written over in rolling 8-hour blocks. Any problems that cannot be resolved quickly result in the loss of hourly data. However, if successful in retrieving daily reads, the Itron EE MDMS is intended to intelligently estimate the missing hourly consumption values. The TWACS® system performs well, but it requires significant operator attention on a daily basis to achieve this performance level. System operation currently requires the equivalent of one additional full-time employee under normal operating conditions. When communication or system problems occur, additional resources are needed to restore the system and recover the available data.

A key part of good system performance is the reliability of the voice grade communication link between the substation and TNS in Boise. For Phase One, IPC used a combination of different technologies (see section 3a above). Reliability of this communication link is critical to collecting a high percentage of hourly data, especially if a time-variant pricing program is in place. From this Phase One experience, IPC has determined that a dedicated, leased phone line is the minimum desirable configuration for this communication link.

d. Meter Reading Benefits

The functional benefits of meter reading associated with the TWACS® system include:

- The operational costs of manual meter reading are significantly reduced in the AMR area. Those minor areas identified with single-phase substation service and the listed exceptions still require manual meter reading.
- It is no longer necessary to estimate meter readings because of access issues or weather problems in the area covered by AMR. The number of estimated reads in the AMR areas has decreased significantly as summarized below.

	All*	AMR Areas
2001	24,370	11,307
2002	46,674	11,826
2003	60,373	9,669
2004	64,242	14,665
2005**	44,618	780

*Excludes AMR Areas
**YTD 2005 through October

As noted, in 2005 a small number of estimates do remain in the AMR areas, but primarily due to the continuous manual meter reading as noted in section 2b.

- Meter reading errors are significantly reduced with AMR as summarized below.

	All*	AMR Areas
2001	30,592	2,752
2002	20,471	1,913
2003	19,819	1,618
2004	22,369	2,458
2005**	17,958	892

*Excludes AMR Areas
**YTD 2005 through October

- The elimination of the fieldwork necessary to obtain a meter reading when service transitions to a new customer dramatically reduces the cost of completing customer movement orders and the order completion time of 1–3 days was reduced to one day.

The operational savings associated with these benefits are discussed in section 11 of this report.

e. Limitations

The TWACS® system has the following limitations:

- The TWACS® technology does not currently work for meters served by single-phase substations. There are approximately 17 (14 in Idaho and 3 in Oregon) single-phase substations within IPC's system serving approximately 1100 (approximately 850 in ID and 250 in OR) customers. Six of these single-phase stations are located in the Phase One project area and were discussed in section 2b above. DCSI has indicated to IPC that this issue may be resolved in the future and will work with IPC on the implementation of a single-phase station solution with a commitment by IPC to purchase said equipment. DCSI has not provided any schedule of production of a technology that would resolve this issue.
- Retrieving hourly data from all meters uses up a great deal of the system bandwidth, reducing the flexibility of implementing additional system functionality. The SCE equipment installed in the IPC substations is limited in its functionality to listen for meter responses on various substation bus, feeder, and phase configurations. An individual meter may try to respond multiple times from its configured location, but the SCE equipment can only listen for the meter on one configuration at a time. Multiple attempts by the meter cause a thermal heat build-up in the meter that eventually causes the meter to stop responding until it can cool and reattempt communication.

  DCSI has developed new SCE equipment that can listen for meter responses on multiple configurations. IPC has made requests of DCSI to allow IPC to test the new equipment. As of this status report, the vendor has not provided a unit to IPC for evaluation and testing, so a viable solution to the problem has not been tested.
- The system is currently retrieving an average of 98 percent of the hourly consumption data from all meters under normal operating conditions. Failed data retrieval is typically the result of automated processes failing to restart properly when an after-hours communications or electrical system problem occurs. A higher successful reading rate could be achieved by staffing TNS operations 24/7 for system oversight and intervention.
- The meter transponders can hold up to 24 hours of hourly data in 8-hour blocks. If this data is not retrieved within this time period, the hourly data is overwritten with new data. This makes data loss susceptible if there are problems with the substation equipment or the communication link that lasts longer than 16 hours. DCSI is in the process of developing new meter modules that can store up to seven days' worth of hourly data. These new modules have not been released for production use, and cost figures are not available as of this status report to predict the incremental increase in cost of these extended memory modules. This technology improvement would need to be evaluated when the new product is

made available in 2006. If the equipment works as stated by the vendor, it should alleviate this issue on all future installations.

- IPC experienced AMR meter failure rates consistently on irrigation pump locations using VSD. To date, nine installations (out of 380 irrigation accounts in the AMR deployment area) with a VSD unit have failed. The failures were recognized when the meter stopped communicating with the AMR network. Physical review of the meter indicated heating issues and burned fuses within the meter. These failures represent a population of just over 2 percent of irrigation AMR installations, and IPC believes that more failures may appear in the future if AMR were to be expanded. If this holds true over the entire service area, IPC could expect about 450 or more VSD locations in which AMR technology would not be usable. As of this status report, the vendor has not diagnosed the problem or provided a resolution. This is a situation of concern that limits the functional feasibility of a larger scale AMR implementation in which the use of variable speed drives is common throughout the IPC service area. During the Phase One project, IPC was required to reinstall standard meters on these installations and to manually read them to obtain usage data.
- On November 18, 2005, IPC received a service announcement from DCSI to immediately discontinue the use of 480-volt S4 meter operation and installations due to safety concerns of thermal overheating in the meter that caused melting of the outer meter cover. This raises a concern about the viability of the technology for use on irrigation and commercial installations if multiple attempts to communicate with the meter are necessary for time-variant interval data. This issue impacts approximately 330 meters within the IPC Phase One project. IPC is continuing to work with the vendor to understand the problem and identify potential options. In the mean time, IPC is not able to collect hourly or daily reads on these installations. IPC has concluded that reading the meter on a monthly basis can be done safely as it minimizes the amount of communication attempts to the meter.

4. Assessment of Meter Data Management System

a. Description of System

The MDMS, a software system residing on a server in the Boise Data Center, uses the Itron EE software provided by Itron, Inc. An MDMS is required to manage the hourly interval data collected by TWACS®. The MDMS is intended to perform the following major functions:

1. Validate interval consumption data.
2. Allow for editing and versioning of interval consumption data.
3. Estimate hourly read data to fill in for any lost or missing data. This estimation is based on the daily usage readings and customer's previous usage profile.
4. Calculate complex kWh billing determinants for those customers on time-variant pricing programs.

5. Interface with IPC's billing system to facilitate automated billing of time-variant pricing programs.

b. System Operation

The intended system operation for MDMS is as follows. The MDMS receives hourly interval data and daily meter reading data from TWACS®. The MDMS then runs the appropriate VEE routines and algorithms on each day's data. Depending on the quality of the data provided, this VEE process can take several hours each day.

For those customers on a time-variant pricing program, MDMS was intended to aggregate the interval data into the appropriate billing determinants and pass this accumulated kWh data to IPC's customer information system for customer billing.

c. System Performance and Evaluation

IPC's criteria for VEE required some very complex calculations and algorithms for hourly interval data for the 23,474 meters. When the MDMS request for proposal was issued in early 2004, IPC determined there were no vendor-provided MDMS systems currently in a production status having the same functionality, volume, and requirements for hourly interval data management that IPC specified. Given this, IPC contracted with Itron, an industry leader in metering related systems, to implement an existing product which they believed could be modified to meet IPC's criteria. Actual modification of the Itron EE product to fit IPC's criteria proved to be much more difficult than anticipated and Itron EE experienced significant difficulty meeting IPC's acceptance test criteria for VEE. Itron has not been able to deliver acceptable VEE functionality for Itron EE version 4. While Itron has diligently worked with IPC during this time, this vendor delay has largely prevented IPC from utilizing the MDMS functionality during the Phase One project period. The two time-variant pricing programs offered in the Emmett area required hourly data to be VEE'd for billing purposes. Because of the Itron MDMS delays, all meter reading data for these two pricing programs were manually extracted, reviewed, and entered into IPC's billing system.

A major upgrade (version 5.0) of the Itron EE VEE functionality was released by Itron in November 2005. This new release requires a new implementation, testing, and acceptance process prior to its being placed in production. This software testing and acceptance process will carry over into 2006. Given this timeline, the final assessments and evaluations of the MDMS technology will not be complete until April 2006.

c. Benefits

Since IPC's acceptance test criteria for VEE have not been met, IPC has not had an opportunity to fully explore all benefits associated with MDMS. However, the following are the expected major benefits once a future version of MDMS is fully tested and accepted:

1. The MDMS will be the source of validated interval data to IPC employees and other IPC systems for various business uses.

2. The MDMS will be the source of validated interval data provided to IPC customers.
3. The MDMS will perform automated calculations of complex kWh billing determinants for use in billing those customers on time-variant pricing programs.

d. Limitations

Because the current system does not have full VEE functionality, it has been difficult to positively identify any limitations of the MDMS since the implementation delays have allowed IPC little time to work with the system prior to the writing of this status report. However, IPC has identified the following issues to date:

- **VEE Capability:** The MDMS software was not able to VEE the data to individual customer profile specifications. Any missing hourly data or validation of data accuracy is a critical requirement.
- **Billing Determinant Intervals:** It is a requirement to aggregate the hourly data into billing determinants such as on-peak, mid-peak, off-peak, and critical peak. During the Phase One Project, no version of the MDMS software capable of aggregating the usage data into output file formats required for use by the TOD and EW programs was available. During the Phase One Project, IPC manually manipulated the data and entered it separately into its billing system.
- **Scalability:** The scalability of the IEE MDMS system for a company-wide AMR deployment is unknown and needs further investigation. IPC will evaluate the scalability of version 5.0 of the MDMS during its implementation and testing process.
- **Long-Term Data Management and System Performance:** Collecting hourly data on a mass customer scale creates database management system issues in managing large quantities of data. In the Phase One Project, one month of hourly data for 23,474 customers creates nearly 17 million database records. To store this massive amount of data for several months or years with the expectation of querying the data for customer or other historical purposes may not be practical. Specific decisions surrounding data availability and retention are under consideration.

In summary, IPC believes that MDMS products will continue to receive more extensive attention from the utility industry as collection of interval data from advanced metering systems becomes more prevalent. After speaking with other utilities and vendors, IPC has not been able to identify any other utilities that have attempted to manage mass volumes of billing-quality hourly interval data from AMR meters without individual mass memory features. Some other utilities are currently planning large MDMS projects, which should help speed up improvement in the technology. A workable MDMS product is a critical path item for time-variant pricing programs when collecting hourly data. Until such time that a workable MDMS can be installed, any expansion of time-variant pricing programs is limited.

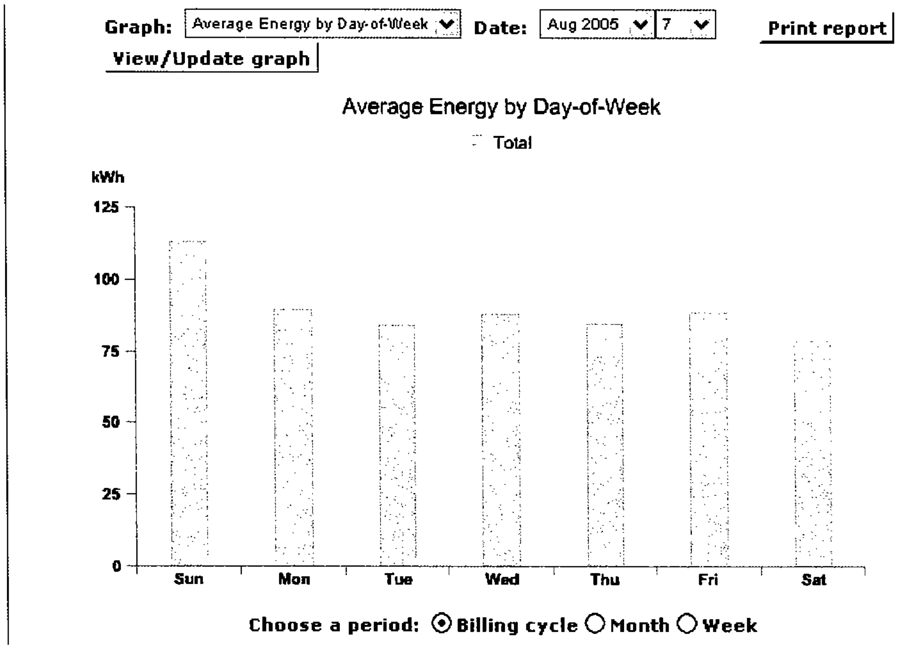
5. Assessment of Nexus Energy Software System

a. Description of System

The Nexus Energy Software system is a vendor-hosted Web application accessible via links on IPC's Web site (Idahopower.com). Services are provided to residential and business customers with expanded options for customers with AMR meters. Information from CIS *PLUS*® and MDMS is compiled and transmitted via the Internet to the Nexus Web site for presentation and analysis. IPC customers with AMR meters can also contact the Customer Service Center to have graphs of hourly energy usage mailed to them or to discuss energy saving strategies specific to their homes or businesses.

The following major functionalities are provided to AMR customers registered as Account Managers at Idahopower.com and to Customer Service Representatives assisting AMR customers:

1. **Energy Usage:** View/Print hourly energy consumption information via five graphs, see Figures 3 and 4.
2. **Energy Analysis and Savings Center:** Use analytical tools to make informed decisions about how to use energy in the future.
3. **Energy Calculator:** View an annual cost savings estimating tool, available in conjunction with time-variant pricing programs.
4. **View Estimated Savings:** View summer period savings estimates in conjunction with time-variant pricing programs.
5. **Bill Center:** View and print basic account information.



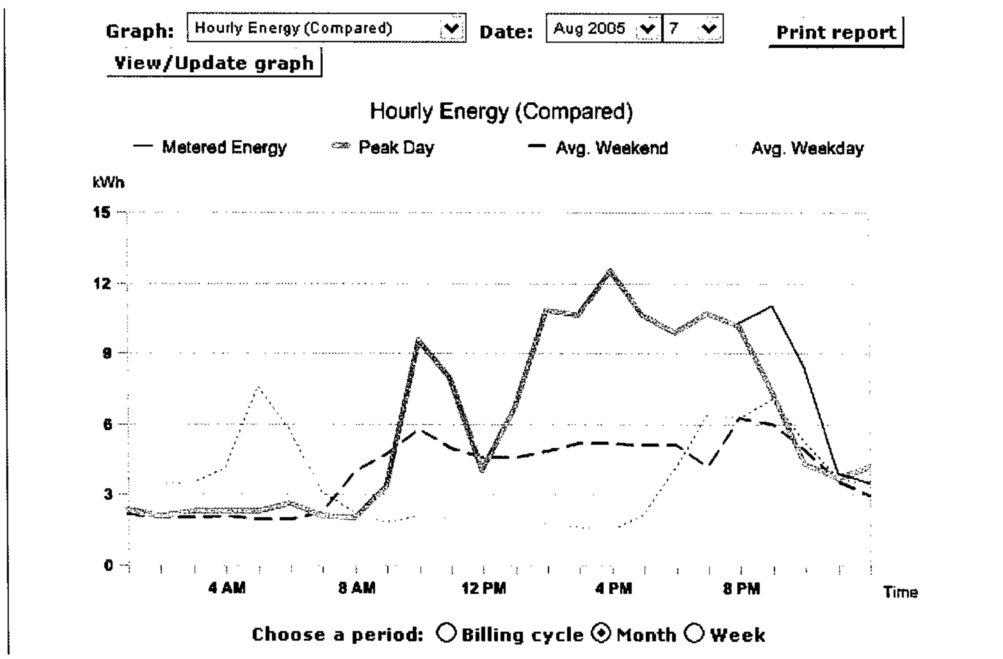


Figure 3 AMR Customer Usage Pattern Graphs

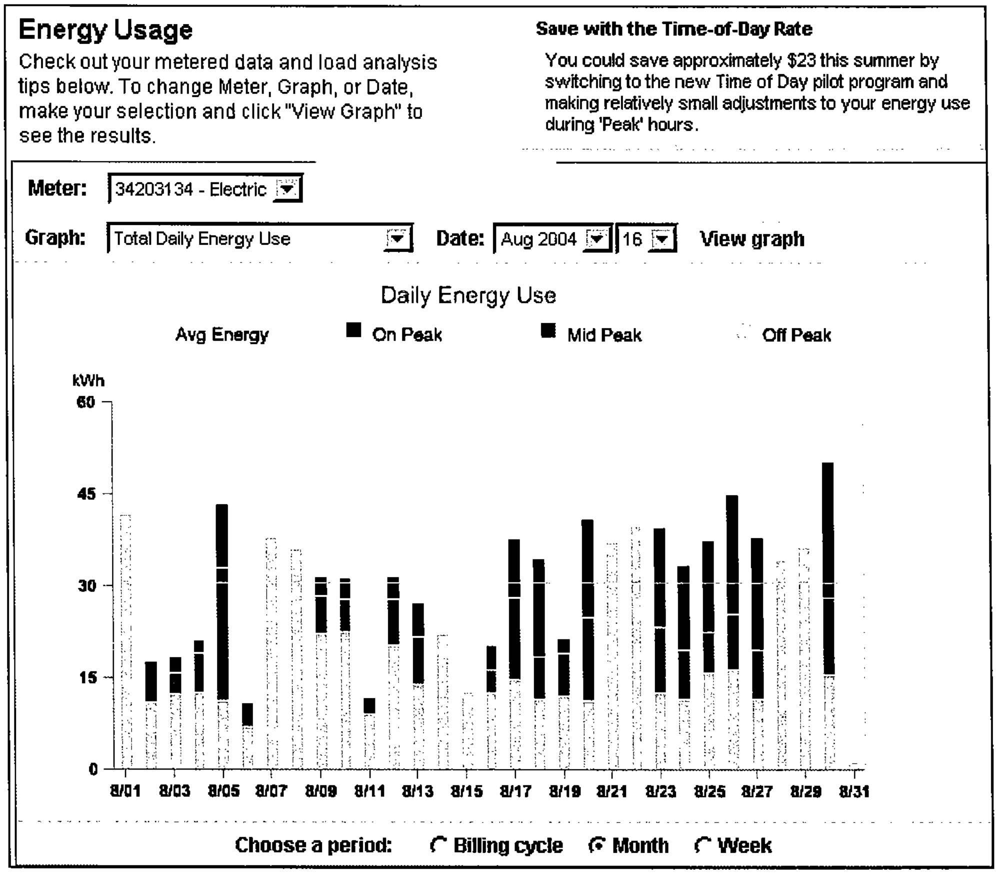


Figure 4 Promotion of the TOD program

b. System Operation

The IPC Web site, hosted on servers in the Boise Data Center, interfaces with the Nexus Energy Software Web site and presents usage and analysis information appropriate for the customer type and rate. The Idahopower.com site gathers this data via interfaces with the following systems:

- **CIS *PLUS*®:** When the customer registers and/or logs into the secure portion of the Idahopower.com site, data is requested from the CIS *PLUS*® system to validate user identity and present customer billing and monthly usage information. Based on the customer type and rate, appropriate links to Nexus-hosted products are displayed on the IPC Web site.
- **MDMS:** When the customer initiates a secure link to Nexus-hosted products related to hourly energy usage, his or her estimated and actual hourly energy use information is requested from the MDMS system. MDMS returns that data, compiled with data from CIS *PLUS*®, and transmits it to Nexus's Web site for presentation to the customer. When the user elects to transmit data to Nexus for display, there is a notable pause before they can view and use the data (due to the high volume of data being sent to Nexus).

c. System Performance and Evaluation

The Nexus Energy tools were implemented in phases. Beginning on April 4, 2005, AMR customers were able to use the Bill Center, Savings Center, and Energy Usage tools. On July 11, 2005, all residential and small commercial customers were able to use the Bill Center, Savings Center, and other customer-specific tools.

Customers' interest in viewing and examining their AMR data was minimal during the time-variant program period in Emmett in 2005. During the solicitation period for the time-variant pricing programs in April and May, IPC sent out direct mailing pieces to 5,000 targeted customers. These mailings provided the Internet address where customers could look at their previous summer's hourly data and load profiles and also use the calculator to help them see if there were potential savings by signing up for the program. Of the 5,000 recipients, only 35 accessed their data in Nexus. Of the 170 eventual program participants, 24 looked at their previous summer's usage prior to signing up for the program. The data in the following table for April through September represents usage for the approximately 23,474 AMR customers.

	April	May	June	July	Aug	Sept	Total
Total Number of Users	4	18	11	13	9	3	58
Total Energy Usage Reports Viewed	8	29	17	18	18	3	93
Total Charts Viewed	29	132	86	117	82	35	481

d. Benefits

The Nexus Energy software application allows AMR customers the opportunity to not only view their hourly energy usage, but to view trends in that usage and review ways to save energy. The system is not specific to AMR customers, but was originally offered by Nexus as an energy management tool for customers to understand how they use energy. IPC is evaluating its usefulness for both AMR hourly presentation as well as mass customer education of energy consumption and conservation techniques.

e. Limitations

The Nexus Energy software presents the following limitations:

1. The Nexus Energy software program is designed for use by customers with a demand of 300 kW or less. Nexus Energy Software does not have a product available that will accurately display and analyze demand higher than 300 kW.

2. Data transmission is limited to three months to ensure reasonable response times over the Internet when transmitting AMR data. Sending more than three months of data slows down the response time to an unacceptable level. IPC customers and IPC employees using the tool are experiencing 90-second or longer browser loading times as the data is queried, compiled, and communicated between IPC's data center, Nexus, and the customer's Internet.
3. Per-user costs are charged by Nexus Energy Software in the form of "Success Sharing Fees." Increasing the number of users for this product suite would increase Success Sharing Fees as well as require additional licenses of IBM's Tivoli Access Manager on IPC servers to accommodate additional registered users at the IPC Web site.

6. Customer Communication

The focus of the AMR communications campaign was to introduce Phase One to the customers of the Emmett and McCall operating areas. It focused primarily on external communications to reach approximately 10,000 customers in the Emmett operating area and 13,000 customers in the McCall operating area prior to, during, and after the meter change-out process. The goal of this campaign was to help the customers in these two service areas understand how and why IPC was changing out their meters to install a new AMR system. IPC also wanted to create an awareness of the efforts to introduce new technology that would enhance efficiency and improve service.

The key audiences were customers in the Emmett and McCall service areas, including community leaders and the news media. The first part of the campaign took place in the Emmett area in March and April of 2004, prior to the beginning of the meter replacement process on April 19, and communication continued throughout the summer. In the McCall area, the first part of the campaign began in May and June of 2004, prior to the beginning of the meter replacement process, and communication continued through the fall of 2004.

The central message in Phase One was, "Over the next few months, you will experience a brief power outage as IPC installs an Advanced Meter Reading (AMR) meter at your home or business." The secondary message was, "We will be utilizing AMR technology to read your meter remotely and no longer visit your home or business on a monthly basis to obtain the meter readings."

In both areas, and the surrounding municipalities, the first communication was made to local community leaders. They received letters from the IPC Community Relations Representatives along with an AMR Frequently Asked Questions/Answers (FAQs) sheet, a copy of the postcard that their citizens would soon be receiving in the mail, and a copy of the advertisement that would appear in the local papers. In addition, an IPC representative appeared at City Council and County Commission meetings to present the information.

Most customers first learned about the AMR meter exchange in their local weekly newspaper–a result of media visits, press releases, and a photo opportunity in which a well known member of the community was selected to receive the first AMR meter in the service area. In both areas, the stories and photos of the events received prominent placement in the media coverage. Following this, a large advertisement was placed in the newspaper, followed by smaller weekly ads reminding customers that technicians would be in the neighborhoods changing out their meters.

At the beginning of the meter exchange process, each customer received a postcard in the mail with the key messages, including notification that their meter would be exchanged within the new few months. At the time of the meter exchange, the technicians left a door hanger at customers' homes and businesses to notify them that the service had taken place.

7. Customer Feedback on AMR

a. Survey Methodology

In September 2005, IPC contracted with Northwest Research Group, Inc. to conduct a survey with Emmett area customers to determine awareness and perceptions of IPC's service since installing AMR technology. A telephone survey was conducted with 533 of IPC's Emmett area customers.

Objectives of the study were to help IPC understand the perceptions of these customers with regard to service and the customer's ability to gather relevant energy usage information from IPC. Customers who participated in one of the two pricing programs offered in the Emmett area during the summer of 2005 were asked an additional battery of questions. Information from this portion of the research will be included with the final program report to be filed in April 2006.

b. Survey Results

Overall satisfaction with the level of service received from IPC was high with 61 percent of customers in this study stating they were "very satisfied" and 33 percent stating they were "somewhat satisfied." When asked if their level of satisfaction with IPC had changed within the past 12 months, 84 percent of these customers indicated their satisfaction level had stayed the same. Survey respondents indicated that IPC does a good job of providing information to customers about how and when to use electricity (mean score of 4.33 on scale of 1 to 5).

Most of the customers surveyed were aware that an AMR meter had been installed at their residence and that they no longer had a meter reader coming onto their property monthly. Many of the customers were unaware that they were able to get hourly and daily electricity usage information on IPC's Web site (mean score of 4.52 on scale of 0 to 10). When asked if they had a need or interest in knowing daily or hourly electricity usage, 43 percent of those surveyed said they were interested in knowing their daily usage and 37 percent said they were interested in knowing hourly usage.

Only 9 percent of the customers included in this study said they had ever gone to IPC's Web site for electricity usage information. Younger customers were more inclined to go to the Web site than older customers for usage information. The majority of survey participants who had gone to IPC's Web site for energy usage information indicated they found the information useful and it met their needs. When asked where they would prefer to get electricity usage information, 87 percent of the customers involved in this research said they would prefer to see it on their IPC bill rather than on the IPC Web site.

In reviewing the customers who accessed the portions of the Nexus system that contains hourly data, only 58 customers actually viewed hourly data. This is less than the nine percent who stated they went to the Web site for electricity usage information. This disparity may be accounted for in that the customers may have viewed usage information at IPC Web site for their premises, but this information was the typical monthly information available to all customers.

c. Conclusions

General conclusions of the research are that customers in the Emmett area are satisfied with the level of service they receive from IPC and that Emmett customers' satisfaction level has stayed constant within the past 12 months. Customers are generally aware that they have AMR meters but most aren't aware of the amount and type of usage information available to them. It also suggests that the majority of the customers would prefer to see usage data on their bill rather than going to a Web site to view this information. Finally, the limited number of customers that viewed hourly data suggests a minimal amount of interest from customers to view such detailed information.

8. Assessment of Time-Variant Pricing Programs

a. Program Descriptions

In its AMR Phase One Implementation Plan, filed with the IPUC in December 2003, the company committed to investigate and file with the Commission time-of-use pricing programs that use the AMR technology. Consistent with this commitment, the company implemented the EW (Schedule 4) and the TOD (Schedule 5) pilot pricing programs for residential customers in the Emmett valley during the summer of 2005. Each of these programs used the hourly energy consumption data made possible by the Phase One AMR implementation. The design of each program incorporated information obtained from customers who participated in two focus groups held in Emmett in early December 2004, as well as input from discussions between the IPC and IPUC staff held in January 2005.

These programs were billed using hourly interval data collected by the TWACS® AMR system. Aggregation of the hourly interval data into the proper time periods for customer billing was calculated by hand. The original intent was to aggregate this data with the MDMS; however, the inability of the MDMS to pass acceptance testing, as discussed in section 4, prevented this automated process from taking place requiring manual manipulation of the hourly data. Basic details for each program are as follows:

Time-of-Day: The TOD program uses a "standard" time-of-use rate design during the months of June, July, and August. During the rest of the year the energy rate is the same as that paid by all other residential customers. The summer pricing under the TOD program is:

Energy Time Period	Day of Week	Time of Day	Rate
On-Peak	Weekdays	1 p.m.- 9 p.m.	6.8686 cents/kWh
Mid-Peak	Weekdays	7 a.m.- 1 p.m.	6.1717 cents/kWh
Off-Peak	Weekdays	9 p.m.- 7 a.m.	5.3004 cents/kWh
Off-Peak	Weekends, Holidays	All Hours	5.3004 cents/kWh

TOD encouraged customers to shift their energy usage from the on-peak period to the off-peak and mid-peak periods, which include evenings and weekends. Ninety-two customers participated in the TOD program.

Energy Watch Program: The EW program is a critical peak pricing program under which participants' electricity rates increased significantly for up to ten weekdays between June 15 and August 15 between the hours of 5:00 and 9:00 p.m. Under this program, the participants were notified by 4:00 p.m. the day preceding the EW Event by phone and email (when available). In the summer of 2005, IPC called nine EW Events. Participants paid the standard residential under-300 kWh rate for all other hours between June 1 and August 31. IPC's standard residential rate in the summer is 5.428¢/kWh for 300 kWh or less and is 6.0936¢/kWh for all kWh over 300. The benefit for the participants under the EW program was paying the lesser under-300 kWh rate for all summer hours except the EW hours.

b. Program Operations

IPC solicited approximately 5,000 Emmett Valley customers simultaneously for participation in three AMR related programs: the TOD, the EW, and the A/C Cool Credit programs. The TOD Program had 97 customers apply to participate and the EW program had 80 customers apply to participate.

Customers were restricted to participation in only one of the three programs offered. One EW applicant and three TOD applicants also signed up for the A/C Cool Credit program. When contacted by IPC, these four customers opted to participate in the A/C Cool Credit program instead. Three EW participants and two TOD participants quit the program following enrollment. As a result, there were 92 TOD participants and 76 EW participants by the end of August. Based on the total number of customers solicited for participation in both programs, the combined response rate was approximately 3.5 percent for the TOD and EW programs and the attrition rate was approximately 2.3 percent*.

IPC contracted with Northwest Research Group to survey AMR customers in general and EW and TOD participants—specifically to measure customer satisfaction with the programs and to gain information for future marketing of such programs. IPC also contracted with RLW Analytics to validate and estimate the hourly data when necessary, and to estimate participants' peak impacts, energy impacts, and bill impacts for the EW and TOD participants. RLW Analytics is also contracted to analyze weather data to determine the relationship, if any, between weather and peak reduction for these programs.

IPC also noted significant complexities in converting the individual customers to the two pricing programs. In each individual case, a manual process to exchange the meter in its CIS system and re-install the meter with the specific time-variant registers was necessary. As of this status report no automated means exist to convert customers from normal monthly readings to time-variant registers. If further time-variant programs are implemented on a mass scale, it will be necessary to seek modification from the supporting third-party provider of the CIS system to enable an automated approach.

c. Conclusions

The Northwest Research Group preliminary survey findings indicate that overall Emmett residents who participated in the programs would be likely to participate in the programs in the future – 22 percent are "somewhat likely" and 60 percent are "very likely." It appears one of the main reasons why the non-participants do not want to be a part of these programs is because they think they will lose control over when they can use their electricity.

RLW Analytic's preliminary analysis results of the TOD program indicate that for all three months and the summer season in aggregate, there was not a statistically significant change in the usage patterns of the TOD participants when compared to the control group. However, there was some indication that there was some reduction of load during the on-peak periods and an increase in load during the off-peak periods. Preliminary bill comparisons for the TOD participants indicate that participants' average bill might have been slightly less for the summer season when compared to the control group's average bill under the standard residential rate.

The preliminary results of the analysis of the EW group by RLW Analytics indicate that on average a statistically significant level of peak load reduction was realized from the EW participants during the nine EW Events. The preliminary bill analysis indicates that for both the control group and the participant group the average bill at standard

*Excluding those customers who signed up for more than one program and were retained on the A/C Cool Credit program.

residential rates was slightly higher than the average bill under EW rates. This preliminary finding indicates that the pricing under the EW program may be set such that participants can benefit without reducing their usage during EW Events. When the control group's average bill under the standard rate is compared to the participant group's average bill under the EW rate, it appears as if the EW customer experienced a slight savings for the entire summer season. This demonstrates that the rate might provide sufficient motivation for the customers to reduce load during the critical peak pricing period.

Overall, the preliminary analysis of the TOD and EW pilot programs shows that these programs were reasonably successful for both the participants and IPC. As required by the IPUC in Order No. 29737, IPC will submit a final report upon the completion of the programs in April, 2006.

9. Assessment of TWACS® Load Control Functionality

a. Description of System

The TWACS® LCT is a device that can be installed at service points and used as a switch for load control applications. The LCT is a completely separate and independent device from the AMR-enhanced meters. It is controlled by TNS and is capable of two-way power line carrier based communications as are the AMR meters. Each LCT has the ability to cycle two appliances at the installation location. The LCT can open and close a direct current thermostat/control circuit and it can also switch a 30-amp 240-volt circuit.

b. Emmett AC cycling program

During the summer of 2005, IPC's A/C Cool Credit program was expanded to include Emmett Valley customers. Those customers who enrolled in the program had their air conditioners cycled by the TWACS® LCT (as opposed to a radio pager technology that was being used elsewhere in IPC's service areas). Approximately 170 Emmett customers enrolled in the AC cycling program.

The LCTs leverage use of the same TWACS® power line carrier technology-based system as the AMR meters use. Once this system is established for AMR, there is no additional incremental cost to add the LCTs, outside of the material and installation costs of the LCTs themselves.

c. Assessment TWACS® Load Control Transponders

IPC used the same contractor to install the LCTs for its Emmett AMR customers as it does for the radio pager technology in other A/C Cycling areas. During the data evaluation period, IPC discovered that the LCTs were wired to the low-voltage connection, which is the normal procedure for radio-controlled switches, not the high-voltage connection, which is the normal procedure for LCTs. This wiring configuration gave IPC false indications that the air conditioners were being cycled on and off through the AMR technology, when in fact they were not. Further testing is underway as of the writing of this status report to correct the switching issue for the 2006 season. Beyond this error, all indications are that the AMR technology and LCTs can effectively conduct load control of appliances using on-demand technology.

10. Assessments of AMR-Enhanced Features

a. General

The AMR Phase One Implementation Plan, submitted to the IPUC on December 23, 2003, listed various AMR enhanced features and functionalities that would be evaluated as part of the Phase One Project. Each evaluation is summarized in the following subsections.

b. Integration of AMR Readings into Billing Process

The introduction of AMR required two processes for integration of billings for AMR customers: normal monthly billing, and time-variant billing for those customers on time-variant pricing programs. Each process is discussed below.

Normal Monthly Billing: A custom interface was developed between IPC's existing CIS and the TWACS® database to accomplish normal monthly billing for AMR customers. When a customer's monthly billing cycle day arrives, the interface automatically retrieves the daily meter reading from the TWACS® database and supplies it to the CIS system. Once this billing reading is in the CIS, the billing process flows through the identical process as non-AMR customers. This monthly billing process for AMR customers has functioned extremely well with no errors.

There are no cost savings associated with this normal monthly billing process for AMR customers since it simply retrieves the billing reading from the TWACS® database as opposed to retrieving it from the existing manual meter reading system.

Time-Variant Program Billing: IPC's existing CIS has the ability to bill customers on time-of-use and critical peak pricing programs once it is supplied with the appropriate billing determinant kWh data aggregation. The intent of the MDMS was to automatically provide this aggregated kWh data to CIS for billing through a custom-developed interface. However, as previously discussed, the MDMS vendor was unable to pass acceptance testing for the VEE functionality prior to the time-variant pricing aspect of the pilot programs concluded in August 2005. Given this, IPC followed a contingency plan of hand-calculating the aggregated data and then manually supplying it to CIS for billing. This manual contingency process was manageable for a pilot program of less than 200 customers. However, any larger time-variant pricing program deployments will require that an automated MDMS be fully functional and operational. A fully tested and accepted MDMS is critical to the time-variant billing process and must be in place prior to expansion of time-variant pricing programs.

Since time-variant pricing is new to IPC's residential sector, there are no cost savings associated with an automated time-variant billing process; rather, it adds additional workload associated with setting up and administering the programs.

c. Flexible Billing and Account Aggregation

Account Aggregation--Capturing a Simultaneous Reading for Multiple Locations. This consists of collecting simultaneous reads for multiple meters on summary billing accounts. This benefit would occur in situations where a customer has multiple service locations with similar service, and in which the meters are not in physical proximity to one another.

For example, in the current billing process, a customer with a primary residence in Boise and a cabin in McCall may have two separate accounts, each billing at different times during the month. The billing dates for each account were determined by the process to collect monthly meter data in each area; so one account may read and bill at the early part of the month and the second at the latter part of the month. Today, IPC can accumulate both bills under a summary bill process, but the meter read date for each of the meters would reflect the different time periods between readings due to the different meter reading schedule for each location. If both locations were equipped with AMR meters, a simultaneous reading could be utilized for billing a summary account, which could reduce customer confusion and present a uniform basis for usage comparison.

In summary, account aggregation has a customer satisfaction benefit, but it does not present any significant operational dollar cost savings to IPC.

Flexible Billing--Customer-Selected Billing Dates. IPC currently does not allow its customers to select their billing dates. The current billing process spreads all customer billing dates over 21 billing cycles for the month. IPC generates billings on approximately 21,000 accounts for each of the 21 cycles. This process minimizes capacity and/or manpower limitations by spreading billings out equally over the course of a given month. This creates the most efficient use of resources and minimizes costs.

Customer inquiries for changing billing dates typically center around three basic requests:

- 1st of the month
- 15th of the month
- the customer's particular pay date

Most requests would typically center around the first or middle of the month. This would create a significant imbalance in resources and workload. For example, if a significant customer base requested billing on the 1st, extra processing time would be required to create the bill file, more time and larger-capacity machines would be required to process the file, more billing/collection activity would require additional resources to process the peak days and would be under-utilized the remaining billing dates. This would add costs and result in a less efficient billing process due to an imbalance of resources.

In summary, while the daily meter reading retrieval by AMR could facilitate flexible billing, the associated inefficiencies and unbalanced resources associated with the remainder of the billing process would result in wide-scale customer selected billing dates not being cost effective to implement. Flexible billing would be a customer satisfaction benefit, but would be costly and inefficient for IPC to implement.

d. Remote Connect/Disconnect

The TWACS® remote connect/disconnect device is a single-phase 200-amp switch mounted in a socket meter base extension. The device is installed between the meter and the customer's meter base; it is totally separate and independent from the AMR-enhanced meter. When the device is signaled from TNS to open, the self-contained breaker opens. When the device is signaled to close, it is armed to close. There is a switch on the outside of the device that the customer must operate to restore power. The arming switch is a safety feature to prevent remotely restoring power without local acknowledgement.

Because the TWACS® remote connect/disconnect device is rated for single-phase 200-amp services, it is not applicable to a large portion of our commercial and irrigation service points. Given this, the device would be most applicable to residential service points, particularly those residential service points with higher than average per visit costs and/or sites requiring frequent actual disconnects or connects.

The TWACS® remote connect/disconnect devices cost about $200 each. IPC's average cost for the field work associated with a site visit within the Emmett and McCall operating areas to perform a disconnect or connect is $18. Given this cost, any remote connect/disconnect device installed on an average service would have to be operated more than 10 times to break even on the purchase of the device.

There are two activities on residential service points that could have some application for automated remote connect/disconnect switches. They are "customer-requested" actual disconnect or connect, and "credit and collection" actual disconnect or connect.

IPC received about 170,776 customer requests for service disconnection in 2004. Of these requests, 30,902 resulted in dispatch orders for residential customers where an employee was sent to the residence to perform the service. Only 15,160 of these orders actually resulted in service disconnections. The difference between the number of orders dispatched and the number actually performed is the result of the premises being occupied when the site visit was made. In these cases, the new customer was either signed up for service at that time or a notice was left by the employee requesting the resident to contact IPC to sign up. There were only 15 residential service points company-wide with four or more "customer requested" actual connects or disconnects in 2004. This establishes the basis that the majority of customer connect/disconnect orders do not require an actual disconnect of the meter, but a reading to transition between two customers.

IPC built an interface between its CIS system and TWACS® to coordinate the automation of "read only" orders with AMR meters. The orders taken in CIS are held until the work request date of the customer, at which time the interface provides the midnight reading back to CIS for order completion. This has provided benefits in reduced labor and mileage and order completion timeliness. Because IPC already had built an interface between its hand-held devices and CIS, no added benefit was obtained in actually completing the orders.

IPC performed 40,721 site visits for "credit and collection" activity in 2004. Sixty-two percent of the site visits resulted in collection of at least partial payment and arrangements for balance payment; disconnection of service accounted for 38 percent of the visits; and one percent were disconnected at the source. Only 64 service points were disconnected four times or more during the year, and in those cases many were disconnected at the source.

In conclusion, the practical application of automated connect/disconnect technology using remote switch units would be so limited that it would not provide any significant cost or process benefit for the following reasons:

1. Automated remote connect/disconnect devices are expensive compared to the cost of manual site visits. At least 10 manual site visits would have to be eliminated for the payback of the automated device to break even.
2. There are very few incidences of multiple customer-requested actual connects or disconnects at the same site. These incidents are too few to have any impact on staffing levels.
3. Most customer-requested disconnects turn into succession orders after the field personnel arrive at the site and find the residence occupied. An automated disconnect could lead to customer dissatisfaction.
4. Application of automated connect/disconnect devices on credit and collection problem accounts raises more issues than it would resolve:
    a. No personnel contact or notification of disconnect.
    b. No opportunity for the customer to pay or make arrangements at the time of disconnect. Over 62 percent of current disconnect visits result in some form of payment.
    c. Communications other than in person are difficult with customers who have delinquent accounts.
    d. No opportunity to ensure the customer is safe and sound before disconnecting.
    e. On accounts where multiple disconnects are performed, the service is often disconnected at the source and the meter removed.
    f. Communicating with customers to inform them that their remote disconnect device has been armed for closing and that they have to go out and manually flip the switch could be problematic. It is not uncommon for customers to not have phone service, which makes explaining where and how to restore their service more be difficult.

Using the AMR technology to obtain succession readings between tenants and completing the orders does have a recognizable benefit. During the Phase One project, IPC successfully built the technology interfaces to obtain a midnight reading from TNS for the day requested by the customer and automatically complete the customer order in its CIS system.

e. Theft Detection

The AMR system does not actually detect energy theft; rather, it provides information to help facilitate investigations of suspected energy theft. The Company's analysis of the applicability and benefit of theft detection/revenue loss is based on information recorded by the AMR system in the McCall and Emmett areas.

AMR has three methods to assist in identifying suspected energy theft and revenue loss: Blink Count, 24-Hour No Power, and Reverse Rotation.

- **Blink Count** is the number of events in which the meter module recorded an outage or momentary drop in voltage at a customer's location. Possible causes for a Blink Count can include switching the feeder, power failure, voltage drop, or removing the meter. When the Blink Count is recorded, it doesn't register what caused the blink or how long it lasted; it is simply a cumulative count. The great majority of blinks are attributable to normal operations. As a general rule, it is very difficult to correlate Blink Count to energy theft. It should be noted that a Blink Count may not be recognizable to the customer in service reliability.
- **24-Hour No Pulse** occurs when there is no consumption in a 24-hour period. Possible causes include occasional-use applications, such as a cabin or pump, or situations in which a meter is removed and jumpers placed behind it. When the 24-Hour No Pulse is recorded, it isn't readily apparent if that is historically normal for the location or if there is something wrong. Currently, an average of 2,439 daily no-pulse events are recorded daily. In order to reduce this number to something that is manageable, it would be necessary to make some modifications to how these meters are grouped and identified by the AMR system. By using the Device Location field to identify different groups of meters, it would be possible to reduce the list of meters that required research to a more manageable amount. For instance, if all meters that were turned off at the meter or source were assigned a Device Location of OFF, they could be grouped together in the 24-Hour No Pulse query and not be reviewed. Other possibilities include assigning a Device Location of SEASONAL to any location that historically has been noted as zero or minimal use during the winter season. Irrigation metered accounts could be assigned a Device Location of IRRIGATION. Additional grouping could be used comparing current use to historical use, etc. All of these options would reduce the number of scenarios requiring manual review; however, it must be noted that this isn't a foolproof method. For instance, a meter that was once used mostly during the summer and thus listed as SEASONAL could become a year-round premise, or vice versa.

  To reduce the number of cases of 24-Hour No Pulse to a manageable amount would require additional work, alternations, and resources. Additionally, the suggestions outlined above would reduce the quantity of cases investigated to a more manageable amount, but would not be foolproof.

- **Reverse Rotation** means the power is running backwards through the meter. A possible cause of this could be if the meter was turned upside down. Very few reverse rotation situations have been recorded thus far. To determine if a problem exists, it is necessary to manually investigate each occurrence. The Customer Account Management Center (CAMC) can also identify many reverse rotations as part of the billing process. Because of the small number of reverse rotation occurrences, the instances are manageable to follow-up on manually by investigating each occurrence.

  IPC has noted the following quantities of events in 2005.

  - Blink Count: Approx. 366,796 blinks were recorded from Jan 1, 2005 to November 17, 2005.
  - 24 Hour No Pulse: 2,439 Average Daily Count
  - Reverse Rotation: 10 Occurrences from two meters

Conclusions regarding the energy theft capabilities are as follows:

1. The large number of Blink Counts recorded are mostly the result of normal operations. When Blink Counts are recorded, there is no addition information provided such as cause, duration, etc.
2. The 24-Hour No Pulse counts are recorded anytime an active meter has gone 24 hours without any recordable usage. This includes many scenarios where this occurrence is acceptable. When a 24-Hour No Pulse is recorded, there is no indication as to what type of service it is and whether or not no pulse event is consistent with historical data. With additional changes, time and resources, it may be possible to customize the 24-Hour No Pulse into a more usable format.
3. Reverse Rotations are recorded when power is flowing backwards through a meter. It is possible for the CAMC to discover some reverse rotations through their normal billing errors. There are relatively few Reverse Rotations recorded. The limited quantity makes it feasible to manually investigate each one.

   IPC is not relying on Blink Count and 24-Hour No Power to detect revenue loss. The time and cost it would take to manually investigate each situation would be much greater than any benefit realized. However, IPC is using the Reverse Rotation feature, combined with the work the CAMC already does, to locate and correct reverse rotation situations as soon as possible.

   While this will aid in investigating potential energy theft, during the Phase One project, IPC was unable to document actual energy theft occurrences using the AMR technology. Two meters were flagged for Reverse Rotation. The first instance was a result of a meter being installed in an inverted position by a contractor after the pole it was mounted on was knocked over by a tractor. The second site was legitimate reverse rotation due to a solar panel installed on the customer's service.

f. Outage Confirmation

Pinpointing and responding to an outage is the most immediate reason for outage confirmation. AMR technology can improve IPC's operations regarding outage confirmation and outage management.

Outage Call Confirmation
When a customer calls in to report that power is out, yet there are no other reports of power outages in the same general location, the outage call must be confirmed. Such an outage report requires dispatching personnel to determine whether the power has been interrupted in IPC's system or within the customer's premises. A query of trouble orders entered in our customer information system for the months of May, June, and July indicates there were 11,190 trouble orders. It was determined that in 26 of these cases, the outage was a result of a problem on the customer's premises. An outage detection feature of an AMR system could improve efficiency by allowing IPC to remotely poll the service meter to verify IPC's system integrity prior to dispatching personnel.

Background of Existing Customer Outage Management
Outage management is comprised of 1) detection of a customer outage, 2) identification of the outage magnitude, 3) determination of the open device, and 4) confirmation of restoration of all customers affected by the outage. IPC has implemented a centralized software-based outage management system (OMS). The system is monitored 24/7 by outage coordinators.

Detection of an outage is accomplished by calls from either customers and/or outage monitoring devices known as sentry units. IPC has installed sentry units at customer premises throughout the service territory. The units have been strategically placed on the load side of each feeder protective device (protective devices open to remove short circuits from the power system) to allow detection of the opening of any of these devices. Each sentry unit detects an outage and calls into the OMS. The OMS allows operators to input customer outage reports and automatically time-tags an event reported by the sentry units.

The OMS performs analysis on all customer calls and reporting sentry units. The system displays the magnitude of the outage and determines the probable open protective device. The outage coordinators are able to dispatch crews to the outage area and direct them to the open protective device.

Confirmation of restoration is also provided by the sentry units. When voltage is restored to a sentry unit, it calls in to the OMS to report that voltage has been restored. This indicates that the protective device has been closed; however, it does not provide confirmation that voltage has been restored to all customers.

Outage Restoration of Large-Scale Outages
Other utilities cite significant cost savings from the improved ability to manage the restoration of customers during severe weather events such as ice storms, hurricanes etc. IPC's system does not experience these large magnitude events, but events resulting in

the outage of greater than 25,000 customers do occur every three to five years. During these events there are often smaller clusters of customers who incur loss of power due to an outage of a single transformer. These localized outages may not be detected by IPC's sentry system.

IPC crews patrol and restore the main feeder service first and may only detect the localized outage during the patrol. The failure to identify this localized outage would result in the re-dispatch of the crews. This re-dispatch occurs at a rate of 25 times per large scale event at a cost of $400 per dispatch. The ability to detect the localized outage clusters would save an estimated $10,000 per large-scale event.

AMR's Ability to Perform or Augment Existing Outage Management
IPC evaluated both the capabilities inherent in the TWACS® system described previously and DCSI's software package that is designed as an outage assessment tool named OASys.

Three features built into the TWACS® OASys system provide informative customer outage information.

1. The ability to report meters that do not reply to the automated meter polling
2. Blink Count, an outage accumulator within each meter
3. The ability for a meter system operator to select a meter (or group of meters) to initiate a polling of the meter(s)

The first and second features are not able to detect the beginning of a customer outage. The practical use of these two features is periodic reporting of the non-responding meters and blink count. These features may help identify single-customer outages where the existing OMS does not monitor the customer and the customer does not call to report the outage. The third feature allows identification of outage magnitude by initiating a polling of a group of meters. However, it requires knowledge of the general location of the outage and a meter system operator to initiate the polling action.

The OASys software tool feature for initiating meter polling may be linked, programmatically, to the existing OMS to allow operators to verify that all customers' voltage has been restored following an outage.

Implementation requires purchase and installation of the DCSI OASys software module. DCSI is allowing IPC to evaluate the current OASys product at no cost through 2005. In summary, with a system-wide AMR deployment, it is expected that IPC would realize an average estimated $22,500 savings per year in reducing unnecessary trouble dispatches.

g. Voltage Monitoring

AMR technology provides additional voltage monitoring information that can be used by IPC technicians and engineers.

The voltage supplied throughout the power system varies based on loading conditions. Devices are deployed to correct the voltage before it exceeds the operating band provided for in the ANSI C84.1 standard of 114 and 126 volts. Voltage monitoring is desired to verify proper performance of the automated voltage regulating devices.

Background of Existing Voltage Monitoring

The distribution level voltage is monitored by IPC's energy management system (EMS) at the substations. Alarms within the EMS notify the dispatcher when the voltage varies outside 126 and 114 volts. The dispatcher sends a technician to the station to determine the cause of the alarm. When power flow analysis determines that a feeder section voltage is low, a technician is dispatched to the feeder section to measure the voltage. Additionally, a customer notification of low voltage results in dispatching a technician to measure a customer's voltage. Once low voltage is verified, IPC attempts to correct it with adjustments of operating equipment. If there is no ability to correct the voltage with existing operating equipment, IPC makes a budget request for capital improvement funding. These requests are reviewed monthly and implemented based on systematic evaluation between projects.

AMR Voltage-Monitoring Capability

The three-phase AMR enhanced meters provide a revenue-accurate voltage reading. However, the single-phase residential AMR enhanced meter provides a voltage measurement within the communications module. This voltage is specified to have an accuracy of +/-5 percent. For IPC evaluation, 30 meters were selected near each regulating device and along each branch of the feeder. These meters were polled at 12:00 AM, 6:00 AM, 4:00 PM, and 8:00 PM. IPC's experience with the single-phase meters has shown 26 voltage readings above the ANSI C84.1 range. All of these high voltages occurred on four meters. IPC believes that the accuracy of the readings is suitable to detect voltage operation outside the allowed band. Finally, in order to use the AMR system to monitor voltage, IPC would have to develop software that analyzes voltage data for reading out-of-tolerance and that generates a report of the analysis.

Implementation costs would include programming and development of a system to automatically report out-of-tolerance meter voltage (provided the single-phase meter accuracy is not an issue).

The AMR voltage-monitoring technology could theoretically reduce dispatch of personnel to verify voltage complaints. However, other costs associated with investigating and correcting voltage problems will remain and are not impacted by AMR. Additionally, there will be initial costs in developing an automated voltage reporting system from data retrieved by AMR.

Given all of this, IPC views the AMR voltage monitoring functionality as an additional tool that will help technicians and engineers in their ongoing evaluation of system voltages; however, AMR will not result in any hard dollar cost savings related to the voltage monitoring functionality.

h. Potential for Improvements to Distribution Engineering, Planning, and Operations

IPC's Engineering Operations and Planning department may use the load data provided by AMR. However, IPC also believes there is limited benefit from AMR implementation because it is able to generate the data programmatically with acceptable accuracy via other state of the art software modeling tools.

Background of Existing Operations and Planning
The distribution system is analyzed for device overloads (conductor, transformer, fuses, switches, etc.), under-voltage, and over-voltage conditions using standard industry feeder modeling software (SynerGEE). Analysis of present and future loading scenarios may be performed. The loading scenarios have recently been improved by the implementation of the Nexus Wire Vision software which allocates and forecasts loads based on customer usage modeling and weather data. The load models in Wire Vision were determined from load research data and are of suitable accuracy for operations engineering and planning. Additionally, the software is designed to accept customer interval data.

AMR's Effect on Operations and Planning
The implementation of AMR will augment the existing approach to operations engineering by providing increased accuracy of the load peaks. However, IPC does not believe that the increased accuracy provided by AMR will change operations engineering. There are two situations where determining the loading of feeder sections becomes necessary: planned feeder section work and emergency ties. The planned switching operations for feeder maintenance or construction are dependent on the near-term loading, which strongly correlates with weather conditions. With regard to emergency switching associated with outage, we believe it will be faster to use the Wire Vision and SCADA substation data to determine how much load could be transferred from one feeder to another. IPC has only a short period of time to analyze the load when trying to switch loads to restore customers during emergency conditions (when a device failure occurs). Also, IPC does not foresee benefit for planning as the load growth is determined by many factors, such as the economy and 20-year weather extremes.

Implementation costs would include system programming to develop interfaces to automatically transfer AMR retrieved interval data to the Wire Vision data base. One of the reasons for using complex modeling software such as this is to avoid having to handle and manipulate huge volumes of actual interval data.

In summary, while there may be some specific situations where AMR can provide load data to help with distribution planning/engineering, IPC sees AMR bringing little benefit to distribution planning and engineering due to the presence of the Wire Vision and SynerGee modeling systems.

11. Costs - Phase One AMR Project

a. Capital Costs

Projected final capital costs, including all vendor costs, contract costs, IPC labor and costs, loadings, overheads, and AFUDC for each of the three major project components of the Phase One AMR Project are as follows:

TWACS® AMR System	Projected Cost
Installed Cost of Meters, Substation, Software, Servers, including labor	$5,855,144
Installed Cost of Itron EE MDMS System Software & Servers including labor	$ 770,000 (See Note 1)
Installed Cost of Nexus Energy Software including labor	$ 234,280 (See Note 2)
Total Projected Phase One Project Cost	**$6,859,424**

Notes:

1. Final Phase One Project costs for the Itron EE MDMS system will carry over into 2006 as IEE version 5.0 VEE is implemented. The amount shown ($770,000) is the projected final capital cost, including anticipated 2006 capital expenditures.
2. Final Phase One Project costs for the Nexus Energy Software system will carry over into 2006 as the final business version enhancements of Nexus are installed. The amount shown ($234,280) is the projected final capital cost, including anticipated 2006 capital expenditures.
3. Installation of the TWACS® load control transponders are not included in these numbers, as those costs were included in the A/C Cool Credit program.

The average cost per meter for the Phase One AMR Project, based upon an installed count of 23,474 meters, is $292 per meter.

b. O&M Operational Costs

Ongoing operation and maintenance (O&M) costs associated with AMR-related systems are primarily IPC labor to operate and maintain the systems and annual software maintenance fees to the system vendors.

IPC Labor Additions: Daily operations and support of the MDMS and TWACS® system is conducted by the IPC Meter Support department. Daily operation of these systems has added the equivalent of one full-time employee under normal operating conditions, with additional resources needed when communications and system problems occur. This figure correlates to an estimated labor cost of $90,000 to $100,000 per year.

The Nexus application is hosted by Nexus. The hosting costs are reflected in their annual hosting fees; hence, there is not a significant increase in IPC labor requirements for ongoing maintenance of the Nexus system.

Annual Fees to Vendors: All of the three major AMR systems require the payment of annual software support fees to the respective software vendors. These fees include problem support and fixes and eligibility to receive software updates and upgrades. An annual fee is also due to DCSI Technology Escrow Services, for maintenance of an escrow account that holds the DCSI source code.

AMR Meters Installed	O&M Fees
Annual O&M Fees to Support the Phase One Project for all Vendors	$91,080

Per the contract agreements, the Itron and Nexus annual fees can appreciate at a pre-determined percentage annually. It should also be noted that these fees are based on the current size of the Phase One project, any further AMR deployment would increase these fees based on the number of installations. IPC licensed the TWACS software for 100,000 meters, and the Itron software for 25,000 meters. Increased quantity of meters beyond these contract limits will require an additional cost.

IPC Labor Savings: IPC experienced a reduction of four meter specialist positions in the Emmett and McCall areas after AMR was installed. This correlates to an estimated cost savings of $303,000 per year. This includes labor and associated vehicle usage and equipment.

IPC also experienced a small decrease in workload in its CAMC due to the elimination of work associated with erroneous meter readings and estimated meter readings. However, this did not correlate to any manpower reductions since the Phase One AMR project area comprised only 5 percent of the entire IPC customer base. The time saved was reallocated toward other related work functions, including support activities for the time-variant pricing programs (TOD and EW).

The installation of the Phase One AMR Project did not result in any other manpower reductions in other departments of the company.

A summary of the annual O&M costs, in year 2005, attributable to operation of the Phase One AMR project are as follows:

New O&M Costs:	
Labor for AMR system operations	$90,000
Annual O&M fees to vendors	$91,080
Phone charges	$8,356
Total – New O&M Costs	**$189,436**
O&M Savings	
Operational Savings	$303,000
Net Change in annual O&M costs (year 2005):	**$(113,564)**

It should be noted that these costs and savings are reflective of the Phase One Project. The annual fees to vendors would increase substantially based on increased number installed meter points, therefore this is not reflective of operating costs in an expanded AMR deployment.

12. Benefits of the Phase One AMR Project

a. General Discussion

Much information available regarding AMR-related benefits and cost savings has been presented by numerous viewpoints, including AMR industry groups, AMR vendors, AMR consultants, AMR owners, and regulators. IPC's assessment is that the AMR benefits provided by these sources vary significantly depending upon the respective author's point of view and affiliation. Also, benefits can vary significantly from utility to utility based upon each utility's existing cost structure, geography, customer base, and regulatory environment. Given this, AMR benefits must be quantified based upon IPC's own set of current conditions and environment. Therefore, in determining projected benefits of AMR, IPC has reviewed the information presented by these various outside sources, but has focused primarily on its own assessments to quantify AMR-related benefits and cost savings.

There are "hard" and "soft" benefits associated with an AMR deployment. A "hard" benefit is one in which firm dollar cost savings have been identified through either manpower reductions or some other firm, fixed-cost savings. A "soft" benefit is one in which there is not any documented manpower reductions or other firm, fixed-cost savings associated with the benefit. included in the financial model since they don't result in any documented cost savings.

b. Hard Benefits of AMR

Hard benefits of AMR are those benefits that result in manpower reductions or other documented hard dollar cost savings. These hard benefits may include:

Meter Operation Benefits

Manual meter reading is significantly affected by AMR technology. IPC was able to identify many of the follow benefits in its Phase One project.

- Reduction of manual meter reading workforce. Savings for Phase One included reduced meter reading transaction costs of $303,000.
- Reduction of the Manual Meter Reading System (MVRS) software maintenance fees, hand-held maintenance fees, and repair costs. This benefit is only realized if a full implementation of AMR is undertaken; any partial or mixed technology solutions would still require IPC to maintain this product. No MVRS-related cost savings were realized in Phase One.
- Erroneous meter readings are essentially eliminated. This reduces re-read orders and improves bill quality. Savings related to improved meter reading accuracy for Phase One are included in the reduced meter reading transaction costs of $303,000.
- Estimated meter readings due to access or weather issues are significantly reduced.
- Vehicle usage and fuel costs for manual meter reading are reduced. Vehicle-related cost savings for Phase One are included in the reduced meter reading transaction costs of $303,000.
- Move in/move out orders not requiring physical connect/disconnect can be completed through automation rather than with a manual visit. Savings associated with this automation for Phase One is included in the reduced meter reading transaction costs of $303,000.
- Stopped or dead meters are identified within 8-24 hours, as opposed to being identified during the next monthly manual reading cycle. No hard benefits were identified in Phase One.
- Routine meter testing is reduced due to an entirely new meter population being in place. This is a temporary benefit that would cycle again in 15 years and require a large full-scale change out of the new meters as the majority of the meter population reaches its life cycle at the same time.

During the Phase One Project, the meter reading staff was reduced by four employees as a result of no longer needing to manually read the routes. This reduction also includes the benefit of completing the move in/move out orders for those who did not require a physical connect/disconnect. In comparing actual costs from 2003, prior to AMR implementation, to IPC operating costs of 2005, a total of $303,000 hard savings will be realized for 2005 in the two AMR service areas.

Customer Service Benefits:
AMR results in the following hard benefits at IPC's Customer Service Center (i.e., the Call Center) and the CAMC:

- Reduction in the volume of customer calls (since calls regarding erroneous bills will be eliminated).
- Reduction in CAMC workload for reviewing exception reports from manual meter reading, issuing orders and completing billing adjustments due to erroneous readings and estimated readings. Erroneous readings and estimated readings will be significantly reduced with AMR.

During the Phase One project, the IPC CAMC and Call Center organizations were not able to reduce any staffing of employees. The billing staff for the entire company in the CAMC to review exceptions and correct billing consists of nine employees. Because the Phase One Project was only five percent of the company's overall customer base, there was not a significant enough benefit to reduce staffing. Two benefits in the CAMC were noted; the first being the elimination of reviewing exception reports associated with the manual meter reading system for high/low validation and meter exceptions; the second being improved accuracy resulting in less corrective work. In total, these two benefits appear to create a 30 percent improvement in CAMC billing efficiency. There are other billing related functions, such as Budget Pay management, that were not affected by AMR efficiencies.

No benefits were obtained from other CAMC processes such as collections. During the implementation of the AMR meters, a spike in workload was created to assist in coordination of meter exchanges, billing cycle coordination, and exception handling of large volumes of the meter exchanges. For the five percent project volume of overall customers, this spike accounted for an additional 25 percent work increase for one employee. In summary, AMR implementation creates a cost to manage the meter exchange processes, but the end result does provide billing efficiency.

The IPC Call Center logs approximately one million calls annually from various channel sources and for different call types. The improvements in billing accuracy of AMR would not make a blanket improvement in overall call volume that would include all call types, but more likely in the billing-specific type. Observations of the overall call volume between 2004 and 2005 for the months of January through October showed that the billing related call volume increased slightly less than one percent overall, 146,757 versus 147,950, for the Company. Tracking mechanisms to track calls by geographic area are not available, but evaluation of the customer contacts stored both by employee and system transactions in IPC's CIS system show that the number of billing customer contacts decreased by 8 percent in the AMR areas, while they increased by 13 percent in the non-AMR areas of the Company. The eight percent is equivalent to 200 calls per year for the AMR areas, not significant enough to reduce IPC call center labor during Phase One. If this is an accurate estimate, applying the eight percent to approximately 150,000 calls per year would equal a 12,000 call reduction annually, or approximately one employee in the Call Center.

c. Soft Benefits of AMR

Soft benefits are those AMR-related benefits that don't translate into manpower reductions or some other form of documented cost savings. No soft benefit cost savings are included in this status report for the Phase One project. Soft benefits include the following.

Customer Satisfaction
AMR deployment will result in increased customer satisfaction in several areas:

- Access to meters by IPC is no longer needed on a monthly basis.
- More accurate bills due to elimination of meter reading errors and estimated meter readings.
- Flexibility to participate in a time-variant pricing program if desired.
- Energy usage data made available to customers to help them make educated decisions regarding their energy usage.
- The ability for IPC to offer aggregated billing to customers with multiple service points, although there may be additional non-AMR costs to IPC in providing this service.

Meter Operations

- **Remote Connect/Disconnect:** If necessary, the remote connect/disconnect devices could be installed on selected high-turnover service points. As discussed in section 8d, it is expected that this functionality will be seldom used, but it is available if necessary or justified.
- **Theft Detection:** As discussed in section 8e, the AMR technology offers some features which may be of assistance in investigating potential instances of energy theft. These tools will be helpful but are not expected to solely result in any significant cost savings.

Engineering, Planning, and Operations

- **Voltage Monitoring:** As discussed in section 8g, voltage data made available by the AMR system will be another piece of information for technicians and engineers to use in identifying, evaluating, and correcting voltage issues on IPC's distribution system. While the data will be helpful, it is not expected to be responsible for any cost savings pertaining to correction of low- or high-voltage situations.
- **Improvements to Distribution Planning and Engineering:** The benefit of the AMR interval data to distribution system planning and engineering activities was discussed in section 8h. The presence of specific electrical system modeling software makes the actual interval data of little benefit for planning and engineering functions. While the actual load data will be of benefit in some

specific situations, it is not of a scale where actual hard dollar benefits can be attributed to it.

13. Conclusions

While there were many "lessons learned" and conclusions drawn during the course of the Phase One AMR Project, the following are the major high-level conclusions reached:

1. **Extremely complex integration of AMR systems with each other and with existing IPC systems**
   a. No true enterprise system existed that met all of IPC's AMR requirements. Data collection, data validation, and data presentment all required different systems from different vendors.
   b. The three separate systems required 11 custom-designed system interfaces. This necessitated significant back office system programming efforts to create, test, and maintain the proper interfaces.
2. **TWACS® AMR technology**
   a. The two-way power line carrier AMR technology works well and is very accurate.
   b. Read accuracy has increased and estimated readings are significantly reduced.
   c. System operation requires significant daily attention along with increased skill requirements of IPC employees to diagnose system issues across the AMR network of systems.
   d. The TWACS® technology doesn't currently work for single-phase substations.
   e. The vendor has issued a service bulletin asking utilities to avoid reading 480-volt meters due to safety concerns of thermal heating of the meters.
   f. Variable-speed drives in irrigation pumps were a common denominator in meter failures; the vendor has not provided a diagnosis or solution.
   g. Once installed, the AMR system can be successfully leveraged and used for load control functionality and for other AMR-enhanced functionalities. However, some of the AMR-enhanced functionalities, while useful, do not contribute to hard dollar cost savings.
   h. The technological interrelationship between the AMR software, substation equipment, and meter requires that each component of the technology be of the correct vendor version that allows synchronization to enable communication and functional operation. Upgrades to a specific component may also require upgrades to the other two components.
3. **MDMS technology**
   a. IPC views its use of meter data management software as leading edge in the industry. At the time of the Phase One AMR Project, there were few, if any, other utilities attempting to validate, edit, and estimate mass volumes of hourly interval data and turn it into billing-quality data in the manner that IPC was doing. These

"leading edge" requirements contributed to the delays experienced by IPC's vendor in providing an acceptable MDMS.

b. IPC foresees that MDMS software will receive extensive industry attention as more utilities attempt to properly manage their AMR data. IPC expects to see continued and rapid enhancements in meter data management systems over time.

c. The scalability of MDMS software to a full IPC deployment needs evaluation during the ongoing version 5.0 implementation. This is an open issue that must be resolved prior to moving ahead with further large-scale AMR deployments.

4. **Data Collection–Hourly Consumption Data and Daily Meter Readings**

   a. Collection, management, and storage of hourly consumption data on a mass scale requires significant additional processing time and storage for both the TWACS® and Itron EE MDMS systems. Given this, IPC suggests collection of hourly consumption data should only be conducted when a valid business reason exists.

   b. Collection of a daily meter reading should be the minimum requirement for all meters.

5. **Customer Interest in AMR Data**

   a. Customer interest in looking at their AMR data was very low during the solicitation period for the time-variant pricing programs in Emmett. Interest remained low during the program period for those customers enrolled in the programs.

   b. The AMR customer survey conducted in September 2005 indicated 87 percent of respondents would rather see usage information on their monthly bill than through the Internet; 13 percent indicated a Web solution would be preferred.

6. **Project Cost and Benefits**

   a. The limited implementation schedule was not sufficient for IPC to negotiate contract terms and pricing.

   b. The cost of the project was $6.8 million, or $292 per installed meter. This cost included products and services from three vendors to enable time variant pricing programs through the collection, management, and presentment of hourly data. This infrastructure was sized accordingly for Phase One; if further AMR is pursued, it will require expansion of licensing and hardware.

   c. The realized benefits are $303,000 annually in labor, mileage, and overhead costs associated with the meter reading and service order transactions. IPC did not recognize any other hard benefits.

Part 3—Future Actions Relating to AMR

1. Analysis of Future AMR Deployments.

The AMR project has shown potential benefits, but before any decisions can be made about expanding this program more work is needed with respect to economic analysis, business requirement definition and planning, monitoring of the maturity of AMR technologies, an AMR industry analysis, and defining and understanding customer needs and behaviors. This work should acknowledge the following conclusions reached as a result of the Phase One project:

- The cost of the Phase One Project was $6.8 million, or $292 per meter point. The associated realized benefits are $303,000 annually. In combination, these values do not reflect a positive cost-benefit analysis. AMR will require time to mature in its technology lifecycle; IPC will continue to analyze increased and other realizable benefits, along with further evaluation of implementation cost options. By continuing to monitor and develop these items in combination, IPC will be able to monitor any change in the balance between costs and benefits.

- TWACS® performs well when asked to provide monthly or daily reads. The system and its limited bandwidth of communication start to show limitations in the collection of hourly reads. This limitation required dedicated manual oversight to collect hourly reads.

- Meter reading accuracy has increased and estimated readings are significantly reduced. This demonstrates that AMR can improve bill quality. IPC was not able to translate these soft benefits into a hard dollar savings during the Phase One project.
- The AMR system provides an abundance of data to evaluate for theft detection and outage events. The volume of data will require either advanced software, or added labor costs to evaluate the data for effective determination of any benefit.

- The current service advisory from DCSI regarding the 480-volt meters, meter issues associated with the use of variable speed drives, and single phase substation limitations leave a portion of IPC's meter population without an AMR solution, or at a minimum without the ability to collect time-variant daily or hourly data.

- TWACS® has effective add-on components such as the load control devices used to cycle air conditioners. Even though IPC-related implementation issues with the air conditioning cycling in the Emmett area resulted in the program not working as intended, the technology worked as designed. .

- The Itron MDMS was not functional during Phase One, requiring manual intervention for the bill processing of all interval data used for the two time-variant pricing programs. As of this status report, IPC and Itron continue to work with the new version 5.0 MDMS to evaluate is effectiveness. No definitive conclusion can be reached until testing is completed in 2006.

- A workable MDMS solution is required to expand time-variant pricing programs.
- Customers showed limited interest in obtaining hourly data via the Nexus software accessed via IPC's Web site. Only 58 customers in the Emmett and McCall areas viewed their hourly data. Of the customers surveyed by Northwest Research Group, Inc., 87 percent stated they would rather see usage information on their bill.
- Evaluation of the AMR industry with respect to recent announcements that large, investor-owned utilities may sign sizeable AMR contracts in the near future. These large contracts may provide industry vendor incentive and opportunity to improve the technology, along with lowering the cost through increased production.

2. Next Steps

During the Phase One AMR Project, IPC has gathered valuable information on the operation of its AMR system and the interaction between various systems needed to fully utilize and implement AMR-related features and capabilities. In order to facilitate our in-depth evaluation of AMR and potential future options and strategies, IPC contracted with MW Consulting, a leading consulting firm with extensive experience in the AMR field. Based on the guidance provided by MW Consulting, the company has adopted the following twelve- to twenty-four-month strategy for determining its future AMR policy.

- Allow the AMR technology to mature for a minimum of one year. It is expected, as with most technology lifecycles, that the technology functionality with memory, bandwidth, and reliability will improve. IPC plans to continue testing and evaluating new TWACS® products in 2006 with regard to substation equipment improvements and new meters with expanded memory, in addition to software upgrades. These items are not presently available for testing or evaluation. These specific activities include:
  - Upgrade TWACS® software from version 2.1 to 2.3, or possibly to 2.4, dependant upon version compatibility requirements with substation or meter evaluations.
  - Evaluate new substation equipment to test increased bandwidth ability. This item is dependant upon the vendor providing equipment in a production release, plus a software upgrade that is compatible with the new equipment.
  - Evaluate new extended memory (XM) meter modules with 7-day memory. This item is dependant upon the vendor providing equipment in a production release, plus a software upgrade that is compatible with the new equipment.
  - Identify resolution options for 480-volt meter problems This item is dependant upon the vendor providing equipment in a production release.
  - Identify resolution options for VSD compatibility. This item is dependant upon the vendor providing equipment in a production release.
  - Evaluate primary metering AMR options with the vendor.
  - Further evaluate tamper detection data and processes that make the data meaningful.

- Further evaluate the OASys outage management abilities from DCSI to identify operational benefits and integration with other IPC outage systems and operations.
- Request information from the vendor in regards to single-phase substation solutions and costs.
- Test AMR equipment using temporary substation transformers while a substation is taken down for planned maintenance with the intent of gaining a better understanding of how to maintain AMR quality of service while performing normal IPC equipment maintenance.

- Allow the MDMS technology to mature for a minimum of one year. IPC and Itron have agreed to a testing plan for Version 5.0 of the MDMS that is to be completed in April 2006. This is a critical technology link to enable time-variant pricing programs such as TOD or EW on a larger scale. Key activities include:
  - Install Version 5.0 and conduct a functional test of the software for VEE and time variant billing output.
  - Load the 2005 hourly data collected from TWACS® and reproduce the 2005 customer TOD and EW pricing program outputs as a parallel test.
- Conduct further investigation to identify and quantify other realizable hard benefits that may be available from AMR. Any identified benefits would be used to update the ongoing financial models assessment.
- Define the specific business requirements and associated functionality needs that require AMR implementation.
- Evaluate possible implementation models using a measured approach to geographical implementation of AMR in defined areas of IPC's service territory that provide the greatest economic value and use of the AMR systems.
- Evaluate other AMR technologies more thoroughly with the possibility of a mixed AMR approach using varied technologies such a radio frequency and TWACS® in combination.
- Conduct a competitive bidding process during the first half of 2007 that includes new Request for Proposals to multiple vendors. The intent is to achieve the maximum value for customers and IPC, as well as provide updated information to the financial analysis while considering updates in technology. IPC must evaluate the market for technology solutions that meet business requirements in the most cost effective manner.
- Conduct an in-depth financial analysis of AMR during the second half of 2007 using varied scenarios of cost options and benefit possibilities. IPC recognized tangible results from the Phase One Project; further evaluation is necessary to construct a business case that fully compares the cost options to other realizable benefits.

IPC believes this strategy will allow it to fully understand the costs, benefits, and customer impacts of AMR prior to determining its future AMR policy.