BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-090134

DOCKET NO. UG-090135

DOCKET NO. UG-060518

(consolidated)

EXHIBIT NO. SJK-6

SCOTT J. KINNEY

REPRESENTING AVISTA CORPORATION

REDACTED

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/06/2009
CASE NO:	UE-090134 & UG-090135	WITNESS:	Scott Kinney
REQUESTER:	WUTC Staff	RESPONDER:	Scott Kinney
TYPE:	Data Request	DEPT:	System Operations
REQUEST NO.:	Staff – 046	TELEPHONE:	(509) 495-4494
		EMAIL:	scott.kinney@avistacorp.com

REQUEST:

Re: Testimony of Scott J. Kinney

For each of the Transmission and Distribution Capital Projects described beginning on page 12 of your testimony, please provide all cost-benefit analyses prepared by the Company or its agents. Please specifically identify any increases in revenues or decreases in costs as a result of each project described in the testimony and included in pro forma period costs.

RESPONSE:

The Transmission and Distribution Capital Projects described in my testimony are all being constructed to meet either compliance requirements, improve system reliability, fix broken equipment, or replace aging equipment that is soon to fail. Included in the compliance requirements are the North American Electric Reliability Corporation (NERC) requirements, which are national reliability standards for utilities to follow to ensure interconnected system reliability. Beginning June 2007 the standards became mandatory and non-compliance may result in monetary penalties. The reliability standards include several transmission planning and operating requirements. The planning standards require utilities to plan and operate their transmission systems in such a way as to avoid the loss of customers or impacting neighboring utilities with the loss of transmission facilities. The transmission system must be designed and operated so that the loss of up to two facilities simultaneously will have no impact to the interconnected transmission system. These requirements drove the need for Avista to invest in its transmission system.

Avista project requirements are developed through system planning studies, engineering analysis, or scheduled upgrades or replacements. The larger specific projects that are developed through the system planning study process typically go through a thorough internal review process that includes multiple stakeholder review to ensure all system needs are adequately addressed. For the smaller specific projects, Avista doesn't perform a traditional cost-benefit analysis. Projects are selected to meet specific system needs. However, both project cost and system benefits are considered in the analysis to select the final projects.

Three of the projects included in my testimony are associated with the Company's 5-year 230 kV Upgrade projects that were constructed from 2003 though 2007 (previously approved by the WUTC). These projects include:

- Lolo Substation ($2.05 million): This project involves the rebuild of the existing Lolo substation to increase the capacity of the substation bus, breakers, and supporting equipment to match the upgraded area transmission lines. The new Lolo substation design significantly improves reliability and operating flexibility. The Lolo Substation project was constructed in phases to allow operational flexibility due to system reliability concerns associated with other scheduled construction in the area. Phase 1 was completed and placed into service in 2007 and the second phase will be constructed over a two year period with energization scheduled for fall of 2009. Approximately \$0.80 million of work was completed in 2008 and will be transferred to plant in 2009 with the additional estimated amount of \$1.25 million. The Lolo Substation project costs were developed by the Engineering Department and approved through the capital budget process.

- Noxon-Pine Creek Fiber (\$0.65 million): This project is required to reinforce the optical fiber wire supported by the transmission poles on the Noxon-Pine Creek 230 kV line. This line routes through the mountains of north Idaho and is subjected to severe winter weather. Operational history has demonstrated a need to reinforce the communication circuit. This communication circuit is part of the Noxon/Cabinet WECC certified RAS scheme and is required to meet reliability standards.
- Benewah-Shawnee 230 kV Line Construct (\$0.56 million): This work is necessary to increase separation between the 230 kV and 115 kV conductors on this double circuit line. The lines have contacted each other during high winds resulting in line outages. In addition to line work to increase phase clearance, Avista plan to install a Hathaway-traveling wave monitoring system to more accurately determine the location of phase to phase contacts. The 230 kV line was constructed to meet reliability standard requirements.

The Noxon – Pine Creek and Benewah – Shawnee are supplemental projects that will enhance the reliability and utilization of the projects completed during the 5 year 230 kV Upgrade program. As described above, these projects involve the redesign and minor rebuild of sections of these lines that have experienced equipment failure or malfunction. These project costs were developed by the Transmission Design Department and have been reviewed and approved through the Company's capital budget process.

Several of the projects are being constructed to meet requirements in the mandatory reliability standards, and we are required to construct all of these compliance-related projects, to avoid fines and penalties associated with the reliability standards. These projects include:

- Spokane/Coeur d'Alene area relay upgrade phase 2 (\$1.25 million): This project involves the replacement of older protective 115 kV system relays with new micro-processer relays to increase system reliability by reducing the amount of time it takes to sense a system disturbance and isolate it from the system. This is a five year project and is required to maintain compliance with mandatory reliability standards. See attachments listed below for additional need information.
- SCADA Replacement (\$0.74 million): The Supervisory Control and Data Acquisition (SCADA) system is used by the system operators to monitor and control the Avista transmission system and the upgrade is required to ensure Avista has adequate control and monitoring of its Transmission facilities. This project, to be completed in 2009, involves upgrading the SCADA program to the latest version released by the third party software provider. Several Remote Terminal Units (RTUs) located at substations throughout Avista's service territory will also be replaced. The RTUs are part of the transmission control system.
- System Replace/Install Capacitor Bank (\$0.80 million): This project includes the construction of a 115 kV capacitor bank at Airway Heights (\$0.60 million) to support local area voltages during system outages. The project is required to meet reliability compliance and provide improved service to customers. Another \$0.20 million will be spent to replace leaking or old capacitors on the Avista system. See attachments listed below for additional need information.
- Burke 115 kV Protection and Metering (\$0.53 million): This project includes upgrading the Burke interchange meters as well as 115 kV line relaying for the Burke-Pine Creek #3 and #4 lines. The meter replacement and upgrade projects are required to ensure Avista has adequate interchange metering with adjacent utilities to keep track of power flow between the entities and is required to

meet reliability compliance standards. The estimated cost of the relay upgrade is $400,000 and the metering upgrade is estimated at $125,000.

Reports describing the need for the Spokane/Coeur d'Alene area relay upgrade phase project, and the Replace/Install Capacitor Bank can be found in attachments "Staff_DR_046 Attachment A", "Staff_DR_046 Attachment B" and "Staff_DR_046 Attachment C".

Also the Beacon Storage Yard Oil Containment project is required for environmental compliance:

- Beacon Storage Yard Oil Containment ($0.53 million): The Beacon Storage Yard is a location where circuit breakers and power transformers are staged for rotation into existing substations or for new construction. This site is near the Spokane River and this project work will provide an oil containment system to protect the local environment.

Many of the projects discussed in my testimony are being constructed to improve system reliability and service to customers. These projects include minor transmission line and feeder rebuilds or reconductor projects, circuit breaker replacements, transformer replacement at Othello, and the Northeast substation rebuild. The replacement projects involve the removal of older deteriorated equipment and the installation of newer in-kind equipment. These projects don't require significant engineering analysis or design. Most of the reconductor projects involve engineering or system analysis. For these projects a project diagram is developed that illustrates the project needs, requirements, and costs. Project diagrams for the feeder reconductor projects can be found in attachments "Staff_DR_046 Attachment D", "Staff_DR_046 Attachment E" and "Staff_DR_046 Attachment F". A recap from my testimony of these types of projects is as follows:

- Power Circuit Breakers ($0.54 million): The Company transfers all circuit breakers to plant upon receiving them. In 2009 the Company will receive and replace 4 circuit breakers in its system.
- Mos230-Pullman 115 Reconductor ($0.59 million): The transmission line is being upgraded from 1/0 Copper to 556 kcm Aluminum (100 MVA-Summer) to mitigate thermal overloads experienced during heavy summer load conditions. The line upgrade will improve load service between Moscow and Shawnee.
- The remaining transmission specific projects ($0.94 million total) being constructed in 2009 are smaller projects, including a line reconfiguration to provide back up service, minor work associated with Colstrip transmission, and re-insulating a 230 kV line due to failing insulators. These smaller projects are required to operate the transmission system safely and reliably.
- Othello Transformer Replacement ($0.67 million): One of the existing transformers at the Othello substation needs to be replaced because of its age and concerns that if it fails it could have an impact on the environment. The project includes the cost of the replacement transformer and the labor to install it.
- Northeast Substation ($0.23 million): Northeast Substation is being rebuilt to eliminate high fault duty issues caused by the present substation configuration where the two parallel 20 MVA transformers feed the 4-feeder bay switchgear. This project also rebuilds the distribution structures to Avista's present outdoor substation feeder standards, eliminating old metalclad switchgear.
- Increase Valley Mall Transfer Cap ($0.20 million): This project involves increasing the capacity of a distribution feeder from Spokane Industrial Park by replacing the existing voltage regulators. Increasing the regulator size will improve customer service and reliability during outage conditions.
- Distribution Feeder Reconductor Projects ($1.05 million): These projects involve the reconductor of sections of four feeders in Washington. The feeders are required to be reconductored to eliminate thermal loading issues and improve service reliability to existing customers during normal and outage conditions.

Two new substations projects are included in my testimony:

- Terre View Substation ($1.96 million): Terre View Substation is located in northeast Pullman on the north side of the WSU campus. This substation is required to improve system reliability and meet capacity requirements in and around the WSU/Pullman area. The substation will serve highly sensitive WSU biotech loads. The engineering design and a portion of the construction were completed in 2008. The substation will be energized in 2009. Avista has signed an agreement with WSU to construct this project to meet the needs of the University. A copy of the agreement can be found in Avista's Confidential response Staff_DR_046C.
- Otis Orchards Substation ($0.98 million) is located in the Spokane Valley: In 2009 the Company will begin the engineering design and site work for a new 20 MVA transformer and two new feeders to be added to the existing Otis Orchards Substation. The addition is required to meet existing customer capacity needs and maintain system reliability in the Spokane Valley. The transformer will be transferred to plant in 2009 since the Company transfers all power transformers to plant upon receiving them. The two feeders will also be constructed and energized in 2009. The transformer will be placed into service in 2010. A project diagram that describes the project requirements and costs is included as "Staff_DR_046 Attachment H".

The company has also started a capital program to improve system reliability and load service on feeders or areas that experience outage frequency or durations above the average. Avista monitors and tracks several industry reliability metrics (CAIDI, SAIFI, SAIDI, MAIFI) on a system basis and per feeder to measure system reliability. This information is consolidated into an annual report that is also sent to the Washington State Commission. The 2007 report is included in this data request as "Staff_DR_046 Attachment I". From this annual analysis the company selects several feeders to work on to improve load service. The 2009 projects in Washington include rebuilding portions of feeders and adding equipment in Chewelah and Valley Washington.

Most of the capital projects listed on pages 17 and 18 are non project specific annual programs that involve the replacement of failed equipment that occurs during the year or involve equipment replacement due to observed failure rates. These programs were created to improve system reliability and reduce customer outages by replacing equipment prior to failure. The Company has developed a 5 year asset management plan that describes the costs and benefits of the program. The plan is described in "Staff_DR_046 Attachment J". "Staff_DR_046 Attachment K" shows the budgeted 2009 costs associated with these programs as well as the actual expenditures over the last three years where applicable. A recap from my testimony of these types of projects is as follows:

- Electric Distribution Minor Blanket Projects ($7.92 million): This effort includes the replacement of poles and cross-arms on distribution lines in 2009 as required, due to storm damage, wind, fires, or obsolescence.
- Capital Distribution Feeder Repair Work ($4.10 million): This work is to be done in conjunction with the wood-pole management program. As feeders are inspected as part of the wood-pole management program, issues are identified unrelated to the condition of the pole. This project funds the work required to resolve those issues (i.e. leaking transformers, transformers older than 1964, failed arrestors, missing grounds, damaged cutouts).
- Wood Pole Replacement Program ($3.70 million): The distribution wood-pole management program is a strength evaluation of a certain percentage of the pole population each year. Depending on the test results for a given pole, that pole is either considered satisfactory, reinforced with a steel stub, or replaced.
- Electric Underground Replacement ($3.16 million): Replace high and low voltage underground cable as required in 2009, due to cable failure or obsolescence.

- T&D Line Relocation ($2.30 million): Relocation of transmission and distribution lines as required due to road moves.
- Failed Electric Plant ($1.99 million): Replacement of distribution equipment throughout the year as required due to equipment failure.
- Spokane Electric Network Increase Capacity ($1.61 million): These projects are associated with the Downtown Spokane electric network. The projects involve the installation of vaults, cables, network transformers and protectors as required to maintain reliable service to existing customers by replacing overloaded and deteriorated equipment.
- System - Dist Reliability - Improve Worst Feeders ($1.10M total, $750K in Washington): Based on a combination of reliability statistics, including CAIDI, SAIFI, and CEMI (Customers Experiencing Multiple Interruptions), feeders have been selected for reliability improvement work. This work is expected to improve the reliability of these feeders.
- Open Wire Secondary ($1.00 million): Avista has over 60 miles of secondary districts that consist of 2, 120 volt to ground uninsulated (open wire) conductors installed between poles and served by one overhead transformer. These service installations were installed in the 1950's and 1960's. When there is contact across the 120 volt conductor and the ground wire due to trees or other causes, the conductor fails resulting in customer outages. This project replaces the open wire conductor with insulated conductor and reduces the length of some of the secondary circuits. This effort should reduce the number and length of outages and improve customer service.

Project costs are estimated by the engineering department based on a number of factors. In general, the budget process starts with a high level project scope and basic construction requirements like materials, equipment, and labor. Costs for completed jobs of a similar nature are always used to help determine budget estimates. All construction materials and equipment are included in the estimates with the exception of power transformers and high voltage (60 kV or higher) circuit breakers, which are both budgeted separately. Labor estimates are broken into man-days that include both design and construction functions. Design labor includes engineering, drafting, real estate (permitting), surveying, and overall project management. Construction labor includes the various crews necessary for structural, electrical, relaying, and communication work. Additional items included in the budget process are transportation loadings, room and board costs, special contracts (engineering consultants, construction contracts, etc.), job type loadings (distribution vs. transmission), and AFUDC calculations. "Staff_DR_046 Attachment L" is an example of a 2009 budget item for Burke 115 kV Substation. Also a copy of a Capital Project Request Form that shows an example of the additional project cost review and approval by management is included as "Staff_DR_046 Attachment M".

Since the capital projects included in my testimony are being constructed to meet compliance requirements, improve system reliability or replace broken or aging equipment, the Company is not anticipating collecting any additional revenues. Some of the replacement projects may reduce future maintenance costs since older equipment is being replaced. That is the objective of the Company's Asset Management program discussed previously. Please see "Staff_DR_046 Attachment J" for a description of potential future avoided maintenance cost reductions associated with the Company's asset management program.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	03/05/2009
CASE NO:	UE-090134 & UG-090135	WITNESS:	Scott Kinney
REQUESTER:	WUTC Staff	RESPONDER:	Scott Kinney
TYPE:	Data Request	DEPT:	System Operations
REQUEST NO.:	Staff – 046C	TELEPHONE:	(509) 495-4494
		EMAIL:	scott.kinney@avistacorp.com

REQUEST:

Re: Testimony of Scott J. Kinney

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RESPONSE:

The information in these documents are **CONFIDENTIAL** in nature and is protected per Protective Order in WUTC Dockets UE-090134 and UG-090135 and by WAC 480-07-160

Please see "Staff_DR_046C-CONFIDENTIAL Attachment G" containing a copy of the agreement relating to the Terre View substation.

Utilities

ENGINEERING PROTECTION GROUP MEMO

To: FILE

From: Dennis Howey

Subject: Upgrading 115 kV Relay Schemes Around Spokane – Coeur d' Alene Area **REV 1: 12/15/05 REV 2: 10/25/07 REV 3: 3/22/08 REV 4: 3/31/08**

Filename: G:\relay_pr\CDA-Spokane 115 kV Relay Upgrades\115 kV Relay Upgrades\Upgrading 115 kV Relay Schemes.doc

Date: 12/15/05 10/25/07 3/22/08 3/28/08

CC: Randy Cloward, Rick Vermeers, Mike Magruder, Randy Spacek, Scott Kinney, Scott Waples, Dick Schatzka, Jacob Reidt, Rich Hydzik, Garth Brandon, Jim Corder, Larry Hager, Bill Kelley, Jeff Marsh, Tim Figart, Jon Harms

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Revision 4: 3/31/08

Something that I knew but failed to take into account was the fact that if we have a line that can be sectionalized (usually because of intervening substations), then we can't use the SEL 311L current differential relay scheme. This is because if we get a fault on one side of the open the 311L on that side will pickup and issue a trip by current differential but then also sends a direct transfer trip to the other end so we would trip both breakers on that line even though we would only need to trip one side. This transfer trip function is built into the relay and can't be disabled.

Therefore, we won't use the current differential function and won't need high speed SONET data cards for those lines that have sectionalizing capability. For those lines that don't have sectionalizing capability (no intervening load) we will still use the current differential. Also I discussed this with BPA and we decided not to use current differential on the Beacon A-610 to Bell B-358 line either because BPA can't disable the current differential when they use an auxiliary breaker in the B-359 position. However, a POTT scheme works fine with intervening load and sectionalizing and the 311L is capable of using a POTT scheme so we decided to use two POTT schemes (421 is one and 311L is the other) on those lines with intervening load. This means we will use two slow speed SONET cards per terminal instead of one high and one low.

This has the effect of lowering the number of high speed SONET cards needed by 24 to 16 and raising the slow speed from 48 to 72. The savings by doing this is about $10,000. See following updated information.

Revision 3: 3/22/08

The Telecommunications group will need to order specific equipment including high (for current differential – 311L) or low speed (for Permissive Overreaching Transfer Trip [POTT] schemes - 321 &/or 421) data SONET cards. Because of this, to avoid confusion and because some things have changed since the last revision of the memo, we are going to pre-design all of the line positions much more closely than was originally done using the following criteria:

- When we utilize a SEL 421 and a SEL 311L relay (which is our present line relaying standard) at both ends of a line and the line can't be sectionalized, we will use both a 311L current differential scheme (using high speed SONET data cards) and a POTT scheme using the 421 relays (and using low speed SONET cards). If it can be sectionalized, we will use two POTT schemes with two slow speed SONET cards per terminal.
- When we have existing electromechanical relaying on a terminal we will replace it with our present line relaying standard.
- When we have older SEL relaying not including a SEL 321 (like at Ramsey) we will replace the relaying with our present line relaying standard. NOTE: Originally I had called for just the addition of a single relay for these breaker positions but after discussing this with Mike Magruder and Jeff Marsh

we decided it would be cheaper and better to simply use our present line relaying standard because we can build the panels externally and install them with a minimum of disruption.

- When we have an existing SEL 321 relay at one or both ends, we will use a single POTT scheme even if the other end uses both a 311L and 421. The reason we can do this is because COMMUNICATION REDUNDANCY IS NOT REQUIRED BY NERC AS LONG AS A SLG FAULT DOES NOT CREATE A STABILITY PROBLEM. Per Planning we probably do not have a stability problem for SLG faults on the 115 kV system so this design assumes that to be the case. However, additional studies will have to be run to establish this for certain.
- We will better describe the specific relay and communication requirements for each line position below to avoid confusion.
- We plan on upgrading the relays at Sunset but future West Plains planning may change this. The actual configuration won't be known for some time.
- There are some lines like in Tier 4 that do not require communication aided tripping. However, after the relaying upgrades, both ends will have our present standard package and both ends will be connected to the SONET system. Therefore, all we need to do is add low or high speed SONET data cards and we have communication aided tripping which is still an advantage even though it's not a requirement. For example, the 115 kV lines from Beacon to Boulder would fall into this category. I have talked to a couple of people about this and we agreed that it would probably be worth it to go ahead and install the SONET data cards necessary to have communication aided tripping for these lines.
- The Otis Orchards breakers will be replaced in 2009 under ER2390 and we will replace all line relaying with our new standard.
- When the line relaying is being replaced at a substation, we may also decide to upgrade other relaying such as to autotransformers, 115/13 kV distribution transformers or bus relaying. These will be done under separate ER's and are not a part of this ER.
- All scheduling is tentative and subject to change as conditions dictate.
- The line terminals below are in alphabetical order under each tier.

Revision 2: 10/25/07

- Boulder to Otis #1 & 2 115 kV lines

There has been an issue identified in the 2006 Summer Operating and West of Hatwai studies. A Zone 2 three phase time delayed fault from Boulder to Otis will create a major disturbance in the Western Montana Hydro (WMH) area. This necessitates opening the Boulder – Rathdrum 115 kV and Otis – Post Falls 115 kV lines when WMH reaches 1,550 MW. However, this also creates a major disturbance problem for the N-2 loss of both of the Beacon – Rathdrum 230 kV and Boulder – Rathdrum 230 kV lines when WMH reaches 1,600 MW which means the loss of Beacon to Rathdrum 230 kV now drops two units at Noxon via the Clark fork RAS. Therefore, in order to mitigate this problem we need to add communications aided relaying from Boulder to Otis on lines #1 & 2. This moves this item up in priority from TIER 3 to TIER 1.

> NOTE: This item originally was adding communications only based on Otis being rebuilt with new breakers and relays before this was done. However, the Otis rebuild is now scheduled for 2009 and given our present budget situation, it will be difficult to do this before then.

Revision 1: 12/15/05
Breaker Positions

- Ninth & Central A-686 to Third & Hatch A-532.

There is one other line that should be added to **TIER 3** although the circumstances are different. When Setters sub is added we will add MOAS' on both sides of Rockford with the North side MOAS normally open. That means we will close the Eighth & Fancher switch feeding to Rockford which will be adding this exposure to the Ninth & Central to Third & Hatch line. This line presently uses a POTT/DTT scheme with SEL 321 relays over fiber optic cable. However, this scheme can not presently detect and fast trip for multi phase faults beyond about 4 miles past the Eighth & Fancher tap and the subsequent time delayed trip is set for one second to coordinate with other relays around the area. Rich Hydzik has conducted a stability study and the system does not go unstable for this condition. However, this fault would lower the voltage around Spokane for one second which would cause a lot of equipment to trip off line. We also can not extend this

POTT protection without miscoordinating with other distance relays in the area if their communications fail and we get a multi phase fault (Third & Hatch to Ross Park & Post St., Ross Park to Beacon and Post St. to Metro). The easiest way to ensure fast tripping for multi phase faults all the way to Setters is to replace a couple of the SEL relays at both Ninth & Central and Third & hatch with SEL 311L current differential relays (we would leave the SEL 321 POTT/DTT scheme in place). This would use the existing fiber optics. All we would need to do for communications is add high speed data cards at both ends.

TIER 1:

TIER 1: This tier has the highest priority to upgrade the 115 kV line relays. The corrections for this tier are also the most expensive and generally requires the relay replacement at both ends of the line plus the addition of relay communications. The upgrades need to be made for the following reasons:

- Relays have time delay trips that can create a major disturbance.
- There are no communications on the line to enable fast tripping.
- Because of the complexity of the 115 kV system, it is difficult to coordinate the relaying for all system conditions which may result in false trips and unnecessary outages to customers.
- Some relays are older Electromechanical.

Breaker Positions

- Beacon A-609 to Francis & Cedar A-674. Scheduled for 2010.
    - Beacon A-609 has existing E/M relays which will be replaced with a SEL 421 and 311L. Add one low speed SONET data card.
    - Francis & Cedar A-674. This has an existing SEL 321, 221G & 251. The relaying will remain. The 321 can be used in a POTT scheme so only add one low speed SONET data card.
- Beacon A-610 to Bell B-358. Scheduled for 2010.
    - Beacon A-610 has existing E/M relays which will be replaced with a SEL 421 and 311L. Add two low speed SONET data cards.
    - Bell B-358 – Per Bob Beck BPA has existing E/M relays and they would replace them with a SEL 421 & 311L. Add two low speed SONET data cards. NOTE: The contract for this has to be worked out with BPA but since the work isn't scheduled until 2010, this should be able to be done. Also at this time it is unclear if Avista will have to furnish the equipment at the BPA end.
- Boulder A-713 to Otis A-645. Scheduled for 2009.
    - Boulder A-713. This has an existing SEL 421 & 311L relay. The relaying will remain. Add two low speed SONET data cards.
    - Otis A-645. This has a SEL 221G and a Basler relay which will be replaced with a SEL 421 & 311L. Add two low speed SONET data cards.
- Boulder A-714 to Otis A-640. Scheduled for 2009.
    - Boulder A-714. This has an existing SEL 421 & 311L relay. The relaying will remain. Add two low speed SONET data cards.
    - Otis A-640. This has a SEL 221G and a 351 relays which will be replaced with a SEL 421 & 311L. Add two low speed SONET data cards.
- College & Walnut A-431 to Westside A-470. College & Walnut scheduled for 2008 and Westside scheduled for 2011.
    - College & Walnut A-431. Has existing E/M relays which will be replaced with a SEL 421 & 311L. Add two low speed SONET data cards.
    - Westside A-470. Has existing E/M relays which will be replaced with a SEL 421 & 311L. Add two low speed SONET data cards.
- Ninth & Central A-692 to Sunset A-152. Scheduled for whenever we can get the communications connected into Sunset.
    - Ninth & Central A-692. Has existing 2 – SEL 321's & a 351. The relaying will remain. Two low speed SONET data cards already exist (Telecomm needs to double check on this).
    - Sunset A-152. Has existing 2 – SEL 321's & a 351. The relaying will remain. Two low speed SONET data cards already exist (Telecomm needs to double check on this).

TIER 2:

TIER 2: This tier has the second highest priority to upgrade the 115 kV line relays. The corrections for this tier are basically the same as tier 1 which requires the relay replacement at both ends of the line plus the probable replacement of relay communications. The upgrades need to be made for the following reasons:

- Relays have time delay trips that can create a major disturbance if the communications fail.
- The communications are older and less reliable than the more modern fiber or digital microwave.
- Because of the complexity of the 115 kV system, it is difficult to coordinate the relaying for all system conditions which may result in false trips and unnecessary outages to customers if the communications fail.
- Relays are older Electromechanical.

Breaker Positions

- Beacon A-603 to Northeast A-252. Beacon A-603 scheduled for 2010 and Northeast A-252 for 2009.
    - Beacon A-603 has existing E/M relays which will be replaced with a SEL 421 and 311L. Add both a high and low speed SONET data card.
    - Northeast A-252 has existing E/M relays which will be replaced with a SEL 421 and 311L. Add both a high and low speed SONET data card.
- Beacon A-605 to Ross Park A-207. Beacon A-605 scheduled for 2010 and Ross Park A-207 for 2011.
    - Beacon A-605 has existing E/M relays which will be replaced with a SEL 421 and 311L. Add both a high and low speed SONET data card.
    - Ross Park A-207 has existing E/M relays which will be replaced with a SEL 421 and 311L. Add both a high and low speed SONET data card.
- Metro A- 474 to Post St. A-434. Post St. A-434 is scheduled for 2008 and Metro A-474 is scheduled for 2009.
    - Metro A-474 has existing E/M relays which will be replaced with a SEL 421 and 311L. Add both a high and low speed SONET data card.
    - Post St. A-434 has existing E/M relays which will be replaced with a SEL 421 and 311L. Add both a high and low speed SONET data card.
- Metro A-475 to Sunset A-450. Metro A-475 is scheduled for 2009 and Sunset A-450 for 2011. NOTE: Does not create a major disturbance if the communications fail.
    - Metro A-475 has existing E/M relays which will be replaced with a SEL 421 and 311L. Add both a high and low speed SONET data card.
    - Sunset A-450 has existing E/M relays which will be replaced with a SEL 421 and 311L. Add both a high and low speed SONET data card.
- Post St. A-544 to Third & Hatch A-531. Post St. A-544 is scheduled for 2008 and Third & Hatch A-531 is scheduled for 2009.
    - Post St. A-544 has existing E/M relays which will be replaced with a SEL 421 and 311L. Add both a high and low speed SONET data card.
    - Third & Hatch A-531 has existing E/M relays which will be replaced with a SEL 421 and 311L. Add both a high and low speed SONET data card.
- Ross Park A-208 to Third & Hatch A-530. Third & Hatch A-530 is scheduled for 2009 and Ross Park A-208 is scheduled for 2011.
    - Ross Park A-208 has existing E/M relays which will be replaced with a SEL 421 and 311L. Add both a high and low speed SONET data card.
    - Third & hatch A-530 has existing E/M relays which will be replaced with a SEL 421 and 311L. Add both a high and low speed SONET data card.

TIER 3:

TIER 3: This tier has the third highest priority to upgrade the 115 kV line relays. The corrections for this tier can require the entire relaying be replaced, just a relay addition or no relays added. However, all of them will require the addition of relay communications. The upgrades should be made for the following reasons:

- Relays have time delay trips that can create a disruption and degrades the power quality to customers but do not create a major disturbance.
- There are no communications on the line to enable fast tripping.
- Because of the complexity of the 115 kV system, it is difficult to coordinate the relaying for all system conditions which may result in false trips and unnecessary outages to customers.
- Some relays are older Electromechanical.

Breaker Positions

- Coeur d' Alene A-665 to Rathdrum A-505. Rathdrum A-505 is scheduled for 2011.
  - Coeur d' Alene A-665. This has an existing SEL 321, 221G & 251. The relaying will remain. The 321 can be used in a POTT scheme so only add one low speed SONET data card.
  - Rathdrum A-505 has existing E/M relays which will be replaced with a SEL 421 and 311L. Add one low speed SONET data card.
- Ninth & Central A-686 to Third & Hatch A-532. Schedule Ninth & Central for 2011 and Third & Hatch is 2009. NOTE: This increases the relaying budget because we weren't going to replace these relays (see Revision 1).
  - Ninth & Central A-686 has 2 SEL 321's and a 351. Also has a low speed data card. After discussing this with Mike Magruder and Jeff Marsh we decided to replace all of the relaying because it's less labor and outage time to remove the old panel and install a new one than add a relay to an existing panel. Therefore, replace the existing relays with a SEL 421 and 311L and add one high speed data card.
  - Third & Hatch A-532. This has an existing SEL 321, 221G and 251 and a low speed data card. Replace these relays with a SEL 421 and 311L and add one high speed data card.
- Otis Orchards A-642 to Post Falls A-324. Otis Orchards A-642 is scheduled for 2009 and Post Falls A-324 is scheduled for 2011.
  - Otis Orchards has an existing SEL 221G and Basler relays which will be replaced with a SEL 421 and 311L. Add two low speed SONET data cards.
  - Post Falls A-324 has existing E/M relays which will be replaced with a SEL 421 and 311L. Add two low speed SONET data cards.
- Post Falls A-211 to Ramsey A-669. Scheduled for 2011. NOTE: Post Falls has HZ-4 relays which are very old and unreliable.
  - Post Falls A-211 has existing E/M relays which will be replaced with a SEL 421 and 311L. Add two low speed SONET data cards.
  - Ramsey A-669 has an existing SEL 221G and 251 relays which will be replaced with a SEL 421 and 311L. Add two low speed SONET data cards.
- Ramsey A-667 to Rathdrum A-638. Scheduled for 2011.
  - Ramsey A-667 has an existing SEL 221G and 251 relays which will be replaced with a SEL 421 and 311L. Add two low speed SONET data cards.
  - Rathdrum A-638 has an existing SEL 221G and 251 relays which will be replaced with a SEL 421 and 311L. Add two low speed SONET data cards.
- Ramsey A-668 to Rathdrum A-502. Scheduled for 2011.
  - Ramsey A-668 has an existing SEL 221G and 251 relays which will be replaced with a SEL 421 and 311L. Add two low speed SONET data cards.
  - Rathdrum A-502 has existing E/M relays which will be replaced with a SEL 421 and 311L. Add two low speed SONET data cards.
- Sunset A-198 to Westside A-410. Scheduled for 2011.
  - Sunset A-198 has existing E/M relays which will be replaced with a SEL 421 and 311L. Add two low speed SONET data cards. NOTE: The A-198 breaker originally was scheduled to be replaced in 2006 along with new relaying but this was never done pending the outcome of the West Plains Planning study.
  - Westside A-410 has existing E/M relays which will be replaced with a SEL 421 and 311L. Add two low speed SONET data cards.

TIER 4:

TIER 4: This tier has breaker failure relaying that can take up to 3 seconds to clear a fault. This type of breaker failure relaying can cause major disturbances to the entire system if it is called upon to operate. These breakers will require new relaying to solve this problem. NOTE: These are only the positions around the Spokane and CDA area. There are many others with long clearing times that we didn't count.

Breaker Positions

- Airway Heights A-180. Scheduled for 2011
  - Airway heights A-180. Has an existing SEL 221G and a Basler which will be replaced with a SEL 421 and 311L. No communications required.
- Airway Heights A-182 to Sunset A-484. Scheduled for 2011
  - Airway heights A-182. Has an existing SEL 221G and a Basler which will be replaced with a 421 and 311L. No communications required.
  - Sunset A-484. Has existing E/M relays which will be replaced with a SEL 421 and 311L. No communications required.
- Beacon A-604 to Boulder A-712 #1.
  - Beacon A-604. Has existing E/M relays which will be replaced with a SEL 421 and 311L. Add two low speed SONET data cards.
  - Boulder A- 712. Has existing SEL 421 and 311L relays. Add two low speed SONET data cards.
- Beacon A-607 North Auxiliary breaker - Has existing E/M relays which will be replaced with a SEL 421 and 311L. Also need a SEL 2100 to transfer mirrored bits.
- Beacon A-612 to Boulder A-719.
  - Beacon A-612. Has existing E/M relays which will be replaced with a SEL 421 and 311L. Add two low speed SONET data cards.
  - Boulder A- 719 to Beacon A-612. Has existing SEL 421 and 311L relays. The relaying will remain. Add two low speed SONET data cards.
- Beacon A-613 South Auxiliary breaker - Has existing E/M relays which will be replaced with a SEL 421 and 311L. Also need a SEL 2100 to transfer mirrored bits.
- Boulder A-720 to Rathdrum A-501. Scheduled for 2011.
  - Boulder A-720 has a SEL 421 and 311L. The relaying will remain. Add two low speed SONET data cards.
  - Rathdrum A-501 has existing E/M relays which will be replaced with a SEL 421 and 311L. Add two low speed SONET data cards.
- Coeur d' Alene A-593 to Ramsey A-666. Schedule for 2011 (wasn't on original schedule)
  - Coeur d' Alene A-593. Has existing SEL 321, 221G and 251. The relaying will remain. Add one low speed data card.
  - Ramsey A-666. Has an existing SEL 221G and 251. Replace with a SEL 421 and 311L. Add one low speed data card.
- Nine Mile A-654. Scheduled for 2011.
  - Nine Mile A-654 has an existing SEL 221G and a Basler which will be replaced with a SEL 421 and 311L. No communications required.
- Nine Mile A-655 to Westside A-413. Scheduled for 2011.
  - Nine Mile A-655 has an existing SEL 221G and a Basler which will be replaced with a SEL 421 and 311L. No communications required.
  - Westside A-413 has existing E/M relays which will be replaced with a SEL 421 and 311L. No communications required.
- Ninth & Central A-689 to Otis A-641. Schedule for 2009.
  - Ninth & Central A-689 to Otis Orchards A-641. Has existing two SEL 321's and a 351. The relaying will remain. Add two low speed data cards.
  - Otis A-641. Has existing SEL 321, 221G and 251 relays. Replace these relays with a SEL 421 and 311L (this is because we are replacing all 115 kV breakers at Otis). Add two low speed SONET data cards.
- Northwest A-286 to Westside A-412.
  - Northwest A-286. Has existing E/M relays which will be replaced with a SEL 421 and 311L. Add both a high and low speed SONET data card.

    - Westside A-412. Has existing E/M relays which will be replaced with a SEL 421 and 311L. Add both a high and low speed SONET data card.
- Rathdrum A-506. Scheduled for 2011.
    - Rathdrum A-506 has E/M relays which will be replaced with a 421 and 311L. No communications required.
- Sunset A-154.
    - Sunset A-154 has an existing 121G and PJC. Replace with a SEL 421 and 311L. No communications required.
- Sunset A-480 AUX Bkr – Has existing E/M relays which will be replaced with a SEL 421 and 311L plus a SEL 2100.

SUMMARY FOR ER 2217

Summary of new relay panels needed consisting of a SEL 421 and 311L relay. This does not include any new relaying being done under other ER's such as Otis Orchards or for Kendall Yards.

- Airway heights – 2.
- Beacon – 8.
- Bell – 1.
- College & Walnut – 1.
- Metro – 2.
- Nine Mile - 2.
- Ninth & Central – 1.
- Northeast – 1.
- Northwest – 1.
- Post Falls – 2.
- Post St – 2. NOTE: Relaying already purchased for both lines.
- Ramsey – 4.
- Rathdrum – 5.
- Ross Park – 2.
- Sunset – 5.
- Third & hatch – 3.
- Westside – 4.

TOTAL = 46.

Summary of new communication cards required. I included Otis Orchards this time because Telecommunications needs to order all of the data cards.

- Beacon – High - 2 / Low - 9.
- Bell – High - 0 / Low - 2.
- Boulder – High - 0 / Low - 10.
- Coeur d' Alene – High - 0 / Low - 2.
- College & Walnut – High - 0 / Low - 2.
- Francis & Cedar – High - 0 / Low - 1.
- Metro – High - 2 / Low - 2.
- Ninth & Central – High - 1 / Low - 2.
- Northeast – High - 1 / Low - 1.
- Northwest – High - 1 / Low - 1.
- Otis Orchards – High - 0 / Low - 8.
- Post Falls – High - 0 / Low - 4.
- Post St – High - 2 / Low - 2. Note: Cards already purchased for these lines? NOTE: Telecomm needs to double check on this.
- Ramsey – High - 0 / Low - 7.
- Rathdrum – High - 0 / Low - 7.
- Ross Park – High - 2 / Low - 2.
- Sunset – High - 1 / Low - 3.
- Third & hatch – High - 3 / Low - 2.
- Westside – High - 1 / Low - 5.

TOTAL – High = 15 / Low = 72.

AVISTA Utilities

ENGINEERING PROTECTION GROUP MEMO

To:	LIST
From:	Dennis Howey
Subject:	CDA-Spokane Area 115 kV Relay and Communications Upgrade Proposed Schedule
Filename:	G:\relay_pr\CDA-Spokane 115 kV Relay Upgrades\115 kV Relay Upgrades\115 kV Upgrade Schedules_2.doc
Date:	November 30, 2007 3/22/08
CC:	Randy Cloward, Rick Vermeers, Mike Magruder, Randy Spacek, Scott Kinney, Scott Waples, Dick Schatzka, Jacob Reidt, Rich Hydzik, Garth Brandon, Jim Corder, Larry Hager, Bill Kelley, Jeff Marsh, Tim Figart, Jon Harms

Revision 1: 3/22/08

We have changed some items from the original proposal (see "Upgrading 115 kV Relay Schemes REV 3). Because of this I am updating this document also to reflect these changes.

Proposed Relay Upgrade Schedule by Breaker Position

We have already listed the proposed relay upgrades by order of importance from Tier 1 to Tier 4 (see Upgrading 115 kV Relay Schemes memo dated 12/15/05). However, this does not mean the actual installations will follow that same order. The following is a draft proposed relaying schedule with associated costs (not including communications) per breaker of $125,000.

NOTE 1: The original cost estimates for the relaying upgrades was $5.08M and for the communications upgrades was $1.53M for a total of $6.61M. The total budget item for upgrading the relaying and communications is $5M spread evenly over 4 years ($1.25M each year) on ER NEW14.

NOTE 2: The relaying on Post St A-433 to College & Walnut A-432 is already being installed under the Kendall Yards ER 2393 as is the cost of installing the fiber and communications equipment so their costs will not be included in ER NEW14.

NOTE 3: There is an ER 2390 to replace all 4 breakers at Otis Orchards in 2009 which also includes replacing the relaying so the relaying for Otis A-640 and A-645 will **not** be included in ER NEW14. The communications are not included in ER 2390.

NOTE 4: We were going to replace the relaying on Westside A-412 & Sunset A-198 prior to the CDA-Spokane upgrade but this didn't happen so we will need to add these to ER NEW14.

NOTE 5: In 2005 if a breaker had one SEL relay on it, I said to just add one relay instead of our entire new standard line package. However, almost all of these relays are old (15 – 20 years) SEL 221G relays and it would cost a lot to just add one relay to the existing panel. It would be far more efficient (and maybe even less costly) to simply scrap all of the old relays and build all new panels. Right now it appears we will have **46** breakers to replace relays on for all 4 tiers + **4** for Otis = **50** breakers total.

NOTE 6: It may make sense to have a contractor (like SEL) build all of these panels for us at our specifications over the 4 year period and just install them ourselves. We could probably save a lot of money and manpower that way.

I feel it makes more sense to do all of the relaying at a sub at once rather than piecemeal. The following is the total number of breakers we would do at each substation regardless of which tier it fell into and the relaying costs at each using $125k per breaker.

- Airway heights – 2 breakers = $250k
- Beacon 115 kV – 8 breakers = $1M
- Bell – 1 breaker = $125k – Paid by BPA
- College & Walnut – 1 breaker = $125k
- Metro – 2 breakers = $250k
- Nine Mile – 2 breakers = $250k
- Ninth & Central – 1 breaker = $125k
- Northeast – 1 breaker = $125k
- Northwest – 1 breaker = $125k
- Post Falls – 2 breakers = $250k
- Post St – 2 breakers = $250k
- Ramsey – 4 breakers = $500k
- Rathdrum – 5 breakers = $625k
- Ross Park – 2 breakers = $250k
- Sunset – 5 breakers = $625k
- Third & Hatch – 3 breakers = $250k
- Westside – 4 breakers = $500k
- **Total – 46 breakers = $5.75M**

POSSIBLE SCHEDULING

I will lay out the following tentative schedule with the idea in mind of completing all of the communications work in 2008 and 2009. This may not work out and we may have to swap some relaying work for some communications work

Possible 2008 Relaying:

- College & Walnut – 1 breaker = $125k
- Post St. – 2 breakers = $250k
- **Total = 3 breakers = $375k**

This leaves $875k for communications with $1565 – 875 = $690k left to complete.
Communications – Westside, F&C, NW & Ross Park.

Possible 2009 Relaying:

If we do the rest of the communications in 2009 this leaves $1250 – 690 = $560k left for relays (roughly 5 breakers).

- Northeast – 1 breaker = $125k
- Metro – 2 breakers = $250k
- Third & Hatch – 3 breakers = $250k
- **Total = 5 breakers = $750k**

Possible 2010 Relaying:

- Beacon 115 kV – 8 breakers = $1M
- Northwest – 1 breaker = $125k
- **Total = 9 breakers = $1250k**

Possible 2011 Relaying:

- Airway heights – 2 breakers = $250k
- Ross Park – 2 breakers = $250k
- Nine Mile – 2 breakers = $250k
- Ninth & Central – 1 breaker $125k
- Post Falls – 2 breakers = $250k
- Ramsey – 4 breakers = $500k
- Rathdrum – 5 breakers = $625k
- Sunset – 5 breakers = $625k
- Westside – 4 breakers = $500k
- **Total = 26 breakers = $3375k**

The total is almost $2M over the 4 year budgeted amount. However, we may experience some savings by having the panels pre built and other efficiency measures so I doubt we will go that much over. As such, at this time I do not want to exclude any of the work from the items.

2008 West Plains Reactive Study

5/27/2008

RH

Introduction

The West Plains area is served by several Avista and other utility substations. The Avista substations in the area are Airway Heights, Silver Lake, and Hallet & White. Foreign owned substations are North Fairchild, South Fairchild, Hayford, Cheney, Four Lakes, and West Plains. Approximately five years ago, a 20 MVAR capacitor bank was removed from Four Lakes Sub due to PCB contamination. This had the effect of reducing voltage support in the West Plains area.

The West Plains loads are supplied by the Sunset – Westside 115 kV (Garden Springs Tap) line, the Sunset – Airway Heights 115 kV line, and the Airway Heights – Devils Gap 115 kV line. The North Fairchild – Silver Lake 115 kV transmission project is nearing completion. This project moves the Silver Lake load off of the Garden Springs Tap and onto Airway Heights Substation. This project should be complete by June, 2008. Four Lakes and Cheney are normally carried on the Garden Springs tap year around.

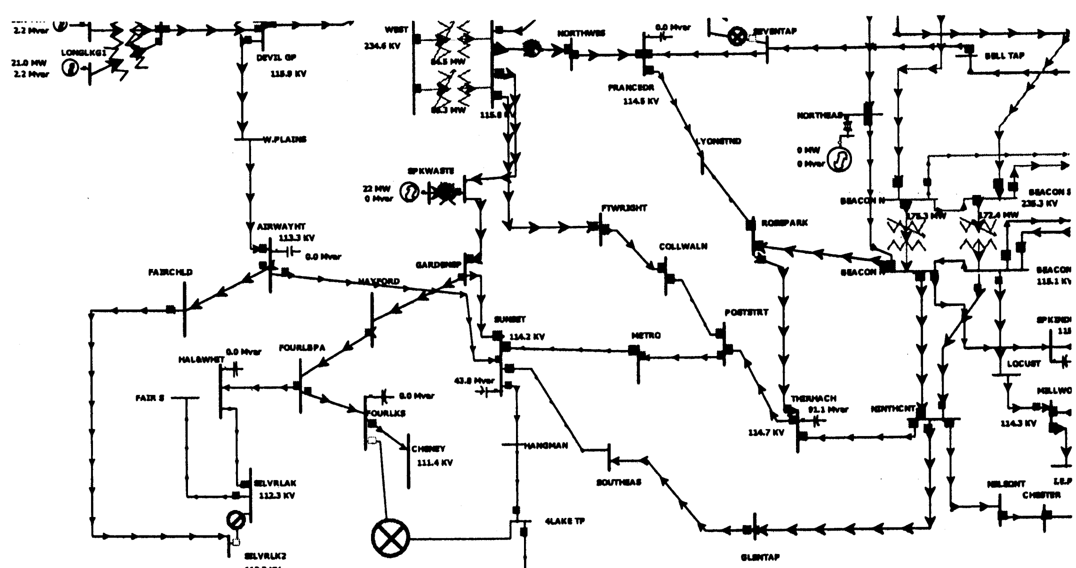


Figure 1. Normal West Plains transmission configuration. 08HS4AP modified powerflow case.

Reliability Issues

The Summer Operating Studies revealed some issues with voltage support in the West Plains in 2007 and 2008. Winter performance is better due to load characteristics. Winter load has approximately one half the reactive load of the typical summer load. The 2008 Summer Operating Studies documented the following performance issues.

Outage	Issue
Westside 115 Bus	Low voltage in West Plains area (107 kV)
Westside 230 Bus	Low voltage in West Plains area (107 kV)
Airway Heights – Sunset 115	Low voltage at Airway Heights (106 kV)
Sunset 115 Bus	Low voltage at Airway Heights (107 kV)

Economic Issues

BPA has a reactive power tariff. This tariff is designed to incent a customer to provide reactive resources during heavy load hours (0600-2200) and limit reactive output to BPA during light load hours (2200-0600). The allowable amount of reactive across and interconnection is 25% of the peak MW demand during the calendar month. The charge only applies if the powerflow is in one direction, to the customer, for the entire month. If the flow is to BPA during the month, the interconnection is deemed a mutual benefit, and no charges apply. The tariff rate is $0.28 / KVAR above the bandwidth ($280 / MVAR). Once the tariff is applied at the interconnection, it is billed on a twelve month ratchet.

Avista was subject to a reactive charge at Westside in July, 2007. The reactive charge was $6884, based on 24.6 MVAR. SCADA data for July, 2007, showed a peak demand hour of -189 MW, which provides a reactive bandwidth of 47.3 MVAR. SCADA data also showed a peak MVAR of -74.7 MVAR, or 27.4 MVAR over the bandwidth. This confirmed the billing. Avista will be billed every month until July, 2008, for $6884 ($82,612 for the year). It is anticipated that another reactive charge will occur in July, 2008, resetting the 12 month ratchet.

Study Methodology

The study consists of three analyses.

1. Sensitivity of capacitor location to Westside var interchange will be evaluated in the heavy load case.
2. QV curves will be used to size capacitors such that the largest voltage change is 2.5% with all facilities in service, and 5% under outage conditions. Both heavy load and light load cases are used for this.
3. Westside var interchange will be compared to the initial heavy load case with the selected capacitors installed.

Two powerflow cases were used for this study. The 08HS4AP_AVA_IDNW case was used for the heavy load case. It was configured as described in the 2008 Summer Operating Studies Report. The voltage schedule was configured per SOP 05, controlling to 115.9 kV on the voltage control busses. The 08HS4AP_AVA_IDNW is configured with an Avista load power factor of 0.91 lagging. This is based on historical data and is described in detail in the *2008 Summer Operating Studies Report.* The interchange values at Bell and Westside are (positive to Avista):

	MW	MVAR
Bell	666	166
Westside	171	99

The 08LW1AP_AVA case was used for the light load case. It was configured as described in the *2008 Winter Operating Studies Report.* The voltage schedule was configured per SOP 05, controlling to 114.4 kV on the voltage control busses. The 08LW1AP_AVA case is configured with an Avista load power factor of 1.000, or unity. This is based on historical data and is described in detail in the *2008 Summer Operating Studies Report.* Avista's distribution system is slightly capacitive in light load winter hours, and this case provides maximum voltage sensitivity to switching capacitors.

Study Results

1. Sensitivity of capacitor location to Westside var interchange

A 15 MVAR capacitor was placed at the locations below. Var interchange at Westside was measure with and without tap changing back to the original bus voltage at Westside.

Capacitor Location	Capacitor	Westside VARS, no tap change	Westside Vars with tap change	Δ Var
No Caps	None	99.1 MVAR/115.8 kV		
4LK	15 MVAR	95.3 MVAR/116.1 kV	85.4 MVAR/115.8 kV	-13.7
H&W	15 MVAR	95.3 MVAR/116.1 kV	85.4 MVAR/115.8 kV	-13.7
AIR	15 MVAR	96.7 MVAR/116.0 kV	87.0 MVAR/115.7 kV	-12.1
F&C	15 MVAR	95.1 MVAR/116.1 kV	85.4 MVAR/115.8 kV	-13.7

Table 1. Westside var sensitivity to capacitor location.

Table 1 indicates that the removal of the 20 MVAR Four Lakes capacitor bank had a significant impact on the reactive loads at Westside. This contributed directly to the reactive charges at Westside, as well as having a detrimental effect on voltage support and reliability in the West Plains area.

2. QV curves will be used to size capacitors such that the largest voltage change is 2.5% with all facilities in service, and 5% under outage conditions. Both heavy load and light load cases are used for this.

QV analysis was used to determine capacitor sizing which would limit voltage step changes under varying system conditions. QV curves were generated for 08HS4AP conditions with heavy reactive loads. The 08LW winter case was used to generated QV curves for a lightly loaded system with almost no reactive loads. Avista's loads are modeled at 0.91 power factor lagging in the 08HS case and unity power factor in the 08LW case. These cases are fully documented in the *2008 Winter Operating Studies Report* and the *2008 Summer Operating Studies Report*. Three substation busses were analyzed.

- Hallet & White
- Airway Heights
- Francis & Cedar

Voltage schedules are followed per *SOP 05 – 230 kV and 115 kV Voltage Schedule*. The 08HS case maintains 115.9 kV at the voltage controlled busses. The 08LW case maintains 114.4 kV at the voltage controlled busses.

BUS	CASE	OUTAGE	Δ VOLTAGE	MVAR
Airway Heights	08HS	None	2.5% / 2.88 kV	70
Airway Heights	08HS	SUN-AIR	5.0% / 5.75 kV	43
Airway Heights	08HS	AIR-WPL	5.0% / 5.75 kV	63
Airway Heights	08HS	WPL-DGP	5.0% / 5.75 kV	60
Airway Heights	08LW	None	2.5% / 2.88 kV	45
Airway Heights	08LW	SUN-AIR	5.0% / 5.75 kV	28
Airway Heights	08LW	AIR-WPL	5.0% / 5.75 kV	65
Airway Heights	08LW	WPL-DGP	5.0% / 5.75 kV	65
Hallet & White	08HS	None	2.5% / 2.88 kV	30
Hallet & White	08HS	SUN-GSP	5.0% / 5.75 kV	50
Hallet & White	08HS	WES-WTE	5.0% / 5.75 kV	63
Hallet & White	08HS	GSP-WTE	5.0% / 5.75 kV	65
Hallet & White	08LW	None	2.5% / 2.88 kV	37
Hallet & White	08LW	SUN-GSP	5.0% / 5.75 kV	50
Hallet & White	08LW	WES-WTE	5.0% / 5.75 kV	60
Hallet & White	08LW	GSP-WTE	5.0% / 5.75 kV	62
Francis & Cedar	08HS	None	2.5% / 2.88 kV	100
Francis & Cedar	08HS	NW-WES	5.0% / 5.75 kV	125
Francis & Cedar	08HS	NW-F&C	5.0% / 5.75 kV	150
Francis & Cedar	08HS	F&C-L&S	5.0% / 5.75 kV	155
Francis & Cedar	08HS	L&S-ROS	5.0% / 5.75 kV	150
Francis & Cedar	08HS	ROS-BEA	5.0% / 5.75 kV	170
Francis & Cedar	08LW	None	2.5% / 2.88 kV	100
Francis & Cedar	08LW	NW-WES	5.0% / 5.75 kV	130
Francis & Cedar	08LW	NW-F&C	5.0% / 5.75 kV	130
Francis & Cedar	08LW	F&C-L&S	5.0% / 5.75 kV	145
Francis & Cedar	08LW	L&S-ROS	5.0% / 5.75 kV	150
Francis & Cedar	08LW	ROS-BEA	5.0% / 5.75 kV	170

Table 2. QV results.

The highlighted values in Table 2 indicated the largest switched capacitor that could be installed at each location and meet the 2.5% / 5.0% criteria. Based on these results, the following recommendations are made.

- Airway Heights – A single 30 MVAR cap is required. It is slightly above the 28 MVAR result, but as load increases, the step voltage change will decrease. This will support Airway Heights, Fairchild North, West Plains, and Silver Lake for the loss of the Sunset – Westside 115 line and loss of the Westside 230 or 115 busses.

- Hallet & White – A single 30 MVAR cap is required. It supports voltage in the area under steady state conditions and particularly for the outage of the Sunset – Garden Springs section of the Sunset – Westside 115 line and loss of the Westside 230 or 115 busses.

- Francis & Cedar – A single 50 MVAR cap is required. At the 50 MVAR level, most of the reactive is consumed at Northwest, Francis & Cedar, and Lyons and Standard during heavy load hours during the summer. This offloads the Westside reactive load. This capacitor also provides voltage support for the loss of the Westside 230 bus. Beyond 50 MVAR, the line loading out of Francis & Cedar will become an issue, similar to overloads around Third & Hatch during outage conditions. 50 MVAR at Francis and Cedar directly supports the var load at Northwest, Francis and Cedar, and Lyons and Standard.

Table 3 illustrates the voltage performance at the 115 busses for various single contingency outages. QV curves for each outage are attached in Appendices 1, 2, and 3. There was adequate reactive margin for each outage studied.

Bus	Case	LL-LF Gen MW	Outage	Voltage kV	Capacitor MVAR	Voltage kV
AIR 115	08HS	116	None	113.3	30	114.9
AIR 115	08HS	0	None	112.3	30	114.4
AIR 115	08HS	116	AIR-SUN	111.1	30	115.4
AIR 115	08HS	0	AIR-SUN	105.6	30	113.4
AIR 115	08HS	116	AIR-WPL	111.6	30	114.2
AIR 115	08HS	0	AIR-WPL	111.6	30	114.3
AIR 115	08HS	116	WPL-DGP	111.0	30	113.6
AIR 115	08HS	0	WPL-DGP	111.0	30	113.8
H&W 115	08HS	116	None	112.4	30	114.4
H&W 115	08HS	0	None	112.1	30	114.4
H&W 115	08HS	116	SUN-GSP	112.8	30	115.7
H&W 115	08HS	0	SUN-GSP	112.6	30	115.6
H&W 115	08HS	116	WES-WTE	111.0	30	113.6
H&W 115	08HS	0	WES-WTE	110.5	30	113.0
H&W 115	08HS	116	GSP-WTE	110.8	30	113.4
H&W 115	08HS	0	GSP-WTE	110.2	30	112.8
F&C 115	08HS	116	None	114.6	50	115.7
F&C 115	08HS	0	None	114.7	50	115.4
F&C 115	08HS	116	NW-WES	112.6	50	114.5
F&C 115	08HS	0	NW-WES	112.6	50	114.2
F&C 115	08HS	116	NW-F&C	113.3	50	115.2
F&C 115	08HS	0	NW-F&C	113.3	50	115.2
F&C115	08HS	116	F&C-L&S	114.9	50	116.1
F&C 115	08HS	0	F&C-L&S	114.9	50	116.1
F&C 115	08HS	116	L&S-ROS	114.3	50	115.5
F&C 115	08HS	0	L&S-ROS	114.2	50	115.4
F&C 115	08HS	116	BEA-F&C	114.5	50	115.5
F&C 115	08HS	0	BEA-F&C	114.5	50	115.5

Table 3. Voltage performance for various single contingency outages.

3. Westside var interchange comparison

The Westside and Bell interchange in the 08HS case was (positive to Avista):

	MW	MVAR
Bell	666	166
Westside	171	99

With the addition of 30 MVAR at Airway Heights and 30 MVAR at Hallet & White, the interchange was:

	MW	MVAR	Δ MVAR
Bell	668	161	-5
Westside	169	65	-34

With the addition of 30 MVAR at Airway Heights, 30 MVAR at Hallet & White, and 50 MVAR at Francis & Cedar, the interchange was:

	MW	MVAR	Δ MVAR
Bell	670	153	-13
Westside	167	26	-73

The addition of 80 MVAR of capacitors resulted in offloading Bell and Westside vars by 86 MVAR. Reactive load at Westside was reduced by 73 MVAR This would mitigate any reactive charges at Westside based on the current bandwidth of 47 MVAR. This bandwidth will increase into the future as Avista's loads continue to grow. Reactive studies verify that adding vars near loads provides a better than even var payback due to the reduction in autotransformer tap ratios required to maintain voltage. As the transformers boost voltage, increased reactive is consumed in the transformers.

Adding reactive at Hallet and White and Airway Heights will provide adequate voltage support during outage conditions and contribute to reduced flow at Westside. However, var flow at Westside will likely continue to exceed the bandwidth unless additional reactive support is installed at Francis and Cedar.

Conclusions

The studies support the addition of the following 115 kV capacitors to meet reliability performance and to mitigate reactive charges at Westside.

- Airway Heights – 30 MVAR (Reliability and var control issue)
- Hallet & White – 30 MVAR (Reliability and var control issue)
- Francis & Cedar – 50 MVAR (Var control issue)

AVISTA Utilities

Liberty Lake 12F1
Reconductor Line - ER2351

Cost Estimate
ER2351 - $200,000

Priority
- 2009

Project Description
Reconductor ¾ of a mile of 2/0CU (CAP: S-319A) to 556AAC (CAP: S-610A). This new trunk will provide support to load located to the south and the north of the line.

There is roughly 150A on this section of line. Presently, there aren't any connecting ties downstream from this reconductor job. In the future this section of line could be used as a tie with EFM12F2.

	Load	O.L.	% O.L.
LIB#1	653A	711A	91.8%
LIB12F1	320A	400A	80.0%

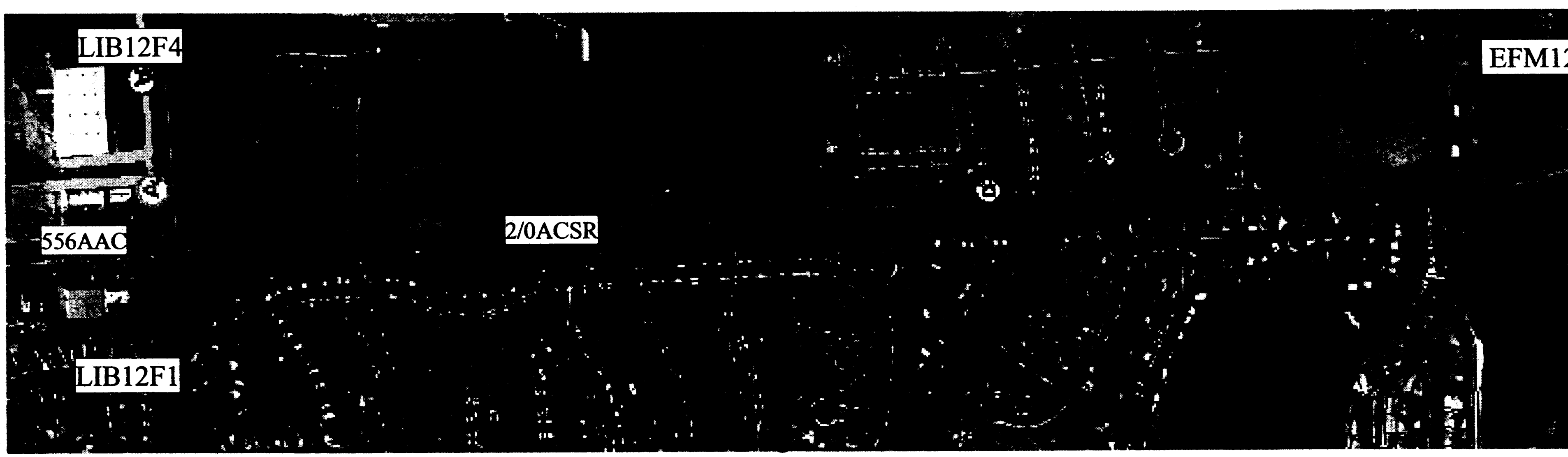


Exhibit No. SJK-6

Area: Spokane

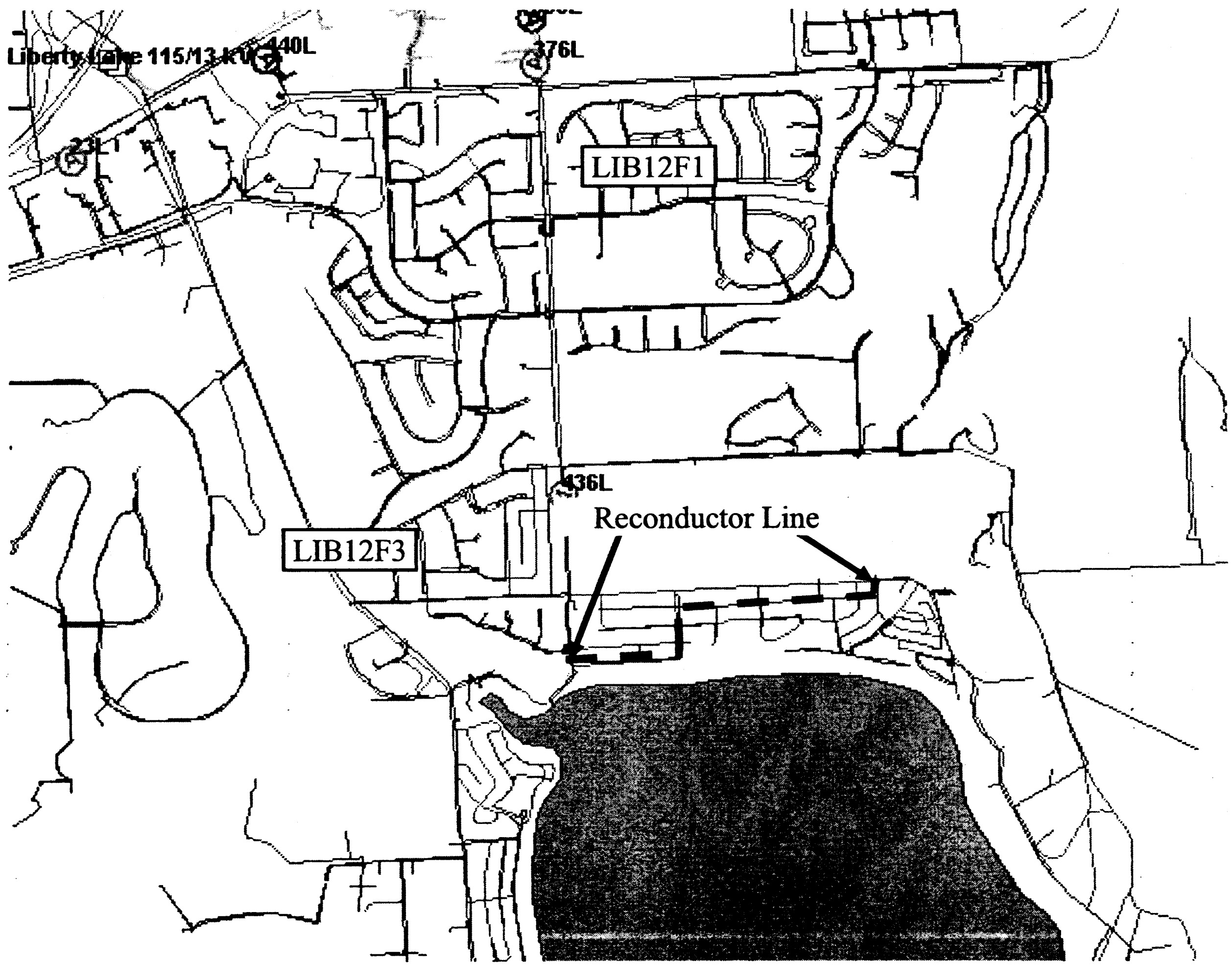
Liberty Lake 12F3
Reconductor Line – ER2464

Cost Estimate
ER2464 - $250,000

Priority
Thermal – 2009

Crew Time
7 weeks

Project Description
Reconductor roughly 1 mile of 6CU to 350ALCN. The 6CU is old and unreliable. It is also loaded to 124% of capacity on b phase during peak conditions. This section is not capable of being balanced, since 55A of the b phase load is all one lateral.



AVISTA Utilities

Kettle Falls 12F2 – Reconductor Line ER2487

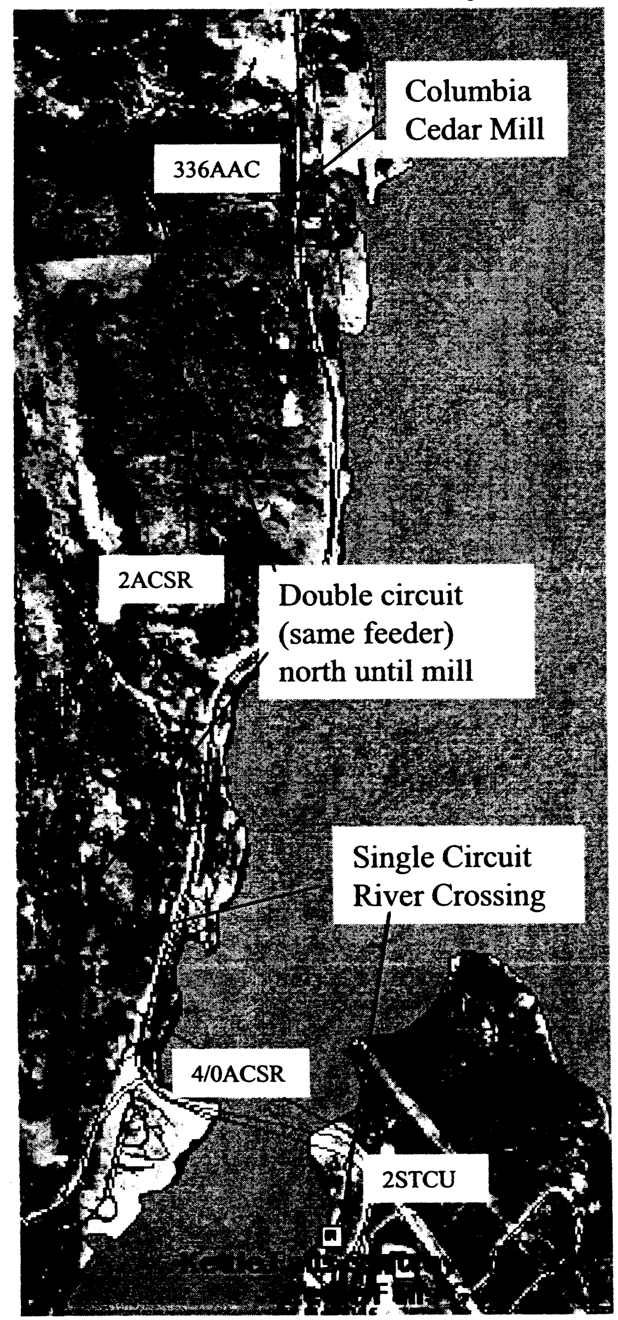
Cost Estimate
$400,000 for 2009

Priority
T

Scope
This project is in response to the feeder being over its operating limit in the winter, due to small conductors. The conductor over its operating limit is 2ACSR (S-161A, W-241A) and there are sections of 2CU (S-205A, W-287A) close to operating limit.

After the river crossing, the feeder travels west, and before the feeder travels north, it splits and there are two sets of lines running north, but not in parallel. One feeder Columbia Cedar and the other feeds the rest of the load to the north. The conductor feeding Columbia is 2ACSR, and the conductor feeding the load to the north is 6CU.

The ideal solution would be to reconductor the main trunk from the sub, over the river and to the corner where the trunk splits and heads north, paralleling itself (about 1.25 miles). The transformer's operating limit is 1000A in the winter and has room for more load. If 556AAC (W-913A) is installed, the feeder will adequate capacity.



Last Updated 6/26/07

WUTC v. Avista Corporation

Docket Nos. UE-090134, UG-090135 and UG-060518

Exhibit SJK-6 (Response to Staff Data Request 046)

REDACTED
Pages 29-44

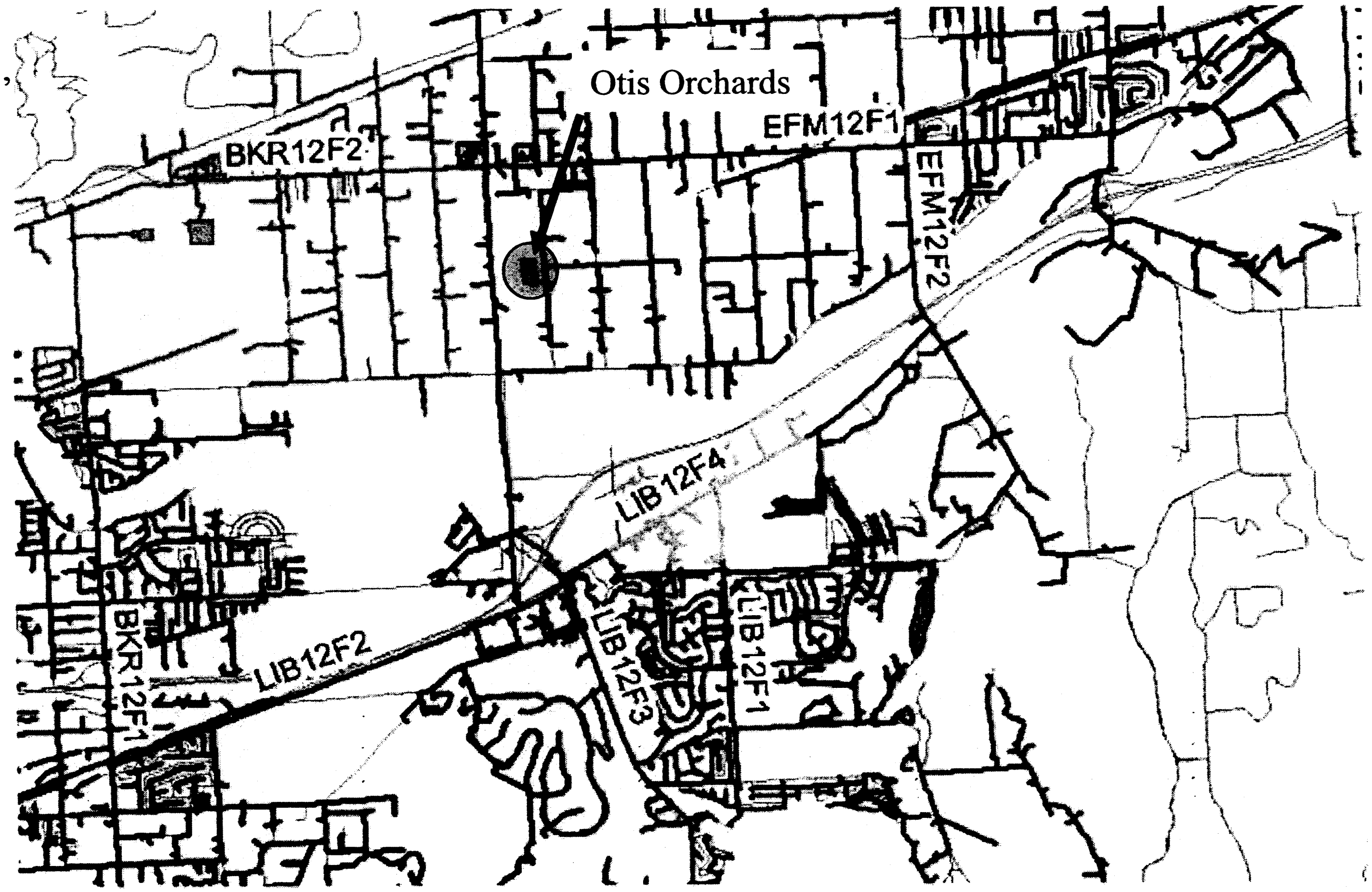
The information in these documents is **CONFIDENTIAL** in nature and is protected per Protective Order in WUTC Dockets UE-090134 and UG-090135 and by WAC 480-07-160.

AVISTA Utilities

Otis Orchards 115-13kV Substation
Construct Fdrs
12F1 & 12F2
ER2443

Cost Estimate
ER2443 –
Distribution $500,000

Priority
RH – 2009



Scope
The intent of this project is to add distribution into the existing Otis Orchards substation in order to unload Barker and Liberty Lake substations. Otis will specifically unload BKR#1 (via BKR12F2), LIB12F4. The figure above shows the present configuration of this area. Slide #2 shows the proposed configuration after the integration of distribution at Otis. Crossings for Otis 12F2 require a river and freeway crossing.

Area: Spokane

Barker	Summer '07	Summer Op Limit	Win '07-'08	Win Op Limit	Comments
Xfmr 1	**802**	711	**991**	837	
12F1	**401**	400	471	500	West Greenstone
12F2	125	400	235	500	
12F3	252	400	369	500	
LIB					
Xfmr 1	700	711	603	837	
12F1	323	400	262	500	
12F2	333	400	313	500	East Greenstone, Legacy Ridge
Xfmr 2	702	711	592	837	
12F3	323	400	322	500	
12F4	**394**	400	353	500	
EFM					
12F1	314	400	334	500	
12F2	308	400	281	500	Huntwood,
Otis					
Xfmr					
12F1					Greenstone, BKR12F1 &12F2, LIB12F2
12F2					LIB12F4, EFM12F2

Avista Utilities

2007
Electric Service
Reliability Monitoring
Annual Report

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Introduction

Washington state investor-owned electric companies are to provide statements describing their reliability monitoring in an annual report pursuant to WAC 480-100-393 and WAC 480-100-398.

This document reports Avista Utilities' reliability metrics for the calendar year 2007. All numbers in this document are based on system data. The Company's system includes eleven geographical divisions. Two of these divisions straddle the Washington and Idaho border and commingle jurisdictional customers. A map of Avista's operating area is included in a following section.

WAC 480-100-393 (3)(b) requires the establishment of baseline reliability statistics. The Company's baseline statistics are included in this report.

Avista continues to review its baseline reliability statistics in light of operational experience under this regulatory protocol. Avista may modify its baseline statistics as appropriate and will update the Commission accordingly.

Avista is proposing to add a new section to the annual report which analyzes the areas where customers are experiencing multiple sustained outages. This new section will analyze a new reliability indice called $CEMI_n$, which implies Customers Experiencing Multiple sustained Interruptions more than n times.

Data Collection and Calculation Changes

WAC 480-100-398 (2) requires the Company to report changes made in data collection or calculation of reliability information after initial baselines are set. This section addresses changes that the Company has made to data collection.

Data Collection

- Since Avista's Electric Service Reliability Monitoring and Reporting Plan was filed in 2001, there have been several improvements in the methods used to collect outage data. In late 2001, centralizing the distribution trouble dispatch and data collection function for Avista's entire service territory began. The distribution dispatch office is located in the Spokane main complex. At the end of September 2005, 100% of the Company's feeders, accounting for 100% of the customers, are served from offices that employ central dispatching.

The data collected for 2007 represents the second full year of outage data collected through the Outage Management Tool (OMT). For 2007, all data was collected using the "Outage Management Tool" (OMT) based on the Company's Geographic Information System (GIS). The OMT system automates the logging of restoration times and customer counts.

Use of the OMT system and GIS data has improved the tracking of the numbers of customers without power, allowed for better prioritization of the restoration of service and the improved dispatching of crews.

With the completion of the transition to the OMT system, there has been an increase in the variability of the data collected from 2001 to 2007. As described in the last three annual reports, the data that was most affected by moving to an OMT system is the number of customers associated with an outage. The OMT system improves the customer count accuracy because OMT uses the customer count from GIS, rather than an estimate. As the Company expected the following reliability statistics were affected as a result of the areas being centralized:

- SAIFI and SAIDI – These statistics were expected to increase since the total number of customers affected by an outage will be used rather than the number of customers that have called in. The OMT system also significantly reduces the estimates made by the Distribution Dispatcher.
- CAIDI – This reliability index has not increased as much as anticipated due to the increases associated with both SAIFI and SAIDI. This is due to the better response time the company can provide through the OMT system.
- MAIFI – This statistic is not expected to be effected by the implementation of OMT. The data for momentary outages is gathered from the System Operators log (not the Distribution Dispatchers). However, the MAIFI statistic may be increasing in the future as more of the distribution feeder Trips and Recloses are recorded through the SCADA system.

The Company believes that centralization will also provide better cause code classification. The improvement will be due to the concentration of dispatchers and associated increased training and quality control.

Interruption Cause Codes

Cause code information is provided in this report to give readers a better understanding of outage sources. Further, the Company uses cause information to analyze past outages and, if possible, reduce the frequency and duration of future outages.

- The Company made several changes in the classification of outage causes for the reporting of 2005 outages and subsequent years. No change is being proposed for 2007.

Customers Experiencing Multiple Interruptions

The IEEE Standard 1366P-2003 provides for two methods to analyze data associated with customers experiencing multiple momentary interruptions and/or sustained interruptions. Avista's Outage Management Tool (OMT) and Geographical Information System (GIS) provide the ability to geospatially associate an outage to individual customer service points. This association allows for graphically showing Customers Experiencing Multiple sustained Interruptions ($CEMI_n$) with Major Event Day data included onto GIS produced areas. Data can be exported to MS Excel to also create graphs representing different values of n. A new section will be added to the report after the Areas of Concern Section to summarize the analysis Avista performed on the 2007 outage data. The calculation for $CEMI_n$ and Customers Experiencing Multiple Sustained and Momentary Interruptions $CEMSMI_n$ is provided in the Indices Section.

Definitions

Reliability Indices

SAIFI (System Average Interruption Frequency Indices), MAIFI (Momentary Average Interruption Frequency Indices), SAIDI (System Average Interruption Duration Indices), and CAIDI (Customer Average Interruption Duration Indices) are calculated consistent with industry standards as described below. Avista adopts these for purposes of tracking and reporting reliability performance. Further explanation and definitions are provided in the "Indices Calculation" section of this report. While these indices are determined using industry standard methods, it is important to note that differing utilities may use different time intervals for momentary and sustained outages. Avista defines momentary outages as those lasting five (5) minutes or less. Sustained outages are those lasting longer than five (5) minutes.

Baseline Reliability Statistics

WAC 480-100-393 (3) (b) requires the establishment of baseline reliability statistics. The Company's 2003 Electric Service Reliability Monitoring and Reporting Plan initially established Avista's Baseline Reliability Statistics. At that time, the Company selected these baseline statistics as the average of the 2001 through 2003 yearly indices plus two standard deviations (to provide 95% confidence level). Last year the Company reviewed the calculation of the baseline statistics in light of the completion of the transition to the OMT in 2005 and the data collected in 2006. Calculating the baseline reliability statistics including the 2004 through 2006 data show an increase in the values, which the Company believes, represents better reporting using OMT. The Company proposed the latest calculated Baseline Statistic values to reflect the best available data collection. Because the Company believes that the OMT data collection has affected the SAIFI index the most it used the years 2004 to 2006 for the SAIFI Baseline Statistic and the years 2002 to 2006 for the MAIFI and SAIDI Indices.

The baseline indices have been adjusted by removing Major Event Days, MED's, as defined in the following section.

The following table summarizes the baseline statistics by indices.

Indices	2004-2006 Average (Excluding Major Events)	Baseline Statistic (Ave + 2 Standard Deviations)
SAIFI	1.09	1.44

Indices	2002-2006 Average (Excluding Major Events)	Baseline Statistic (Ave + 2 Standard Deviations)
MAIFI	4.52	5.82
SAIDI	114	160

Additional comparison of the Baseline Indices is provided in the System Indices section of this report.

Avista is anticipating using the different years in the Baseline Statistics for SAIFI for at least a couple of years until a full five years of data is gathered using the current Outage Management Tool.

Major Events

Major Events and Major Event Days as used in this report are defined per the IEEE Guide for Electric Power Distribution Reliability Indices, IEEE P1366-2003. The following definitions are taken from this IEEE Guide.

> **Major Event** – Designates an event that exceeds reasonable design and or operation limits of the electric power system. A Major Event includes at least one Major Event Day (MED).
>
> **Major Event Day** – A day in which the daily system SAIDI exceeds a threshold value, T_{MED}. For the purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as severe weather). Activities that occur on major event days should be separately analyzed and reported.

The Company will use the process defined in IEEE P1366 to calculate the threshold value of T_{MED} and to determine MED's. All indices will be reported both including and excluding MED's. The comparisons of service reliability to the baseline statistics in subsequent years will be made using the indices calculated without MED's.

The table below lists the major event days for 2007.

Major Event Days	SAIDI (Customer-Minutes)	Cause
2007 Major Event Day Threshold	8.017	
01-06-2007	9.98	Wind Storm
06-29-2007	32.64	Wind Storm
07-13-2007	12.79	Wind Storm
08-31-2007	21.30	Wind & Lightning Storm

Additional analysis of the 2007 Major Event Days is provided in this Annual Report starting on Page 52, section Major Event Days Causes.

Customer Complaints

The Company tracks reliability complaints in two areas, Commission complaints and Customer complaints. Commission complaints are informal complaints filed with and tracked by the Commission. Customer Complaints are recorded by our Customer Service Representatives when a customer is not satisfied with a resolution or explanation of their concern. See the Customer Complaints section on Page 36 for a summary of results for this year.

System Indices

The charts below show indices for Avista's Washington and Idaho ("system") electric service territory by year. Breakdown by division is included later in this report.

The Company continues to use the definition of major events as described above to be consistent with IEEE Standards. Therefore, the following charts show statistics including the effect of major events per this definition.

Chart 1.1 – SAIFI - Sustained Interruptions / Customer

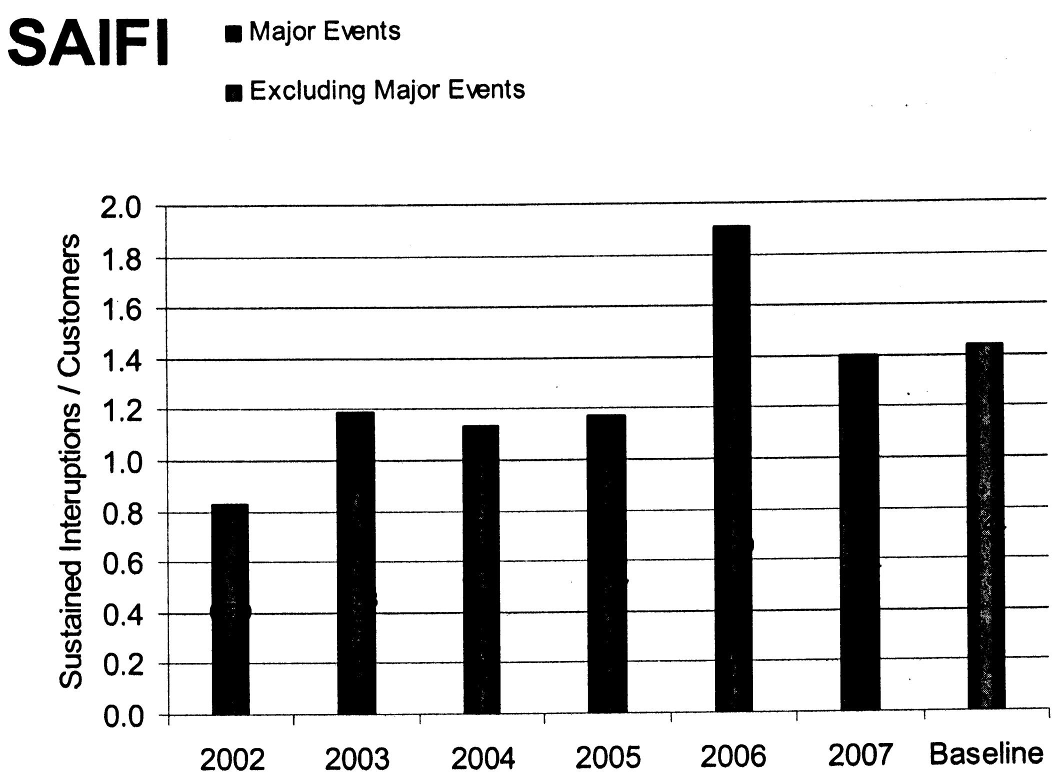
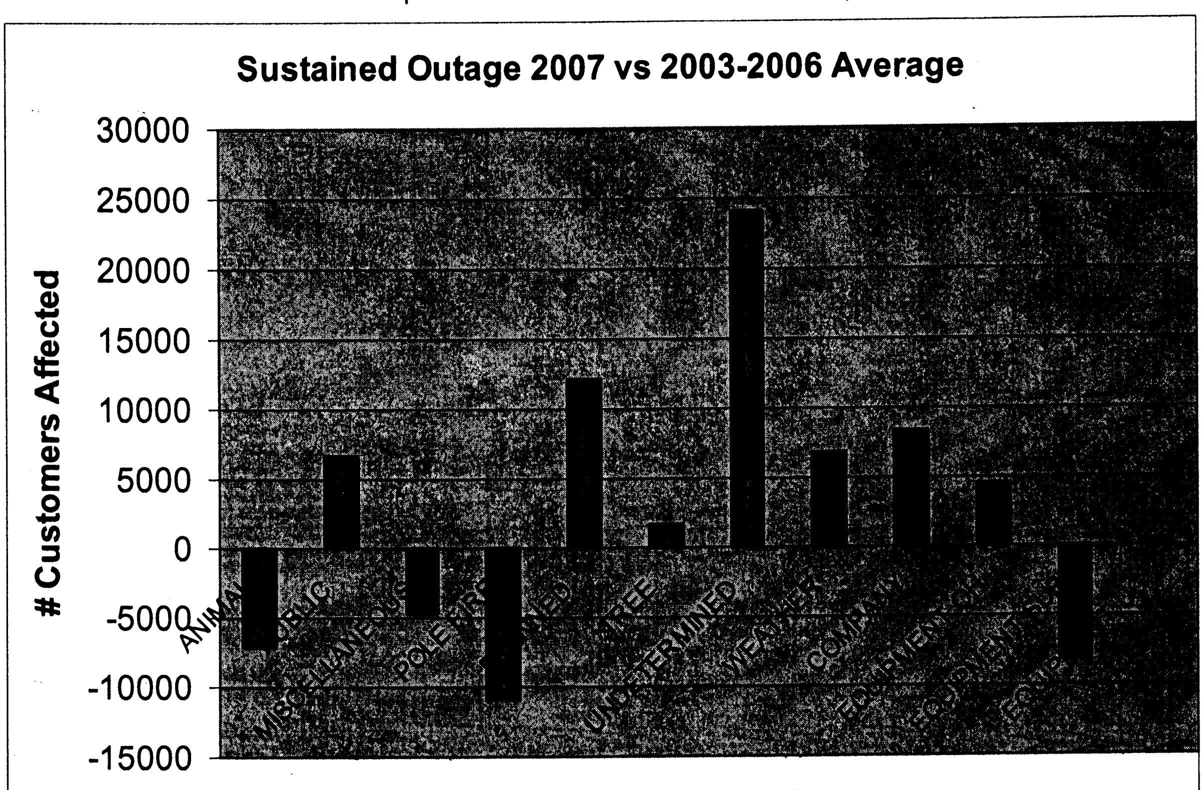


Chart 1.2 – Sustained Interruptions / Customer Historic Comparison



SAIFI for 2007 was within the existing baseline and 12% lower than 2006. Major contributors to this difference were lower weather, tree, public, and overhead equipment outages.

There were 71,949 customers affected by sustained outages caused by weather in 2007. This compares to the 2003–2006 average of 65,115 customers.

47,051 customers were affected by sustained outages associated with tree related incidents. This compares to the 2003-2006 average of 45,350 customers. The vast majority of the tree related reasons were associated with either tree fell or tree weather incidents.

Planned maintenance activities and also forced repairs affected 27,293 customers as compared to the 2003-2006 average of 15,164 customers. Additional maintenance activities associated with the Company cutout replacement program contributed to the increase in this cause and reduced the Overhead Equipment outage causes.

Equipment overhead (OH) failures resulted in outages to 53,397 customers as compared to the 2003-2006 average of 48,817. Major Equipment OH sub-categories were distribution fused cutouts, primary connector failures, arrester failures and other.

Cars hitting poles, felling trees and fires were a majority of the public caused outages.

A large increase in the number of Undetermined Causes occurred in 2007 as compared to the 2003-2006 average. 51,408 customer had undetermined causes as compared to the average of 27,250. A significant number of outages were associated with transformer fuses, but there was no known reason for the fuse to operate.

Chart 1.3 - MAIFI Momentary Interruption Events / Customer

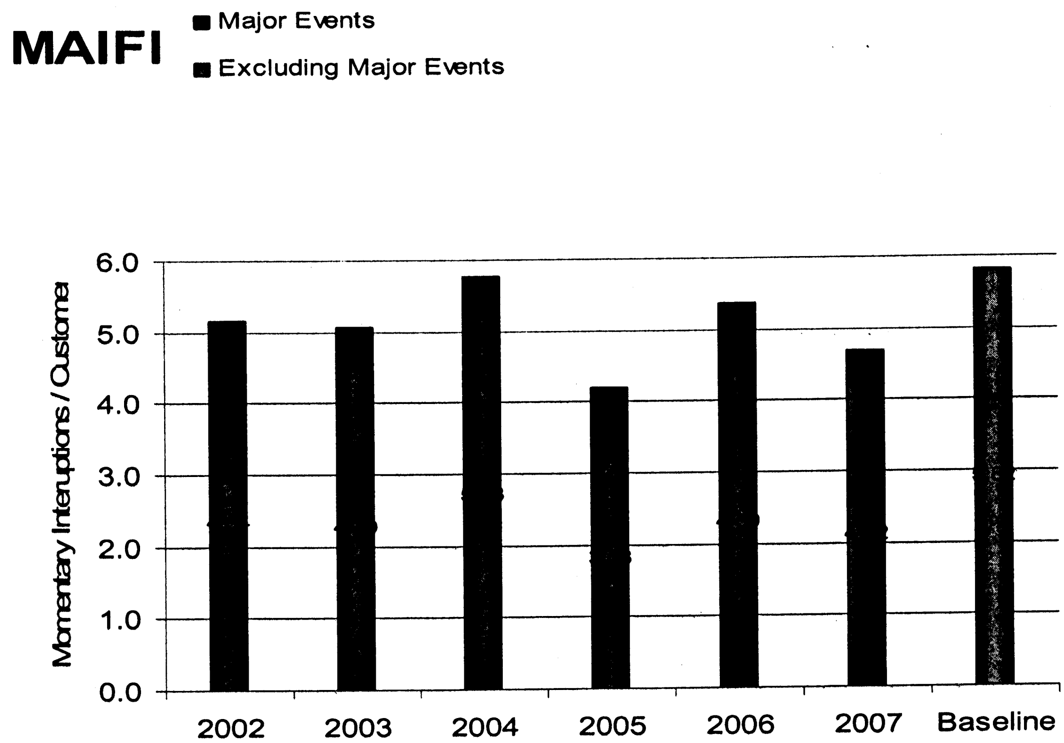
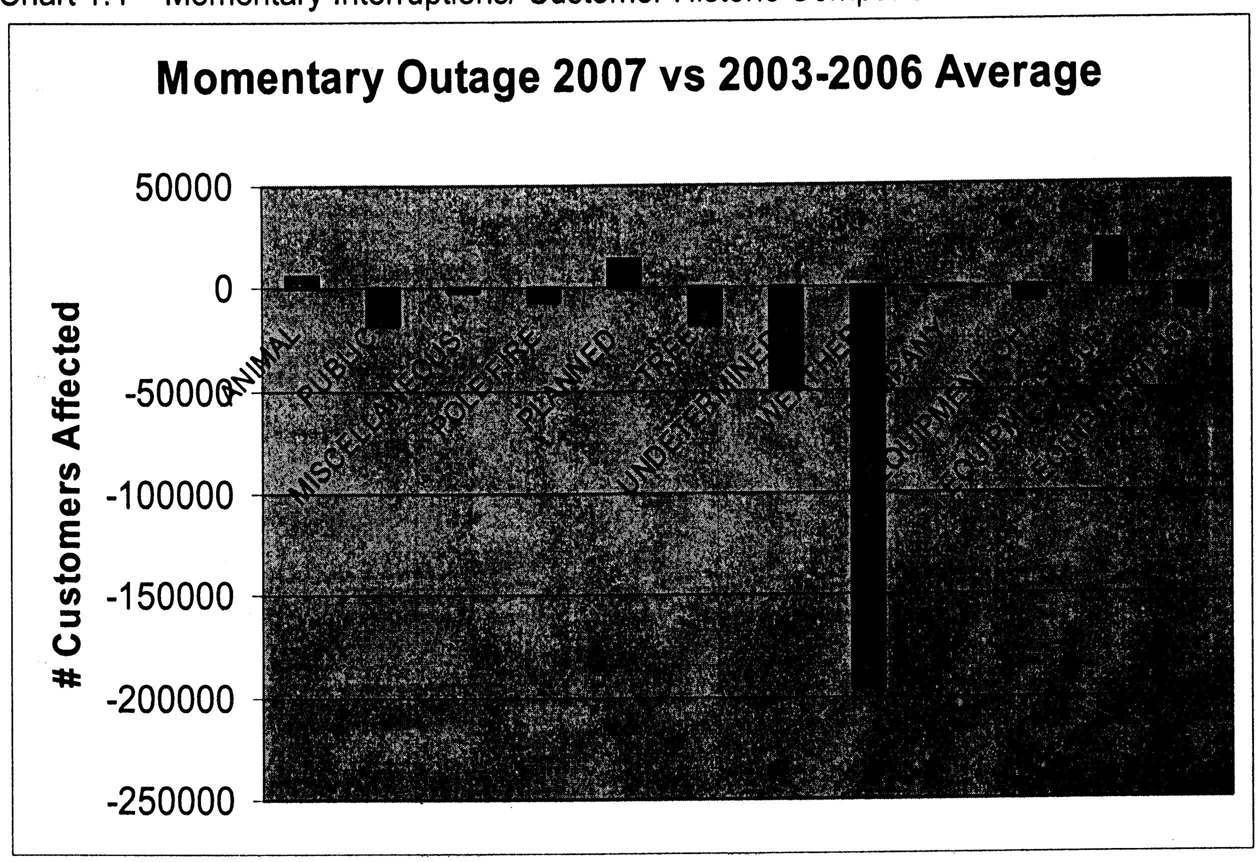


Chart 1.4 – Momentary Interruptions/ Customer Historic Comparison



The 2007 results for MAIFI show a small decrease in the number of incidents compared to the 2003 to 2006 average. There was a significant reduction in weather/undetermined related momentary outages, that were most likely due to the better overall weather conditions. Distribution Dispatch continues to make improvements in correlating the momentary outages with subsequent sustained outages, which reduces the undetermined causes. Wind contributed to 32,157 customers being impacted, Heavy Snow impacted 39,443 customers while Lightning accounted for impacts to 23,566 customers.

All other categories showed either a slight increase or slight decrease that would be consistent with previous years.

Chart 1.5 - SAIDI – Average Outage Time / Customer

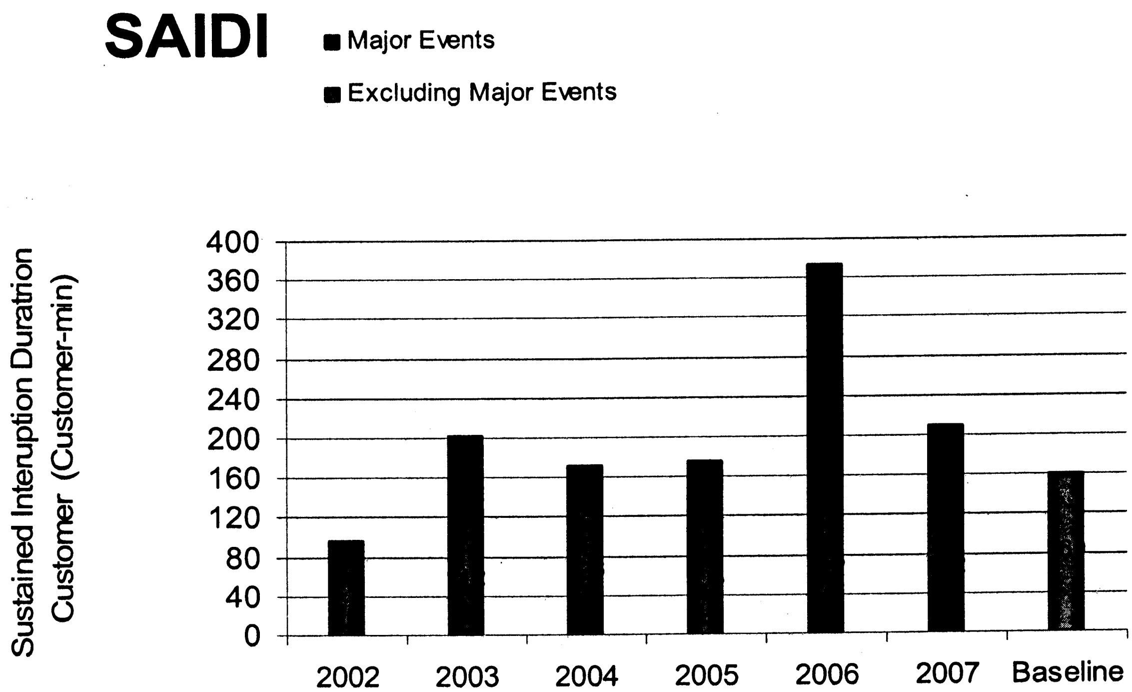
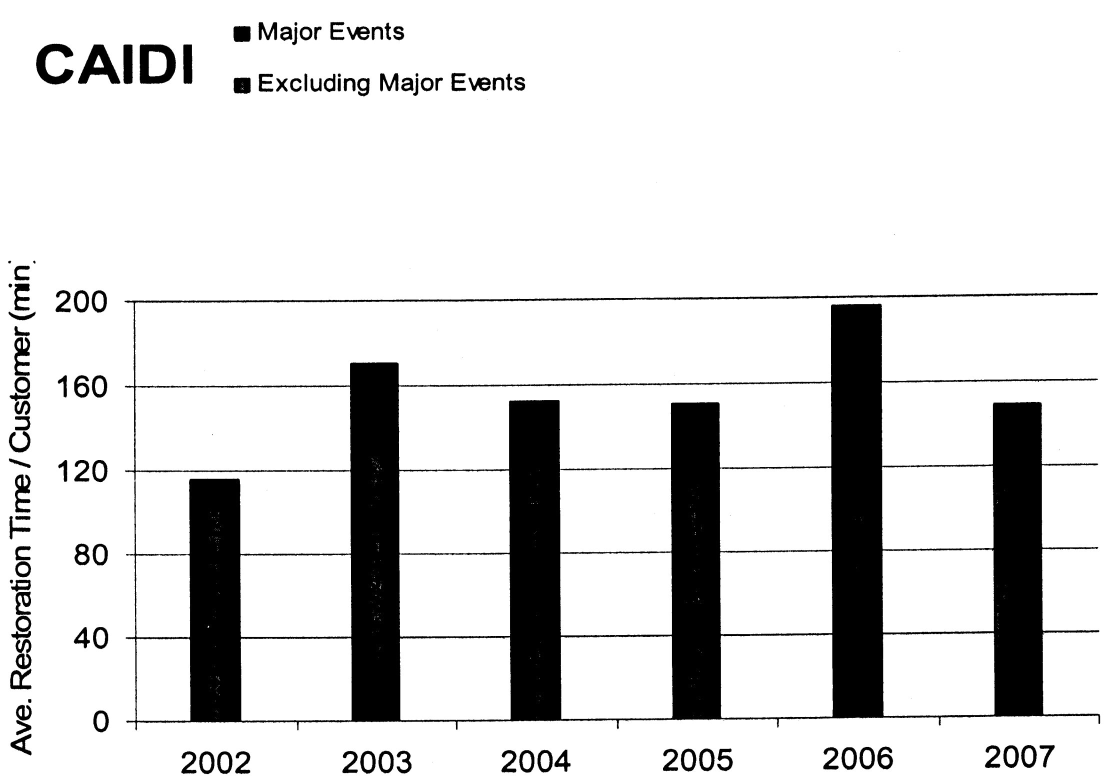


Chart 1.6 - CAIDI – Average Restoration Time



OFFICE Indices

Chart 2.1 – SAIFI - Sustained Interruptions / Customer

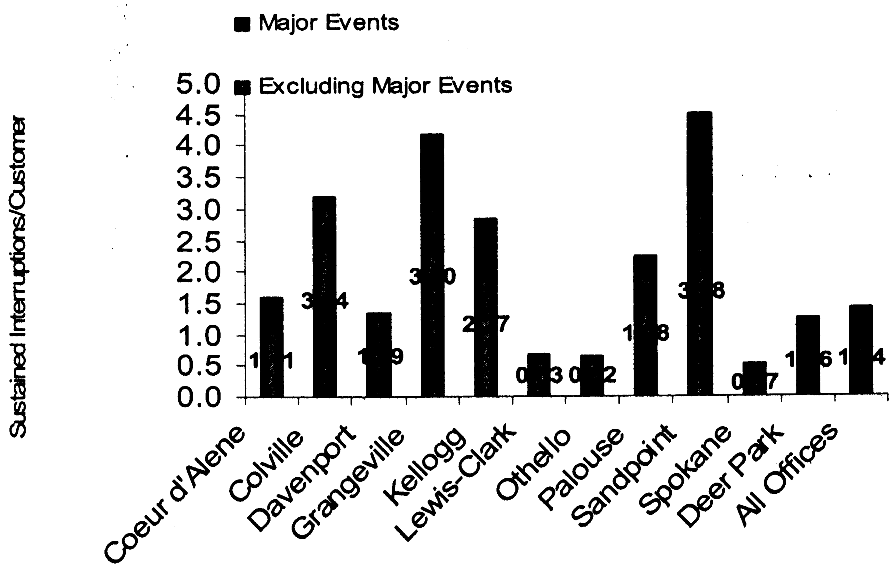


Chart 2.2 - MAIFI Momentary Interruption Events / Customer

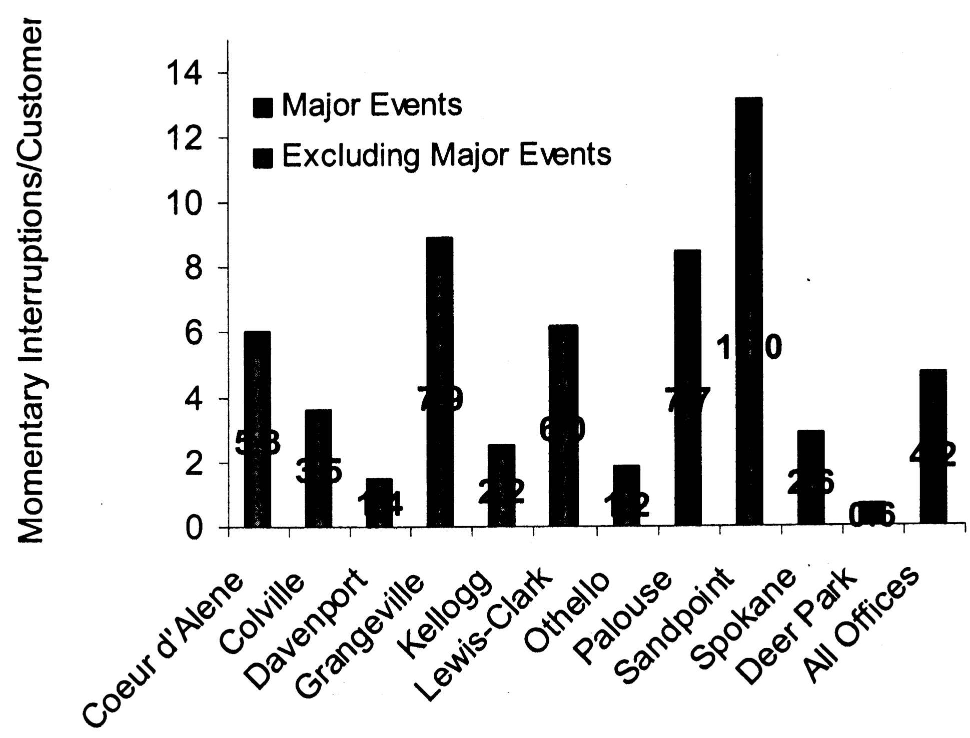


Chart 2.3 - SAIDI – Average Outage Time / Customer

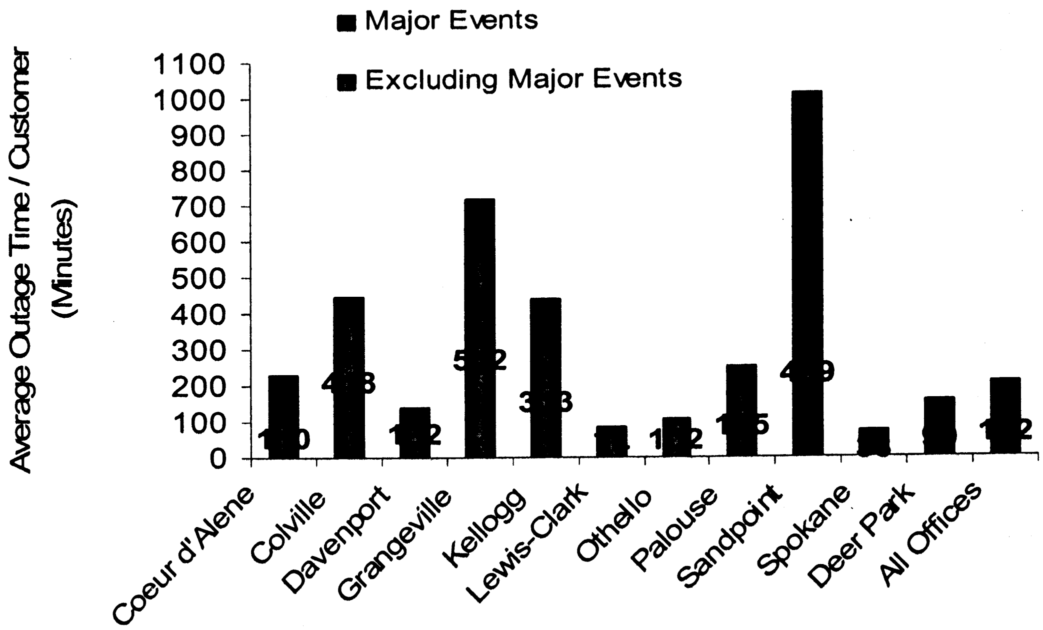
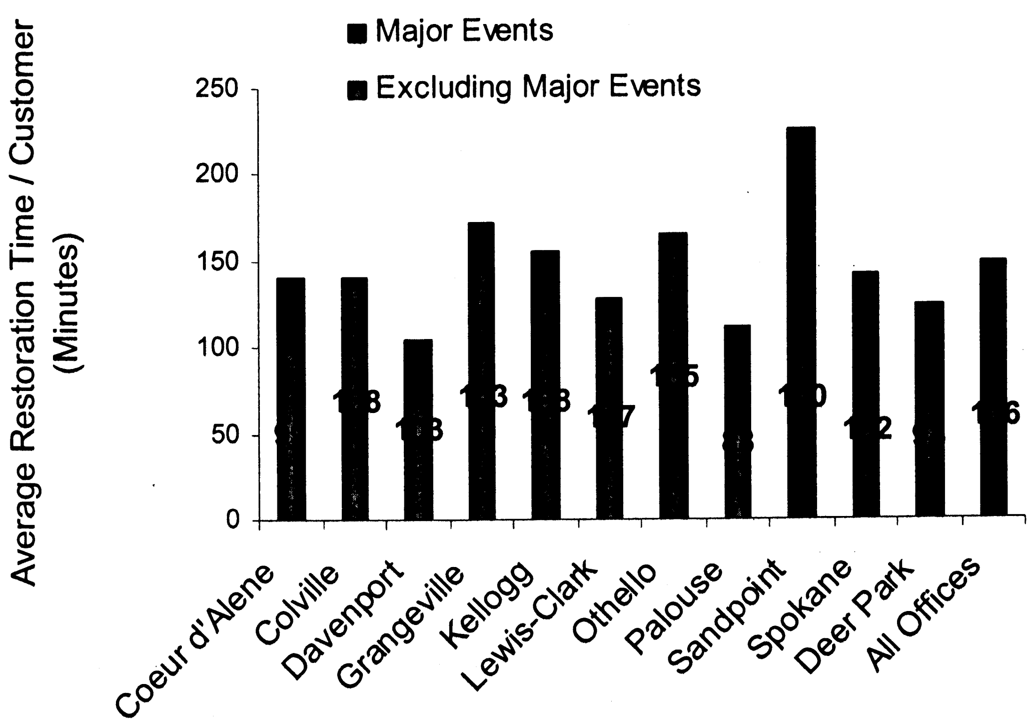


Chart 2.4 - CAIDI – Average Restoration Time



Areas of Concern

As in previous years, Colville has the lowest reliability of Washington's operating areas. However, the Colville area continues to show improvement over previous years as work plans are implemented. Colville was judged lowest based on its performance in the yearly indices for SAIFI, SAIDI, CAIDI, and MAIFI. Within the Colville area, five feeders (Gifford 34F1, Gifford 34F2, Colville 34F1, Colville 12F4, Chewelah 12F3 and Valley 12F1) were identified as areas of concern in 2006. For this report, six feeders are identified as the areas of concern for 2007. These feeders are Gifford 34F1, Gifford 34F2, Colville 34F1, Colville 12F4, Valley 12F3 and Valley 12F1.

Cause Information:

Generally rural areas have a greater number of outages per customer. Colville is a predominately rural and forested area. There are approximately 2342 miles of distribution line exposed to weather, underground cable failures and tree problems. Unlike most of the Company's system, lines in this area are built on the narrow, cross-country rights-of-way, typical of PUD construction practices prior to Avista acquiring the system. These conditions make patrolling, tree trimming, right of way clearing and other maintenance difficult. Over time and when cost effective Avista moves sections of these lines to road rights of way and/or converts them to underground.

Further, when outages occur in rural areas, the time required to repair damage is longer. More time is required for first responders to arrive and assess the damage and more time is required for the crew to reach the site. Often the damage is off road and additional time is required to transport materials and equipment to the site.

Listed below is a summary of the specific cause data for each feeder. This is a compilation of data from the Avista Outage Management Tool and the reporting from our local servicemen to Distribution Dispatch. Data from the reporting system is shown as a percentage of total customer-outages, (SAIFI) for that feeder.

Snow loading on green healthy trees growing beyond the rights-of-way often causes them to bend or break and contact distribution lines. These trees are not cut as part of our vegetation management program because they are outside our right of way and are considered healthy marketable timber.

The reliability of two of the Valley feeders has diminished over the last four years and will be added to the list for this year's report to reflect plans to improve the reliability in future years. Valley 12F3 has poorer reliability for 2007 than Valley 12F1 which was reported for the first time in the 2006 report.

Gifford 34F1

- 30.1% Weather: snow, wind and lightning storms
- 21.4% Equipment: poles, fused cutouts, & connectors
- 11.8% Pole fires
- 16.9% Trees
- 3.3% Planned outages

Colville 34F1

- 23.4% Weather; snow, wind and lightning storms
- 20.8% Equipment: crossarms and poles
- 0.1% Pole fires
- 34.1% Trees
- 10.7% Planned outages

Chewelah 12F3

- 3.7% Weather: snow, wind and lightning storms
- 35.7% Equipment: connector and arrester
- 23.0% Company
- 9.4% Trees
- 15.0% Planned outages
- 3.6% Animal: birds or squirrels

Gifford 34F2

- 14.0% Weather: Wind, snow, and lightning storms
- 0.1% Equipment: regulator failure
- 34.8% Pole Fires
- 37.5% Trees
- 6.3% Planned outages
- 2.6% Public: car hit pole, dig in

Valley 12F3

- 12.0% Weather: wind and lightning storms
- 33.5% Equipment: fused cutouts, insulator, and other
- 5.4% Trees
- 15.8% Public
- 15.5% Planned outages
- 0.5% Animal: birds or squirrels

Valley 12F1

- 3.6% Weather: snow, wind and lightning storms
- 42.6% Equipment: connector and arrester
- 0.3% Trees
- 9.2% Public
- 7.3% Planned outages
- 3.5% Animal: birds or squirrels

Work Plans:

The improvement work that has been accomplished or planned for each feeder is listed below. The Company's reliability working group is continuing to study these feeders to develop additional work plans. Each of the identified feeders also had planned outages that correspond to the maintenance and replacement activities in the area.

Gifford 34F1

- An engineering review was completed in 2006 and construction jobs drawn up to implement improvements to the feeder protection scheme which should break up the exposure on the long single phase laterals. Construction work was completed in the later part of 2007 to replace two reclosers and to add two additional reclosers to the feeder. In addition, adding 320 neutral extension racks should help address the ice unloading issue. However, the work on the extension racks has been delayed for a couple of years.
- No URD cable was replaced in 2007, but 7500' of cable has been identified to be replaced in 2008.
- Vegetation Management was scheduled to complete ROW clearing in 2007, but this was rescheduled to be completed in 2008. Work was rescheduled due to forest access restrictions last summer and completing work on other parts of the Avista system.

Colville 34F1

- No URD cable was replaced in 2007; however a 6620' section of new URD cable was installed to replace a section of overhead line that had a lot of poles that would need to be replaced.
- The remaining 50% of the feeder was re-cleared during 2007. No additional work planned for 2008.
- An engineering review was completed and construction jobs drawn up to implement improvements to the feeder protection scheme, eliminating a step-up transformer, and several 34.5 to 13.2 kV step-down transformers on the HWY 25N-Williams Lake section of the feeder to improve the level of service to customers. Construction work was completed in 2007, however the new recloser installed failed to perform properly and has been removed from service and has been returned to the factory for evaluation.

Chewelah 12F3

- Engineering analysis completed in 2006 and a budget item prepared. Higher priority budget items left these reliability improvements unfunded for 2007. In early 2007, budget money was approved to complete this project. Three reclosers were installed on the feeder to improve the temporary fault protection. Local personnel identified areas where turkeys roost and fly into the distribution facilities during early morning hours.
- Hazard tree patrol and mitigation work was completed during 2007. No work is planned for 2008.
- 3300' of URD cable was replaced in 2007.

Gifford 34F2

- Engineering analysis was completed in 2006 and a budget item prepared to implement improvements to the feeder protection scheme. Higher priority budget items left these reliability improvements unfunded for 2007 and 2008. Current planning is to begin work in 2009.
- No tree trimming work was planned for either 2007 or 2008.
- There is several planned replacement jobs of less than 1000' of URD cable scheduled in 2008.

Valley 12F1

- Engineering analysis was completed in 2006 and a budget item prepared to implement improvements to the feeder protection scheme that should reduce the exposure on long single phase laterals. Higher priority budget items left these reliability improvements unfunded for 2007 and 2008. Work is scheduled to be start in 2009.
- Hazard tree patrol and mitigation work was completed in 2007. No work planned for 2008, but work is planned for 2009.

Valley 12F3

- Engineering analysis was completed in 2007 after a car hit pole incident and subsequent line recloser failure to evaluate the overall protection scheme.
- No tree trimming work was planned or completed for 2007, but work is planned for 2008.
- No URD cable was replaced in 2007 or is planned to be replaced in 2008.

Avista typically uses several different protective devices on its feeders to isolate faulted or overloaded sections and also continue to serve the remaining customers. Generally, two different protection schemes are used to either "save" the lateral fuse or "blow" the lateral fuse by using or not using the instantaneous over current trip. Depending on the feeder, number of customers, types of faults, (temporary or permanent), customer type, time of year, etc. both of these schemes may be used on an individual feeder at different times at the discretion of the field personnel. With the better data and cause code collection that OMT provides and the customer growth on some of the Colville feeders, changes to the type of scheme used has been reviewed. In the last few years, new electronic fault indicators allow for quicker response to outages and help with restoration of customers. Fault indicators are being employed on some feeders to reduce the outage response times. Engineering reviews of some of the sections of the feeder(s) in the Colville area show that the addition of surge arrester protection should reduce outages on the feeder(s) due to lightning.

Avista develops a detailed annual budget for various improvements to the facilities it owns and operates. With the emphasis on Generation upgrades, Electric Transmission upgrades, Electric Substation capacity increases, and Electric Distribution capacity projects, the three projects described below were deferred until later years. Reliability specific projects were prioritized at a lower level than thermal capacity projects which is related to the recent economic growth in the Avista service territory. Many of these capacity projects have large capital expenditures associated with them and have taken the allocated capital budget resources. Also, as result of better data collection the analysis may show that these projects should have a higher priority over the next few years.

Feeder	Decisions/ basis	2008	2009 and beyond
Gifford 34F2	A small part of the initial budget item is being completed in 2008 on a portion of the feeder with the worst performance. The remaining portion of the budget item will be submitted again in 2009.	Planned	Planned
Valley 12F1	This feeder was first identified in mid 2006 as having areas that would be of concern. The priority of the projects identified for this feeder will be reviewed and resubmitted in future years.		Planned
Valley 12F3	A project has been identified to reconductor a section of this feeder near Waitts Lake to allow the addition of a third phase to a section of the feeder beyond the lake. Fusing protection will also be revised.	Planned	Planned

Besides the specific plans listed above, the Company performs ongoing maintenance activities in the Colville area that includes transmission aerial patrols, substation inspections and infrared surveys. Other maintenance activities occur daily as field personnel find and repair problems.

Porcelain cutout failures continue to contribute to outages and also have caused several pole fires on a system wide basis. As a result, Avista began purchasing a newer design of cutout with a polymer insulator beginning in January of 2005. Porcelain cutout failures tend to occur at a higher rate in areas with colder temperatures and wide temperature fluctuations, such as the Colville area. Avista started a system wide change out program in early 2007 to proactively replace problematic porcelain cutouts before this specific style fails. As of the end of February, 2008, 4400 out of about 8000 of this type of porcelain cutout have been replaced on the system. An additional 3600 are being planned to be replaced before year end 2008.

Avista has an annual vegetation management plan and budget to accomplish the plan. The budget is allocated into distribution, transmission, administration, and gas line reclearing.

Distribution

Our current plan for Avista's distribution system is managed by Asplundh Tree Expert Co. Every distribution circuit is scheduled to be line clearance pruned on a regular maintenance cycle of five years. Other distribution vegetation management activities include hazard tree patrol and herbicide application.

Transmission

The transmission system is managed by Avista's forester. All 230 kV lines are patrolled annually for hazard trees and other issues, and mitigation is done in that same year. Approximately one third of 115 kV transmission system is patrolled annually for hazard tree identification, and assessment of right of way clearing needs. Right of way clearing maintenance is scheduled and performed approximately every ten to fifteen years (for each line). Interim spot work is done as identified and needed. Engineering specifications for various voltages, line configurations are followed when clearing the right of way. Currently, the work is bid to a variety of contractors.

Customers Experiencing Multiple Interruptions

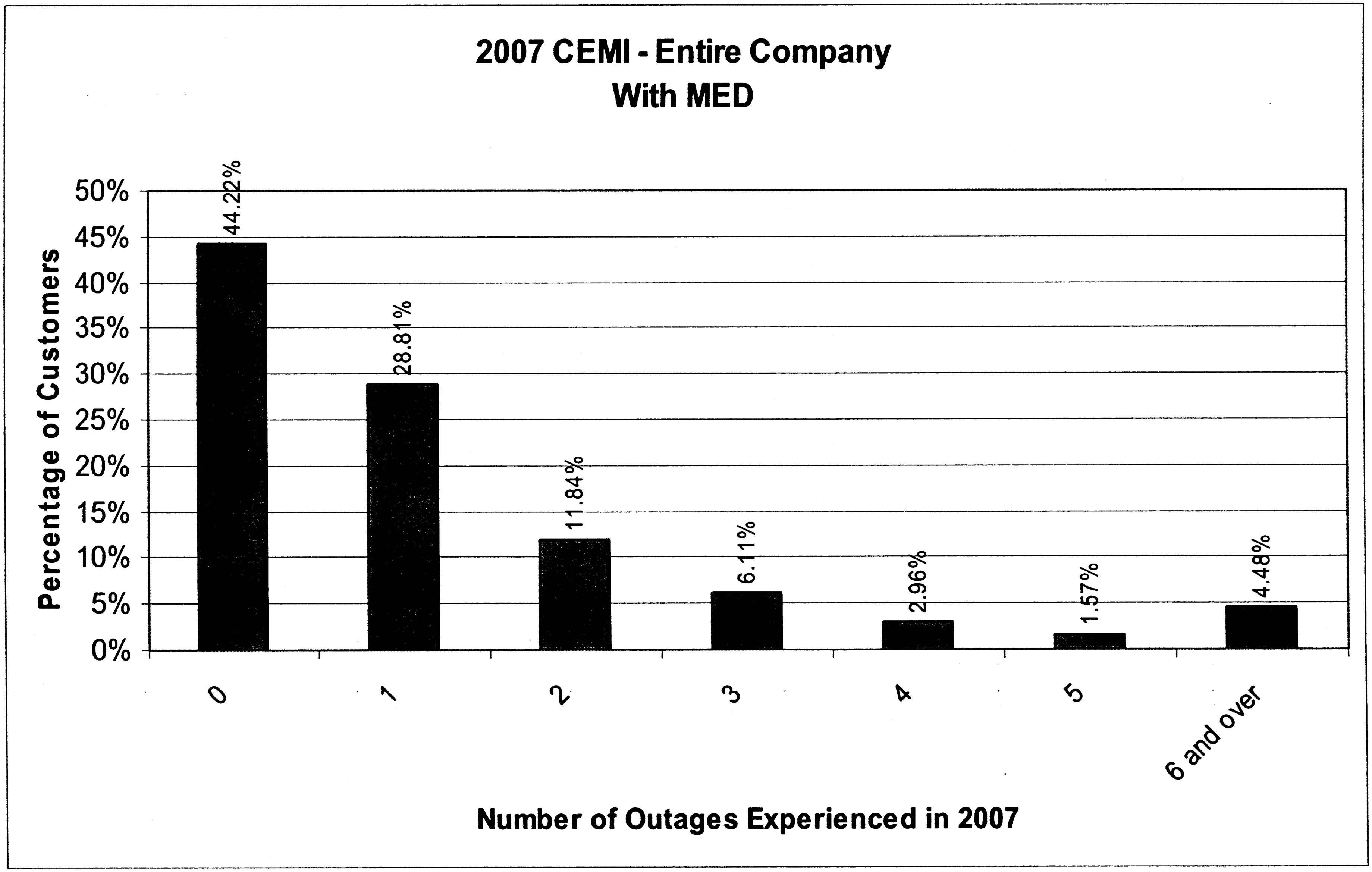
Avista has used the data from the OMT system integrated with the GIS system to geospatially display reliability data for specific conditions. The specific conditions imply looking at the number of sustained interruptions for each service point (meter point). This would be similar to the SAIFI indice, but would be related to a certain number of sustained interruptions. Avista includes all sustained interruptions including those classified under Major Event Days. This provides a view of what each customer on a specific feeder experiences on an annual basis. Momentary Interruptions are not included in the $CEMI_n$ indice, because of the lack of indication on many of the rural feeder reclosers.

The first chart below provides a view of the percentage of customers served from the Avista system that have sustained interruptions. 73 % of Avista customer had 1 or fewer sustained interruptions and 4.48% of Avista Customers had 6 or more sustained interruptions during 2007.

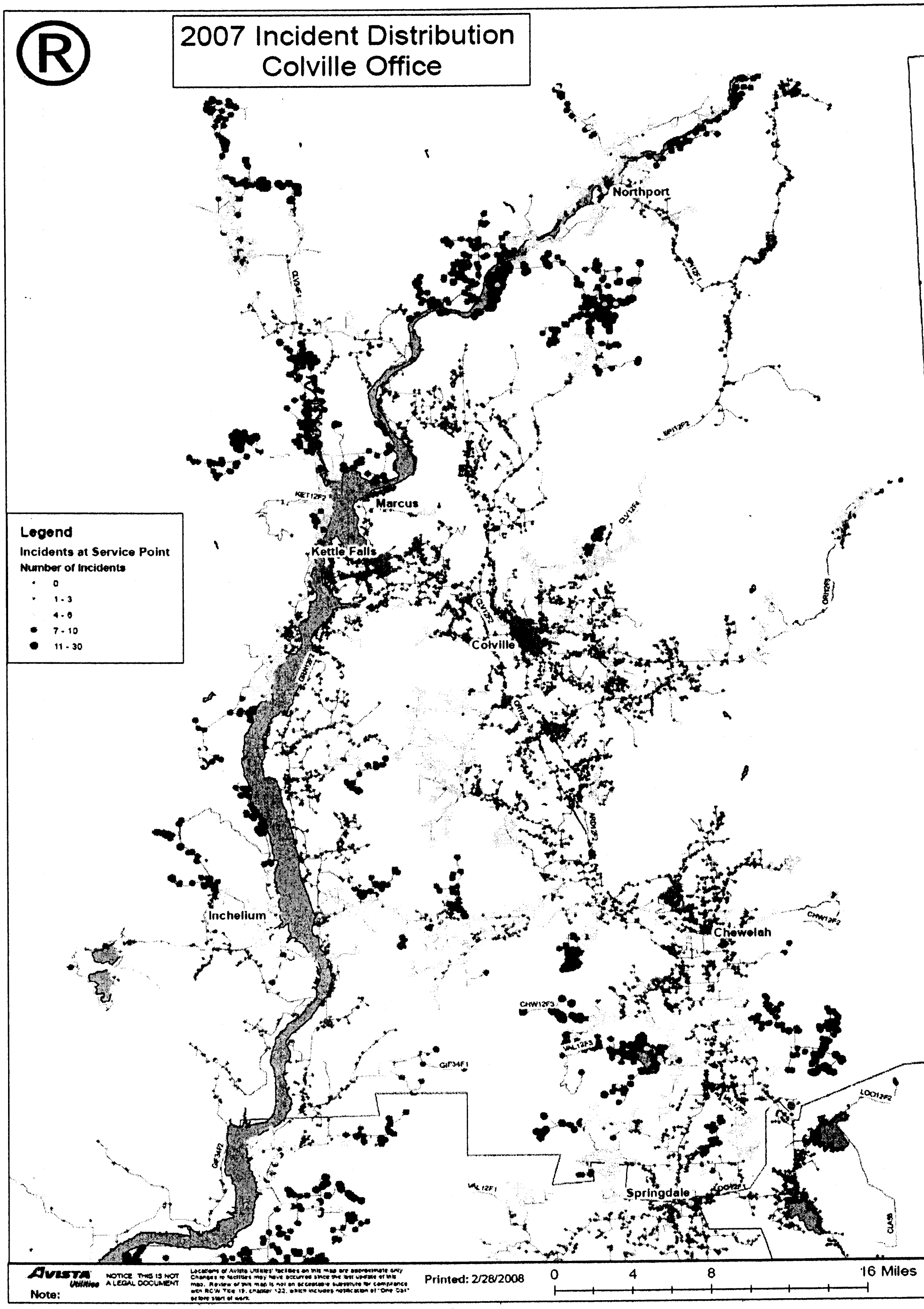
The remaining geographic plots show the sustained interruptions by color designation according to the legend on each plot for each office area. Note the office area is designated as the area in white for each plot and that there is overlap between adjacent office area plots. The adjacent office areas are shown in light yellow.

The plots provide a quick visual indication of varying sustained interruptions, but significant additional analysis is required to determine underlying cause(s) of the interruptions and potential mitigation.

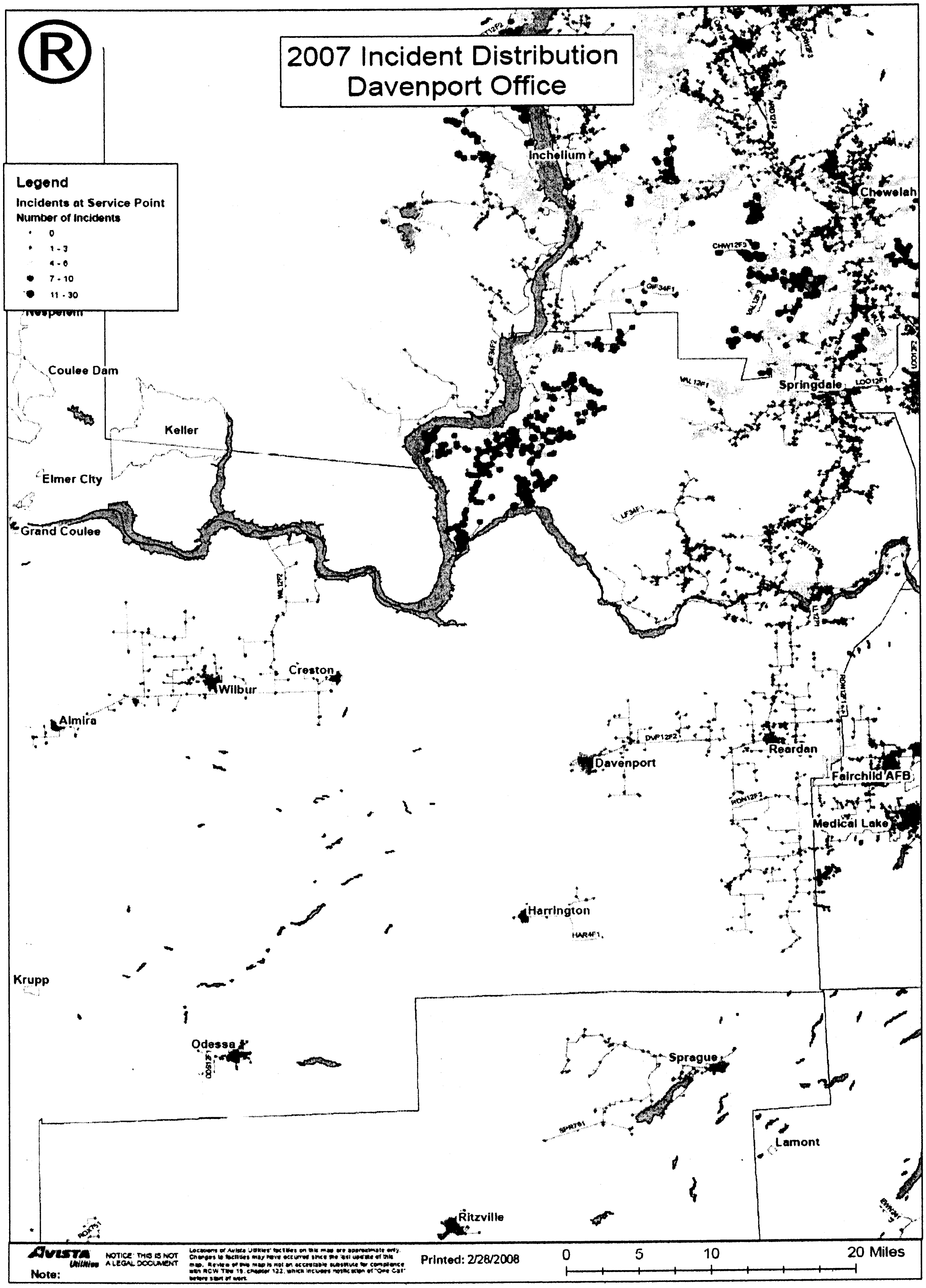
Avista Service Territory $CEMI_n$ Chart



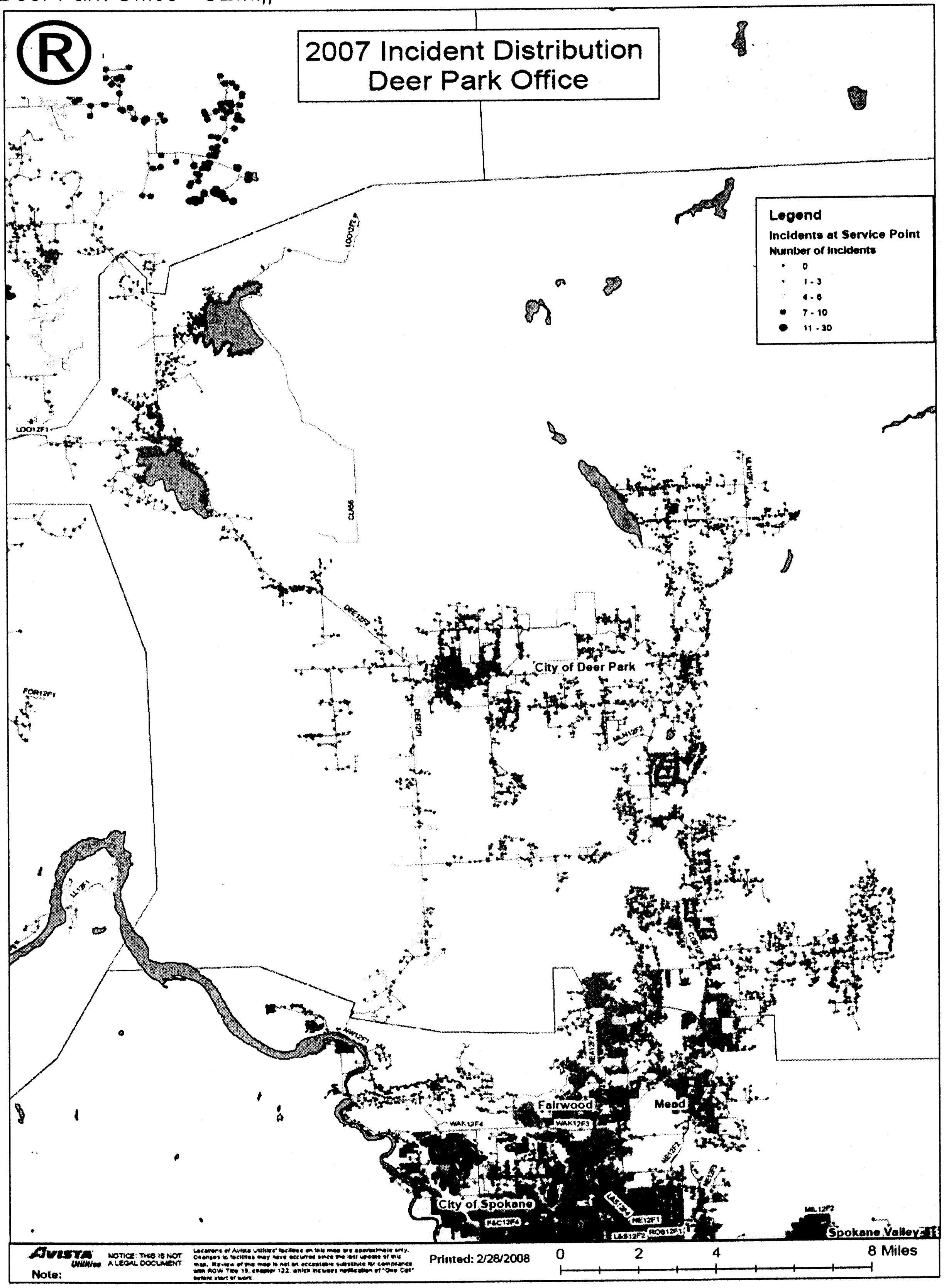
Colville Office - CEMI$_n$



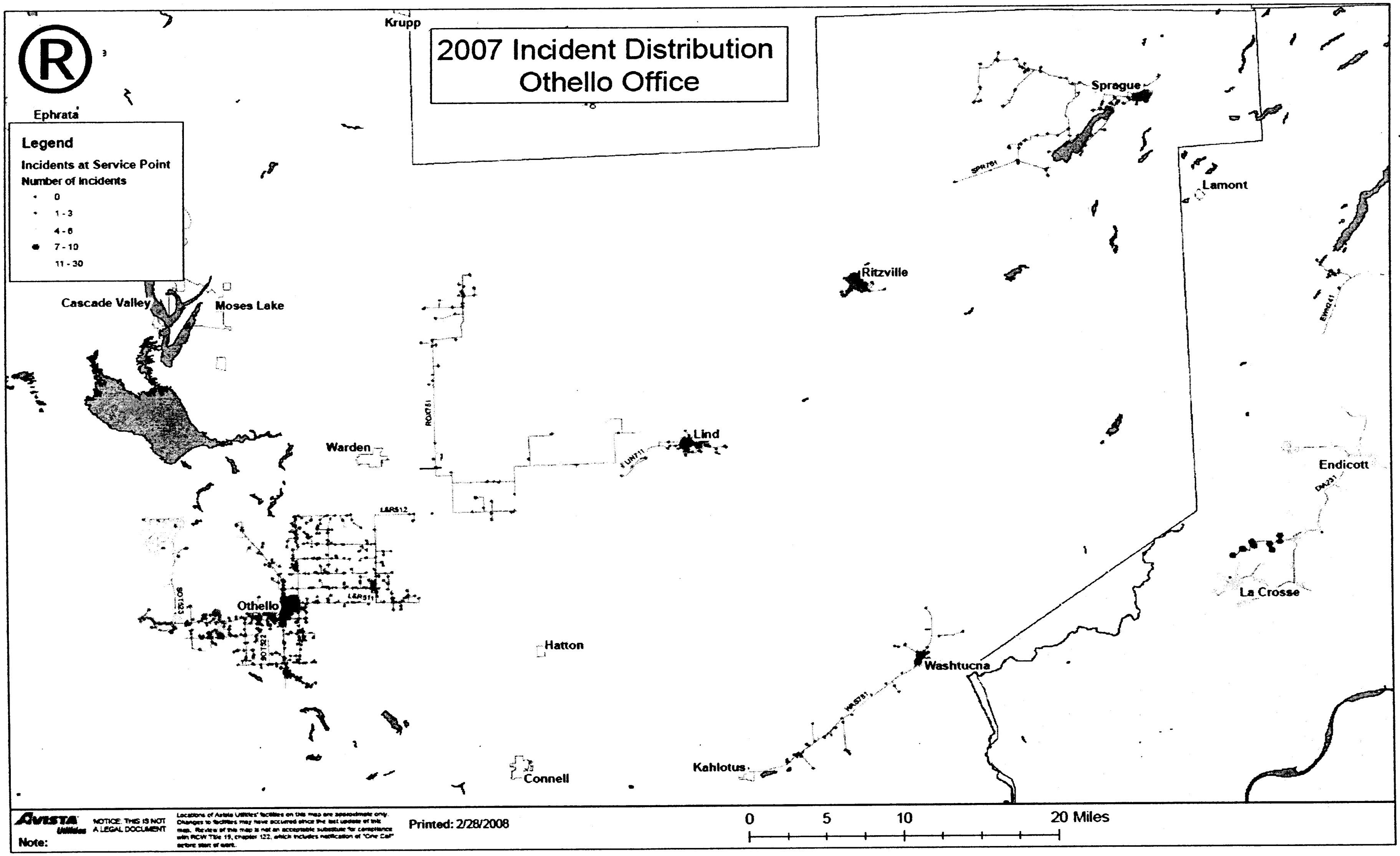
Davenport Office - $CEMI_n$



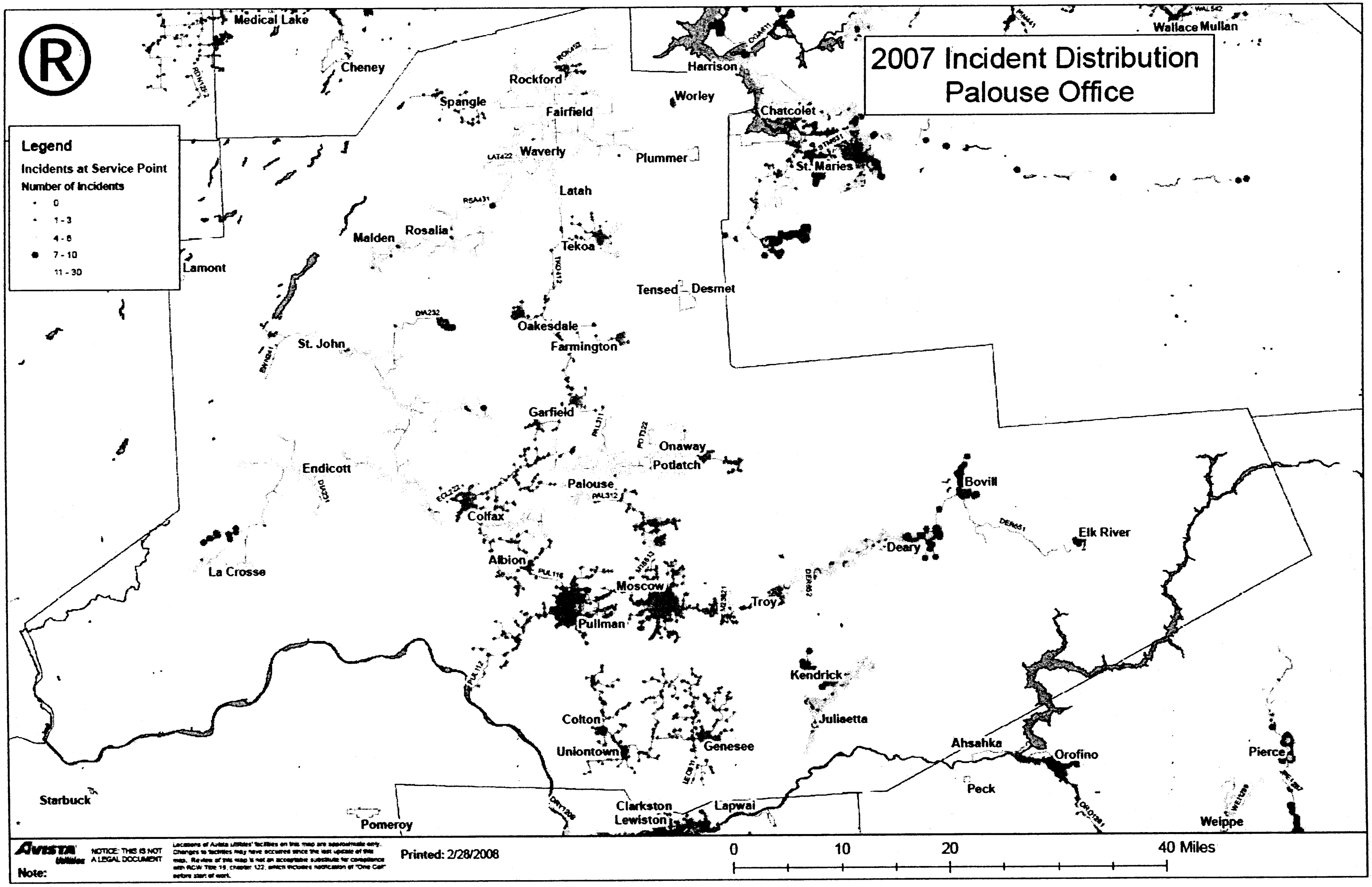
Deer Park Office - CEMI$_n$



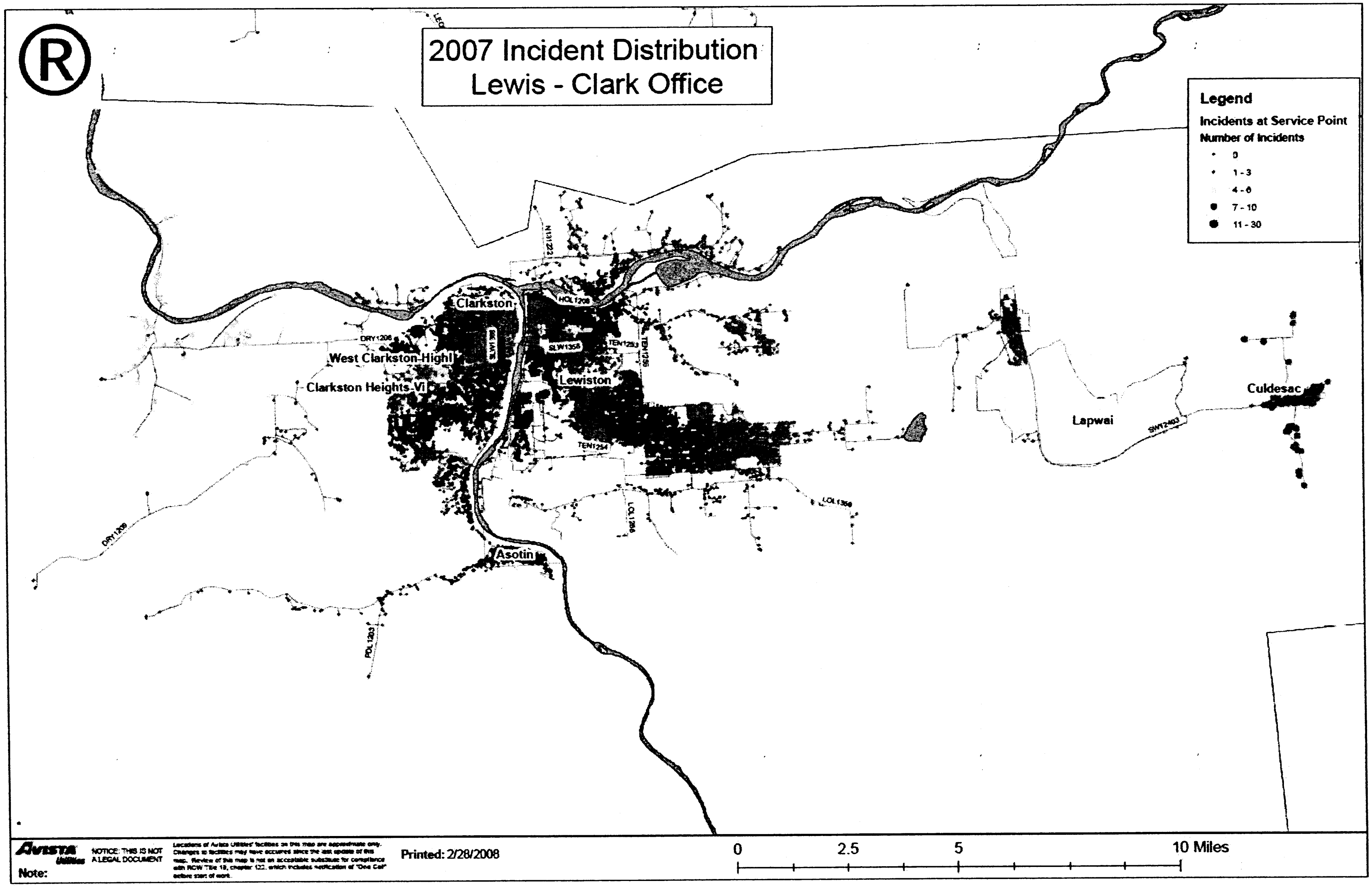
Othello Office - CEMI$_n$



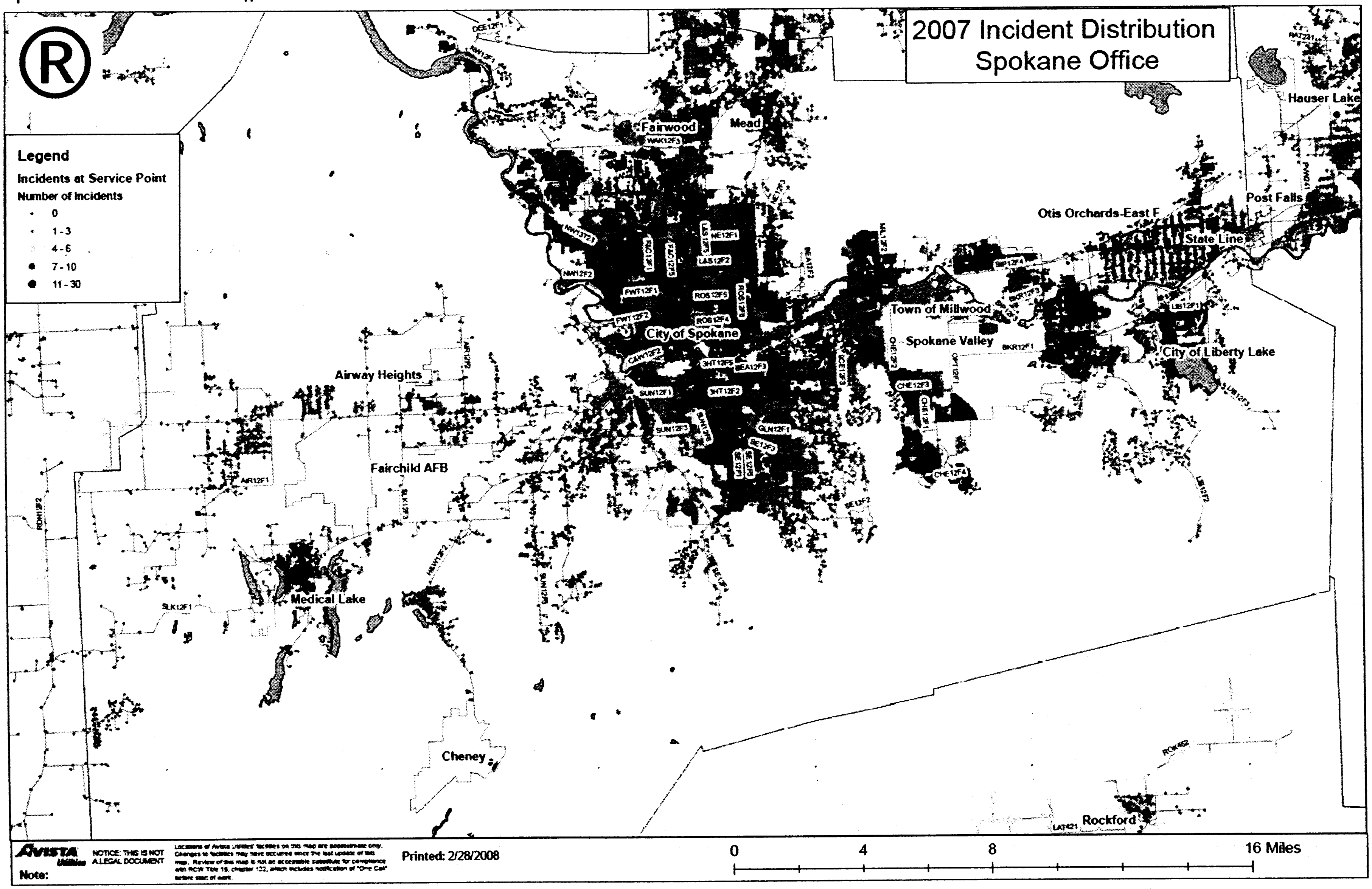
Palouse Office - $CEMI_n$



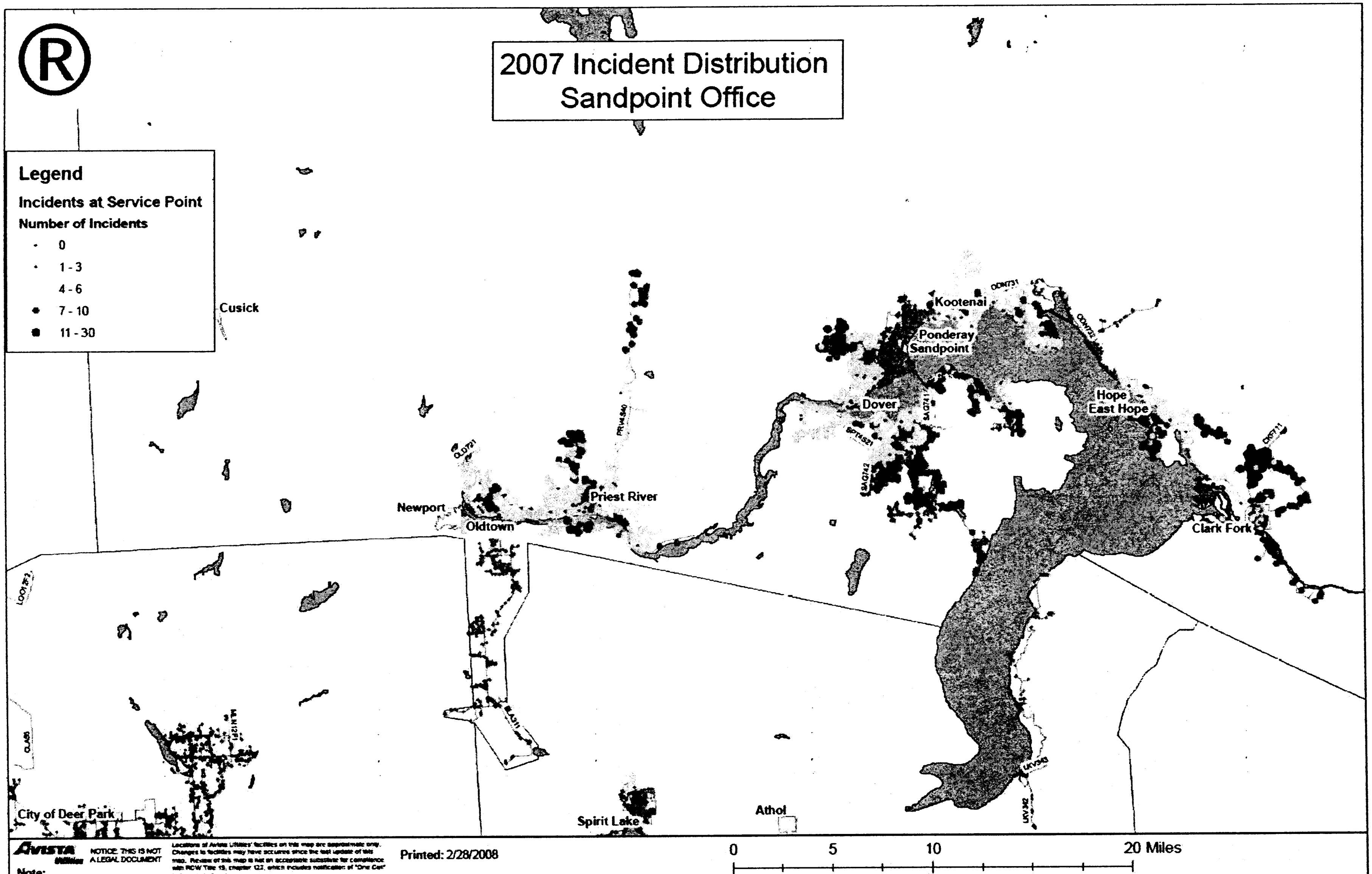
Lewis-Clark Office - $CEMI_n$



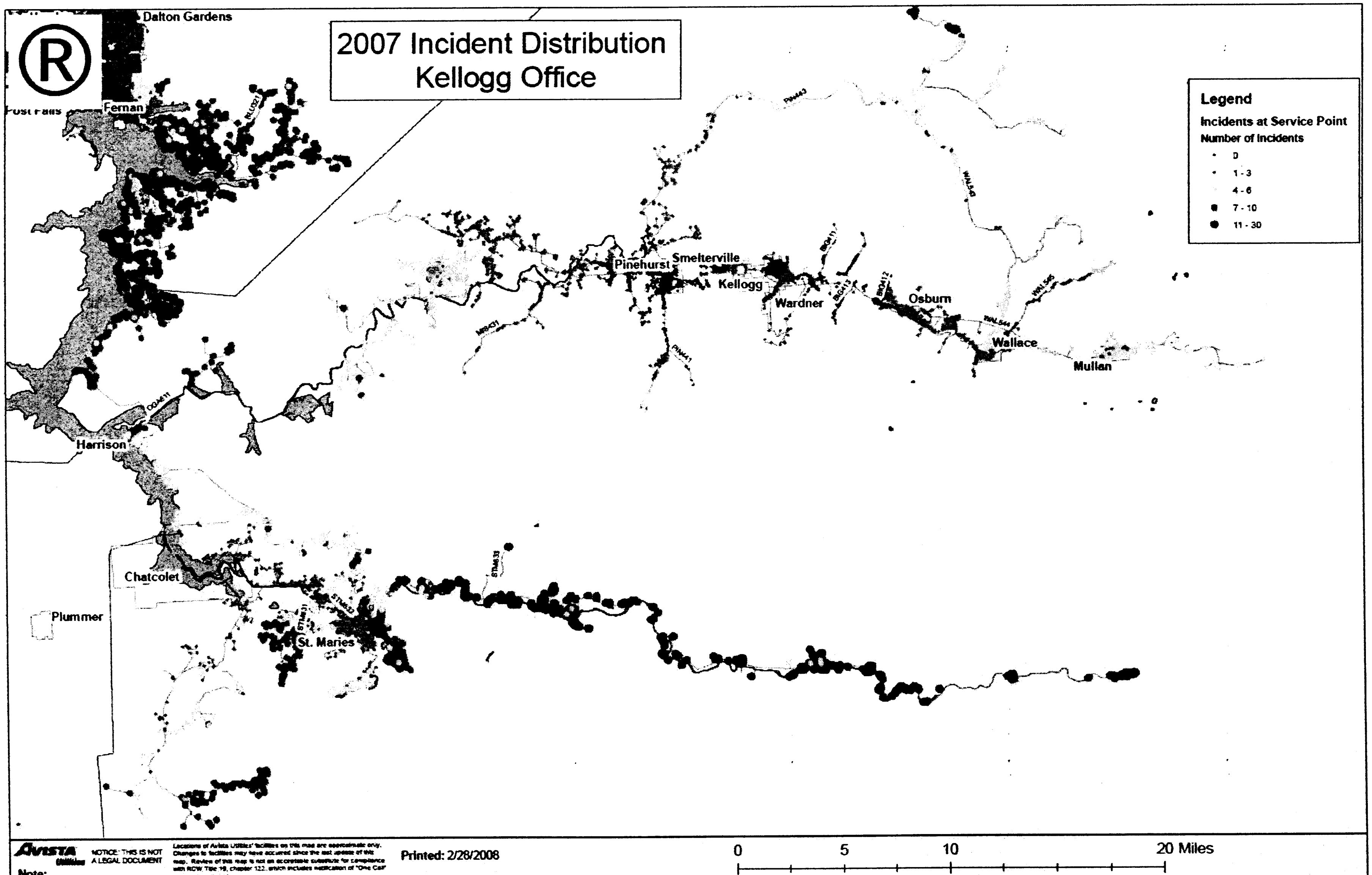
Spokane Office - $CEMI_n$



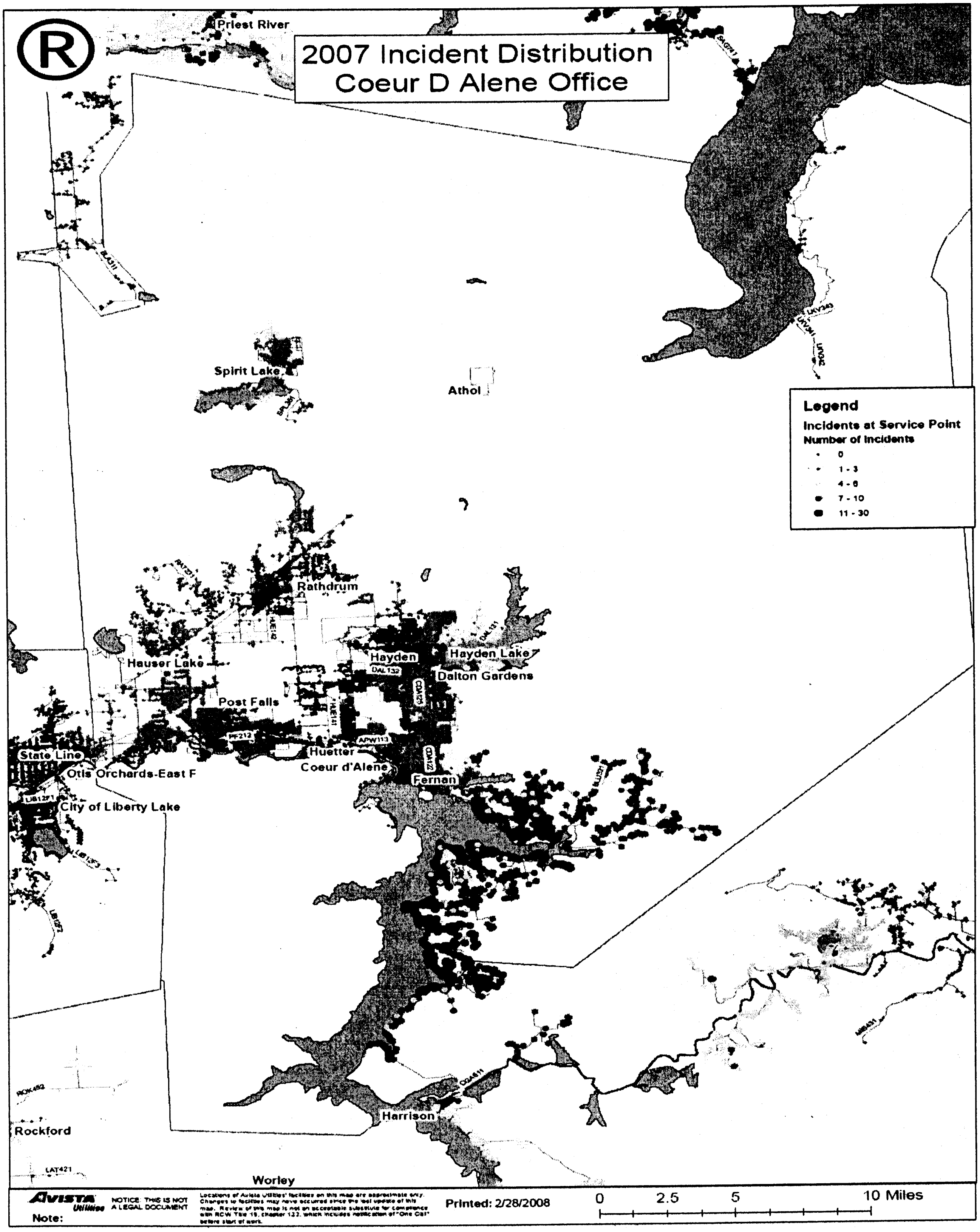
Sandpoint Office - CEMI$_n$



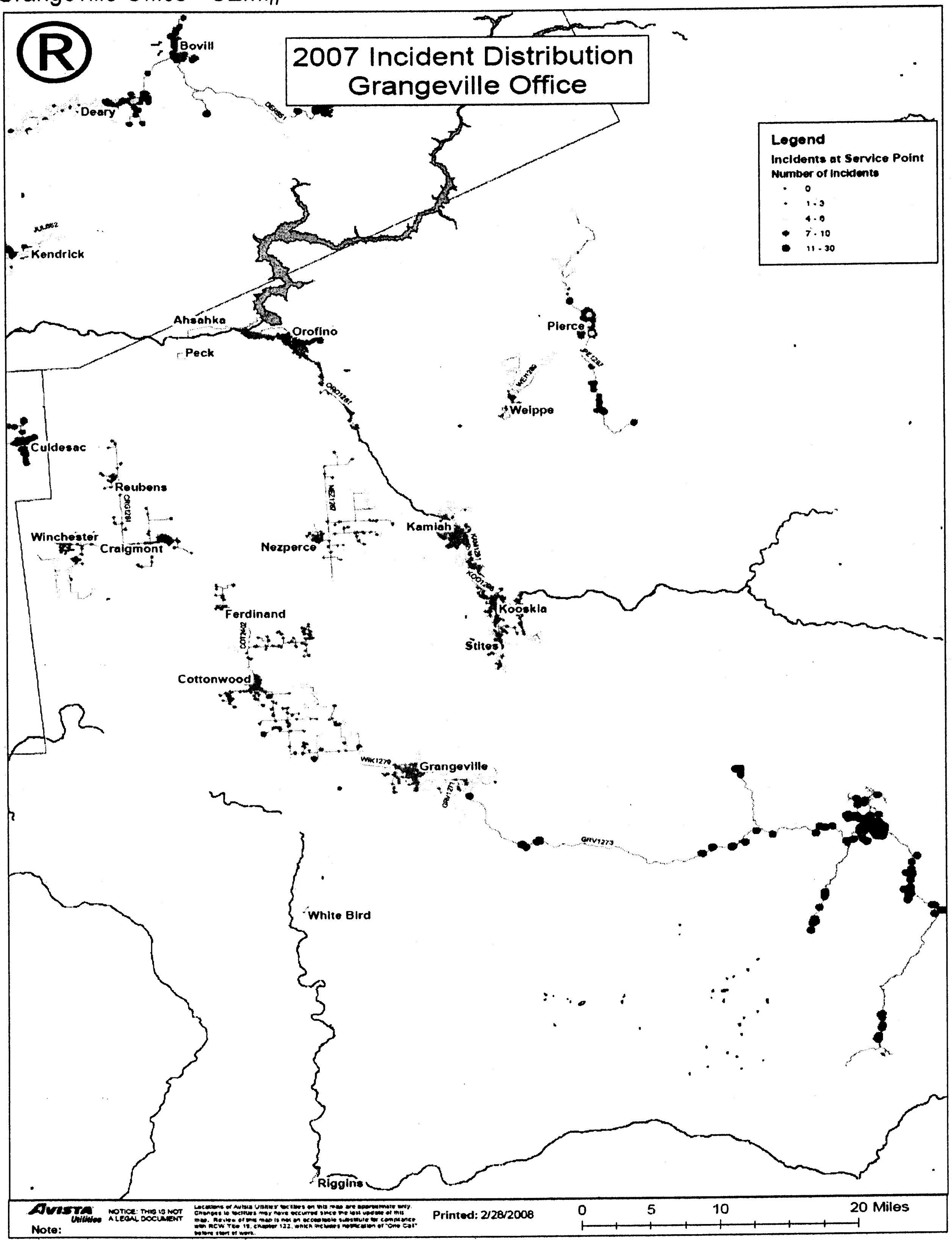
Kellogg Office - CEMI$_n$



Coeur d'Alene - CEMI$_n$



Grangeville Office - $CEMI_n$



Monthly Indices

Each of the following indices, reported by month, shows the variations from month to month. These variations are partially due to inclement weather and, in some cases, reflect incidents of winter snowstorms, seasonal windstorms, and in mid- and late summer lightning storms. They also reflect varying degrees of animal activity causing disruptions in different months of the year.

Chart 3.1 – SAIFI - Sustained Interruptions / Customer

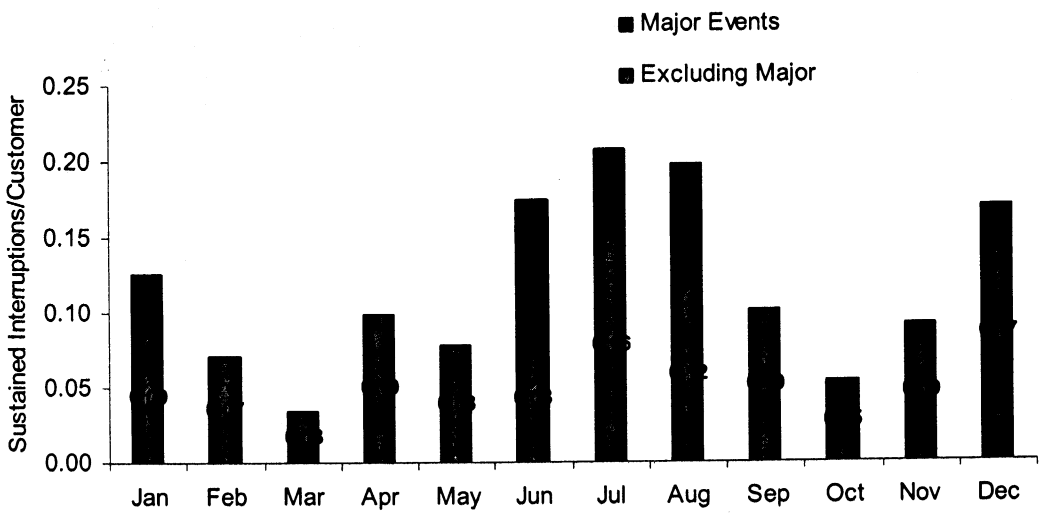


Chart 3.2 - MAIFI Momentary Interruption Events / Customer

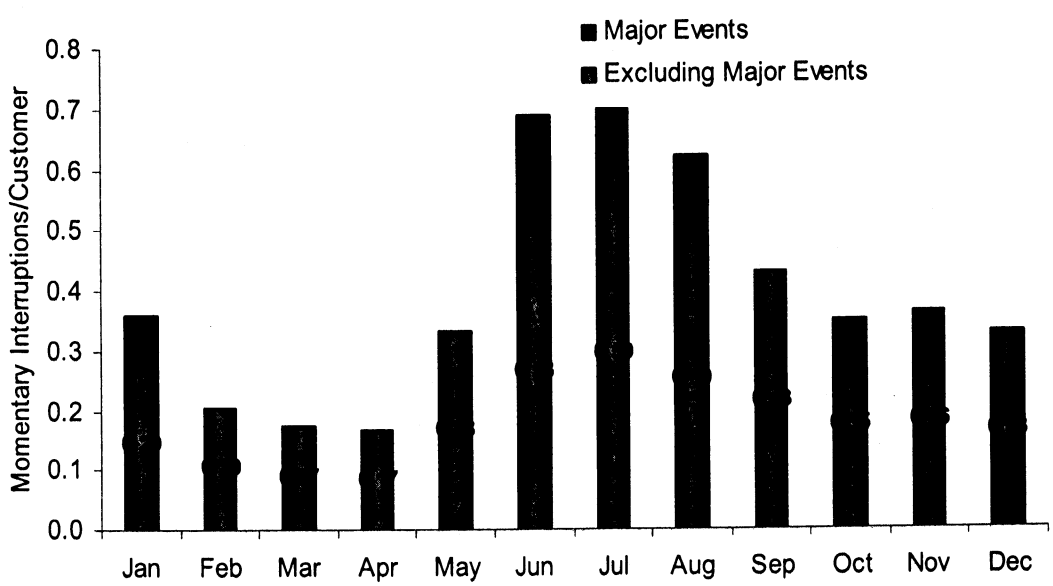


Chart 3.3 - SAIDI – Average Outage Time / Customer

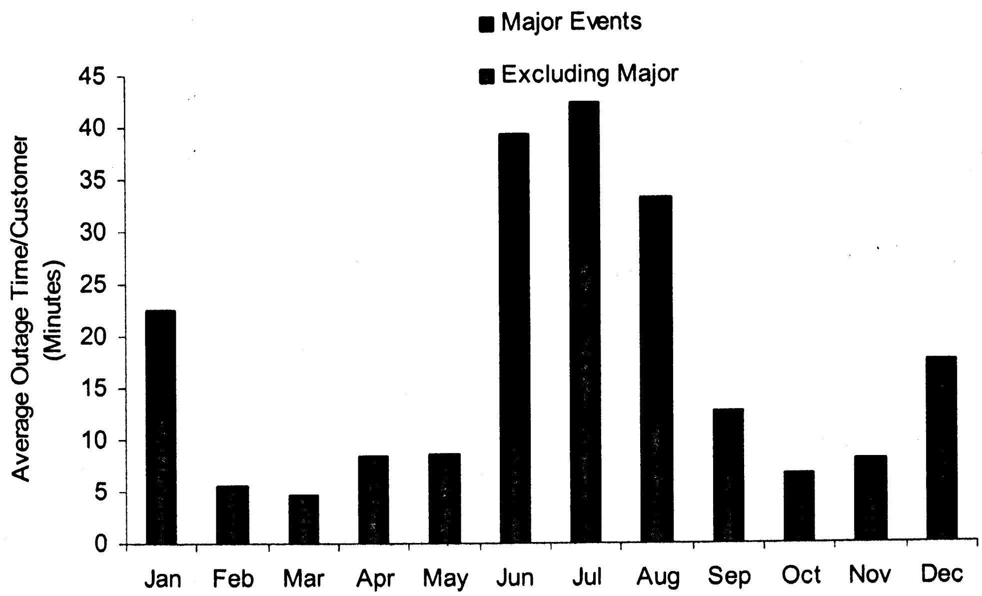
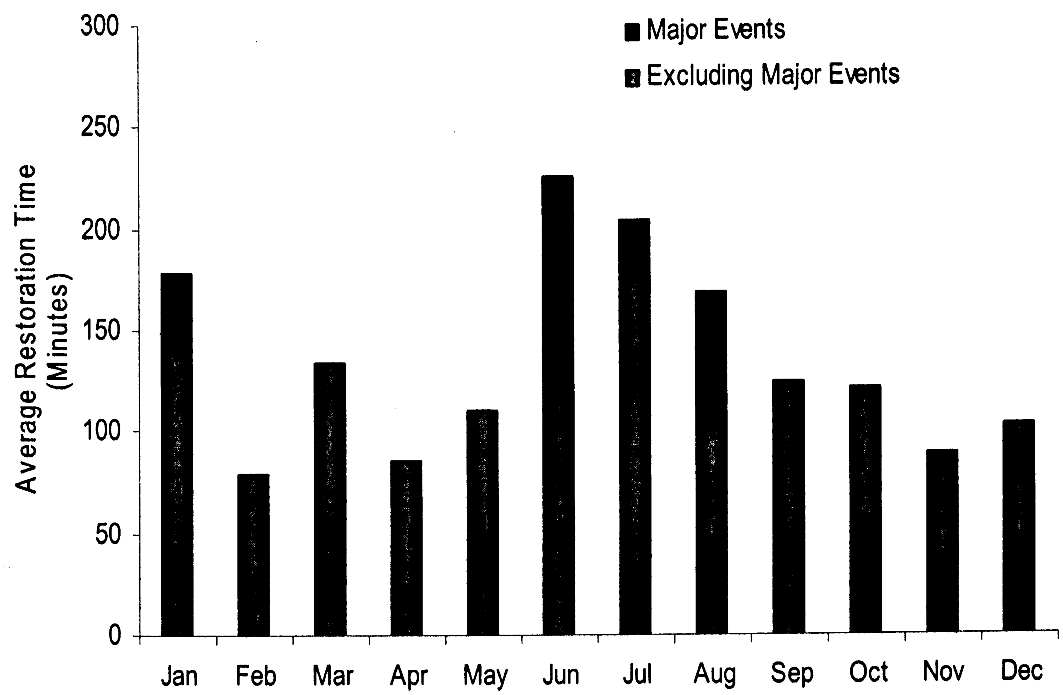


Chart 3.4 - CAIDI – Average Restoration Time



Customer Complaints

Commission Complaints

The following is a list of Complaints made to the Commission during this year.

Customer Address	Complaint	Resolution
Chewelah, WA Chewelah 12F2	The area in which customer lives experiences periodic power outages. Yesterday they were without power for 18 hours for no apparent reason – no bad weather, etc. Neighbors have purchased $3000 generators. Customer does not feel he should have to purchase as generator.	4 sustained outages and 1 momentary outage. 8/03/07 Complaint Closed – Company upheld.

Customer Complaints

The following is a list of complaints made to our Customer Service Representatives.

Customer / Feeder	Complaint	Resolution
Rice, WA Gifford 34F1	03/19/07 – Customer emailed Avista with a complaint about all of the outages in his area this year. Email forwarded on to the Colville office to answer his question.	Colville office sent Customer an email explaining that Avista was unaware that the customer was out of power. Apparently the customer does not live at this location and Avista is unaware when the power is out. Customer did not reply as of November 29, 2007.
Pullman, WA South Pullman 121	08/29/07 – Customer called to complain about several momentary outages over the past few days. Customer had counted 5 momentary outages in the last 4 days.	Electric Transmission Operations reported that this was a transmission problem that should be resolved now. 8/29/2007.
Rice, WA Gifford 34F1 or Gifford 34F2	07/17/07 - Customer called about power outage on July 22, 2007 that was scheduled.	Customer location could not be found, and call back phone number was not valid. No resolution.
Pullman, WA Pullman 112	10/02/07 –Customer called and is tired of coming home every day and having to reset all the clocks etc. due to Avista power surge issues or whatever is causing this in Pullman. Customer was told that if outage is less than 10 seconds it is not a big deal, but it happens constantly. Please get this fixed; customer doesn't have the option of choosing a different power company.	Complaint was forwarded to Pullman office. Customer was sent an apology letter after Avista left a message on his phone. Avista did experience some power outages about that time.
Hope, ID Clark Fork 711	08/14/07 – Customer unhappy power keeps going out. Would like someone to let him know what Avista is doing to fix this problem. Wants resolved before he goes out of town the 1st of September.	Sandpoint office made several attempts to contact the customer and never did talk to him directly. Hope area had numerous outages and momentary outages during the summer due to wind storms and lightning.

Sustained Interruption Causes

Table 4.1 - % SAIFI per Cause by Office

The following table lists the percentage SAIFI contribution by causes for outages excluding major event days.

Reason	CDC	COC	DAC	GRC	KEC	LCC	OTC	PAC	SAC	SPC	DPC	All Offices
ANIMAL	0.9%	2.6%	1.5%	3.1%	8.0%	3.5%	5.0%	0.8%	12.6%	14.8%	8.9%	5.7%
MISCELLANEOUS	0.1%	0.9%	0.0%	1.7%	0.0%	0.0%	0.1%	0.0%	0.0%	0.2%	0.0%	0.3%
POLE FIRE	0.4%	6.5%	12.6%	14.0%	3.0%	12.1%	18.0%	8.1%	0.6%	2.2%	20.4%	6.0%
WEATHER	16.6%	16.7%	9.4%	30.0%	32.4%	1.9%	11.1%	27.7%	16.9%	4.3%	6.7%	18.4%
UNDETERMINED	24.4%	6.0%	10.8%	12.6%	22.3%	18.4%	4.2%	10.3%	8.4%	11.3%	13.7%	13.1%
TREE	5.9%	20.6%	9.7%	8.1%	13.8%	18.7%	0.2%	9.9%	22.5%	2.3%	30.7%	12.2%
PUBLIC	16.4%	8.0%	10.3%	1.7%	3.9%	35.0%	26.6%	16.6%	1.7%	24.1%	5.6%	12.8%
COMPANY	19.2%	3.6%	0.1%	5.1%	0.1%	0.0%	0.0%	3.8%	7.6%	7.7%	0.5%	6.2%
EQUIPMENT OH	8.4%	18.0%	29.2%	15.0%	8.6%	7.8%	9.1%	14.2%	13.3%	17.6%	2.2%	13.6%
EQUIPMENT UG	0.5%	2.5%	4.9%	2.4%	0.6%	1.0%	3.7%	1.8%	0.1%	3.8%	1.0%	1.8%
EQUIPMENT SUB	2.3%	0.0%	6.3%	1.0%	6.2%	0.0%	0.0%	0.0%	6.6%	6.6%	0.0%	2.8%
PLANNED	4.8%	14.6%	5.2%	5.3%	1.2%	1.6%	22.1%	6.7%	9.7%	5.3%	10.2%	7.0%

CDC	Coeur d'Alene	LCC	Lewiston-Clarkston
COC	Colville	OTC	Othello
DAC	Davenport	PAC	Palouse
DPC	Deer Park	SAC	Sandpoint
GRC	Grangeville	SPC	Spokane
KEC	Kellogg/ St. Maries		

Chart 4.1 – % SAIFI per Cause by Office

The following chart shows the percentage SAIFI contribution by causes for outages excluding major event days.

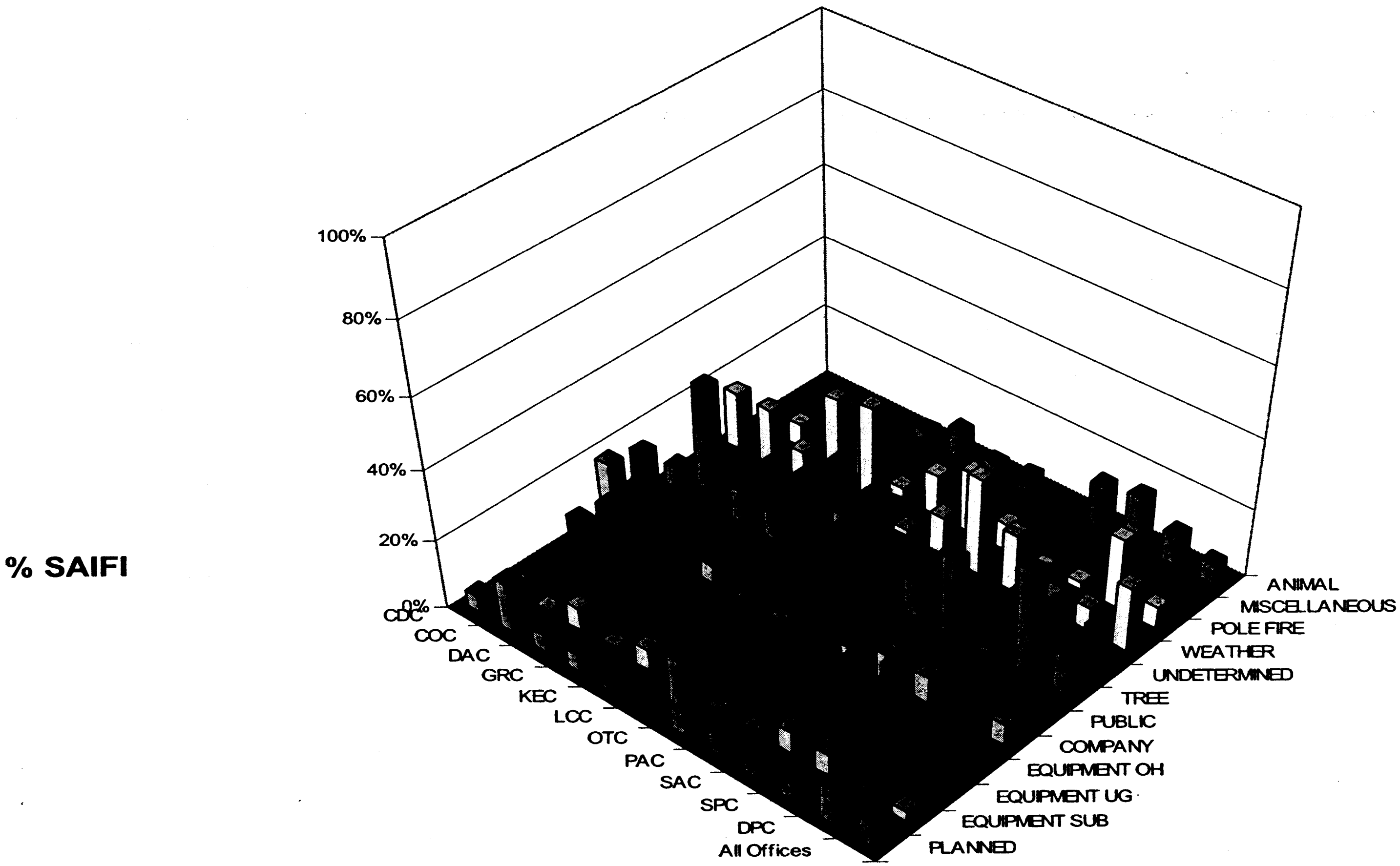


Table 4.2 - % SAIDI per Cause by Office

The following table lists the percentage SAIDI contribution by causes for outages excluding major event days.

Reason	CDC	COC	DAC	GRC	KEC	LCC	OTC	PAC	SAC	SPC	DPC	All Offices
ANIMAL	1.1%	1.7%	1.9%	1.3%	4.0%	3.3%	2.8%	0.5%	7.4%	13.3%	6.1%	4.1%
MISCELLANEOUS	0.1%	0.5%	0.0%	1.2%	0.0%	0.0%	0.1%	0.2%	0.0%	0.1%	0.0%	0.3%
POLE FIRE	1.2%	7.3%	31.2%	25.0%	3.4%	20.6%	42.3%	11.4%	0.5%	3.3%	16.5%	9.2%
WEATHER	27.7%	23.4%	14.9%	18.7%	43.3%	4.3%	15.7%	18.0%	35.3%	11.7%	18.3%	23.3%
UNDETERMINED	15.5%	5.1%	16.5%	9.3%	13.7%	14.4%	2.0%	5.8%	7.9%	6.8%	15.9%	9.1%
TREE	9.8%	20.6%	14.0%	12.0%	23.0%	12.6%	0.1%	15.9%	36.3%	3.9%	25.6%	17.3%
PUBLIC	21.0%	6.8%	6.3%	1.9%	3.5%	33.6%	12.9%	17.3%	1.9%	20.9%	5.3%	11.4%
COMPANY	0.7%	1.3%	0.0%	0.6%	0.0%	0.0%	0.0%	4.1%	0.7%	1.6%	0.3%	1.3%
EQUIPMENT OH	16.4%	14.1%	10.4%	14.3%	5.6%	8.3%	10.9%	13.3%	5.5%	16.7%	4.2%	12.0%
EQUIPMENT UG	1.9%	3.0%	2.0%	2.9%	0.9%	2.3%	6.8%	3.8%	0.1%	11.7%	2.4%	3.5%
EQUIPMENT SUB	3.1%	0.0%	0.5%	6.0%	1.9%	0.0%	0.0%	0.0%	1.8%	6.9%	0.0%	2.4%
PLANNED	1.6%	16.5%	2.3%	6.8%	0.7%	0.7%	6.5%	9.7%	2.6%	3.1%	5.4%	6.1%

CDC	Coeur d'Alene	LCC	Lewiston-Clarkston
COC	Colville	OTC	Othello
DAC	Davenport	PAC	Palouse
DPC	Deer Park	SAC	Sandpoint
GRC	Grangeville	SPC	Spokane
KEC	Kellogg/ St. Maries		

Chart 4.2 – % SAIDI per Cause by Office

The following chart shows the percentage SAIDI contribution by causes for outages excluding major event days.

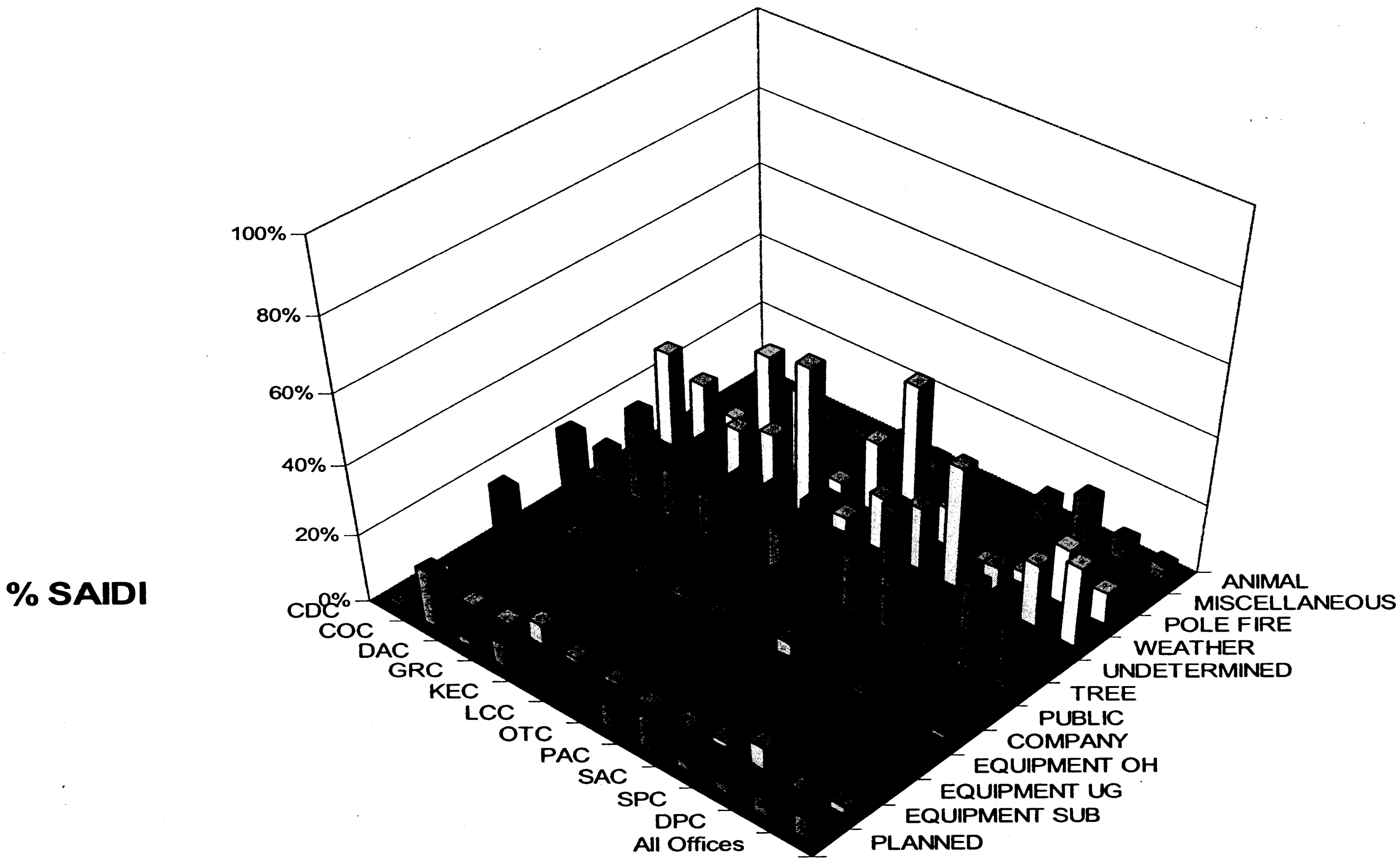


Table 4.3 - % SAIFI per Cause by Month

The following table lists the percentage SAIFI contribution by causes for all outages, excluding major event days.

Reason	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Yearly
ANIMAL	2.9%	0.4%	5.0%	18.9%	2.6%	14.5%	8.9%	5.7%	3.7%	3.1%	1.0%	0.4%	5.7%
MISCELLANEOUS	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	1.3%	0.0%	0.1%	0.1%	0.0%	0.8%	0.3%
POLE FIRE	0.0%	1.6%	12.0%	0.0%	0.6%	1.1%	14.0%	10.0%	24.0%	4.8%	1.4%	0.4%	6.0%
WEATHER	5.7%	16.7%	0.8%	0.1%	20.8%	15.5%	20.9%	3.1%	5.5%	0.3%	39.7%	50.0%	18.4%
UNDETERMINED	24.3%	20.4%	10.0%	11.1%	10.8%	2.7%	13.4%	14.2%	18.7%	21.5%	7.6%	8.3%	13.1%
TREE	33.1%	14.1%	8.9%	11.8%	11.3%	17.7%	2.3%	12.0%	17.0%	20.1%	5.0%	6.5%	12.2%
PUBLIC	18.1%	13.6%	33.6%	8.9%	8.3%	2.8%	18.6%	12.2%	10.1%	18.7%	3.6%	14.8%	12.8%
COMPANY	0.5%	0.0%	0.9%	8.0%	11.0%	4.2%	4.1%	13.1%	5.9%	0.2%	22.1%	1.6%	6.2%
EQUIPMENT OH	5.4%	8.2%	19.7%	32.4%	15.1%	27.6%	5.5%	18.9%	9.7%	16.4%	5.1%	10.4%	13.6%
EQUIPMENT UG	0.8%	0.2%	1.2%	0.1%	1.0%	3.8%	4.1%	2.0%	3.4%	4.1%	0.6%	0.3%	1.8%
EQUIPMENT SUB	4.3%	17.0%	3.3%	0.6%	0.0%	0.0%	0.0%	4.9%	0.0%	0.0%	9.2%	0.0%	2.8%
PLANNED	4.8%	7.7%	4.7%	8.1%	18.5%	10.0%	6.9%	3.8%	1.9%	10.7%	4.6%	6.5%	7.0%

Chart 4.3 – % SAIFI per Cause by Month

The following chart shows the percentage SAIFI contribution by causes for all outages, excluding major event days.

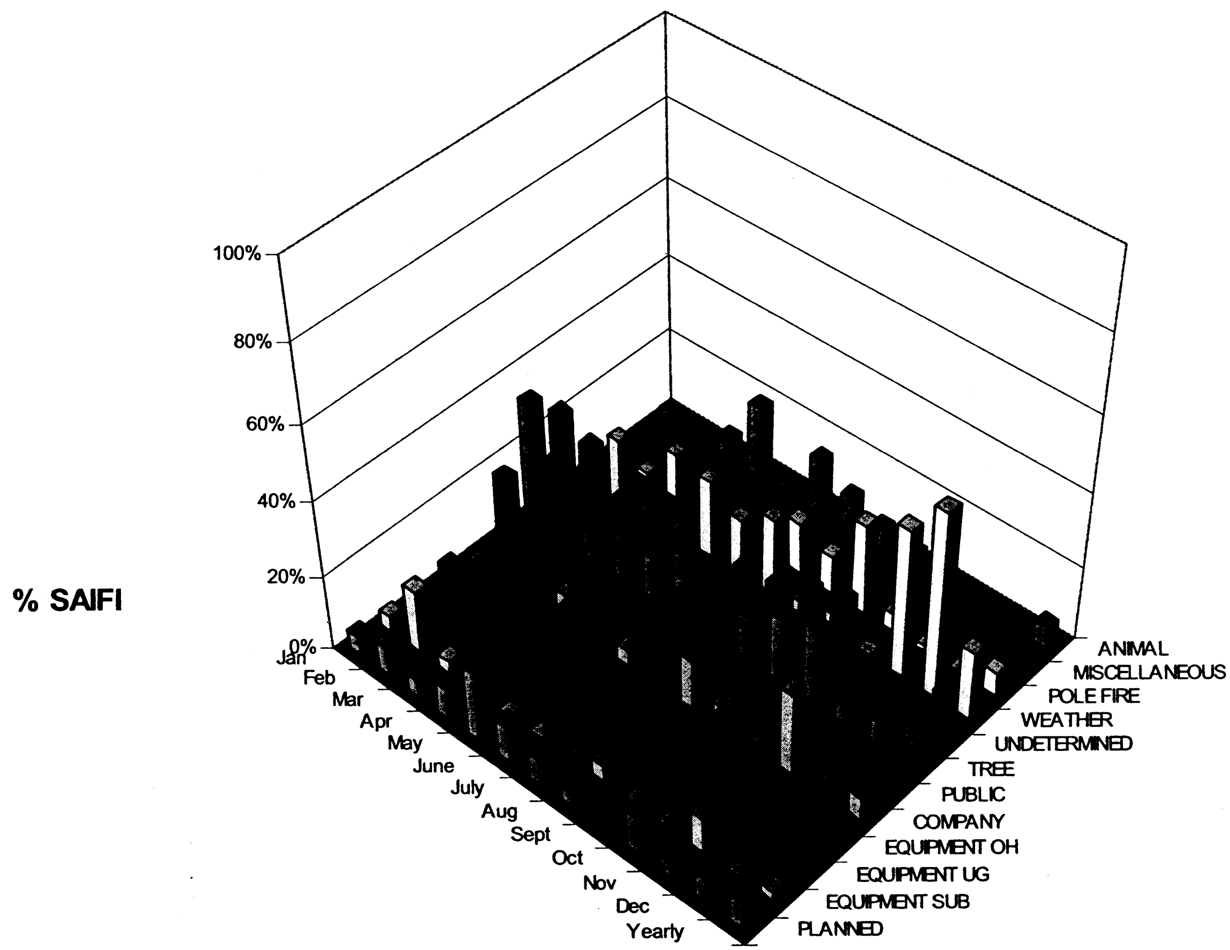


Table 4.4 - % SAIDI per Cause by Month

The following table lists the percentage SAIDI contribution by causes for outages excluding major event days.

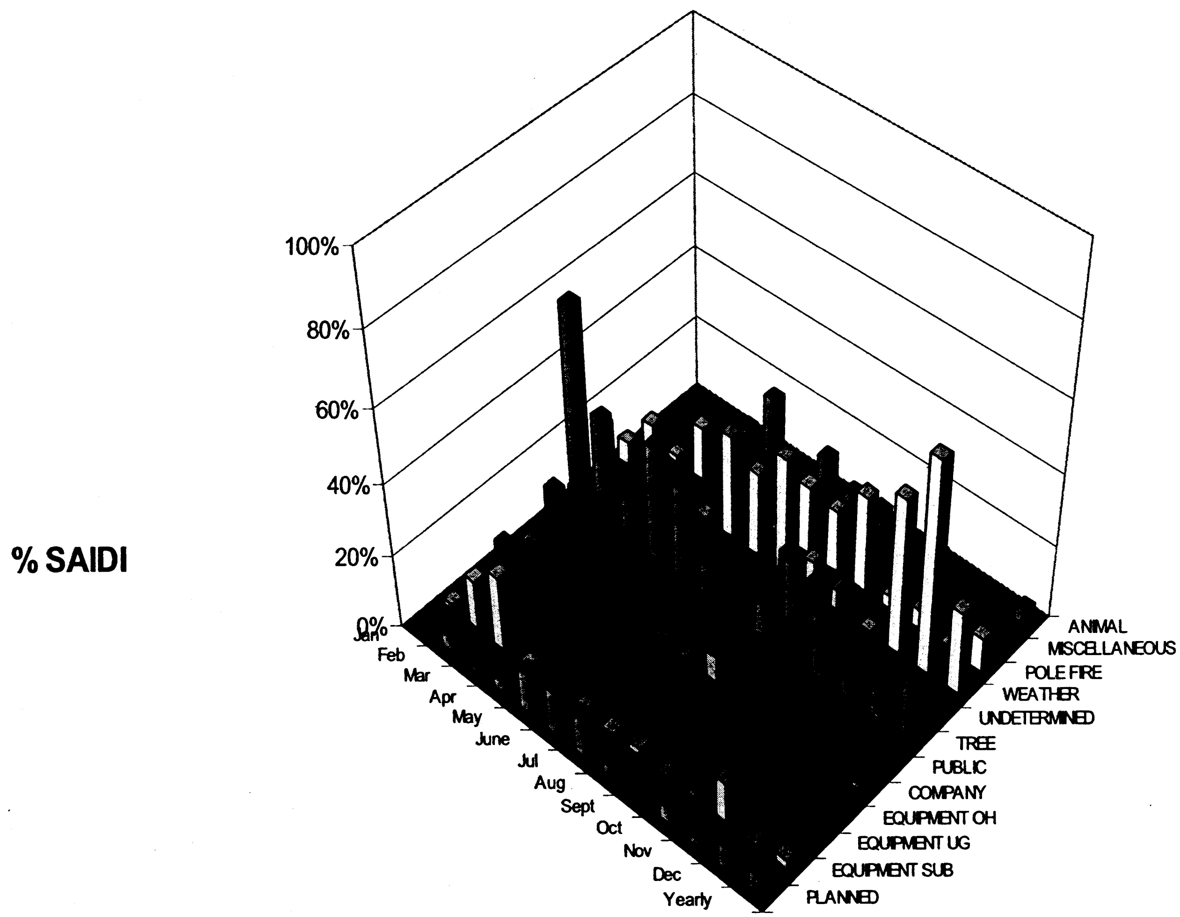
REASON	Jan	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec	Yearly
ANIMAL	1.5%	0.5%	3.1%	16.9%	2.4%	9.9%	4.9%	4.9%	2.0%	3.3%	1.4%	0.2%	4.1%
MISCELLANEOUS	0.1%	0.4%	0.0%	0.0%	0.0%	0.1%	0.7%	0.0%	0.0%	0.1%	0.0%	0.5%	0.3%
POLE FIRE	0.0%	1.7%	15.0%	0.0%	0.8%	1.6%	18.8%	17.3%	26.7%	3.6%	5.4%	0.7%	9.2%
WEATHER	6.4%	16.6%	0.8%	0.3%	28.6%	23.3%	32.8%	8.9%	5.8%	0.3%	43.1%	59.0%	23.3%
UNDETERMINED	16.9%	6.6%	10.6%	4.8%	3.0%	2.8%	9.0%	16.8%	14.4%	17.8%	5.9%	2.3%	9.1%
TREE	55.8%	29.6%	11.1%	31.8%	25.7%	10.2%	1.6%	9.3%	26.5%	17.3%	8.6%	7.3%	17.3%
PUBLIC	9.6%	15.4%	15.9%	12.3%	6.4%	4.9%	12.0%	13.9%	9.9%	21.8%	10.3%	11.0%	11.4%
COMPANY	0.3%	0.0%	0.5%	2.9%	1.9%	0.2%	0.4%	7.5%	0.7%	0.3%	0.9%	0.1%	1.3%
EQUIPMENT OH	5.9%	9.6%	18.1%	25.7%	17.9%	26.0%	5.3%	10.6%	7.9%	18.7%	9.3%	10.9%	12.0%
EQUIPMENT UG	1.0%	0.9%	2.1%	0.4%	2.0%	8.3%	3.6%	5.4%	5.0%	11.9%	1.6%	1.2%	3.5%
EQUIPMENT SUB	1.5%	14.0%	20.7%	1.1%	0.0%	0.0%	0.0%	2.1%	0.0%	0.0%	11.3%	0.0%	2.4%
PLANNED	1.1%	4.8%	2.0%	3.7%	11.4%	12.7%	10.8%	3.4%	1.1%	4.8%	2.3%	6.6%	6.1%

Table 4.4.1 Ave Outage Time (HH:MM)

Reason	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Yearly
ANIMAL	1:33	1:37	1:41	1:37	1:45	1:59	1:57	1:46	1:48	1:44	1:25	1:24	1:48
MISCELLANEOUS	1:18	2:20	0:00	0:00	2:05	25:27	1:47	0:05	0:11	2:09	0:59	0:40	3:06
POLE FIRE	0:00	2:52	3:37	4:25	2:21	3:57	3:38	5:23	3:19	3:04	4:16	2:26	3:45
WEATHER	2:57	2:29	9:48	4:33	3:01	4:26	11:07	5:01	3:11	2:04	3:42	2:43	5:02
UNDETERMINED	2:00	1:54	1:54	2:05	2:01	2:58	2:26	1:44	1:50	1:46	1:40	1:42	2:03
TREE	4:19	3:24	2:25	7:40	3:01	2:34	3:02	2:34	3:18	3:06	2:33	2:37	3:20
PUBLIC	2:28	2:56	2:05	2:19	2:21	2:14	2:27	2:29	2:56	2:37	2:48	3:49	2:34
COMPANY	1:55	2:09	1:06	1:29	2:21	0:53	1:16	1:59	0:22	2:18	0:25	0:23	1:18
EQUIPMENT OH	2:51	2:40	2:23	1:55	2:41	3:00	4:45	2:56	3:09	2:59	3:10	2:55	2:59
EQUIPMENT UG	3:55	6:00	3:53	4:07	4:30	4:55	6:41	5:46	5:32	5:20	4:59	4:39	5:19
EQUIPMENT SUB	0:50	1:02	13:59	1:47	2:50	0:00	0:00	0:42	0:00	0:00	2:17	0:00	2:16
PLANNED	0:57	1:19	0:49	1:14	1:33	1:24	1:28	1:09	1:00	1:06	0:44	1:09	1:09

Chart 4.4 – % SAIDI per Cause by Month

The following chart shows the percentage SAIFI contribution by causes for outages excluding major event days.



Momentary Interruption Causes

The cause for many momentary interruptions is unknown. Because faults are temporary, the cause goes unnoticed even after the line is patrolled. Momentary outages are recorded using our SCADA system (System Control and Data Acquisition). On average, about 88% of Avista's customers are served from SCADA controlled stations.

Table 5.1 - % MAIFI per Cause by Office

The following table lists the percentage MAIFI contribution by causes for outages excluding major event days.

REASON	CDC	COC	DAC	GRC	KEC	LCC	OTC	PAC	SAC	SPC	DPC	All Offices
ANIMAL	0.1%	4.6%	0.0%	1.3%	0.0%	7.5%	0.0%	0.6%	6.2%	12.6%	0.0%	5.5%
POLE FIRE	1.6%	0.0%	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%	2.8%	0.0%	1.1%
WEATHER	22.4%	22.7%	53.2%	36.6%	23.8%	5.5%	9.5%	13.9%	13.9%	5.9%	0.0%	14.2%
TREE	2.2%	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%	1.8%	5.3%	0.9%	0.0%	1.6%
PUBLIC	3.6%	0.0%	0.0%	0.0%	0.0%	1.1%	0.0%	3.9%	0.0%	4.5%	0.0%	2.8%
COMPANY	2.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	3.0%	3.2%	0.0%	1.7%
UNDETERMINED	51.7%	68.7%	46.8%	61.0%	76.2%	81.1%	84.8%	71.2%	60.2%	58.8%	0.0%	63.8%
EQUIPMENT UG	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	1.4%	5.1%	0.0%	1.7%
EQUIPMENT OH	5.6%	4.0%	0.0%	0.2%	0.0%	2.8%	0.0%	5.2%	6.9%	4.8%	0.0%	4.5%
PLANNED	1.8%	0.0%	0.0%	0.0%	0.0%	0.0%	5.8%	1.2%	3.0%	1.3%	0.0%	1.2%
EQUIPMENT SUB	8.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	0.0%	0.0%	0.0%	1.6%
NOT OUR ROBLEM	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%

CDC	Coeur d'Alene	LCC	Lewiston-Clarkston
COC	Colville	OTC	Othello
DAC	Davenport	PAC	Palouse
DPC	Deer Park	SAC	Sandpoint
GRC	Grangeville	SPC	Spokane
KEC	Kellogg/ St. Maries		

Table 5.1.1 - % MAIFI per Cause by Office (Washington only)

The following table lists the percentage MAIFI contribution by causes for outages excluding major event days.

REASON	COC	DAC	OTC	SPC	DPC	PAC-WA	LCC-WA	Grand Total
ANIMAL	0.0%	0.0%	0.0%	4.2%	0.0%	0.0%	4.4%	3.3%
POLE FIRE	1.4%	0.0%	0.0%	0.8%	0.0%	1.6%	5.2%	1.4%
WEATHER	26.7%	29.1%	29.8%	34.2%	100.0%	31.5%	19.1%	31.6%
TREE	1.8%	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%	0.8%
PUBLIC	0.9%	0.0%	10.6%	2.7%	0.0%	0.0%	3.8%	2.6%
COMPANY	2.1%	0.0%	0.0%	2.1%	0.0%	0.7%	0.0%	1.7%
UNDETERMINED	63.0%	70.9%	59.6%	49.9%	0.0%	65.9%	52.0%	53.0%
EQUIPMENT UG	0.0%	0.0%	0.0%	2.1%	0.0%	0.3%	4.1%	1.9%
EQUIPMENT OH	3.9%	0.0%	0.0%	3.0%	0.0%	0.0%	8.9%	3.5%
PLANNED	0.1%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.1%
EQUIPMENT SUB	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.6%	0.3%

COC	Colville	OTC	Othello
DAC	Davenport	PAC-WA	Palouse Washington
DPC	Deer Park	SPC	Spokane
LCC-WA	Lewiston-Clarkston Washington		

Chart 5.1 – % MAIFI per Cause by Office

The following chart shows the percentage MAIFI contribution by causes for outages excluding major event days.

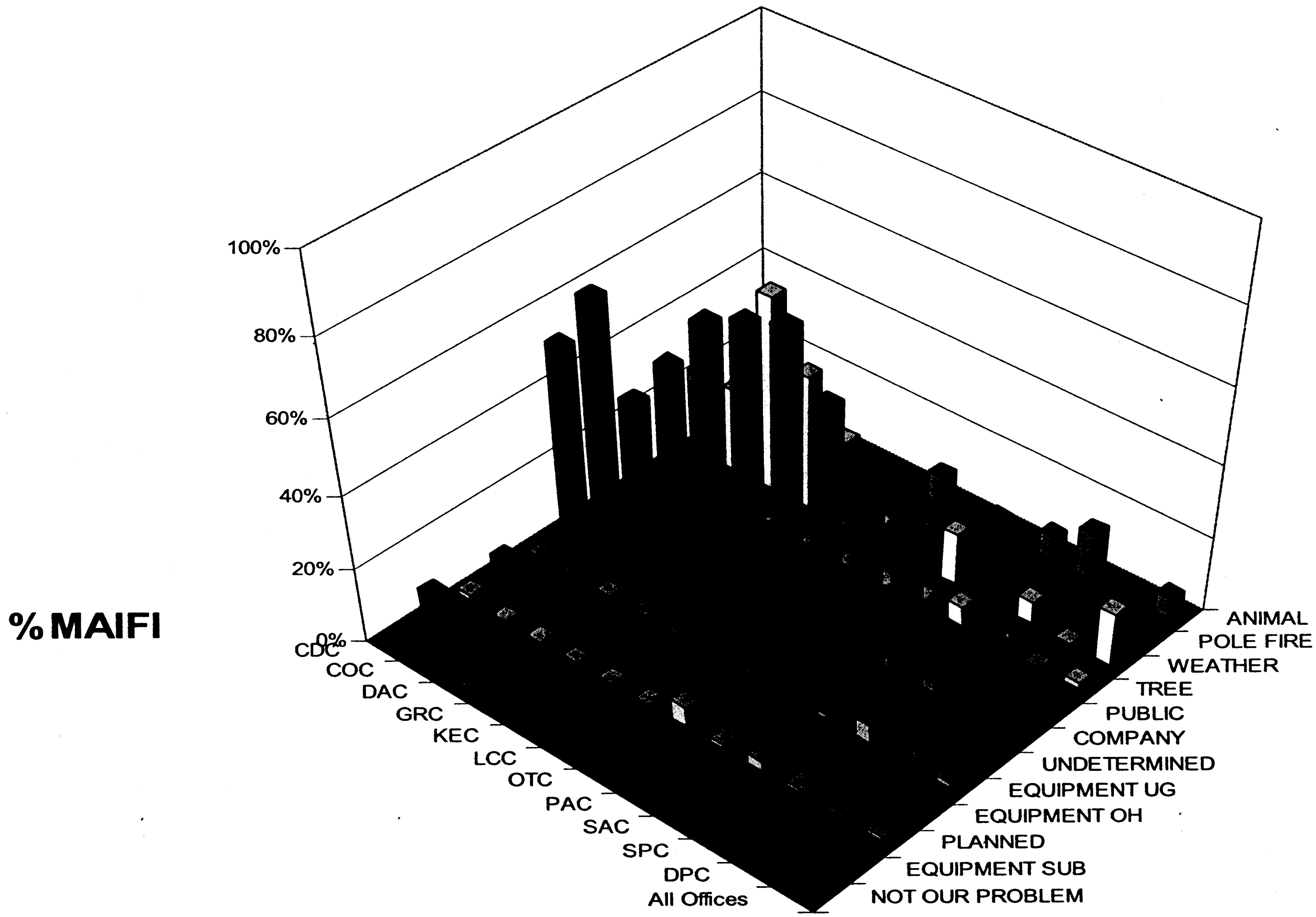


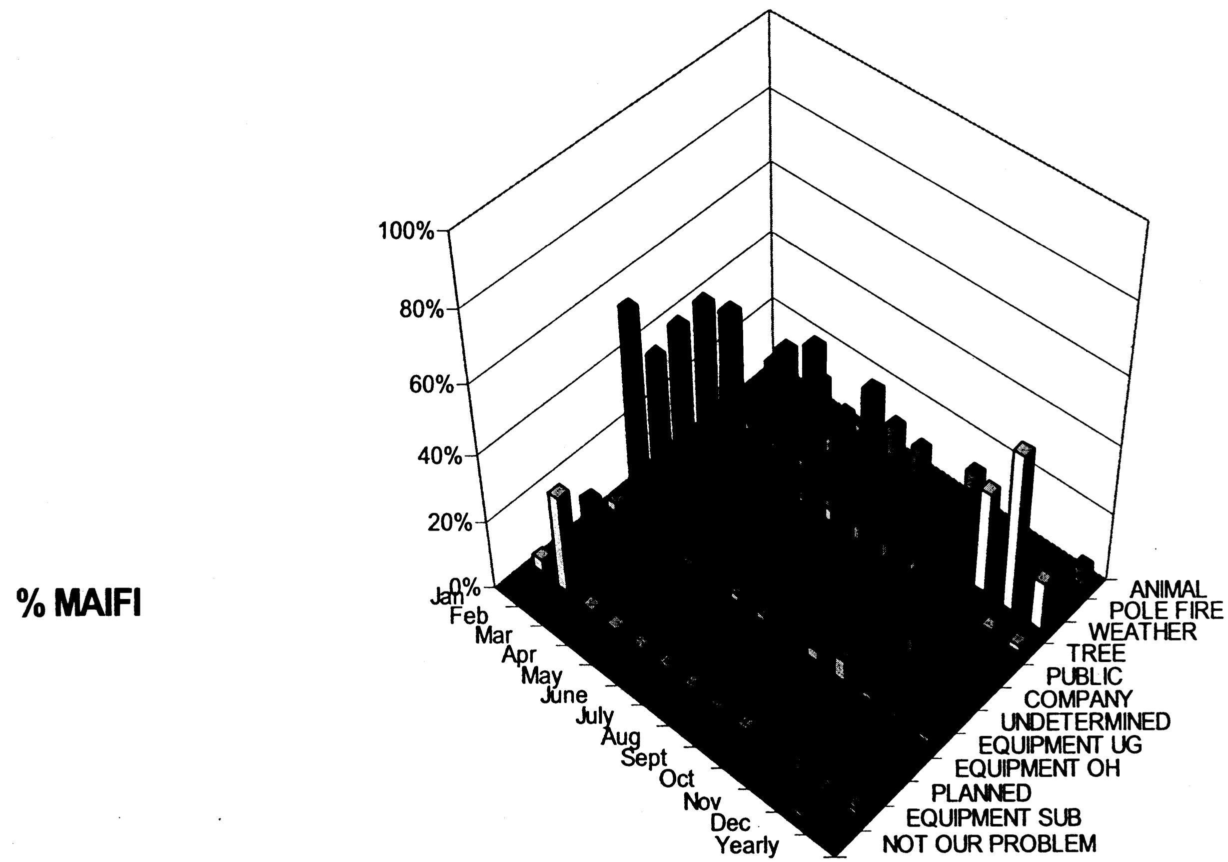
Table 5.2 - % MAIFI per Cause by Month

The following table lists the percentage MAIFI contribution by causes for outages excluding major event days.

REASON	Jan	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec	Yearly
ANIMAL	5.2%	0.0%	9.9%	4.2%	6.4%	10.8%	8.9%	0.2%	12.2%	1.6%	1.5%	0.0%	5.5%
POLE FIRE	0.0%	2.2%	9.6%	4.5%	2.7%	0.0%	0.1%	0.0%	2.5%	0.0%	0.0%	0.0%	1.1%
WEATHER	15.0%	2.9%	0.0%	0.0%	10.5%	20.9%	11.2%	14.7%	2.7%	0.0%	29.7%	46.2%	14.2%
TREE	1.3%	10.9%	0.0%	0.0%	1.6%	3.8%	0.0%	0.0%	1.1%	2.6%	0.0%	0.6%	1.6%
PUBLIC	3.3%	0.0%	4.1%	3.9%	2.2%	4.1%	2.3%	0.0%	1.3%	0.0%	8.8%	2.6%	2.8%
COMPANY	1.1%	0.0%	6.1%	7.6%	2.5%	0.0%	0.0%	2.8%	1.6%	0.0%	4.7%	0.0%	1.7%
UNDETERMINED	54.2%	45.7%	58.7%	69.7%	72.1%	56.9%	71.6%	77.5%	63.6%	76.1%	56.8%	45.7%	63.8%
EQUIPMENT UG	2.7%	0.0%	0.0%	0.0%	0.0%	2.0%	2.1%	0.0%	3.4%	6.2%	2.0%	0.0%	1.7%
EQUIPMENT OH	9.3%	5.8%	12.1%	4.6%	2.7%	2.2%	4.7%	0.9%	5.0%	8.9%	2.1%	3.8%	4.5%
PLANNED	3.5%	4.1%	0.0%	3.8%	1.4%	1.6%	0.5%	0.0%	1.1%	0.0%	2.1%	0.0%	1.2%
EQUIPMENT SUB	3.8%	28.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.6%
NOT OUR PROBLEM	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%	0.2%

Chart 5.2 – % MAIFI per Cause by Month

The following chart shows the percentage MAIFI contribution by causes for outages excluding major event days.



Maintenance Plan Summary – Overhead Equipment with Sub category components

With the increasing quality of the SAIFI data, Avista has completed a preliminary analysis, based on our subject matter experts, indicating that performing a preventative maintenance or an inspection program will not provide the best value to our customers in all cases. As shown in the table, the projected failure rates impact on SAIFI do not justify the expenses of a preventative maintenance program on all of this equipment. However, we continue to evaluate and monitor these to determine if and when a preventative maintenance program would be in the best interest of our customers.

Visual Inspections of the poles and crossarms is being increased in 2008 to a 20 year cycle in order to maintain a reliable system. This visual inspection along with field personnel will identify some problem equipment during the course of their work and will get them repaired or replaced, but this is not part of a scheduled preventative maintenance program.

OH Equipment/Sub category component	Maintenance Plan Summary	Projected Average Annual SAIFI contribution
Arrestors	No Program	0.013
Capacitor	No Program	Not calculated
Conductor – Pri	No Program	0.013
Conductor – Sec	No Program	Very Small
Crossarm – Rotten	1-2% visually inspected annually but planning to move to 5% annually in 2008.	0.002
Cutout/Fuse	No specific program, but one vintage of cutout is being replaced on a planned basis.	0.073
Insulator	No Program	0.10
Insulator Pin	No Program	0.024
Other	No Program	Not calculated
Pole – Rotten	1-2% inspected annually but planning to move to 5% annually in 2008.	0.01
Recloser	Midline Reclosers – opportunistic or suspect, No defined cycle program. Substation Reclosers – 13 year maintenance cycle and planning to move to a 10 year cycle. Switchgear breakers – 7 year maintenance cycle.	0.025
Regulator	Substation Regulators inspected monthly with most midline regulators being inspected monthly.	0.003
Switch / Disconnect	No Program	0
Transformer - OH	No Program, but transformers that are removed from service for any reason and are older than 1980 are not refurbished and returned to service.	0.004

Major Event Day Causes

Chart 6.1 – % SAIFI by Cause Code for the Major Event Days

The following chart shows the percentage SAIFI contribution by causes for outages during major event days

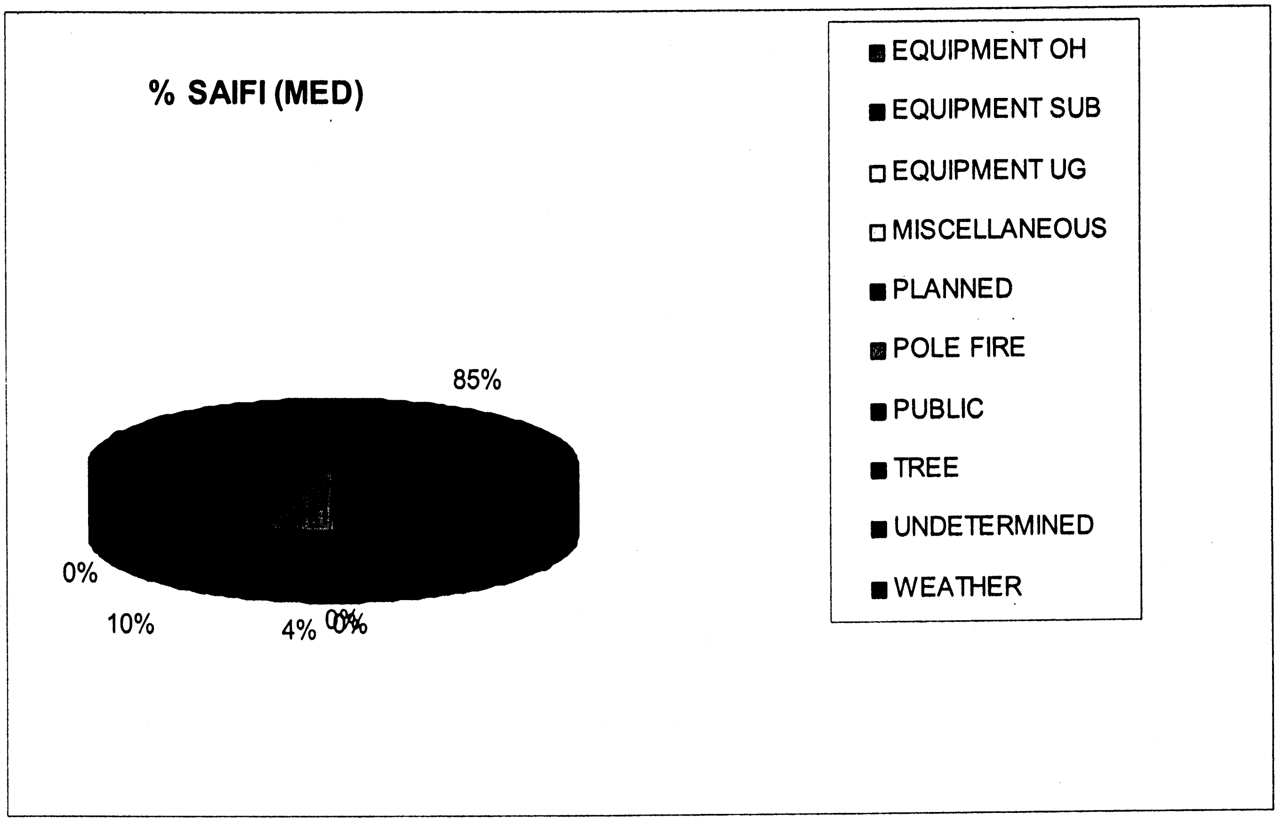


Table 6.1 – % SAIFI by Sub Cause Code for the Major Event Days

The following table shows the SAIFI contribution and Customer hours by sub causes code for the three main outage causes during major event days.

Cause Code	Sub reason	Sum of Ni	Sum of ri x Ni (hours)
Pole Fire	Pole Fire	3799	9005:24
Total		3799	9005:24
TREE	Tree Fell	71	320
	Tree Growth	6	7
	Weather	9018	50031
Total		9095	50359
WEATHER	Snow/Ice	1980	378
	Lightning	28484	120689
	Wind	44823	252280
Total		75287	373348

Table 6.2 – Yearly Summary of the Major Event Days

Table 6.2 is provided as an initial review of Major Event Day information. The main premise of the IEEE Major Event Day calculation is that using the 2.5bmethod should classify 2.3 days each year as MED's.

The following table shows the previous major event days, the daily SAIDI value and the relationship of the yearly T_{MED}.

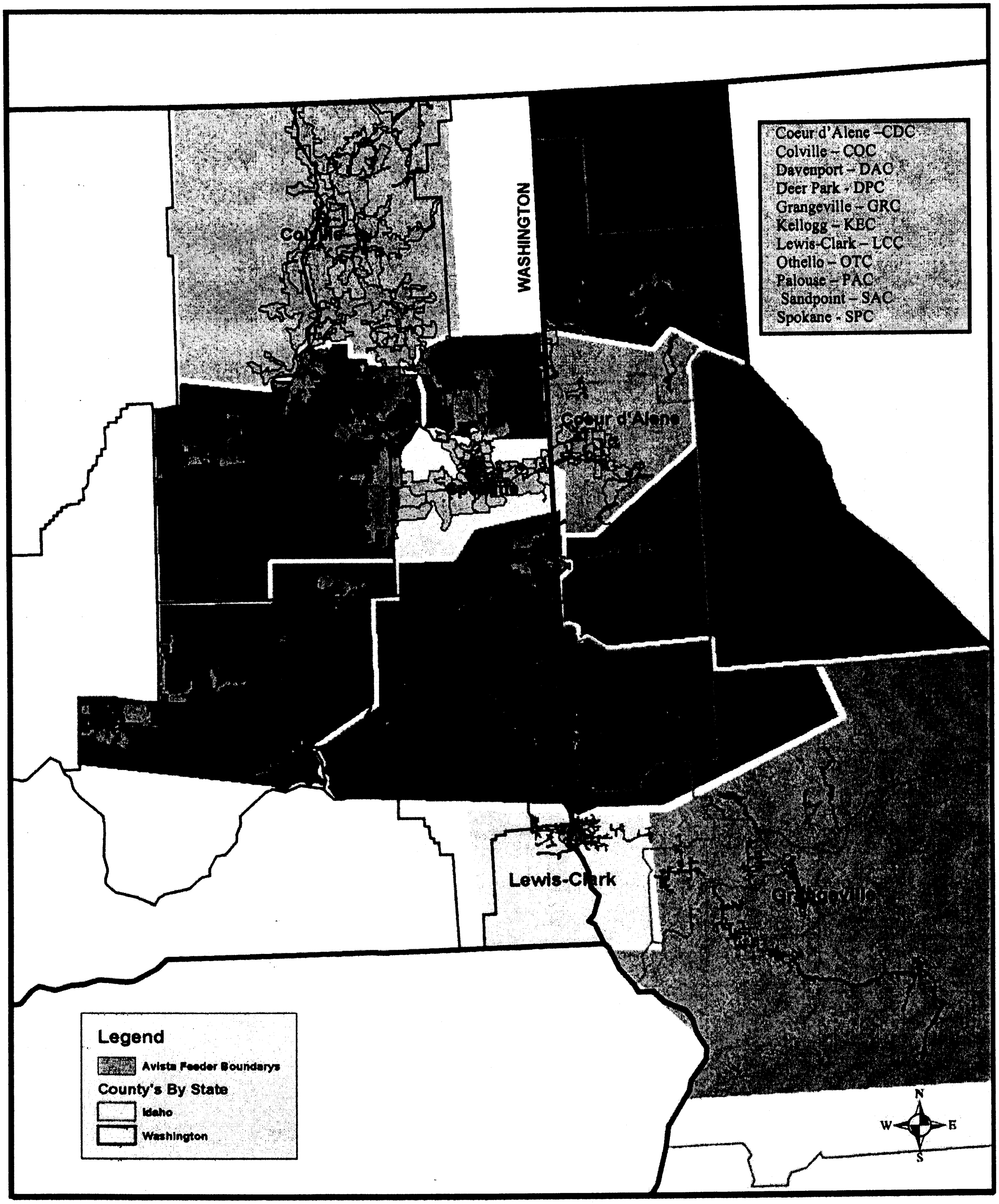
Year	Date	SAIDI	T_{MED}
2003	01-03-2003	5.38	4.96
	05-24-2003	5.11	
	09-08-2003	5.47	
	10-16-2003	6.62	
	10-28-2003	9.25	
	11-19-2003	57.06	
2004	05-21-2004	7.11	6.35
	08-02-2004	7.36	
	12-08-2004	31.00	
2005	06-21-2005	39.53	4.916
	06-22-2005	9.03	
	08-12-2005	19.60	
2006	01-11-2006	12.10	7.058
	03-09-2006	8.58	
	11-13-2006	30.79	
	12-14-2006	29.26	
	12-15-2006	158.31	
2007	01-06-2007	9.98	8.017
	06-29-2007	32.64	
	07-13-2007	12.79	
	08-31-2007	21.30	
2008			9.224

Interruption Cause Codes

MAIN CATEGORY	Proposed (Changes Only)	SUB CATEGORY	Proposed (Changes Only)	Definition
ANIMAL		Bird		Outages caused by animal contacts. Specific animal called out in sub category.
		Protected		
		Squirrel		
		Underground		
		Other		
PUBLIC		Car Hit Pad		Underground outage due to car, truck, construction equipment etc. contact with pad transformer, junction enclosure etc..
		Car Hit Pole		Overhead outage due to car, truck, construction equipment etc. contact with pole, guy, neutral etc.
		Dig In		Dig in by a customer, a customer's contractor, or another utility.
		Fire		Outages caused by or required for a house/structure or field/forest fire.
		Tree		Homeowner, tree service, logger etc. fells a tree into the line.
		Other		Other public caused outages
COMPANY		Dig in		Dig in by company or contract crew.
		Other		Other company caused outages
EQUIPMENT OH		Arrestors		Outages caused by equipment failure. Specific equipment called out in sub category.
		Capacitor		
		Conductor - Pri		
		Conductor - Sec		
		Connector - Pri		
		Connector - Sec		
		Crossarm- rotten		
		Cutout / Fuse		
		Insulator		
		Insulator Pin		
		Other		
		Pole - Rotten		
		Recloser		
		Regulator		
		Switch / Disconnect		
		Transformer - OH		
EQUIPMENT UG		URD Cable - Pri		Outages caused by equipment failure. Specific equipment called out in sub category.
		URD Cable- Sec		
		Connector - Sec		
		Elbow		
		Junctions		
		Primary Splice		
		Termination		
		Transformer - UG		
		Other		

MAIN CATEGORY	**Proposed** (Changes Only)	**SUB CATEGORY**	**Proposed** (Changes Only)	**Definition**
EQUIPMENT SUB		High side fuse Bus Insulator High side PCB High side Swt / Disc Low side OCB/Recloser Low side Swt / Disc Relay Misoperation Regulator Transformer Other		
MISCELLANEOUS		SEE REMARKS		For causes not specifically listed elsewhere
NOT OUR PROBLEM (*Outages in this category are not included in reported statistics*)		Customer Equipment SEE REMARKS		Customer equipment causing an outage to their service. If a customer causes an outage to another customer this is covered under Public.
		Other Utility		Outages when another utility's facilities cause an outage on our system.
POLE FIRE				Used when water and contamination causes insulator leakage current and fire. If insulator is leaking due to material failure list under equipment failure. If cracked due to gunfire use customer caused other.
PLANNED		Maintenance / Upgrade		Outage, normally prearranged, needed for normal construction work
		Forced		Outage scheduled to repair outage damage
TREE		Tree fell		For outages when a tree falls into distribution primary/secondary or transmission during normal weather
		Tree growth		Tree growth causes a tree to contact distribution primary/secondary or transmission during normal weather.
		Service		For outages when a tree falls or grows into a service.
		Weather		When snow and wind storms causes a tree or branch to fall into, or contact the line. Includes snow loading and unloading.
UNDETERMINED				Use when the cause can not be determined
WEATHER		Snow / Ice		Outages caused by snow or ice loading or unloading on a structure or conductor. Use weather tree for snow and ice loading on a tree.
		Lightning		Lightning flashovers without equipment damage. Equipment failures reported under the equipment type.
		Wind		Outages when wind causes conductors to blow into each other, another structure, building etc. (WEATHER/TREE) used for tree contacts.

Office Areas



Indices Calculations

Sustained Interruption

- An interruption lasting longer than 5 minutes.

Momentary Interruption Event

- An interruption lasting 5 minutes or less. The event includes all momentary interruptions occurring within 5 minutes of the first interruption. For example, when an interrupting device operates two, three, or four times and then holds, it is considered a single event.

SAIFI – System Average Interruption Frequency Index

- The average number of sustained interruptions per customer
- $= \dfrac{\text{The number of customers which had } \textbf{\textit{sustained interruptions}}}{\text{Total number of customers served}}$
- $= \dfrac{\sum N_i}{N_T}$

MAIFI$_E$ – Momentary Average Interruption Event Frequency Index

- The average number of momentary interruption events per customer
- $= \dfrac{\text{The number of customers which had } \textbf{\textit{momentary interruption events}}}{\text{Total number of customers served}}$
- $= \dfrac{\sum ID_E N_i}{N_T}$
- MAIFI can be calculated by one of two methods. Using the number of momentary interruptions or the number momentary events. This report calculates MAIFI$_E$ using momentary events. The event includes all momentary interruptions occurring within 5 minutes of the first interruption. For example, when an automatic interrupting device opens and then recloses two, or three times before it remains closed, it is considered a single event.

SAIDI – System Average Interruption Duration Index

- Average sustained outage time per customer
- $= \dfrac{\text{Outage duration multiplied by the customers effected for all } \textbf{\textit{sustained interruptions}}}{\text{Total number of customers served}}$
- $= \dfrac{\sum r_i N_i}{N_T}$

CAIDI – Customer Average Interruption Duration Index

- Average restoration time
- = $\dfrac{\text{Outage duration multiplied by the customers effected for all } \textbf{\textit{sustained interruptions}}}{\text{The number of customers which had } \textbf{\textit{sustained interruptions}}}$
- = $\dfrac{\sum r_i N_i}{\sum N_i}$

Quantities
i = An interruption event;
r_i = Restoration time for each interruption event;
T = Total;
ID_E = Number of interrupting device events;
N_i = Number of interrupted customers for each interruption event during the reporting period;
N_T = Total number of customers served for the area being indexed;

$CEMI_n$ – Customers Experiencing Multiple Sustained Interruptions more than n.

- $CEMI_n$
- = $\dfrac{\text{Total Number of Customers that experience more than } n \textbf{ sustained interruptions}}{\text{Total Number of Customers Served}}$
- = $\dfrac{CN_{(k>n)}}{N_T}$

$CEMSMI_n$ – Customers experiencing multiple sustained interruption and momentary interruption events.

- CEMSMIn
- = $\dfrac{\text{Total Number of Customers experiencing more than } n \textbf{ interruptions}}{\text{Total Number of Customers Served}}$
- = $\dfrac{CNT_{(k>n)}}{N_T}$

MED - Major Event Day

A major event day is a day in which the daily system SAIDI exceeds a threshold value. Its purpose is to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in daily operation that would be hidden by the large statistical effect of major events.

T_{MED} is calculated (taken from the IEEE 1366-2003 Standard)
The major event day identification threshold value, T_{MED}, is calculated at the end of each reporting period (typically one year) for use during the next reporting period as follows:

a) Collect values of daily SAIDI for five sequential years ending on the last day of the last complete reporting period. If fewer than five years of historical data are available, use all available historical data until five years of historical data are available.
b) Only those days that have a SAIDI/Day value will be used to calculate the T_{MED} (do not include days that did not have any interruptions).
c) Take the natural logarithm (ln) of each daily SAIDI value in the data set.
d) Find α (Alpha), the average of the logarithms (also known as the log-average) of the data set.
e) Find β (Beta), the standard deviation of the logarithms (also known as the log-standard deviation) of the data set.
f) Compute the major event day threshold, TMED, using equation (25).

$$T_{MED} = e^{(\alpha + 2.5\,\beta)} \qquad (25)$$

g) Any day with daily SAIDI greater than the threshold value TMED that occurs during the subsequent reporting period is classified as a major event day. Activities that occur on days classified as major event days should be separately analyzed and reported.

Numbers of Customers Served

The following numbers of customers were based on the customers served at the beginning of the year. These numbers were used to calculate indices for this report.

Office	Customers	% of Total
Coeur d'Alene	46032	13.3%
Colville	17349	5.0%
Davenport	6759	2.0%
Deer Park	10001	2.9%
Grangeville	9981	2.9%
Kellogg/St. Maries	13978	4.0%
Lewis-Clark	28713	8.3%
Othello	5949	1.7%
Palouse	37454	10.9%
Sandpoint	13793	4.0%
Spokane	155186	45.0%
System Total	**345195**	

ASSET MANAGEMENT 5 YEAR PLAN AND BUDGET SUMMARY

2008

Prepared By: Dan Whicker
Rodney Pickett

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Purpose of Asset Management

Asset Management (AM) strives to manage key company assets to perform optimally throughout their life and provide the best value for our customers, employees and investors. Bringing together industry practices, company experts, key stakeholders, and analytical tools, Asset Management creates a comprehensive plan including a sound tool set to manage an asset throughout its life from beginning to end, so an asset's value is maximized. Maximizing the value to our customer will come through minimizing the life cycle costs, maximizing system reliability, balancing needs of other stakeholders, and minimizing the cost per kilowatt-hour to generate and deliver energy. Maximizing the value to our shareholders will come through maintaining the assets for the least amount of life cycle costs, demonstrating prudent investment in our current assets, and enabling the investors to see a return on their investment. For our employees, providing a safe and reliable system with a practical and a well thought out asset management plan creates an environment for them to succeed and satisfy their customers.

When fully implemented, Asset Management will become a way of doing business and not a program. People will no longer use the term Asset Management to describe individual processes but instead talk about an integrated business process. The company will have an overarching vision and plan of what is needed to manage their Generation, Transmission, Substation, and Distribution systems.

In 2007, Avista spent $10.6 million in O&M money on Failed Electric Maintenance and $1.25 million of Capital budget on Failed Electric Plant. Where it makes sense, AM works to transfer money out of the failed accounts and into the planned activities at a lower cost. Implementing the different programs will stabilize the rising number of equipment failures and potentially reduce them. This will in turn improve our customer satisfaction.

Benefits of Asset Management

The Asset Management process brings the tools, people, and resources together in a way that integrates information from a myriad of sources into a comprehensive and extensive picture for everyone to see and arrive at a plan that maximizes the value of every asset. From this process, we can then identify what approach provides the best life cycle costs, best reliability, resource needs for the future, metrics to prioritize projects, evaluate different alternatives or new technology, and ultimately determine an overall asset management plan.

Without Asset Management, our equipment related failure rates will continue their trend upwards and drive our costs upwards as our system ages.

Figure 1, Outage Management Tool Only Failure Information, shows how the number of failures affecting our customers has changed over the past three years. The overall trend has been upwards and is anticipated to continue without further action. While proactive maintenance is not always the answer, just reacting to failures drives costs upward, reliability down, and customer dissatisfaction. Applying asset management tools to several areas in Figure 1 will help determine the best approach to deal the issue and arrive at the right answer.

Figure 1, Outage Management Tool Only Failure Information

Sum of Total Failures			Number of Customers Affected	Outage Duration (hh:mm)	[illegible]	[illegible]
Equipment	3 Yr Avg	2007 Comparison	3 Yr Avg	3 Yr Avg	[illegible]	[illegible]
Squirrel	775	4%	11	1:45	TRUE	8.4%
Lowside Swt/Disconnect	1	[illegible]	1380	0:47	TRUE	6.7%
Bus Insulator	3	[illegible]	1228	0:49	TRUE	6.0%
Tree Fell	398	[illegible]	68	2:57	TRUE	5.3%
Highside Breaker	2	[illegible]	982	1:18	TRUE	5.0%
Relay Misoperation	4	[illegible]	904	1:17	TRUE	4.7%
Transformer	5	0%	671	3:48	TRUE	4.4%
URD Cable - Pri	216	[illegible]	15	5:49	TRUE	4.1%
Connector - Sec	290	[illegible]	2	3:06	TRUE	3.9%
Cutout/Fuse	275	2%	32	2:26	TRUE	3.7%
Pole Fire	149	[illegible]	175	3:58	TRUE	3.6%
Transformer - OH	195	[illegible]	9	4:36	TRUE	3.5%
Tree Growth	239	[illegible]	9	2:41	TRUE	3.3%
URD Cable - Sec	171	[illegible]	2	4:48	TRUE	3.3%
Switch/Disconnect	4	[illegible]	172	7:31	TRUE	3.2%
Highside Fuse	2	[illegible]	360	4:40	TRUE	3.2%
Conductor - Sec	209	[illegible]	2	2:31	TRUE	2.9%
Primary Splice	3	0%	10	7:36	TRUE	2.5%
Regulator	11	[illegible]	274	2:07	TRUE	2.1%
Transformer UG	44	[illegible]	7	4:49	TRUE	2.0%
Conductor - Pri	57	5%	65	3:28	TRUE	2.0%
Insulator	31	[illegible]	135	3:13	TRUE	2.0%
Crossarm-rotten	35	[illegible]	156	2:47	TRUE	2.0%
Connector - Pri	71	[illegible]	77	2:34	TRUE	1.9%
Insulator Pin	17	[illegible]	154	2:33	TRUE	1.7%
Arrester	31	[illegible]	69	2:19	TRUE	1.4%
Termination	9	4%	10	3:37	TRUE	1.3%
Pole-rotten	31	[illegible]	12	2:36	TRUE	1.2%
Recloser	10	[illegible]	105	1:35	TRUE	1.1%
Elbow	6	[illegible]	7	3:09	TRUE	1.1%
Capacitor	5	[illegible]	29	2:50	TRUE	1.1%
Junctions	3	[illegible]	37	2:31	TRUE	1.0%
Lowside OCB/Recloser	1	0%		2:22	TRUE	0.8%
Customers		351,585				

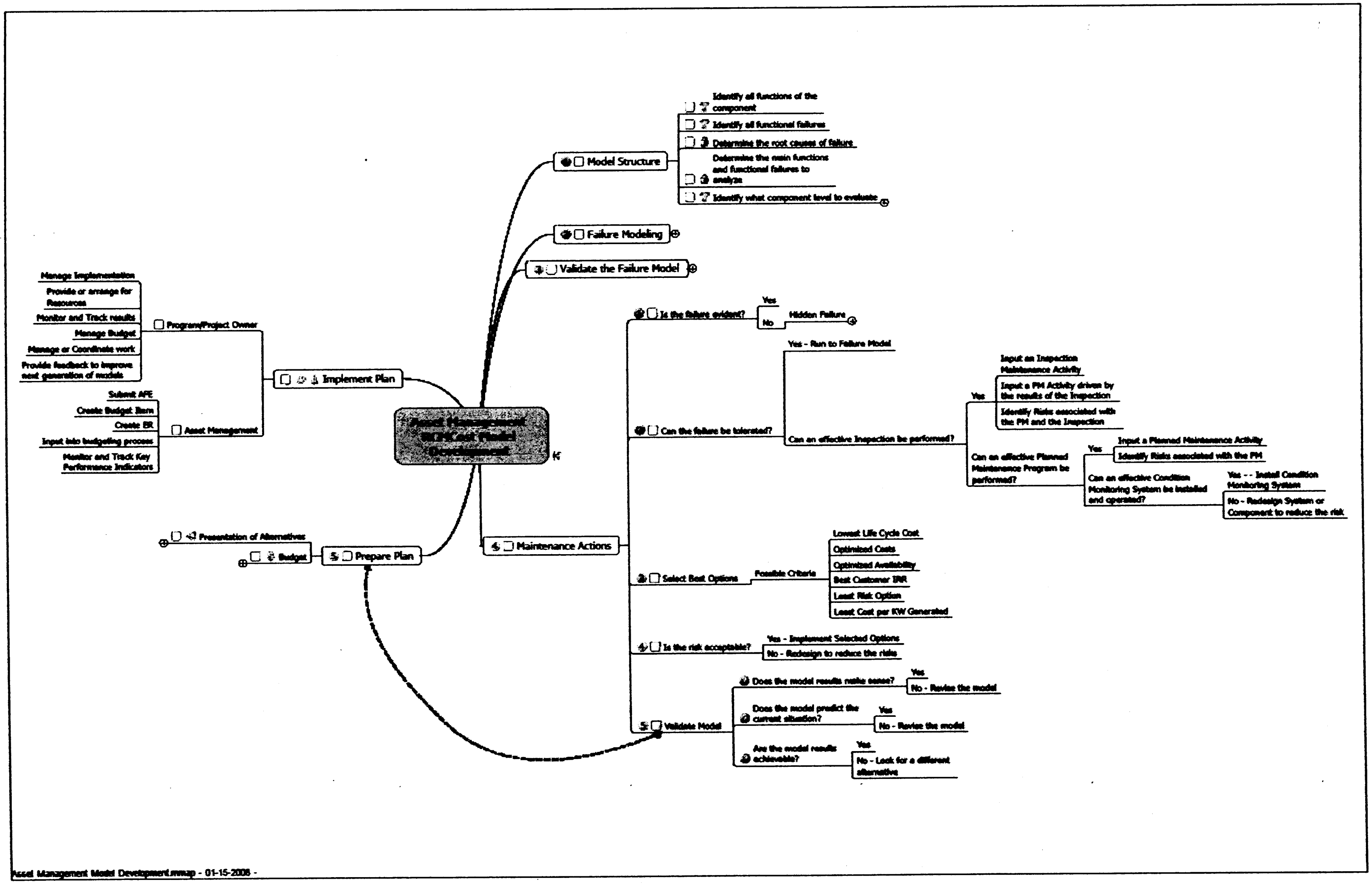
Significant Degradation in performance for 2007
Small Degradation in performance for 2007
Improved performance in 2007
Recommended for better tracking

Implementation of Asset Management

Asset Management starts with questions like, "what do we need to achieve with this asset" "why do we need to improve this assets performance", and "what do we hope to accomplish for this asset". Once questions like these have an answer, we then begin to work on arriving at an answer. The process of arriving at the answer starts with the data and a team. A team representing the stakeholders and experts is put together and develop an Asset Management Model and ultimately formulate the plan. The available data is examined and where it is not available, expert opinion from the team is used to fill in the gaps. They can then begin the process of developing the Asset Management Plan. Figure 2, General Asset Management Plan Development, shows the steps in the process for developing an Asset Management Plan. The foundation for the plan is in determining what the future failures will look like based on available data and expert opinion if nothing is done and becomes the failure model. The failure model incorporates not only the frequency but all aspects of a failure such as environmental, reliability, safety, customers, costs, labor, spare parts, time, and other consequences. The failure model then becomes the baseline to compare all other options. The team reviews the failure model and ensures that it makes sense and represents what they understand of the asset and its impacts. With this foundation, all other alternatives can be examined and evaluated until the best maintenance plan is identified. With the best maintenance plan, the team then must determine how we change and achieve the maintenance plan. This will include determining and getting a budget approved and resources identified to perform the work.

With the Asset Management Plan completed, someone is then assigned to become the plan manager and implement the plan. Who this person is varies based on the type of plan and historically has been an engineer within Substation, Transmission, Distribution, or Substation Support. However, as more AM plans come on line, this practice will need to change because the existing workload already takes up all of the assigned resources time. More Senior I Engineers will be needed to act as program or project managers.

Figure 2, General Asset Management Plan Development



Current Asset Management Programs

Several Asset Management Programs have been implemented in recent years or are continuations of existing historical programs. Wood Pole Management, Underground Cable Replacement and Vegetation Management have existed several years. The Vegetation Management Program reduces tree and vegetation related outages and has proven a success over the past several years.

The Wood Pole Management program has been around for years. The level of work has not been sufficient to reach all of the poles in a timely fashion until 2008. The plan is to inspect all Distribution wood poles on a 20 year cycle and all of the Transmission wood poles on a 15 year cycle. We anticipate this program will provide a tremendous benefit to our customers and provide a cost effective method of reducing outages and costs related with wood pole failures.

The Underground Residential Distribution Cable Replacement program has been replacing an old direct buried primary distribution cable that is plagued by frequent faults. This cable has a high enough failure rate to justify planned replacement. Over the past few years, this program has stabilized and slightly reduced the number of cable faults, but several thousands of feet of the cable remain to be replaced before the full savings can be realized.

A new program started in 2007 is a focused replacement of a particularly problematic and failure prone cutout used to isolate Distribution Feeders and Transformers as well as hold fuses. This program found that a planned replacement would provide a significant benefit to our customers and should be replaced on a planned basis. Many of these cutouts were replaced at the end of 2007, so the benefits have not been realized yet. It is anticipated the benefits of this program will be seen in 2008.

Another new program starting in 2008 belongs to the Network. The Network is the distribution system supporting downtown Spokane with a highly reliable underground distribution system. The specific program is the planned inspection, maintenance, and replacement of the Network's Vaults, Manholes, and Handholes. The program includes periodically inspecting them and then repairing or replacing them as identified by condition. Many of these structures are nearly 100 years old and are approaching their end of life, so this program will begin a planned replacement of them to ensure the reliable operation of the Network.

Other smaller programs are continuation of historical programs such as Substation Batteries, Substation Inspections, Substation Power Transformers, High Voltage and Low Voltage Circuit Breakers, Distribution Reclosers, and others. The current Asset Management process has not been used to revise all of the existing practices but for those programs that will be revised; these are discussed in the next section.

Proposed or Modified Asset Management Programs

The following represents the proposed changes to start in 2009 for Asset Management. These programs usually represent a change from the past practices. However, some of the current practices have proven to be the best option and will remain in place except their resource needs are projected to increase due to aging of the system. Each plan will be discussed under Transmission, Substation, Distribution, or Network areas.

Network

While the Network Vault and MH/HH programs began in 2008. They are not fully implemented and we plan on fully implementing it in 2009. So, we are including it as a modified program as well.

Transmission

A long standing Transmission activity, Minor Rebuilds, continues with modestly improved funding in 2008 and is projected to have steady funding levels for 2009. This activity is follow-on work to accomplish repairs identified during Transmission Wood Pole Management inspection and testing.

A new capital program is proposed for 2009 to replace a specific vintage of 230kV suspension and dead-end insulators that experienced high failure rates with subsequent long duration outages.

Several new, or expansions of former small programs, Operations and Maintenance measures are considered for the Transmission system: (1) fire retardant paint for the lower 6 to 8 feet of critical wood structures, (2) testing and replacement of sleeve couplings that are showing increased failure with age and, (3) painting of older steel transmission structures for corrosion resistance.

Substation

While we are currently performing Dissolved Gas Analysis on our Substation Transformers, the Power Transformer program involves the planned replacement of transformers not only based on condition but also based on their efficiency. The purpose of the plan is to maximize the value of the transformer. Several older transformers are inefficient enough and old enough to justify replacing them. This will reduce system losses and improve the reliability of the system.

The Power Circuit Breaker AM Plan is based on our historical maintenance of these breakers. However, more of the breakers are reaching their end of life and are no longer supported by their manufacturer. Based on our analysis, we will begin to replace the worst high voltage circuit breakers based on their condition and age.

Some of our smaller substations use a Power Fuse to provide protection on substation transformers. The Power Fuse AM Plan will replace these fuses with new protection systems. These Power Fuses no longer have parts and do not meet our current requirements. The program will replace these on a planned basis and better protect our substation transformers.

The Recloser AM plan covers substation and distribution system Reclosers. The plan calls for maintenance and inspection of the substation Reclosers based on the type as well as the anticipated replacements. The propose program matches the current plans but they have not been achieved yet because of resource limitations. The plan also includes more planned replacements because several have already reached their end of life. This will improve the reliability and extend the life of the existing equipment.

The Relay Replacement AM Plan will replace older Electromechanical Relays on our 115 kV system with newer microprocessor based relays. While this program will not save much money overall, it will reduce the amount and cost of maintenance. The old relays require a significant amount of maintenance to keep functioning and replacing them will cut this cost significantly along with improve the reliability.

Several of our smaller substations are constructed out of wood. The Wood Substation Rebuild program will either repair or replace the wood structures based on their condition and determine when the whole substation structure will be rebuilt. The purpose of this program is to retain the systems reliability and prevent structural failures within the substation.

The Circuit Switcher AM Plan addresses a circuit breaker type of device used to control and protect several substation transformers. This plan will implement a maintenance program to test and maintain them based on condition as well as identify when a circuit switcher has reached its end of life and must be replaced. The function of this program is to maintain reliable operation and protection of substation transformers.

Distribution

The Distribution Transformer AM Plan covers the planned replacement of older transformers. These older transformers are less efficient and are nearing their end of life, so a planned replacement is cost justified largely due to the reduced system losses.

Future Asset Management Programs

The current AM plans have focused on individual assets and have not examined improved efficiency with integrated maintenance. We selected the individual AM approach to develop the fundamental building blocks needed to then develop the integrated models. The future AM programs will begin to integrate into system programs based on a Distribution Feeder model and incorporate several efficiency improvement opportunities so that our program goes from individual AM plans into system plans like a Distribution Feeder Plan. Work that is underway on analyzing potential efficiency improvements within our system when integrated with AM analysis should yield opportunities to not only improve the systems reliability but also reduce losses while replacing older components that alone are not cost justified to be replaced.

The Generation Plants have begun to develop AM plans that are currently focusing on Generator Circuit Breakers and Generator Step-up Transformer Replacements. Based on the completion of this analysis, these and other programs will be developed to support Generation.

Asset Management programs will also transition into a formal Root Cause Analysis (RCA) to further improve AM plans. Combined with better information and tracking, Root Cause Analysis will allow for a better cause focused approach to managing all of our assets.

As our information collection and data analysis capability grows and feedback comes in, we will periodically review the models to refine them and identify further areas of improvement.

Needed Changes to support Proposed and Future Asset Management Programs

Over the past few years, Asset Management developed expertise, processes, tools, and information systems focused on creating Asset Management plans. However, once the plan was developed, it was handed over to a selected project owner or project manager to implement and track. This work has been in addition to their existing workload. This approach has been successful but has some drawbacks. With our current resources, AM has been limited to planning only, but they are looked to as the expert and owner of the program. However, as the number of programs expands along with the need for further expertise development, more time is needed to support the programs and exceeds the current resources. To address these issues, we propose adding two Senior Level I Engineers position for this work.

These Senior Level I Engineering positions will fill the role of project manager/owner. They will relieve much of the work from the current program owners and allow for development of Asset Management experts who can not only understand the current plans but also seek out and explore new technology. They will also become a resource for the formal RCA and planned maintenance expert. While the various engineering departments will retain their current responsibilities, these engineers will support the AM portions of their system and coordinate with them to get the plans implemented.

A second skill set needed to implement the proposed AM plans are two Customer Project Coordinators (CPC). They are needed to support the Distribution Transformer Replacement Plan. The Distribution Transformer Replacements will take over 10 years to complete and requires 1.5 full time CPC to support. The remaining 0.5 CPC will provide support to other Distribution AM plans. The CPC's will plan the specific work packages for the line crews to perform the work and provide customer coordination for each of the outages required to replace the transformers. For the remaining time of the CPC's not used for Distribution Transformers, other programs such as the Distribution Infrared Inspection Pilot program, Wood Pole Management, porcelain cutout replacements, and other programs will need the same planning and support to accomplish their purpose.

Another portion of the AM program that has and will continue to expand is the database management, analysis, and maintenance. We are also proposing to expand the existing Engineering Technician position from 20% to full time. An increasing amount of data is gathered, stored, and analyzed each year to monitor existing programs, identify new trends, and prepare information for the next round of analysis. With the implementation of a Failure Tracking Process, we have centralized all failure information into one place, so we can begin to paint a complete picture of what is occurring throughout the system. Our information comes from all kinds of systems that include paper copies of reports and field work to automated data systems. In order to integrate such a diverse set of information, we have used an Engineering Technician and a student employee to help gather the information. However, our current resource allotment has begun to exceed our current allotment. Over the past few years, AM has also worked on improving the data gathering process and systems. This effort has a lot more work to accomplish and improve the automation of managing and collecting information.

To support all of the additional required work, seven Electricians and one Relay Technician are needed. Our current resources are over extended and on average working 300 hours of overtime per individual to meet our current workload. The program proposed and changes to our existing programs will drive increasing our current workforce. However, the current labor markets have tapped all available resources, so we anticipate that they will be hired as apprentices and will require time to become qualified. This will force the implementation of several Asset Management plans and programs in phases as people become qualified. The phase-in time is estimated to take three years. Initially, these new personnel will be loaded in the Operations and Maintenance budgets exclusively and then transition into an appropriate mix of Capital and O & M budgets. The cost estimates for these employees are included in the individual proposed plans.

A program deficiency in our current AM planning process is an effective and system wide Root Cause Analysis. In order to focus asset management activities properly, we must address the root causes of failure and understand what the real impacts of failure are upon all stakeholders. The Asset Management process needs to develop the administrative tools, processes, purchase the technology, and train key personnel to support this portion of the program. While our experts are effective at determining the causes of failures, retirements and promotions have reduced the number of experts and the new generation needs to learn RCA to develop them further as experts.

The largest issue and change needed to support AM in the future is a new Work Management System or Computerized Maintenance Management System. Currently, AM processes gather data manually from sources ranging from drawings, spreadsheet, a financial database, paper reports, Outage Management Tool, and personnel interviews. Our Asset Management models require an extensive amount of information that currently gets completed with expert opinion and analysis instead of actual data and information. Much of the information needs could be met with a new Work Management system such as MAXIMO or equivalent systems. Most companies using our AM tools get their information using such systems and have much more accurate and refined information to base their analysis on.

Asset Management Programs/Plan Details

The following outlines each of the individual AM plans for the next 5 years.

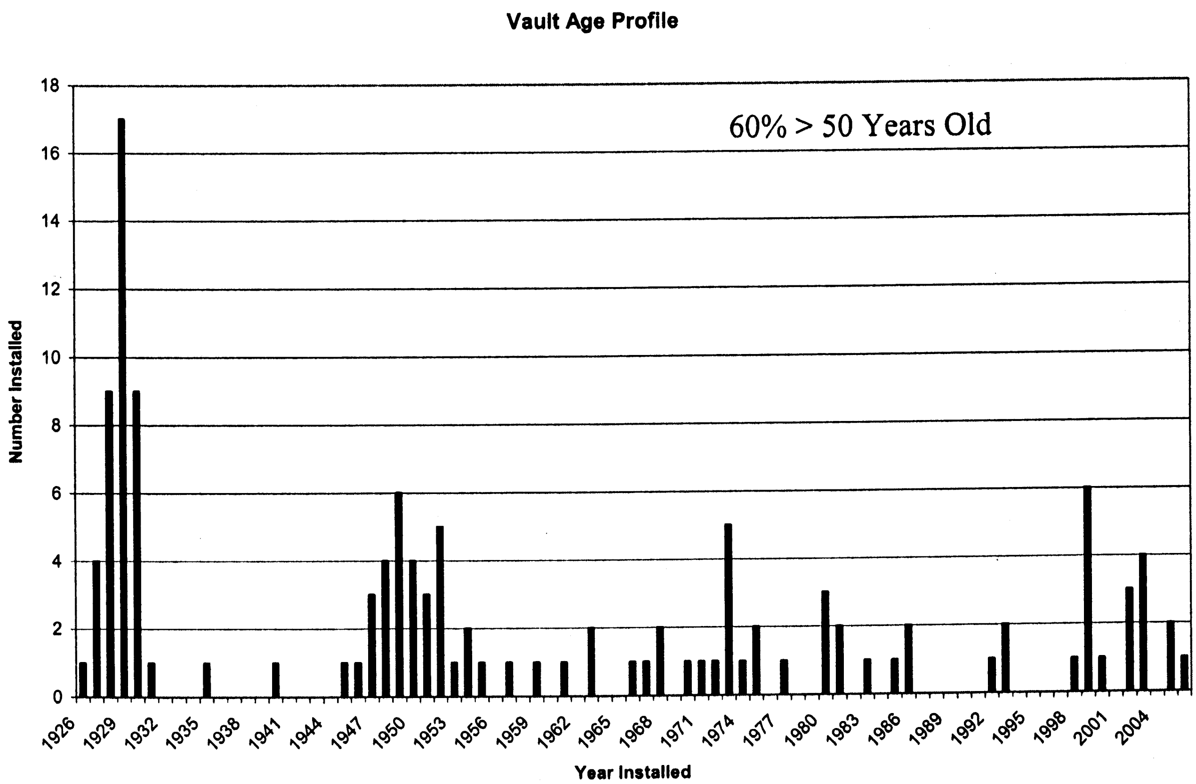
ER NEW28 Network

Network Vaults

The Network Vaults AM plan covers all of the vaults in downtown Spokane, WA. These vaults usually contain a network transformer, a network protector, and feeder cable. Many will have a floor drain or a sump to aid removing water. Some of the vaults if flooded will also flood a customers building because of their location within a customers building or due to the vault access. Figure 3 shows the current age profile of the Network Vaults. Below are some significant statistics on the Network Vaults:

- 124 Vaults
- 20 Vaults are Vacant
- 8 Vaults can flood and cause customer damage
- 16 Vaults have Sump Pumps
- 29 Vaults have drains

Figure 3, Network Vault Age Profile



This program is based on inspecting the vaults every six months and making repairs based on condition. The repairs could range from replacing the Vault plug, Vault top, or complete Vault. Some maintenance includes re-painting any exposed steel and yearly cleaning out Vaults to prevent fires and corrosion due to debris buildup. Based on the inspections, we anticipate performing the following work:

- 1 Fan Replace every 5 years
- 11 Sump Pumps every 4 years
- 12 Vault Plugs every 5 years
- 8 Vault Tops every 6 years

In order to accomplish this work,

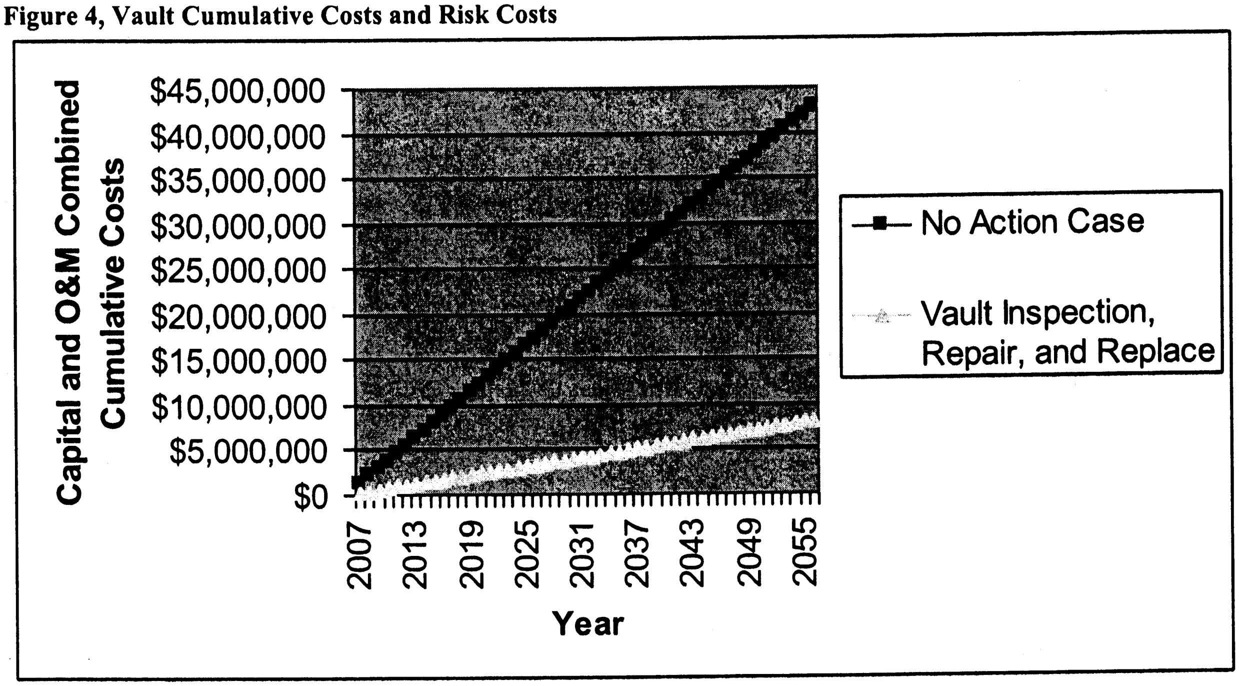
Table 1 shows the estimated Capital and Operations and Maintenance budgets to support the planned work. This work will also require an average of 1,500 man-hours of Cableman labor to perform the inspections and maintenance.

Table 1, Network Vault Capital and O&M Budget Estimates

Year	Capital Costs	O&M Costs
2009	$60,000	$83,000
2010	$62,000	$86,000
2011	$65,000	$90,000
2012	$67,000	$94,000
2013	$69,000	$97,000

The benefits of the Vault Inspections and Maintenance come from reducing the overall costs of the vaults and protecting the public. The financial savings of this program come from the projected additional costs associated with vault failures and mishaps since they are reaching their end of life. On average, the program is anticipated to save ~$700,000 annually due to reduced risks associated with the vaults and reduced customer outages or impacts. These savings are predominately our customers saving as avoided costs due to a power outage, and Figure 4 shows the cumulative effect of the plan compared to running to failure.

Figure 4, Vault Cumulative Costs and Risk Costs



Network Manhole and Handholes

The Network Manholes and Handholes AM plan covers all of the downtown Spokane Manholes (MH) and Handholes (HH) used in the Network. These MH and HH usually only contain feeder cable and cable racks. The structures are simpler and smaller than a vault . These also provide connection points to tie customers into the Network and are usually located in the roadway.

Figure 5 shows the current age profile of the Network MH and HH. Below are some significant statistics on the Network MH and HH:

- 287 Manholes
- 293 Handholes

This program recommends inspecting the MH and HH every five years and then making repairs or replacements based on the condition. The repairs could range from replacing the Ring and Cover, MH/HH Top, or complete MH/HH. Based on the inspections, we anticipate performing the following work:

- 5 Handholes every 4 years
- 4 Handhole Tops per year
- 6 Manholes every 5 years
- 4 Manhole Tops per year
- 55 Racks per year
- 33 Rings and Covers per year

In order to accomplish the work, we anticipate budgets as outlined in
Table 2, and have an average annual resource requirement of 1,300 man-hours of Cableman labor and 260 man-hours of Mechanic labor to complete all of the work.

Figure 5, Network Manholes and Handholes Age Profiles

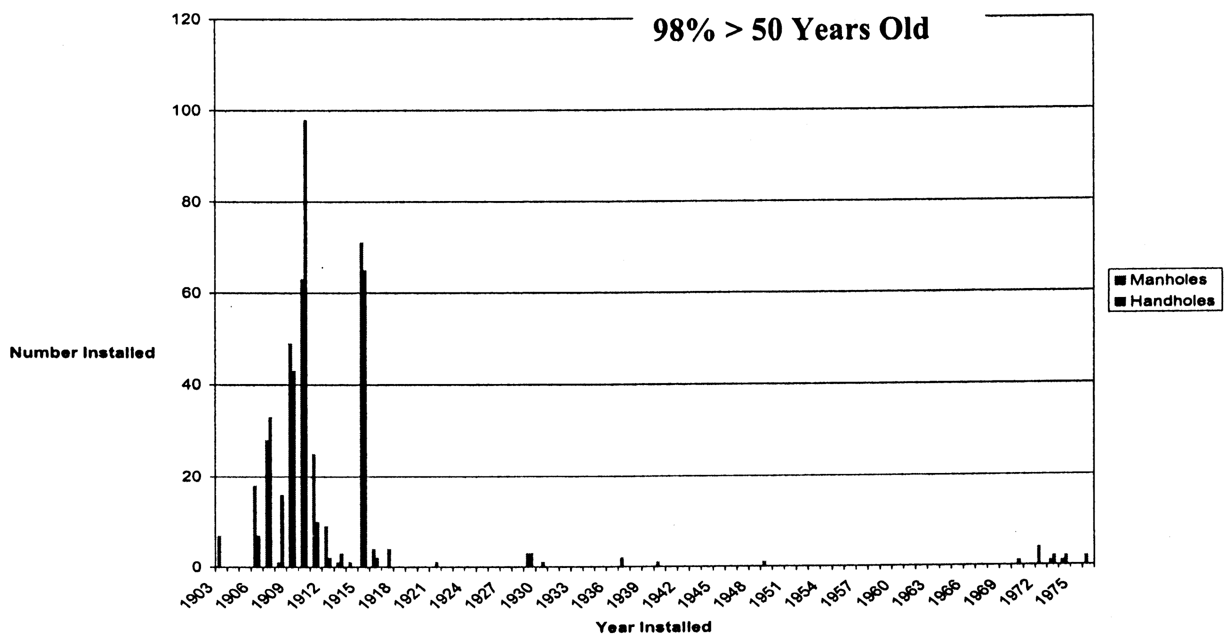
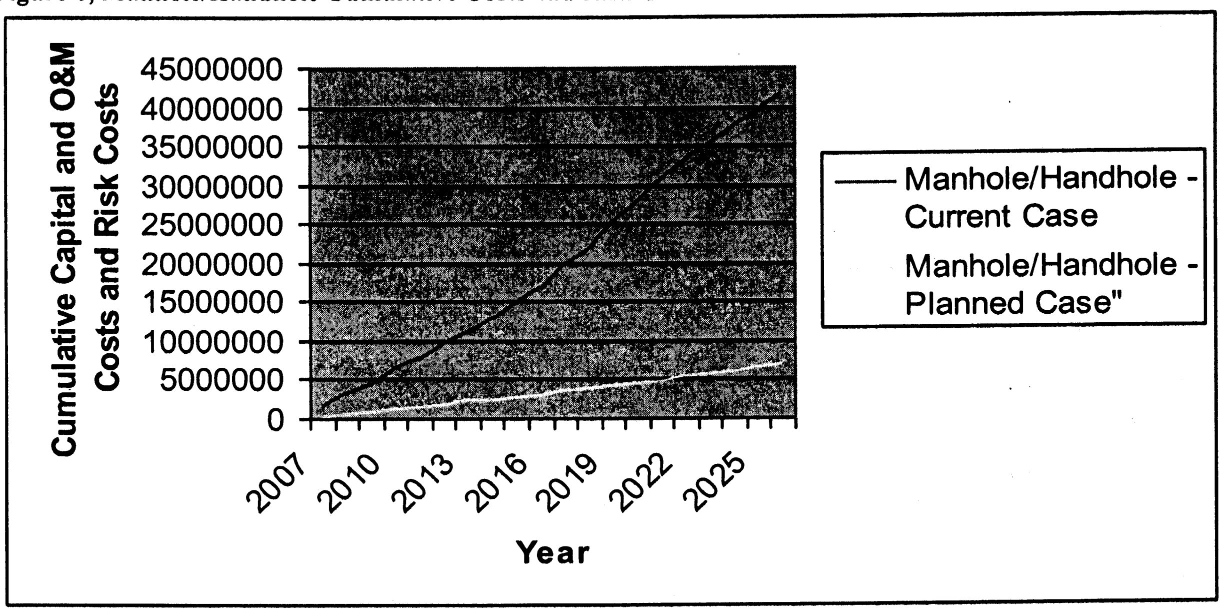


Table 2, Network Manhole and Handhole Capital and O&M Budget Estimates

Year	Capital Costs	O&M Costs
2009	$190,000	$25,000
2010	$198,000	$28,000
2011	$206,000	$28,000
2012	$220,000	$28,000
2013	$244,000	$30,000

The benefits of the Manhole and Handhole Inspections and Maintenance come from reducing the overall costs of the MH/HH and protecting the public. The financial savings of this program come from the projected additional costs associated with vault failures and mishaps since they are reaching their end of life. On average, the program is anticipated to save ~$1,400,000 annually due to reduced risks associated with the Manholes and Handholes and reduced customer outages or impacts. These savings are predominately our customers saving as avoided costs due to a power outage and the savings comparison is shown in
Figure 6. For the company, this represents an average annual increased cost of ~$21,000.

Figure 6, Manhole/Handhole Cumulative Costs and Risk Costs



ER 2054 – Electric Underground Replacement

This ER addresses programmed replacement of aging underground primary distribution cable, commonly referred to as URD. URD installation began in 1971. Outage problems exist on cable installed before 1982, cable installed after 1982 has not shown the high failure rate of the pre-1982 cable.

Over 6,000,000 feet of URD was installed before 1982. Programmed replacement of the problem cable has been on-going at varying levels of funding since 1984. Approximately 900,000 feet of the pre-1982 cable remains in service as of January, 2008.

Historically, over 200 faults primary cable fault happen annually. There have been as many as 264 primary cable faults in 2003. During 2007 there were 168 primary faults. Since 1992 faults have increased from 2 per 10 miles of cable to 8 per 10 miles. The number of faults per mile has stabilized during the last 3 years after steadily climbing between 1992 and 2005.

Programs of differing length after 2009 were evaluated: 2 years, 3 years and 4 years. The option of no programmed replacement after 2009 was also evaluated.

Analysis indicates replacing the remainder of the pre-1982 cable in a short time frame is a fiscally sound decision. The replacement program was funded at $3 million during 2007, the budget amount is again $3 million for 2008 and the budget is projected to be $4 million for 2009.

The computed IRR values between a 7 year program and a 4 year program are within .07% of each other. However, the total number of faults with a 7 year program vs. a 4 year program is estimated to be 30% higher during a 10 year timeframe. Estimated faults double between a 4 year program and the current replacement pace of about 100,000 ft per year during the next 10 years. The results are in
Table 3 Underground Cable Replacement Financial Results.

IRR of 4 year program compared to 10 year program basis is 10.15%.

Table 3 Underground Cable Replacement Financial Results

10 Year Results	Total Cost Capital, O&M, Consequences, Installation, O&M Response	O&M Cost For Outage Response Over 10 Years Note (a)	Total Capital, 3.5% inflation per year applied	Average Capital Budget during replacement timeframe
Current Replacement Pace, 10 years to replace all original cable	$29,970,000	$9,300,000	$18,036,548	$1,803,655
Accelerated Replacement Pace, 4 years to replace all original cable	$22,700,000	$2,935,000	$16,166,461	$4,041,615
Upgrade Voltage Surge Suppression				$433,000
Savings	$7,270,000	$6,365,000		

Note (a) Cost to respond to outages has been decreased as number of outages decreases with the quantity of cable replaced.

Table 4 Underground Cable Replacement Reliability Results

10 Year Results	Number of URD Primary Voltage Cable Faults	CAIDI Note (a)	SAIFI Note (b)	
Current Replacement Pace, 10 years to replace all original cable	4466	6 hours	.017	
Accelerated Replacement Pace, 4 years to replace all original cable	500	6 hours	.0019	
Improvement	893%	0%	893%	

Note (a) CAIDI is predicted as flat value due to estimated time to repair fault remaining constant. Multiple simultaneous outages would result in larger CAIDI value

Note (b) SAIFI value is calculated from the number of faults times average number of customers per fault (13) divided by number of years (10) divided total number of customers (number of customers has been rounded to 340,000).

ER 2057 – Transmission Minor Rebuilds

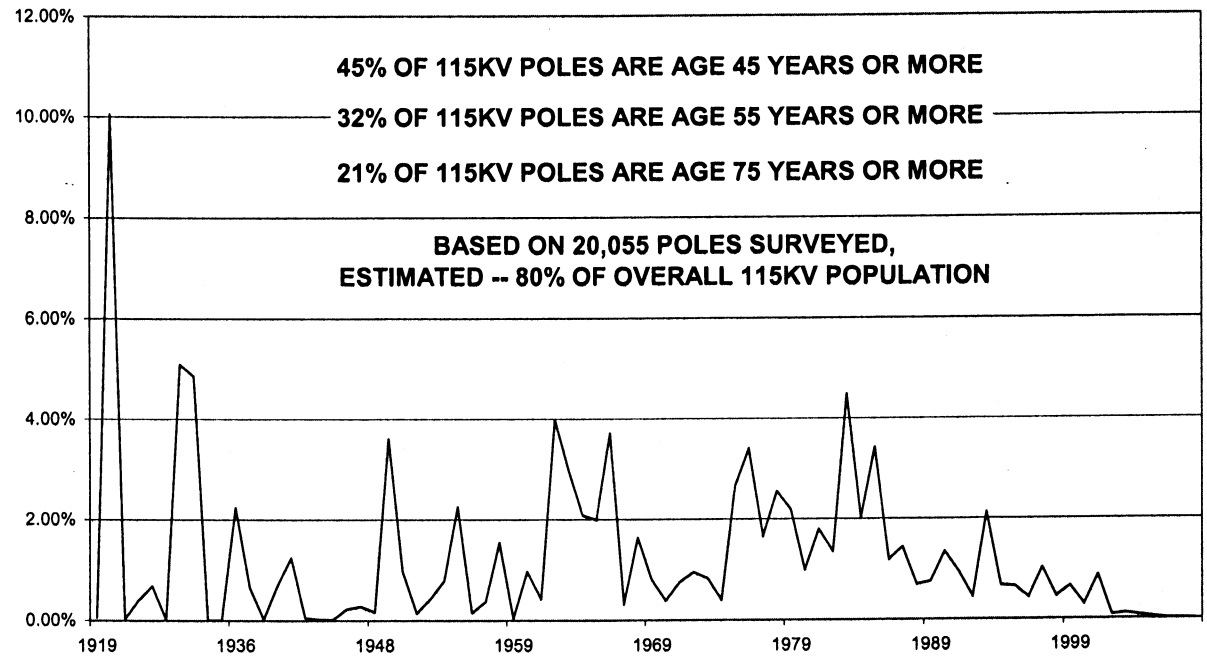
The Wood Pole Management plan optimizes programmed inspection and testing of the transmission system structures at an interval of 15 years.

This optimized time interval comes with a caveat – there are a number of 115kV transmission lines where predominate age of poles is over 70 years. Several lines have significant populations over 80 years old. Data regarding the future performance of wood structures that old is minimal. Projections of performance regarding these poles, which are among the oldest in the nation, is inconclusive; but, statistical projections point toward a high probability of structural problems.

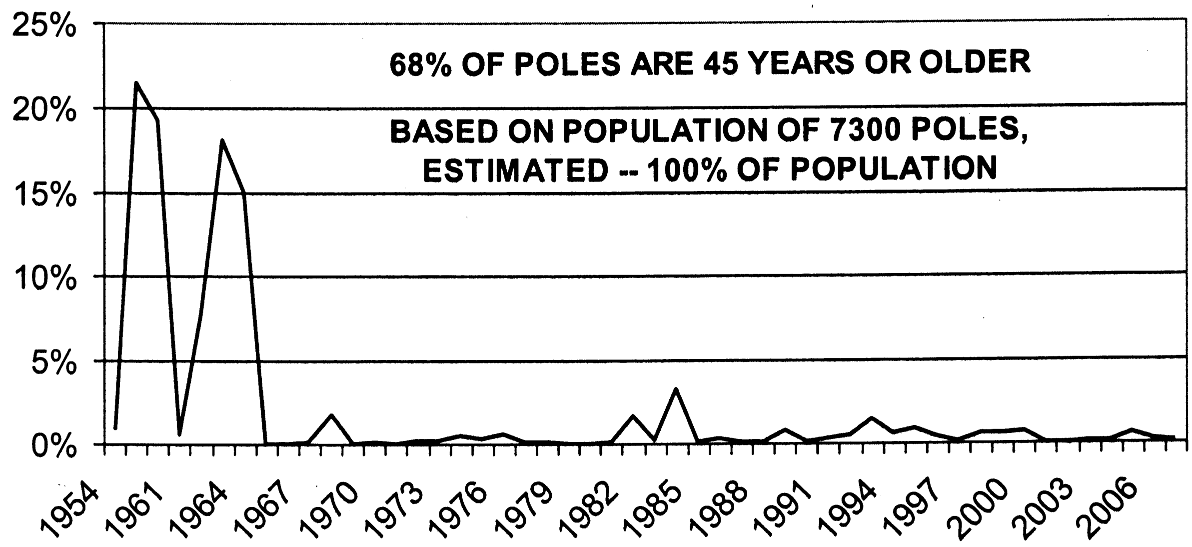
We plan to schedule two of the older lines for inspection during 2008. Results of this testing may revise projections of follow-on capital work. That is, a capital rebuild project exceeding the normal scope of the traditional minor rebuild work is possible.

The majority of wood structures are post-1950 installation. Virtually all 230kV poles were installed after 1950 and about 70% of the 115kV poles are post 1950. Statistical projections predict a characteristic age of 80 years for the 115kV type structures and over 80 years for 230kV type structures. The transmission minor rebuilds are projected to be very effective for the next 20 years in maintaining the integrity of these systems.

115KV Wood Pole Population
(Steel Poles Not Included)



230KV WOOD POLES
(Steel Pole Population Not Included)



ER 2060 Wood Pole Management

This is a continuation of the current program to inspect all wood distribution poles on a 20 year cycle. This includes the O&M costs for the inspections and the capital costs to replace or reinforce the wood poles and cross-arms. Since the program is an existing and approved program already in rates, the projections will be updated after seeing what the actual costs are from the first year. For the rate case, the previous projection was used with $31,000 added to O&M for Distribution Wood Poles for overheads and training expenses.

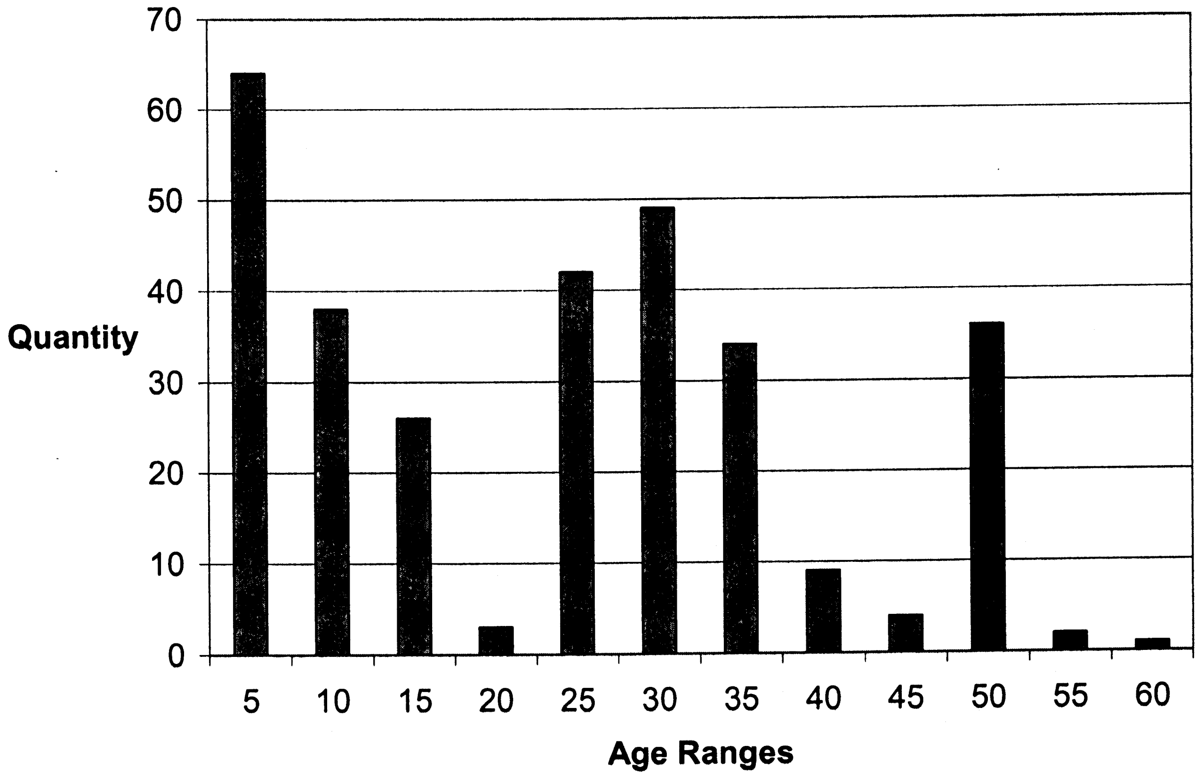
Also included in ER 2060 is continued testing and inspection of wood transmission poles on a 15 year cycle. This includes the O&M costs for the inspections. The capital costs to replace or reinforce the wood poles and cross-arms are accomplished under ER 2057. Since the program is an existing and approved program already in rates, the projections will be updated after seeing what the actual costs are from the first year.

ER's 2001/2211/2215 Power Circuit Breakers

The Power Circuit Breaker AM Plan has been an ongoing and successful program by maintaining approximately 300 High Voltage Oil Circuit Breakers. Due to resource constraints Avista has been unable to reach our goal of a 10 year maintenance cycle are currently at a 15 year cycle, so extra resources are needed to achieve the 10 year cycle. Approximately 14% of these breakers are greater than 40 years old and are reaching their end of life or are no longer supported by their manufacturer. Figure 7 shows the current age profile for all Power Circuit Breakers. Of the 300 Power Circuit Breakers, about 110 are newer Gas Circuit Breakers.

Based on our analysis, Avista will need to replace approximately 5 Substation Power Circuit Breakers every two years to keep up with the number of breakers reaching their end of life. However, achieving a 10 year maintenance cycle is constrained by available resources and cannot be fully implemented until labor resources are in place and qualified. The Transmission Maintenance Inspection Plan outlines an inspection cycle of 15 years for these circuit breaker to support NERC and WECC standards, but this is just a minimum, and our analysis indicates that it should be more frequent to maximize the value of the asset to our customers.

Figure 7, Power Circuit Breaker Age Profile



Our current resources limit the number of breakers maintained each year. In order to achieve a 10 year cycle, The O&M budgets must be increase to $300,000 (see Table 5) and represents about a $170,000 increase in spending from 2007. The labor resources needed to accomplish this level of maintenance and replacement is as follows:

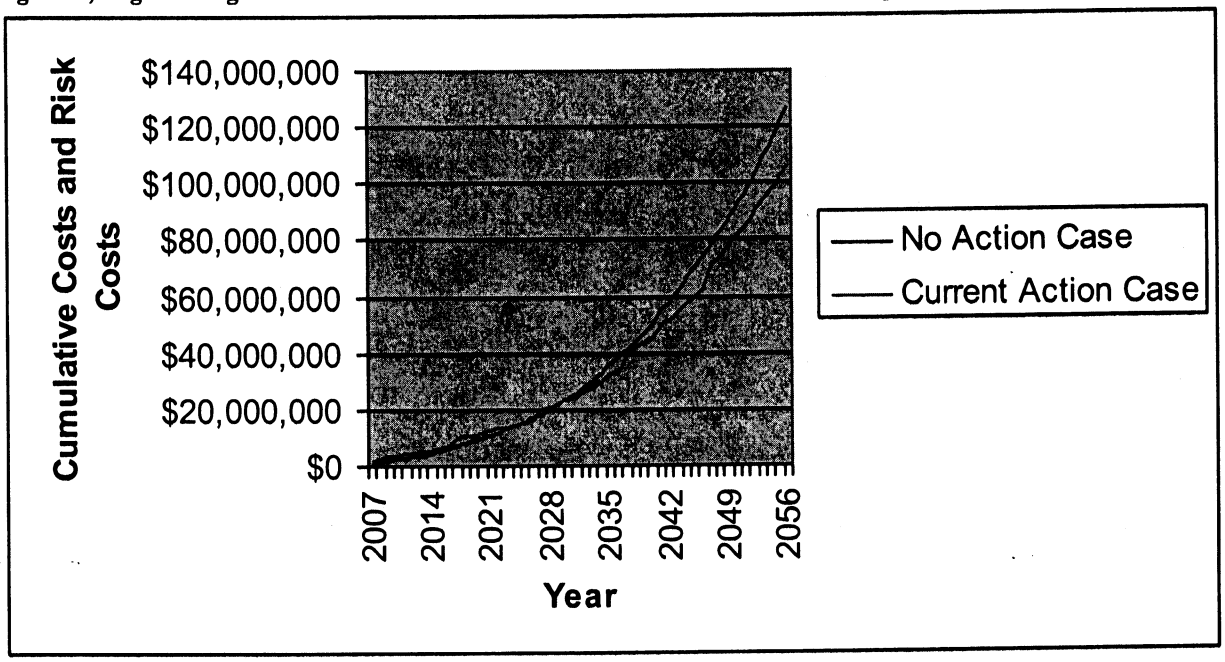
- Substation Electricians – 6,200 man-hours annually
- Relay Technician – 160 man-hours annually
- Substation Engineer – 100 man-hours annually
- Mechanic – 90 man-hours annually

Table 5, Power Circuit Breaker Capital and O&M Budget Projections

Year	Capital Costs	O&M Costs
$2,009	$435,000	$306,000
$2,010	$300,000	$409,000
$2,011	$466,000	$379,000
$2,012	$322,000	$397,000
$2,013	$499,000	$407,000
$2,014	$344,000	$425,000

The benefits of this program come in the future. The breaker maintenance will extend the life of the existing circuit breakers and replace old circuit breakers when they become obsolete and un-maintainable. Figure 8 shows the cumulative cost comparison to taking no action. The no action case is not acceptable because of WECC and NERC standards and the 10 year maintenance cycle balances the requirements and cost to customers.

Figure 8, High Voltage Circuit Breaker Cumulative Costs and Risk Costs Comparison



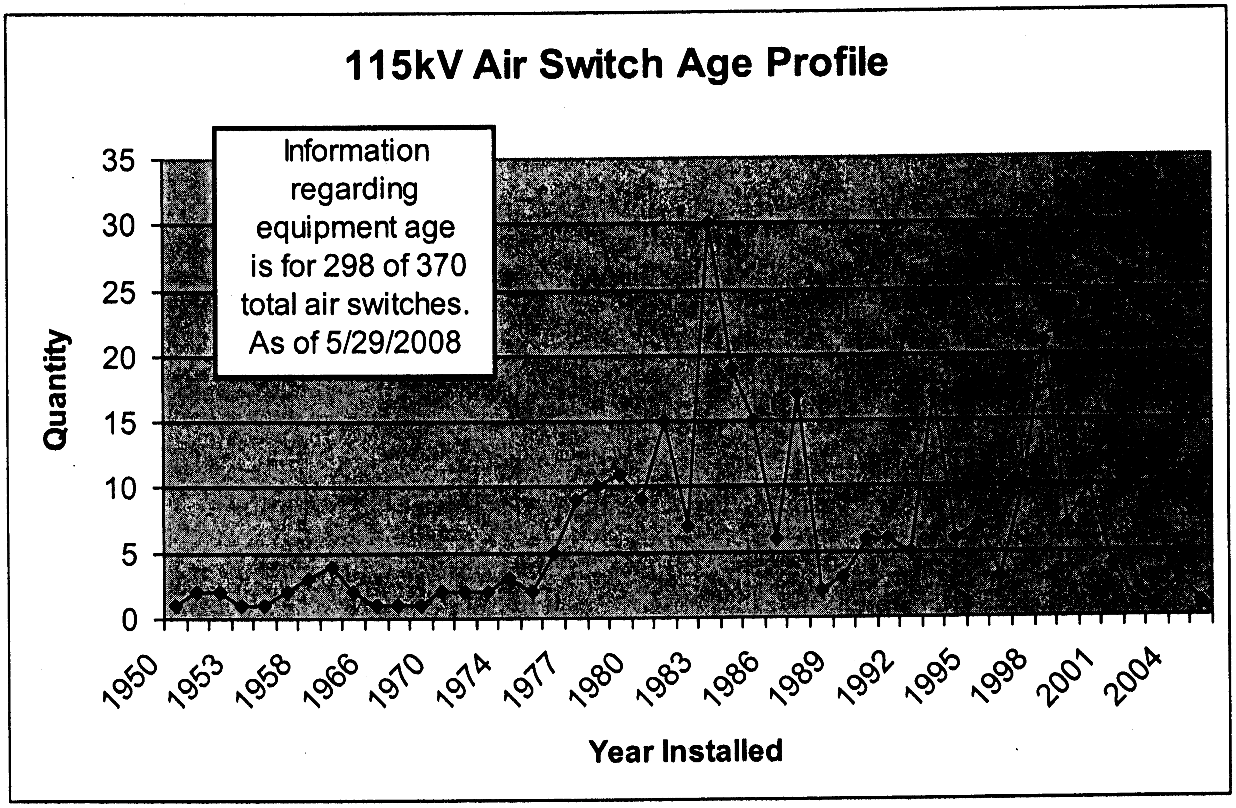
ER 2254 Transmission Air Switches

The transmission air switches have been being replaced at a steady but modest pace during recent years. The average capital expenditure has averaged about $100,000 per year during the past 3 years. This translates to changing or refurbishing 3-4 switches per year. The current 115kV Air Switch inventory consists of 370 operational units.

There are some switches also installed on the 230kV and 60kV systems, however, the preponderance of Air Switches are installed on the 115kV system.

80 air switches are being fit with grounding platforms for worker safety during 2008. During this process a new worm gear handle is installed and disconnecting whips are adjusted. Operating pivot joints of the switch mechanisms are not affected by this work. In short, the 2008 work is safety related, not switch mechanism related.

Avista has an inventory listing of Transmission Air Switches that lists the location and type of switch. Information regarding age of the equipment is not complete but a general age profile can be observed.



At this time, there is not a disturbing trend in Air Switch failure. However, as seen in the age profile, a bow-wave of aging switches will begin to approach during the coming decade. Transmission outage cause tracking is being improved at this time. The improved information will allow tracking of failure trends for the air switch population.

ER 2260 Surge Arresters

Substation Surge Arresters or Lightning Arresters provide protection to several Substation components. Over time the insulating characteristics degrade. This is especially true for the older Silicon Carbide type of Surge Arresters. Avista plans to replace an average of 24 per year on a planned basis out of the approximately 760 in the Substations. The estimated budget by year for this project is shown in Table 6.

Table 6, Surge Arrester Replacement Budget Projections

Year	Capital Costs	O&M Costs
2008	$165,000	$39,000
2009	$178,000	$41,000
2010	$195,000	$42,000
2011	$205,000	$44,000
2012	$204,000	$45,000
2013	$226,000	$47,000
2014	$243,000	$49,000

ER 2275 Substation Fence and Rock

The Substation Rock and Fence AM plan covers the maintenance and replacement of Avista's 164 substations. Avista anticipates an average of 4 Substations will require repairs to the fence or rock ground cover in order to keep the public out and maintain the insulating properties of the Substation Rock. Avista also anticipates that 5 Substations each year will need to be completely resurfaced with new rock. See Table 7 for the projected budget needs.

Table 7, Fence and Rock Repair and Replacement Budget Projections

Year	Capital Costs	O&M Costs
2009	$49,000	$49,000
2010	$53,000	$53,000
2011	$58,000	$58,000
2012	$63,000	$63,000
2013	$63,000	$63,000

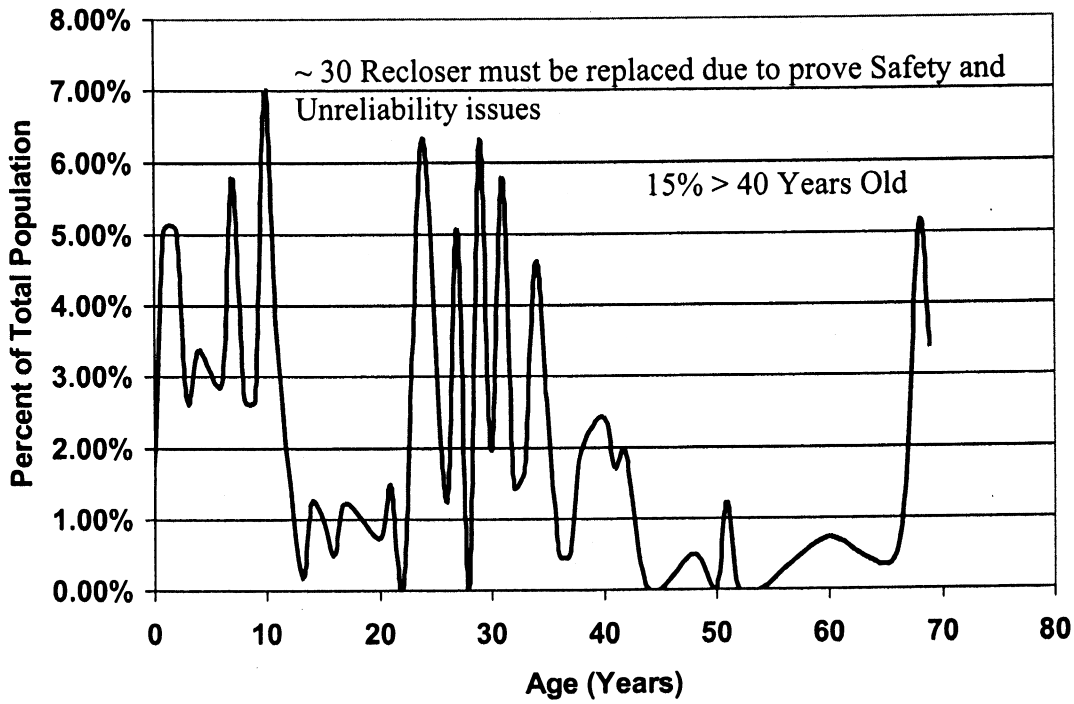
ER 2278 Distribution Reclosers

The Distribution Recloser AM Plan covers the Low Voltage Breakers and Reclosers installed in the substations and out on the various feeders throughout our system. Switchgear or metalclad circuit breakers used in the distribution system are not covered by this program and are included in the Switchgear AM plan. Reclosers and Low Voltage Circuit Breakers provide isolation and protection to a feeder or a portion of a feeder and in the case of a Recloser, they provide restoration of a momentary fault. Our system has ~415 Substation Reclosers or Low Voltage Circuit Breakers and ~145 Feeder Reclosers. From Figure 9, we can see that only a small portion of our Reclosers/Low Voltage Circuit breakers, but as shown in these figures, a significant portion of our Reclosers will become > 40 years old and begin to reach their end of life.

For substations, we have been maintaining Reclosers for several years and have an ongoing maintenance program for them. The current program attempts to perform maintenance on these devices once every 10 years, but due to resources constraints, it has not always been achieved. The change to the maintenance proposed here is to go to a 13 year maintenance cycle on the older Vacuum style Reclosers and on all of the Oil style Reclosers. We will continue to refurbish Reclosers as they fail or come into the shop for other reasons. However, the older Reclosers, usually older than 45 years old, that no longer can be refurbish will require inspection every 5 years until they are replaced. As an additional part of the program, 60 old style Reclosers will be replaced on a planned basis because they are old, spare parts are no longer available and have reached their end of life. The planned replacements include 6 per year over a 5 year period. The new style of Vacuum type Reclosers cannot be refurbished but can only have the mechanical linkages lubricated and a few components replaced, so their maintenance cycle is recommended to be 5 years. Over the next 10 years we anticipate the following parts use based on this program:

- 35 refurbished Reclosers
- 5 new Reclosers
- 60 Planned Replacements

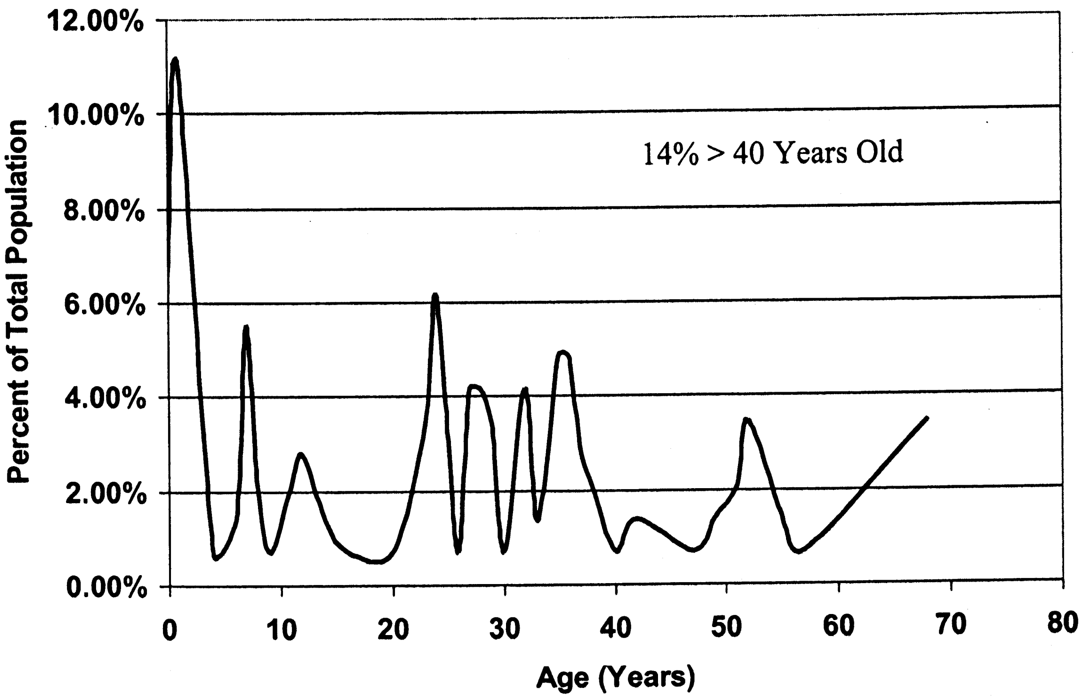
Figure 9, Substation Reclosers & Low Voltage Circuit Breaker Age Profile



For the Feeder Reclosers, no maintenance or planned replacement is recommended over the next 10 years. Feeder Reclosers are not easily accessible as in a substation, so any maintenance on them is equivalent to a planned replacement. Our analysis indicates that any planned replacement program is not cost effective for our customers. Further analysis will be performed to ensure this is the correct approach, but until information is available, no change in our current approach is recommended. Over the next 10 years we anticipate the following parts use based on this program:

- 15 refurbished Reclosers
- 7 new Reclosers

Figure 10, Feeder Reclosers Age Profile



This program will used existing resources and reflects a slight drop in the labor requirements. On average, we will need 1,800 man-hours from Substation Electricians, 60 man-hours from Relay Technicians, and 90 man-hours of Linemen's time each year to manage Reclosers. The budget requirements for Substations is in Table 8 and for Distribution, the budget is in Table 9.

Table 8, Substation Recloser Budgets

Year	Capital Costs	O&M Costs
2009	$351,000	$93,000
2010	$362,000	$95,000
2011	$376,000	$87,000
2012	$389,000	$91,000
2013	$405,000	$74,000

Table 9, Distribution Recloser Budgets

Year	Capital Costs	O&M Costs
2009	$35,000	$3,000
2010	$36,000	$3,000
2011	$37,000	$3,000
2012	$41,000	$4,000
2013	$44,000	$4,000

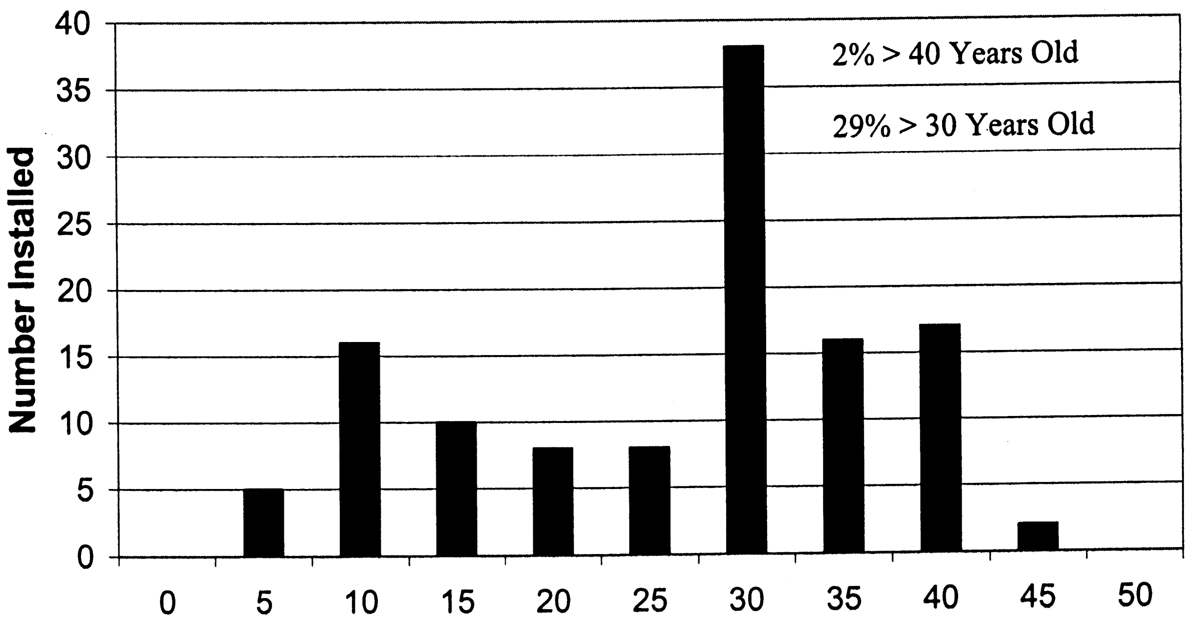
This program is only a small change from our current program and only reduces our maintenance requirements by a small percentage. The benefits of the program come in the out years as the system begins to age further and starts to really benefit our customers out in 2014. Compared to our current case, it has an Internal Rate of Return to our customers of 8.8% due to their avoided costs associated with power outages and durations.

ER 2280 Substation Circuit Switchers

Substation Circuit Switchers are used like Circuit Breakers in a Substation to provide isolation and protection for Substation Transformers and is located on the High Voltage side of the transformer. Some Circuit switchers are used to control capacitor banks in larger substation that provide voltage support on the system. They are normally located on smaller and more rural type of substations except when they are used to control capacitor banks.
Figure 11 shows the age profile for our approximately 120 Circuit Switchers used throughout our system.

Figure 11, Substation Circuit Switcher Age Profile

Substation Circuit Switchers



Our revised plan is to perform periodic testing, inspection, and maintenance on the Circuit Switchers to ensure their timing of operations are within specifications, lubricate the mechanical linkages, and identify when a Circuit Switcher must be replaced. Circuit Switchers are also inspected as part of the month Substation Inspection Program that identifies when a Circuit Switcher's Interrupter does not have enough SF_6 gas for future operations and must be replaced or refilled with gas depending upon the design. The program outlines an inspection program that is time based and varies with the age of the Circuit Switcher. The inspection cycle varies from 11 years for a new one and reduces to a 5 year cycle for the oldest circuit switchers. This will result in approximately 20 Circuit Switcher Inspects per year. Based on the inspections, we anticipate that 2 Circuit Switcher Interrupters will need to be replaced each year, and two new Circuit Switchers will be needed to replace old ones over then next 10 years.

This work will be performed by our own workforce since it is performed inside our existing substations.
Table 10 shows the Capital and O&M Budget projects for the work. The resources needed are 600 man-hours of Electrician and 200 man-hours of Relay Technician support to complete on average each year.

The benefits of this program come from several areas. The program is anticipated to save ~$45,000 annually in O&M costs and ~$16,000 in Capital costs during the first 10 years by reducing the number of unplanned outages and extending the life of the existing equipment. Compared to the current case, the planned maintenance case has an Internal Rate of Return of 10% and saves our customers ~$180,000 in avoided costs due to outages.

Table 10, Circuit Switcher Budget Projections

5 Year Budget		
Year	Capital	O&M
2009	$67,000	$104,000
2010	$0	$108,000
2011	$0	$112,000
2012	$0	$116,000
2013	$0	$120,000

ER's 1006/2000/2336/2357 Power Transformers

Avista's Power Transformer plan covers the large transformers used in the substation to change the power from Transmission voltage levels to distribution level voltage or Autotransformers used to control high voltage levels also located in some substations. For Power Transformers, Avista's system has approximately 175 and an additional 27 Autotransformers. From Figure 12, 26% of Avista's Power Transformers are over 40 years old, but for the Autotransformers, only 2% are more than 40 years old (see Figure 13).

The current Asset Management maintenance and inspection plan is fully described in "Avista Utilities Transmission Maintenance Inspection Plan." In addition, Avista has identified old transformers that based on their age and lower efficiency compared to new transformers should be replaced on a planned basis. Based on this assessment, Avista anticipates replacing one to two transformers per year based on condition and cost savings due to improved efficiency.

This work will require a projected budget shown in Table 11. The labor to complete the work on an annual basis is described below. Some other resource will be required based on different circumstances, but the following represent the average anticipated labor needs.

- Electricians – 860 man-hours
- Lineman – 20 man-hours
- Relay Technician – 100 man-hours

For installing and removing the mobile substation annually, Avista projects we will us the following additional resources:

- Electricians – 400 man-hours
- Communications Technician – 15 man-hours
- Equipment Operator – 50 man-hours
- Substation Engineer – 40 man-hours

Figure 12, Power Transformer's Age Profile

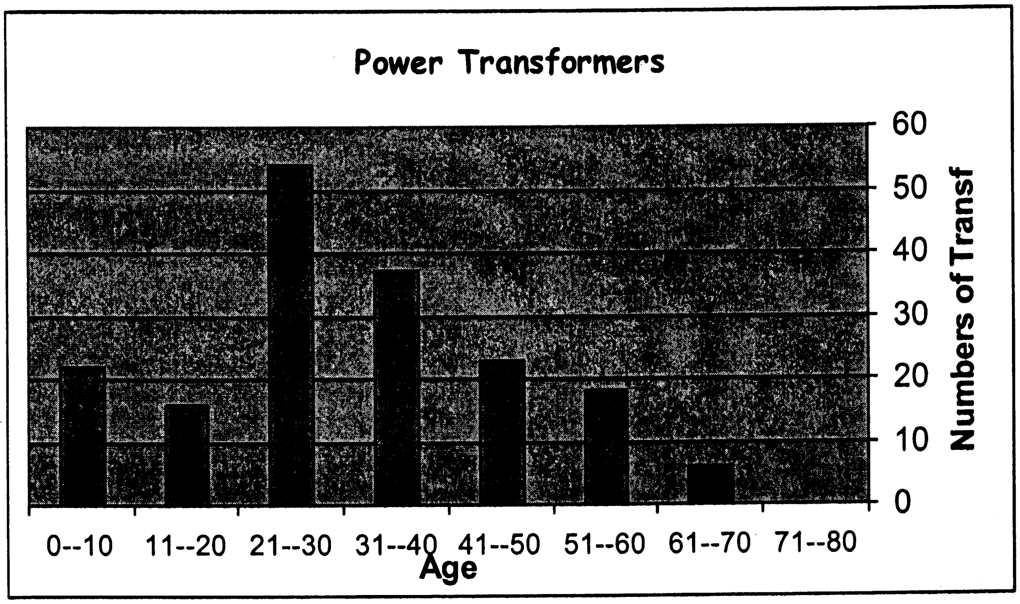


Figure 13, Autotransformer's Age Profile

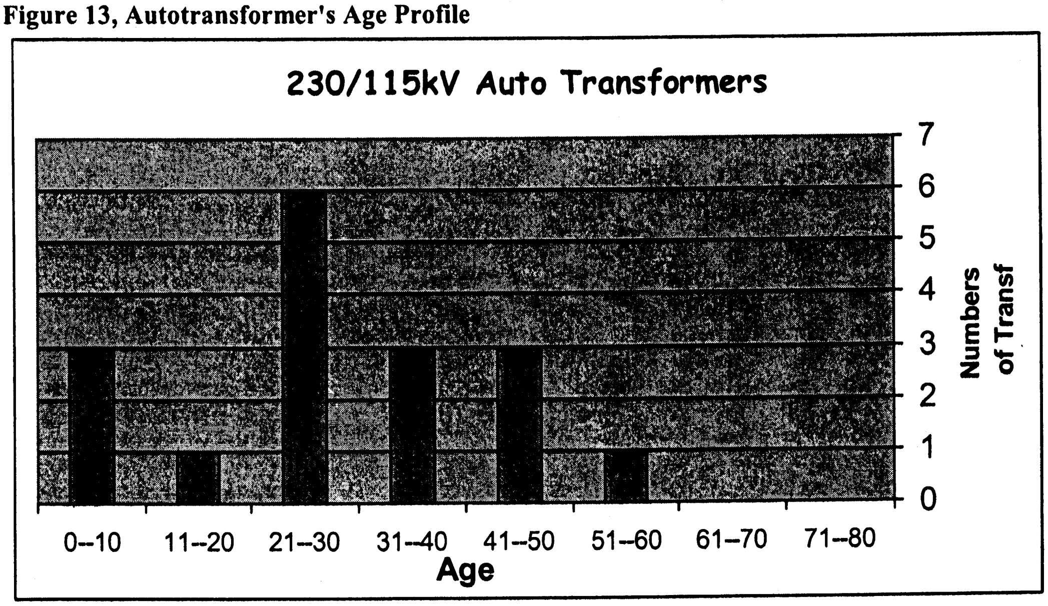
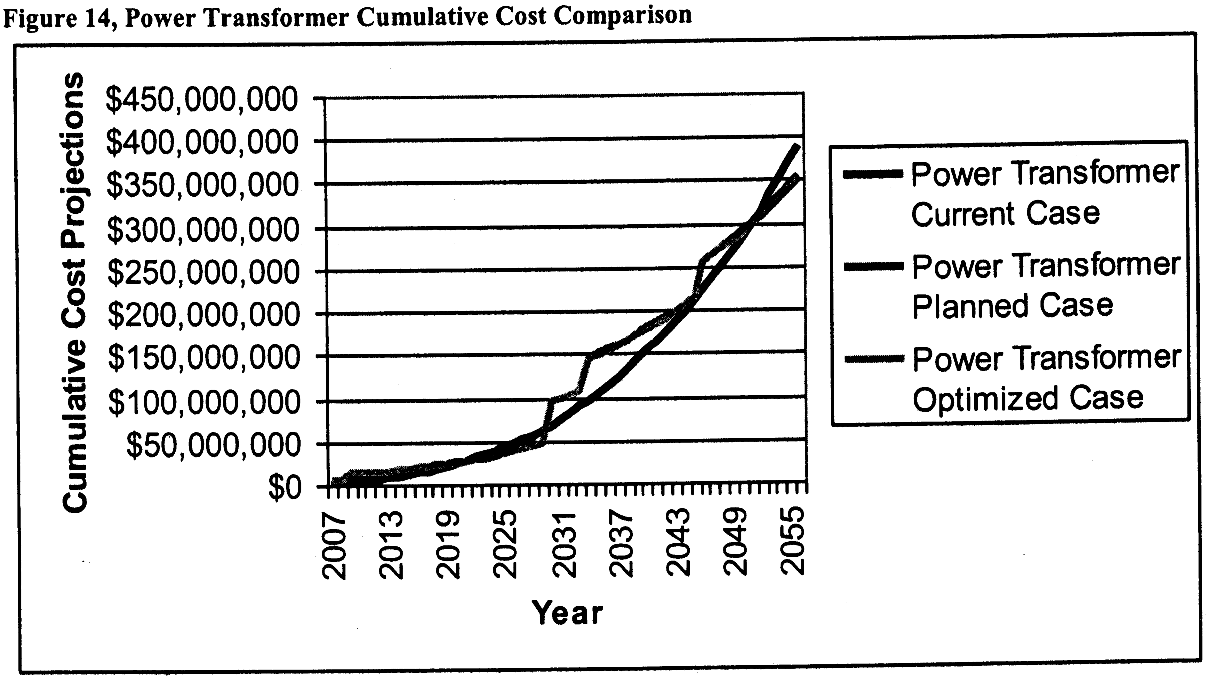


Table 11, Power Transformer Projected Budgets

Year	Capital Costs	O&M Costs
2009	$1,176,000	$40,000
2010	$1,290,000	$42,000
2011	$1,398,000	$43,000
2012	$1,554,000	$45,000
2013	$1,674,000	$46,000
2014	$1,842,000	$48,000

More than 26% of Avista's Substation Transformers are over 40 years old. Replacing them would save an anticipated average of $15,000 per year per transformer through improved efficiency. The combined factors of improving efficiency and age justify a planned replacement of old and inefficient transformers. The overall savings impacts are show in the cumulative cost comparison shown below in Figure 14. Based on the analysis, other options would save money in the future, but not enough to change from our current case.

Figure 14, Power Transformer Cumulative Cost Comparison



ER 2204 System Wood Substation Rebuilds

This ER addresses capital work for substations built with wood timber frame construction. This type of construction utilizes wood poles for vertical structure and treated timbers for horizontal structural components.

There are at least 56 substations in the Avista system that are either all wood or have a major portion of framework that is wood. This count includes installations with significant horizontal structural wood framing. Take off poles, etc, are not included.

The analysis of examines on two complimentary failure/repair scenarios: (1) the substation requires complete rebuild due to poor condition of the wood structure or (2) individual structural timbers can be replaced to extend overall station life. These scenarios are complimentary in that timely inspection and replacement of individual timbers reduces the need for complete rebuilds.

In reality, a further consideration in the decision between these alternatives is the condition of substation components such as insulators and switches. The analysis accounts for this factor indirectly. The study utilizes a statistical curve derived from the historical age of wood substations that have been replaced during the last 20 years. Expert opinion of personnel employed in the Substation Design Group indicates that there is no doubt that structure replacement was necessary in these cases; additionally, a heavily weighted factor in the decision process is the age, condition and maintainability of other substation equipment.

The data set used in the statistical analysis of whole substation replacement ages included those substations rebuilt primarily due to structural reasons. Wood construction substations that were replaced due to capacity upgrades were excluded.

Statistical analysis using the Weibull function regarding the wholly replaced substations yields 65 years as the characteristic life. This curve may be manually adjusted to account for the influence of substation equipment in the decision process. The manual adjustment can also account for structural component replacement that has occurred in the past and has the effect of having extended substation structure usable life.

Adjustment of the curve can then bring results of analysis into a closer match with inspection observations of condition. Analysis and comparison with inspections is indicating an adjustment to bring the characteristic life value to 72 years from 65 years. This value is about 10 years lower than transmission wood pole life cycle analysis results.

A data set used for individual timbers was estimated by a count of timbers observed to be failed during inspections. Failure in this case is defined as visible structural deterioration. Also included in the timber replacement data set is an estimated count and estimated age of previously replaced timbers; i.e., replaced prior to inspections conducted during 2007.

The Weibull curve resulting from estimates regarding the timbers is unsatisfactory. It is widely agreed that timbers, on average, last at most 2/3 as long as a large wood pole. Many timbers have been replaced via maintenance activities that are lost as data points. We are not confident in the visual estimates of age accomplished to date regarding the horizontal timbers.

We are utilizing a failure curve for the horizontal members relying heavily on information gathered during the Wood Pole Management analysis. It is generally agreed that the life of a cross-arm is, at most, about two-thirds the life of a wood pole. The small amount of information gathered on the substation horizontal member had given a characteristic life not much shorter than the substation. The curve was manually manipulated to match the two thirds value for component characteristic life versus the substation overall failure curve.

An informal survey was done via input from area engineers, line personnel, and the electricians who conduct monthly substation inspections. This survey generated a ranked listing by condition of the wood frame substations. An engineer from Substation Engineering and an Asset Management engineer then inspected the 12 substations that ranked worst through the informal survey.

The inspections indicate that 2 of the worst 12 substations should be replaced as soon as possible. Deterioration was extensive enough that intermediate rebuilding of select portions of the substations is not feasible.

Of the remaining substations inspected a majority would benefit from select replacement of timber framing. Several do not need immediate attention.

Title		IRR	Net Levelized Req Savings	Estimated Rate Impact	Levelized Annual Cost
COMPARE: Wood Substations [w/o effects, With Inspection and PM plan] vs. [w/o effects, w/o Inspection and PM plan]		9.42%	$350,307	-0.047%	$1,103,142
COMPARE: Wood Substations [w/ effects, With Inspection and PM plan] vs. [w/ effects, w/o Inspection and PM plan]		10.16%	$442,462	-0.059%	$1,119,341

Table 12, Wood Substation Rebuild Results - ER 2204

20 Year Results	Total Cost Capital, O&M, Consequences, Installation	Predicted Replacements	Average Annual Capital Budget
No Program, Respond with replacements as necessary only	$26,800,000	23 Replacements	$1,130,000
Proactive, Inspections, Minor Rebuilds, Replace per statistical predictions	$14,100,000	13 Replacements 30 Minor Rebuilds	$683,000
Savings	$12,700,000		(-$447,000)

ER 2252 System - Obsolete Protective Relays

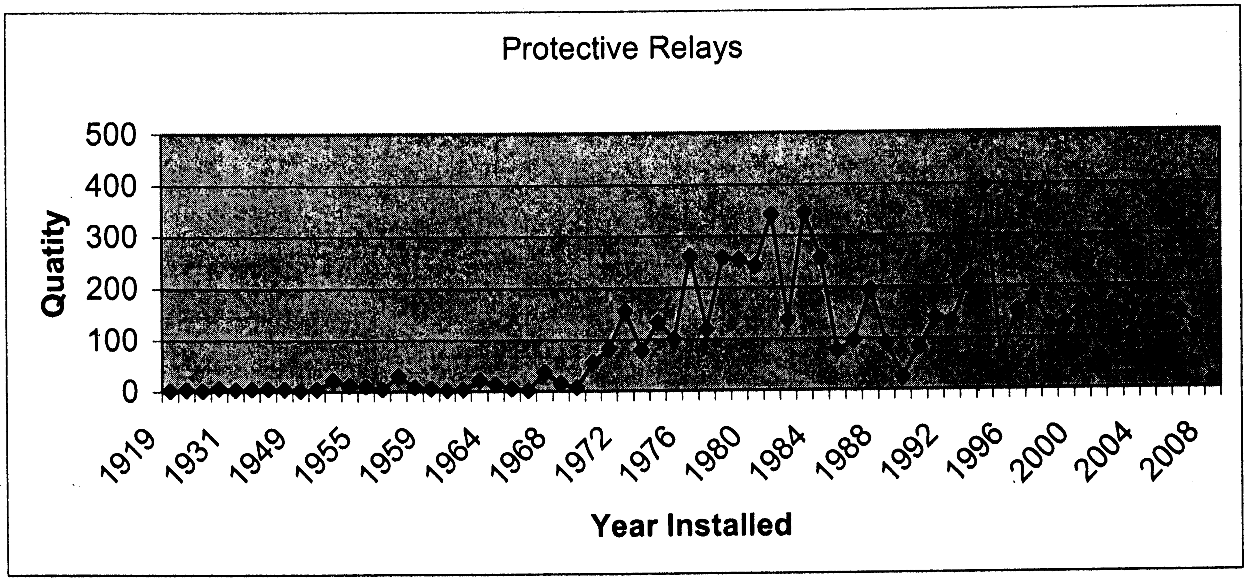
Maintenance/replacement of protective relays is one of the most complex single areas Asset Management has analyzed. The complexity stems from the many types of faults and subsequent differing levels of impact to the system that can result from relay failure or miss-operation.

Industry data regarding the age related life cycle performance of protective relays is virtually non-existent. However, Avista has maintained a log of relay operations that was helpful in the analysis of miss-operation and failure to operate probabilities. The input of the Protection Group staff was invaluable; their combined decades of experience made the conclusions possible.

Traditional protective relaying installations are comprised of multiple devices which work together to protect personnel and equipment during a multitude of fault and system conditions. The Asset Management studies modeled this multi-component architecture as "relay groups"; i.e., a transmission line circuit breaker might be called upon to operate by any of a half-dozen different components but performance is characterized as action of a single protective system.

Modern protective relay hardware technology takes advantage of micro-processors to eliminate the need for multiple hardware devices. Many functions can now be accomplished by a single integrated device. Additionally, the new devices have remote alarm capabilities to alert operators of internal problems before system conditions might require relay operation. With the alarm function it is possible to double the inspection, calibration and test cycles versus older technology.

There are more than 6400 separate relay hardware items listed in the database maintained by the Avista Protection Group. The age distribution of these devices is shown in the graph below.



Two relay replacement strategies were studied: (1) replace all remaining electro-mechanical relays with microprocessor technology and (2) (a subset of (1)), replace electro-mechanical relays that support transmission lines and major substation equipment with microprocessor technology.

The following table documents the results from the Revenue Resource Requirement Model for the two alternatives. Option (2) from the paragraph above is referred to as "PRI UPGRADED" as an abbreviation to priority upgrades in the table below. "UPGRADED" is the option of replacement of all remaining electromechanical relays with current technology.

Title	IRR	Net Levelized Req Savings	Estimated Rate Impact	Avg Annual Capital Cost	Avg Annual O&M Costs
Relays, AS-IS w/ effects vs. UPGRADED w/ effects & w construction	7.65%	$158,968	-0.021%	$1,229,922	$1,299,045
Relays, UPGRADED w/ effects & const vs. As-Is w/ effects	7.22%	-$42,895	0.006%	$1,369,597	$980,527

Relays, UPGRADED w/o effects and w/ const vs. As-Is w/o effects	6.11%	-$443,386	0.059%	$1,369,597	$27,351
Relays, PRI UPGRADED w effects and w/ const vs. As-Is w effects	7.46%	$75,382	-0.010%	$1,114,409	$1,273,684
Relays, PRI UPGRADED w/o effects and w/ const vs. As-Is w/o effects	7.44%	$38,969	-0.005%	$1,114,409	$281,914

The estimated cost to accomplish the upgrade to priority transmission and substation equipment relaying is $15 million. Most distribution level relay upgrades are best accomplished in conjunction with recloser replacement. The cost of relay work for reclosers is included in that project's estimate.

The comparison results of the alternatives are extremely close. The overriding factors brought up time and again in favor of the replacement are difficulty of repair and the appreciable improvement in hardware technology. Especially on transmission and substation equipment relays, there is a growing unavailability of repair parts and difficulty in reliably repairing the older hardware. The alarm feature of the new hardware is a great advantage; at this time, an older EM relay might be tested or repaired, then suffer a component failure that would go undetected until failing when it was required to operate.

ER 2425 Substation High Voltage Fuse Replacements

About 60 of our smaller substations use power fuses to provide protection for substation transformers instead of relays. Of these 60 substations, 18 have High Voltage Power Fuses that are no longer rated to handle the currently available maximum fault currents and 14 of this group average about 50 years old and no longer have spare parts. Approximately, 21% are more than 40 years old. Four of the substations have a fault duty current that exceeds all types of fuses and must be replaced by a Circuit Switcher.
Figure 15 shows an estimated age of the Power Fuses based on the age of the substation.

Based on Avista's analysis, Power Fuses should also be replaced every 40 years, because they become unreliable and not supported with spare parts. The Power Fuse AM Plan will replace an average of 5 fuse installations each year until 18 underrated Power Fuses are removed from the system. Those requiring a Circuit Switcher will be replaced at the end of the replacement of the 18 underrated Power Fuses. Once all of the underrated fuses have been replaced, Avista will continue to replace the remaining as they reach approximately 40 years of age or are no longer supported with spare parts.

Figure 15, Power Fuse Age Profile Estimate

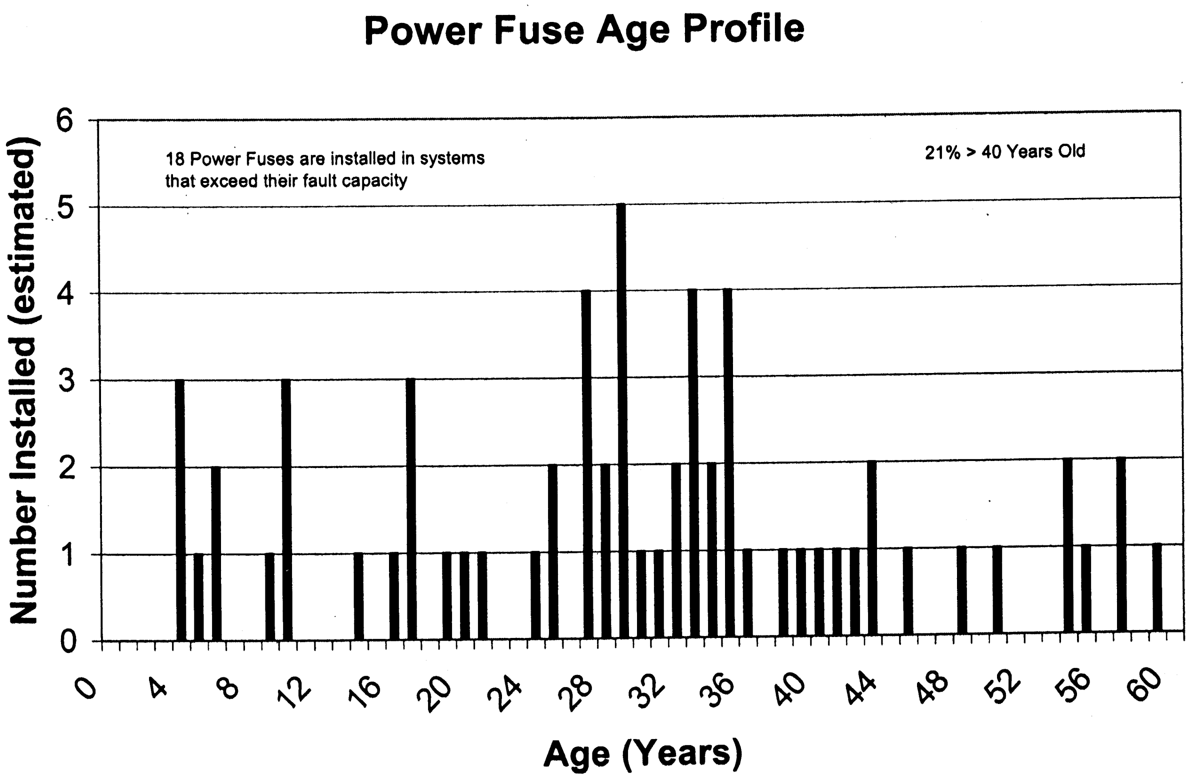
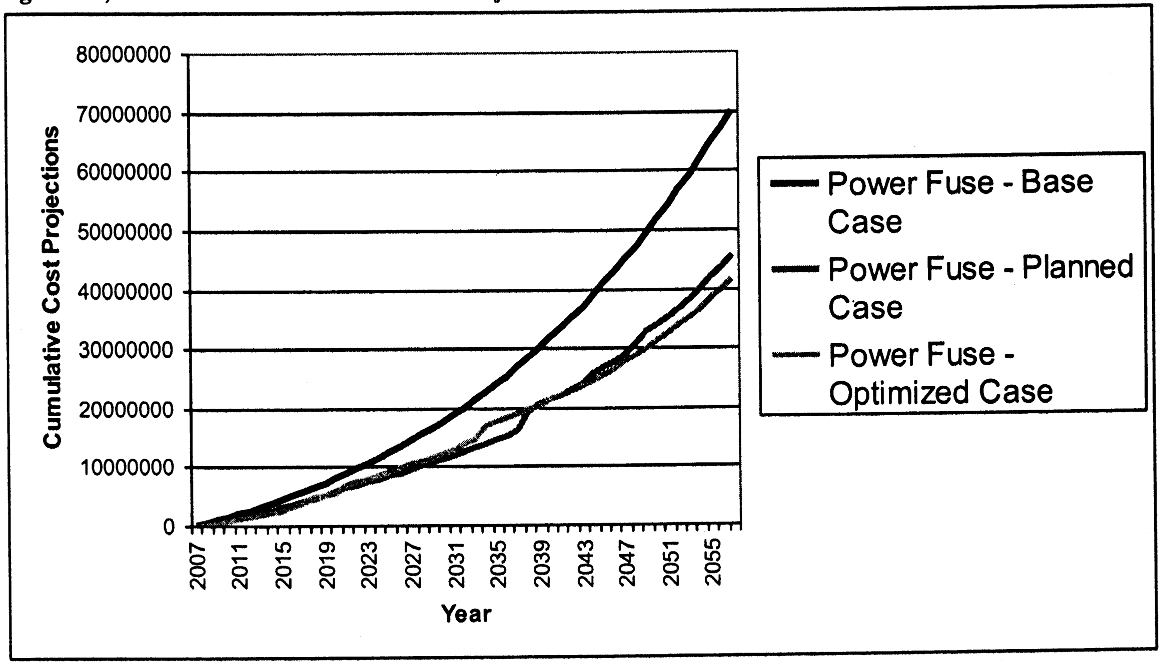


Figure 16, Power Fuse Cumulative Cost Projections



The resources required to complete the work is shown in Table 13, Power Fuse Replacement Capital Budget Projections. The labor resources require are listed below:

- Substation Engineer – 50 man-hours
- Substation Electrician – 210 man-hours
- Linemen – 60 man-hours

For installing and removing the mobile substation annually to support the work, Avista projects we will us the following additional resources:

- Electricians – 600 man-hours
- Communications Technician – 20 man-hours
- Equipment Operator – 75 man-hours
- Substation Engineer – 60 man-hours

The benefits of this program includes improved reliability due to replacing these unreliable Power Fuses with new and more reliable fuses and greatly reducing the risk of damaging the Power Transformer the fuse tries to protect. Avista estimates that the plan will save our customers approximately $55,000 per year in avoided costs due to power outages caused by Power Fuse failure. Figure 16 shows the cumulative cost benefit of the planned replacement program.

Table 13, Power Fuse Replacement Capital Budget Projections

Year	Capital Costs
2009	$297,000
2010	$275,333
2011	$253,571
2012	$237,875
2013	$220,556

ER 2294 System - Batteries

This budget item covers the replacement and maintenance on all Substation batteries. The range of batteries covers from 24 vdc to 125 vdc and can be located in battery rooms or specific equipment. We analyzed not only the capital budget needs, but also the O&M Budget needs to develop the budget requirements shown in Table 14, Substation Battery Budget Projections. However, a decision was made to put the analysis on these batteries on hold until a batteryman was in place and testing batteries before going ahead with any recommendations. So, the current budget requirements will be based on historical spending levels adjusted for inflation until further analysis has been completed.

Table 14, Substation Battery Budget Projections

Year	Capital Costs	O&M Costs
2009	$106,000	$181,000
2010	$115,000	$187,000
2011	$156,000	$193,000
2012	$113,000	$200,000
2013	$95,000	$207,000

ER 2416 System – Porcelain Cutout Replacements

A program was implemented in 2007 and scheduled to be completed in 2008 to replace all of the Chance cutouts in the system. This program should address the immediate issues with the broader category of Porcelain Cutouts. However, we anticipate the other styles of porcelain cutouts to start failing prematurely in the near future and have seem some early indication of this. However, until more data is gathered, we plan on monitoring the data and develop a new plan in the future when the information warrants another look.

ER 2449 System – Replace Substation Air Switches

This program covers the planned and unplanned replacement of Substation Air Switches. Air Switches used in the Transmission System located outside of a substation are covered by ER 2254 discussed above. The analysis used for this budget item was an earlier model and will need to be updated in the future if the need arises. However, we anticipated that the use of an integrated Substation analysis will provide future direction on what should be done to replace Substation Air Switches. The integrated approach will more accurately reflect the best opportunity to use a planned approach since are switches are best replaced when the substation is rebuilt or undergoing a major upgrade. Table 15, Sub Air Switches Projected Budget, provides the basis analysis and estimated needs to address Air Switches that fail each year.

Table 15, Sub Air Switches Projected Budget

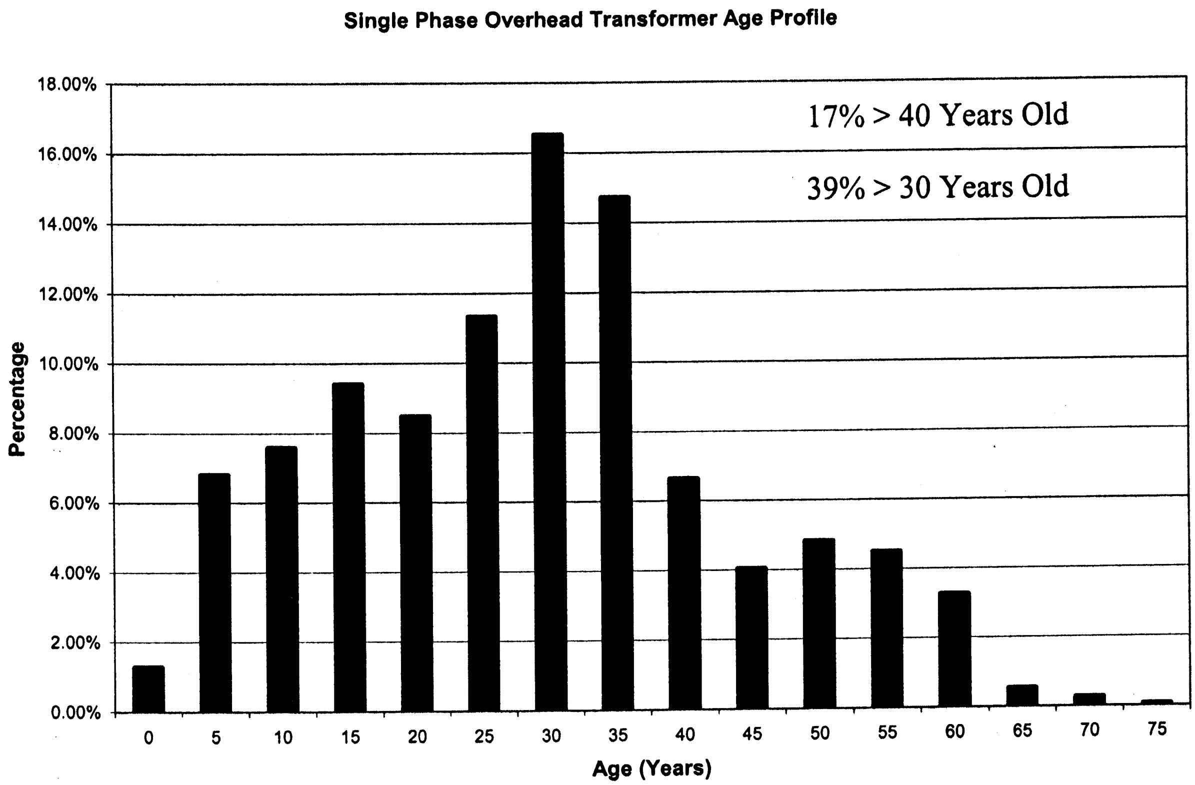
Year	Capital Costs
2009	$114,000
2010	$122,000
2011	$140,000
2012	$156,000
2013	$157,000

ER NEW Distribution Transformer Replacement

This program covers all of the Distribution Transformers on our Avista feeders that supply power to our customers. Specifically, the program replaces two sets of less efficient transformers based on their losses and age. The first set is all Distribution Transformers installed before 1960 and includes about 11,000 transformers that will be replaced over a five year period. The pre 1960 transformers have the largest no-load losses and are the oldest, so they will be the focus of the program first. All of the pre 1960 transformers are overhead transformers mounted on poles and their age profile is shown in

Figure 17. After the pre 1960 transformers are replaced, Avista will work to replace the pre 1980 transformers and includes about 42,000 transformers. The second batch of transformers has a mix of types that includes overhead transformers, pad-mounted transformers (see Figure 18 and for age profiles), and subsurface transformers (see Figure 20 for age profile). The replacement of the pre 1980 batch of transformers will also eliminate the last of the PCB Distribution Transformers from our system.

Figure 17, Overhead Single Phase Distribution Transformers Age Profile

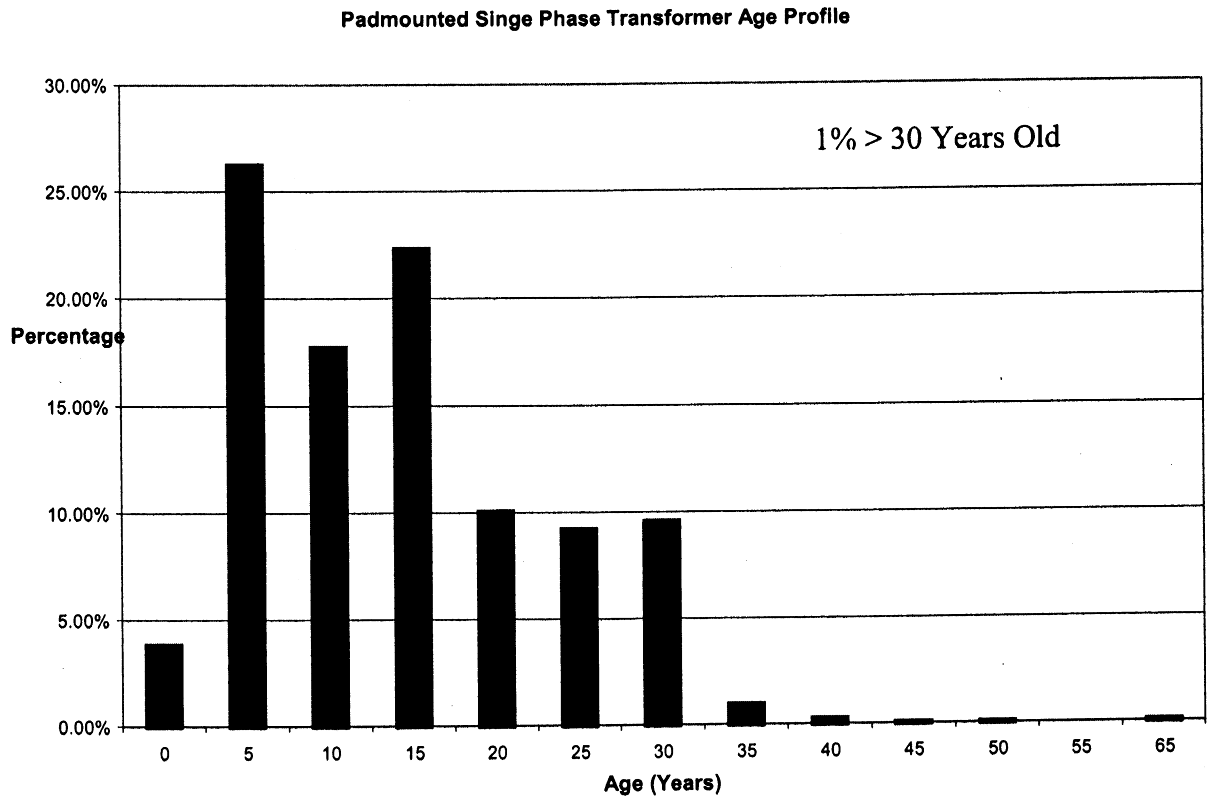


The planned approach to accomplish the transformer replacement is to use three man contract crews with support from one to two Customer Project Coordinators (CPC). The contract crews will work an average of 1,600 hours for five years and require 3,200 man-hours of CPC's time to support them. The budget for the work is shown in Table 16.

Table 16, Capital Budget Estimate for replacing pre-1960 Distribution Transformers

Year	5 Year Capital Budget
2009	$3,768,000
2010	$3,899,880
2011	$4,036,376
2012	$4,177,649
2013	$4,323,867

Figure 18, Padmounted Single Phase Distribution Transformers Age Profile



The benefits of the program come in two forms, reliability improvement and cost savings. Over 10 years, we anticipate that the program will reduce the number of Distribution Transformer outages by ~900 events. In energy savings, we anticipate replacing the pre 1960 transformers to save an average 15,300 aMWh or 1.75 MW of generation. Our customers will see a 10% Internal Rate of Return on this investment due to the reduced number of outages and especially from the power savings. After the pre 1980 Distribution Transformer are replaced, we anticipate an additional savings of an average 33,900 aMWh or 3.87 MW of generation. Figure 21 shows the cumulative costs of the alternatives and illustrates the potential savings over time due to planned replacement of the transformers.

Figure 19, Padmounted Three Phase Distribution Transformers Age Profile

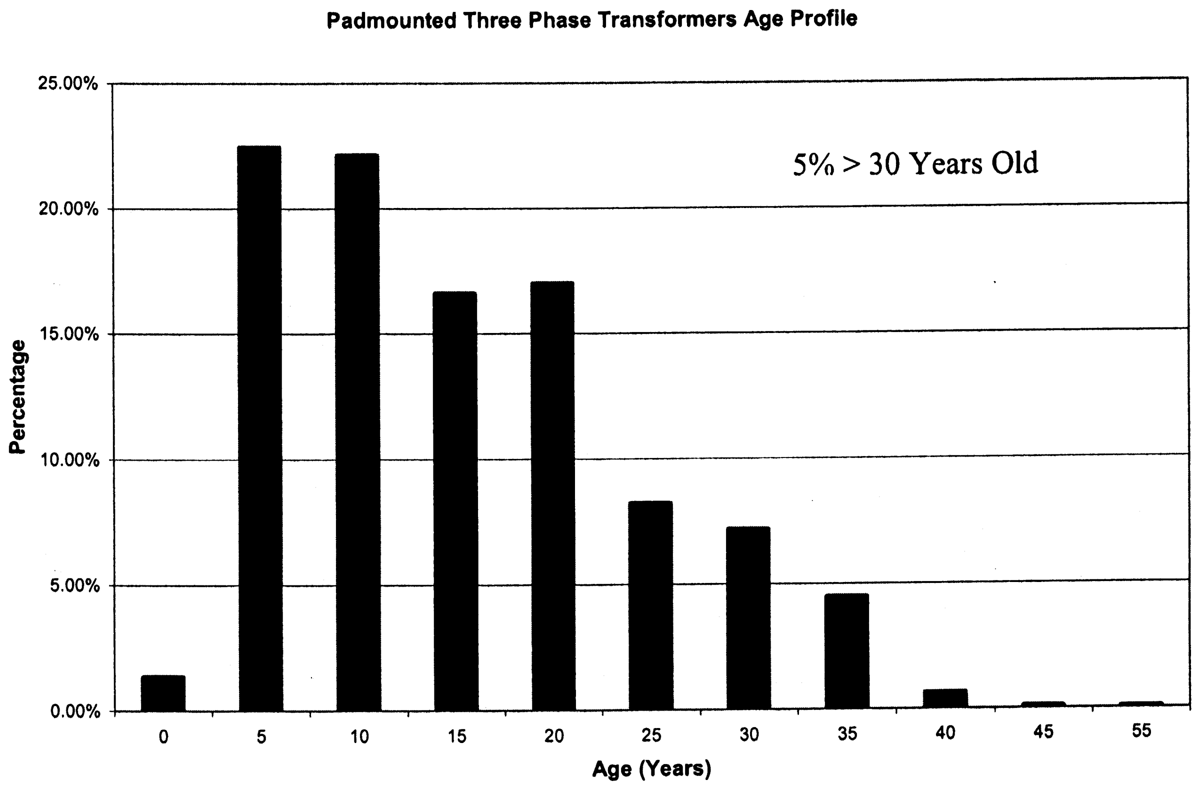


Figure 20, Subsurface Single Phase Distribution Transformers Age Profile

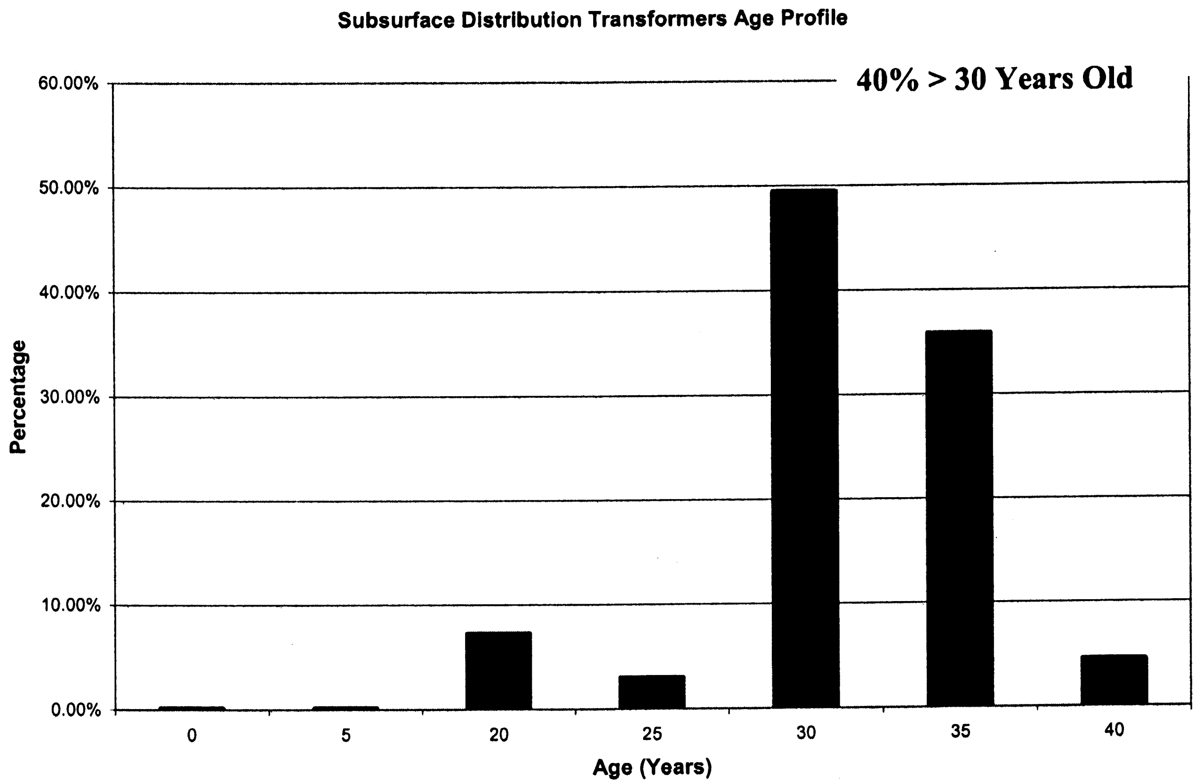
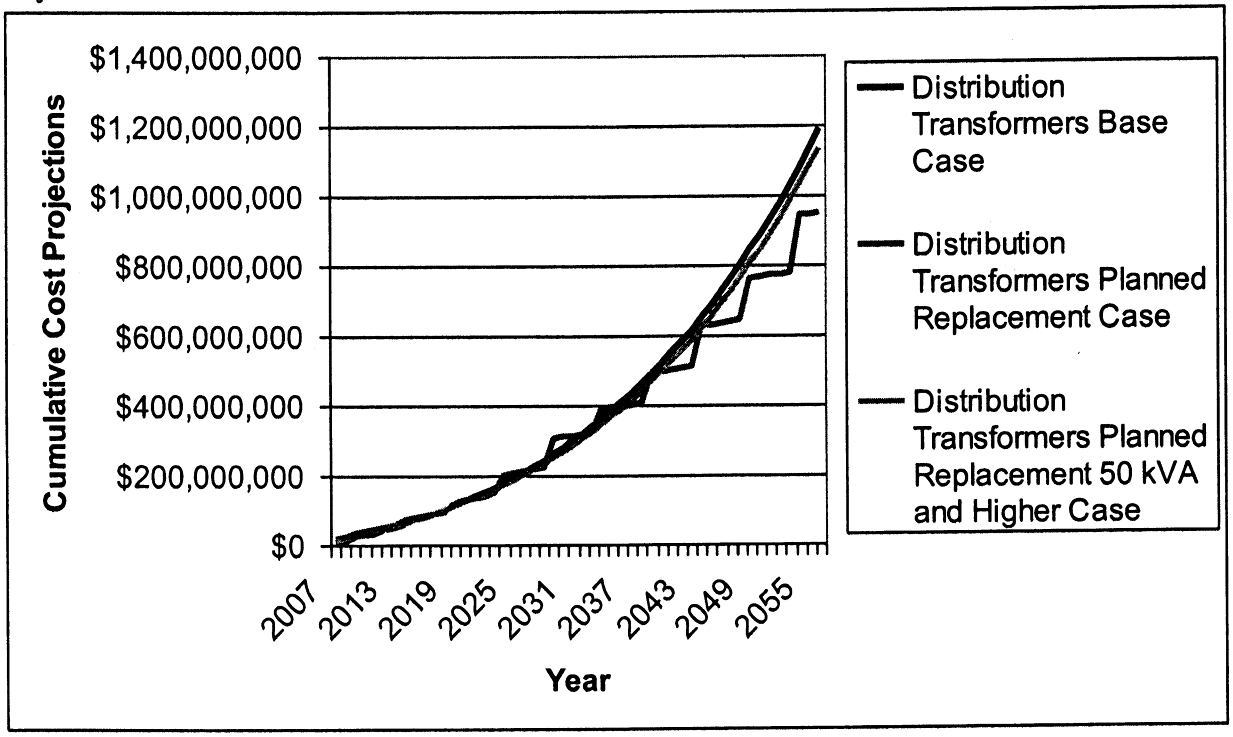


Figure 21, Distribution Transformer Cumulative Cost Projections



ER NEW?? Substation Voltage Regulators

The recently completed analysis indicates that our existing program is best approach overall. However, a more detailed analysis may reveal that specific types or applications may gain some benefit from a different approach. Further analysis will be performed in the future and we will continue to monitor their performance.

MAC 215 - 592550 Wildlife Guards

Wildlife caused outages have a significant impact on electric service reliability to customers. The improved outage tracking implemented in 2001 has consistently shown, within a percent or two either way, that animals cause 19% of outages experienced by electric customers. While generally short in duration, labor impacts to respond are significant.

The need for wildlife guards exists for both bird and squirrel outages. Squirrel outages are more widespread and present a picture that allows quantification of the problem magnitude.

The tables below show the impact of squirrel caused outages occurring on approximately one-fifth (63 out of 325) of the Avista distribution feeders versus the total squirrel caused outages in the system. The benchmark of feeders having had 30 documented squirrel caused outages from 2001 through 2007 was chosen to illustrate how these feeders account for more than half of document squirrel caused outages.

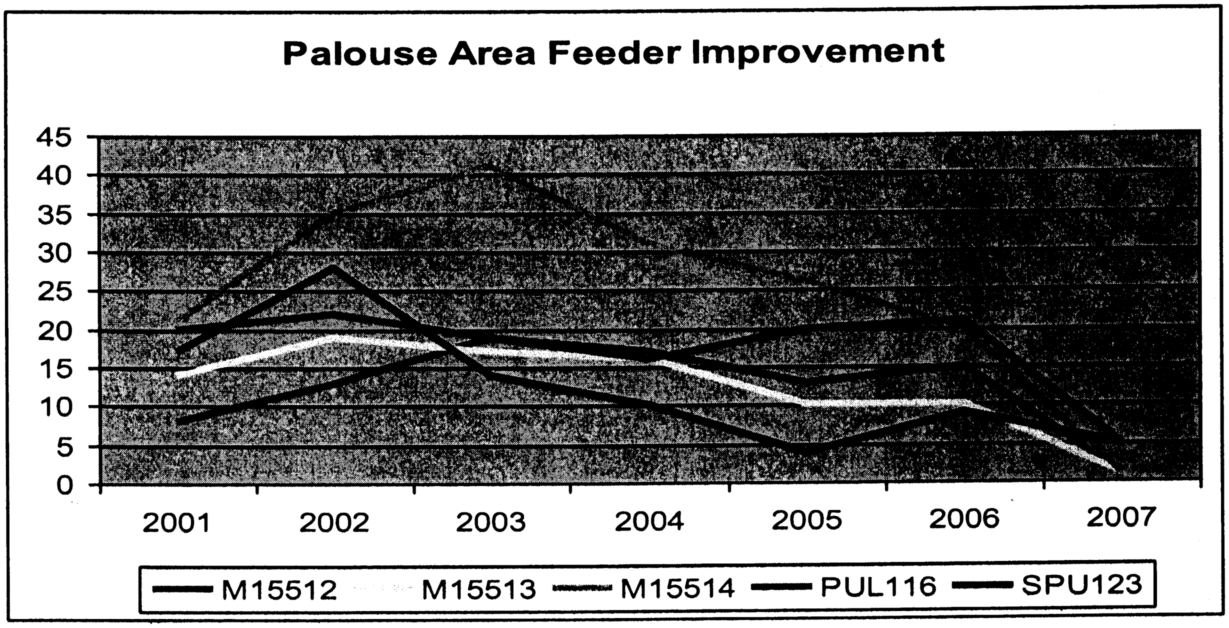
total sq outages per year for feeders >30	
Year	SumOfOutages
2001	490
2002	562
2003	482
2004	384
2005	408
2006	496
2007	415

sq outages total by year	
Year	SumOfOutages
2001	800
2002	815
2003	819
2004	654
2005	711
2006	889
2007	775

A relevant statistic that cannot be quantified is what proportion of outages is caused by squirrels and birds but evidence of the outage cause is not found. There were 852 <u>sustained</u> outages with undetermined cause during 2007. Estimating that 20% of undetermined outages are caused by animals raises the impact of squirrel caused outages to between 900 and 1000 per year throughout the system.

Momentary outages have not been included in cost impact of animal caused outages. There are 11,135 documented momentary outages between 2001 and March, 2008. Of these, 329 are annotated as being squirrel or bird caused and 4,723 momentary outages are undetermined cause.

Several feeders located in the Palouse Area were historically among the worst feeders in the Avista territory for animal caused outages. The graph below indicates the effectiveness of squirrel guards in preventing outages. Feeders that were having as many as 9 outages during a summer month had outages reduced to zero once guard installation was complete.



The proposed initial program for wildlife guards involves installation of guards on 60 feeders. These 60 feeders account for almost exactly half of documented animal caused outages.

IRR information is furnished in table below as calculated with the Revenue Resource Requirement model.

Without Effects: H:\2008 AM studies dan_w\Squirrels\financials\sq guards cost profile for REV REQ.xls		21.82%	$222,071	-0.030%	$93,728	installation of squirrel guards on 60 worst performing feeders for animal outages. Assumes 90% effectiveness for squirrel guards. Labor cost of base case is equivalent to 400 outages per year. Effects such as outage cost to customer is not considered, economic analysis is based on avoided cost of response to squirrel caused outage versus cost of squirrel guard installation is comparison.
With Effects : [H:\2008 AM studies dan_w\Squirrels\financials\cost profile_base case.xls] versus H:\2008 AM studies dan_w\Squirrels\financials\cost profile_with guards.xls]		35.45%	$441,659	-0.059%	$104,292	

Estimated cost of squirrel guard installation on the 60 worst performing feeders is $1.6 million to $1.8 million.

Replacement Projects Historical Spend

2006 - 2008

		2006 ACTUAL	2007 ACTUAL	2008 ACTUAL	2009 COSTS
2051	Transmission Minor Blanket	$1,025,283.94	$878,849.50	$961,301.35	$469,000.00
2054	Electric Underground Replacement	$1,059,349.90	$3,031,835.74	$3,296,005.83	$3,160,000.00
2055	Electric Distribution Minor Blanket	$5,028,755.56	$7,300,764.15	$8,773,170.59	$7,920,000.00
2056	T&D Line Relocation	$3,044,293.16	$1,380,400.69	$1,956,418.02	$2,300,000.00
2057	Transmission Minor Rebuild	$441,242.64	$442,214.46	$458,441.68	$600,000.00
2058	Spokane Electric Network Incr Capacity	$1,243,060.47	$1,480,972.57	$1,483,738.94	$1,610,000.00
2059	Failed Electric Plant-Unknown	$2,272,650.70	$1,633,442.85	$2,373,774.59	$1,990,000.00
2060	Wood Pole Mgmt	$1,085,406.03	$1,968,436.93	$4,749,914.92	$3,700,000.00
2254	System 115kV Air Switch Upgrade	$115,934.44	$75,609.62	$111,256.59	$160,000.00
2260	System-Upgrade Surge Protection	$7,361.37	$58,780.91	$4,174.22	$178,000.00
2275	System-Rock/Fence Restore	$1.32	$1.56	$28,309.97	$50,000.00
2278	System-Replace Obsolete Reclosers	$103,283.09	$245,400.21	$287,106.71	$372,000.00
2280	System Replace Obsolete Circuit Switch	$17,276.51	$73,922.50	$2.70	$300,000.00
2294	System-Batteries	$53,623.79	$116,732.80	$234,721.17	$250,000.00
2416	System-Porcelain Cutout Replacement	$349,569.02	$618,844.61	$224,518.16	$362,000.00
2425	High Voltage Fuse Upgrades		$2,180.73	$116,873.75	$268,000.00
2449	System - Replace Substation Air Switches			$258,842.98	$114,000.00

Mar 2, 2009

	A	B	C	D	E	F	G	H	I
1	Budget 2009 Calculation		Work Order	M08		date:	10-07-2008		
2	C	5				Capital Spend not in Service			
3	ER	BI	Title						
4	2467	KS800	Burke 115 kV Line Relay Upgrade	RC	Rate	MD	MD UL	MD LL	MD Travel *
5			ENGR - Substation	M08	401	35	14,035	22,094	[redacted]
6			ENGR - Real Estate	V08	280		0	0	
7			ENGR - Protection	A08	425	15	6,375	10,036	
8			ENGR - Drafting	N08	200	25	5,000	7,871	
9			ENGR - Communication	B09	389	20	7,780	12,247	
10			ENGR - Const Supv (Proj M)	T08	397		0	0	
11			CNST - Electric Crew	F08	282	160	45,120	71,028	
12			CNST - Relay Crew	X08	324	25	8,100	12,751	
13			CNST - Structural Crew	F08	282	40	11,280	17,757	
14			CNST - Communication Tech	B09	304	20	6,080	9,571	
15			NONC - General	N07	234		0	0	
16								0	
17			Total Labor cost				103,770	163,355	0
18									
19			Transporation Loading (%)	5				8,168	
20			(1% - 5%) Equipment only)						
21			Total Labor & Transportation						
22								171,522	
23						loading (%)			
24		M08	Materials	152,232		8.00		164,411	
25		F08	EE Room & Board (MD * 97)	225	21825	0.00		21,825	
26		F08	Contract	0		0.00		0	
27			EE	0		0.00		0	
28			Sub total					357,758	
29			Job Type Loading						
30			Distribution; D30 = 8.55					0	
31			Transmission; D31 = 9.05	9.05				32,377	
32									
33			Sub Total					390,135	
34									
35			AFUDC =.008/mo					9,864	
36									
37			Job Total					400,000	
38			AFUDC Rate	8.22%	0.00685				
39			Budget plan amount						
40			Transformers						
41			PCBs						
42					AFUDC Calc				
43		Ln7	monthly distribution	Balance	Monthly	Cumulative			
44			Capital Spend not in Svc	0	0	0			
45		Jan	2,000	2,000	7	7			
46		Feb	2,000	4,000	21	27			
47		Mar	3,000	7,000	38	65	END	WAC 12/08	
48		Apr	15,000	22,000	99	164	Now	10/09	
49		May	45,000	67,000	305	469			
50		Jun	60,000	127,000	664	1,134			
51		Jul	140,000	267,000	1,349	2,483			
52		Aug	100,000	367,000	2,171	4,655			
53		Sept	15,000	382,000	2,565	7,220			
54		Oct	8,135	390,135	2,645	9,864			
55		Nov		390,135	0	0			
56		Dec		390,135	0	0	Reconciled?		
57		Total	390,135			9,864	YES		
58			md travel is included in MD		sub total	9,864			
59									
60									
61							rev	10.4.09	
62									
63									

Exhibit No. SJK-6

AVISTA Corp. CAPITAL PROJECT REQUEST FORM (CPR)

Approved 11/3/08 GH

Request Type	PROJECT
Preliminary	95505034

ER	Budget Cat	SERVICE CODE	PROJECT TITLE (30 CHARS)		LOCATION
2464	5 1	ED	LIB 12F3 #6 CU Reconductor	[redacted]	~~956~~ 955

PROJECT DESCRIPTION (250 CHARS)

Reconductor Liberty Lake 12F3 from #6CU overhead primary to 350 ALCN underground primary

APPROVED BUDGET		ORGANIZATION	B/I NUMBER	WMS (Y OR N)	RATE JURISDICTION
X	[redacted]	B50	SD802	Y	WA

BILLING	BILLING CONTACT	PROJECT START DATE
		01-01-2009

LONG NAME (INCLUDE PURPOSE AND NECESSITY - 240 CHARS)

Reconductor LIB 12F3 from #6CU OH primary to 350 ALCN UG primary. The #6CU overhead conductor is currently overloaded and is the main feeder trunk. The 350 ALCN will connect non-overloaded sections of the feeder trunk which are larger conductors.

[redacted]

CONSTRUCTION

	FERC 3XXXXX	ESTIMATED AMOUNT BY FERC NUMBER	AS BUILT AMOUNT BY FERC NUMBER
303110	300100	$4,000	
365110	364000	$36,000	
	365000	$33,000	
107120	366000	$62,000	
107130	367000	$90,000	
GROSS ADDITIONS		$225,000	

NET SALVAGE BY FERC (3XXXXX)

	FERC	AMOUNT	
108	364000	$10,000	
	365000	$15,000	
NET SALVAGE		$25,000	

Non Standard Work Breakdown Structure needed (Optional)

Total Construction Cost	$250,000
NOT REQUIRED	
BUDGET AUTHORIZATION	
PREVIOUSLY APPROVED	
THIS REQUEST	
TOTAL TO DATE	
BALANCE NOT APPROVED	

APPROVALS

SIGNATURE	DATE
Al Fisher *Al Fisher*	10-31-08
Don Kopczynski *Kopczynski*	

Project Contact	Shane Pacini	x2029

APPROVAL SIGNATURE(S) REQUIRED

- To $99,999 - Director
- $100,000-$499,999 - VP or GM Utility
- $500,000-$1,999,999 - Sr Vice President
- $2,000,000-$2,999,999 - CFO
- $3,000,000-$4,999,999 - President/COO
- $5,000,000-$9,999,999 - CEO
- Over $10,000,000 - Board Chair
- Out-of-Budget - Capital Budget Committee

[redacted]

Date Prepared:	10-27-2008

TOTAL COST OF PROJECT	$250,000

Date Work Completed	
Foreman/ Supervisor	