



# TRANSMISSION ASSET MANAGEMENT STRATEGY

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FY2014 – 2023

DECEMBER 2013

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*This asset strategy was prepared before BPA’s proposal to reduce costs. Spending levels in this document do not tie to proposed reductions. The strategy will be revised upon conclusion of the CIR and the IPR.*

## EXECUTIVE SUMMARY

### TRANSMISSION ASSET MANAGEMENT STRATEGY

The Bonneville Power Administration owns and manages about three-fourths of the Northwest region's high voltage transmission assets. This system spans approximately 300,000 square miles and includes more than 15,000 circuit miles of transmission lines and 299 substations. These assets deliver electric power, directly or indirectly, to a population of more than 12 million through four product categories.

- Transmission service to regional utilities and to commercial, industrial and other loads
- Generation and line and load interconnections
- Interregional transfers of capacity and energy
- Ancillary services, such as regulation and load following services

*Assets covered by this strategy:*

**Alternating Current Substations:** 298 Substations and ~32,000 major equipment categories

*Power Transformers and Reactors, Power Circuit Breakers, Circuit Switchers, DC Control Batteries and Chargers. Shunt Capacitors, Current Limiting Reactors, Instrument Transformers, Engine Generators, Surge Arrestors, Fuses, Disconnect Switches, Rigid Riser Replacement, Substation Grounding, Substation Bus and Structures, Low Voltage Station Auxiliary, Control Houses*

**Direct Current Substations:** Celilo Converter Station

*HVDC Converter Station, Static Var Compensators, Fixed Series Capacitor Banks, Thyristor Controlled Series Capacitor Bank*

**Control Center:** 2 Control Centers with 85 plus automation systems

*Real-time Grid control and management systems; Grid and data center monitoring, protection, and alarm systems; CC critical power infrastructure; Non-real-time operations analysis and support systems; Commercial Business Systems/facilities integration and support*

**Power System Control / Telecommunications:** 732 sites and ~ 11,000 pieces of equipment, 3,000 miles of fiber optic cable

*RAS, Transfer Trip, SCADA remote terminal units, Fiber cable, Comm batteries/chargers, SONENT/MW Radios, VHF/mobile/portable radios, UHF, DATS, Multiplex, Power Line Carrier, Telemetry, Operational Networks and their management, Engine Generators, Supervisory Control Systems, UPS, Telephone systems, Telephone protection, Field Information Network, Misc support systems*

**System Protection and Control:** 956 locations, ~28,000 pieces of equipment, 33 equipment types

*Transformer relays, Bus relays, Line relays, Breaker relays, RAS, Reactive relays, Revenue metering and Control, SER, DFR, Control equip, Load shedding relay, Indicating Meter Transducers, Relay Communications*

**Rights of Way:** 195,600 acres of BPA maintained ROW corridors, 319 corridors, 423 transmission lines, 368 communication sites, approx. 11,860 miles of access roads, approx. 80,000 tracts of easement

*Access roads, Roads, Bridges, Culverts, Trails and gates, Tracts of easement*

**Wood Lines:** Approx. 4,800 miles, 336 separate transmission lines with 73,500 wood poles

*Poles, Conductors, Insulator assemblies, Guy assemblies, Fiber optic cable, Line disconnect switches, Ground wire, Counterpoise*

**Steel Lines:** 10,300 circuit miles with 43,500 lattice steel and engineered steel pole transmission lines and all associated towers, hardware and components

*Towers, Connectors, Conductors, Insulator assemblies, Footings, Dampers, Counterpoise*

## Objectives of the FY2014-2023 Transmission Asset Management strategy

The Transmission Asset Management Strategy provides the roadmap for managing the health, performance, costs and risks of transmission assets owned or leased by BPA. This is achieved through ensuring the *sustainment* of critical existing assets, including transmission lines,

### Vision for managing transmission assets:

*Transmission Services will manage its assets to achieve high reliability, availability and adequacy standards and maximize economic value for the region. It will use efficient and transparent practices that are effective in managing risks and delivering results.*

substations, control center equipment and other facilities and equipment to meet reliability and availability requirements; and that *expansion* of the system provides the needed transmission capacity and flexibility into the future. Through an assessment of the current state of BPA's transmission asset management program, this strategy represents the course of action needed to ensure achieving the end-state goals.

### Long-term goals

*For improving asset management practices:*

- Transmission asset management practices conform to leading practices.
- Expansion, replacements, and maintenance are integrated, prioritized in terms of asset criticality and risk, and directed at meeting reliability and other standards at lowest total economic cost.
- Asset management plans deliver on the transmission asset management strategy through an optimized funding and resourcing plan. Projects are completed within scope, on schedule and within budget.

*For expanding transmission:*

- Load service obligations and customer service request projects meet standards and tariff requirements.
- An integrated regional expansion planning process is implemented
- A robust grid that effectively and efficiently integrates diverse energy resources
- Inter-regional transfer capacity meets reliability standards and market requirements
- Fuller, more optimal use is made of existing transmission capacity through technological, policy and process change

*For sustaining assets:*

- Information on asset attributes (condition, performance, and costs) is complete, accurate, and readily accessible
- Assets are proactively maintained and replaced
  - ◆ Maintenance, replacements and sparing integrated
  - ◆ Priority given to critical assets at greatest risk
  - ◆ Reliability, availability, and other standards met at lowest total economic cost
- Maintenance is reliability-centered (condition-based)

### Strategic challenges

Over the past few years much has changed in the utility industry that has placed additional demands on how BPA's transmission assets are managed. From regulatory requirements on how critical cyber assets are classified and managed to market changes that drive differences in how the transmission system is operated, pressures such as these present challenges in ensuring objectives are defined, prioritized, integrated, and achieved, all while minimizing impacts to customer rates. Meeting strategic objectives on all fronts depends on having a healthy and

well planned system infrastructure. The strategy to reach the ideal state for the system infrastructure must mitigate and manage several challenges:

- Taking advantage of new technology that will provide valuable efficiencies
- Staying on top of technology changes to ensure reliability and interoperability of equipment, and avoiding obsolescence
- Having adequate data to inform the prioritization of work and once identified, securing adequate funding levels and committed resources to address backlogs in capital replacement and deferred maintenance
- Balancing customer demand for system availability with the necessary outages to facilitate maintenance and replacement projects
- Responding to evolving and increasing regulatory requirements
- Addressing the increasing physical and cyber hazards that put the transmission system at risk
- Meeting the demands of an evolving market and the increased reliance on critical real time data. Together customer needs, system constraints, and system operating limits will require transmission operators to have greater system visibility, accuracy of models and automated controls in order to maintain reliability.

### **Major elements of the strategy**

BPA's transmission asset management strategy is focused on the efforts necessary to achieve the long term goals of sustaining its existing infrastructure at desired performance levels while addressing the challenges listed above. The Transmission Asset Management strategy document describes the specific approaches to be taken and places particular focus on overarching initiatives and the set of actions and prioritized investments to be implemented in the sustain programs. Expansion investments, driven by capacity and customer requirements, are prioritized through the BPA Capital Investment Prioritization process and are identified in the overview section of BPA's Capital Investment Review (CIR) publication.

Highlights from the sustain strategies are included below to provide context to the capital investment levels forecasted for FY2014-2023. Detailed strategies and supporting asset information are described throughout the rest of this document.

### ***Overarching strategy for program and process improvements***

A recent evaluation of the current state of BPA's transmission program resulted in the development of strategic priorities for Transmission Services in the areas of *System Infrastructure*, *System Operations*, and *Commercial Success*. These three priorities must be addressed in the context of achieving the fourth priority, *System Reliability Compliance*. The System Infrastructure strategic priority forms the basis for this asset strategy with outcomes expected to deliver on the following picture of success:

*Significantly improved annual program delivery levels of 90% for Sustain and 80% for Expand; substantially advanced asset management quality and systems; robust project integration; and implemented technology strategy and governance; together preserve and enhance the reliability and availability of the existing and future transmission system infrastructure.*

Specific process improvements identified in the strategy to facilitate reaching this objective are:

- Greater accessibility of higher quality asset data
- Developing and integrating sustain program asset strategies using a standardized approach for identifying risks through an evaluation of total economic cost metrics.
- Implementing portfolio management tools for greater visibility into asset program information
- Building project management capabilities
- Addressing hurdles in project execution
- Creating a critical spares strategy

### *Sustain Program Strategies:*

The Transmission sustain programs are structured by groups of assets. Each sustain program has an asset specific strategy and corresponding implementation plan of prioritized investments determined to best meet BPA's strategic objectives for its transmission system. Sustain investments are defined as investments the primary purpose of which is to replace existing assets in order to maintain system performance and capability. In an effort to better prioritize investments towards mitigating the most critical risks, Transmission Services adopted an approach for evaluating risks based on reducing *total economic costs*. This approach has currently been applied to the AC Substations, Power System Control, and System Protection and Control programs with the remainder of the sustain programs to be evaluated by the end of FY2015.

### *AC substations*

The AC Substations program has recently undergone a re-examination of strategic approaches using the total economic cost evaluation metrics. The preferred strategic alternative contains the following elements:

- Replacement plans to address the backlog of deferred capital replacements based on an economic lifecycle
- Predictive analysis using information from relays, sensors and camera
- Improving work related processes
- Addition of on-site transformer and reactor spares

Development of the high-level implementation plan to implement selected strategic changes is expected to be complete by FY2014 Q2. In the meantime, the AC Subs program has already begun prioritizing replacements based on the newly developed strategy with a goal of minimizing total economic costs over time.

### *Control centers*

The strategies to improve control center asset performance are focused on:

- Addressing critical asset risks first, as well as high risk asset issues before they reach critical stage
- Migrating Open Virtual Memory System technology systems such as major control systems to a Windows platform to improve manageability and maintain sufficient software vendor support
- Ensuring that critical systems meet their established availability targets by taking appropriate maintenance, support and replacement actions
- Complete Lifecycle Plans with risk assessments for each asset and update them at least annually
  - ◆ Incorporates established server and workstation equipment lifecycle standards
  - ◆ Includes refinement of additional performance standards
- Develop a control center Data Management Program and Strategy
- Develop enterprise architecture and strategic "line of sight" to control center assets
- Develop visibility, tools, and processes to support more complete and proactive Demand & Capacity Management in the control centers
- Strategically plan for control center asset information management improvements meeting a wide range of program stakeholder needs
- Establish dedicated control center technology and architecture planning functions or roles, and better integrate with the Power System Control (PSC) and System Protection and Control (SPC) Technology Evaluation and Testing Council and test team processes
- Develop a cyber-security and risk management strategy towards evolving the current practices for system visibility, risk assessment, decision making and compliance response

### *Power system control (PSC) and system telecommunication*

The strategy is aimed at aggressively minimizing total economic cost by reducing the risks of:

- Asset failure through surmounting large backlogs resulting from years of underinvestment
- Interoperability issues by designing and conducting a comprehensive, integrated testing program

- Technological obsolescence by developing and implementing a long-term strategy for moving off SONET and other equipment

PSC and system telecommunication equipment is upgraded and replaced to support BPA's delivery on its strategic objectives, including possible energy imbalance market formation, greater use of dynamic transfer capacity and demand response resources, and changes in scheduling. PSC replacement plans are integrated with SPC and associated control center assets. Process improvements in documentation accuracy and enhanced training enable achievement of objectives to address backlogs and reduce rework.

### *System protection and control (SPC)*

Over the next 10 years, replace specific populations of equipment groups that are at highest risk of failure or technological obsolescence and contribute the most to total economic cost. Targeting these replacements will mitigate the risks associated with:

- The documented poor health of aged equipment
- The lack of manufacturer support for older equipment
- The increased corrective maintenance on aged asset population
- The challenge of retaining the skill set necessary to work on older equipment models

Improvements in the SPC program include better coordination with the PSC program for replacements and integrated testing, which will also incorporate innovative technology.

### *Rights-of-way*

#### Vegetation management

- Implement an integrated vegetation management approach – a system of managing plant communities whereby managers set objectives, identify compatible and incompatible vegetation, consider action thresholds and evaluate, select and implement the most appropriate control methods to achieve set objectives. The choice of control methods should be based on the environmental impact and anticipated effectiveness along with site characteristics, security, economics, current land use and other factors.
- Assure the highest level of regulatory compliance by adopting the integrated vegetation management approach, which is considered an industry best practice.

#### Access roads

- Implement a systematic long-term method for upgrading and maintaining BPA access to and through rights-of-way corridors. This allows a corridor approach for planning work in support of the wood pole and steel lines sustain programs. It also considers bundling projects to allow greater implementation through the owner's engineer contract.
- Ensure that safe access in compliance with environmental regulations is provided throughout the entire transmission system.

#### Land rights

- Develop a long-term plan to meet program objectives/targets, including reducing backlogs and supporting asset plans for access roads, vegetation, and lines. This strategy prioritizes the needs for rights (alternative routes, risk of complaints/litigation/trespass violations, criticality of the line, tribal renewals) in a comprehensive view.

### *Wood lines*

The strategy is an asset life cycle strategy which is a combination of life extension and systematic replacement of the worst performing and highest consequence of failure assets.

- The life extension strategy replaces all of the aged components on a priority pole replacement structure

- The systematic replacement strategy addresses rebuilding approximately 100 miles of aged, poorly performing wood pole lines each year
- Projects are implemented on a three-year program schedule to allow adequate time for gaining road rights, acquiring land and materials, and performing NEPA activities
- Old de-energized lines are removed to mitigate safety and liability risks and reduce maintenance responsibility

### *Steel lines*

The strategy includes a proactive plan to replace vital overhead system components nearing end of life by:

- Setting standard metrics for collecting and retaining asset condition data with enough granularity to identify condition trends, target and pace replacement efforts, manage components over time and better predict remaining service life
- Standardizing the process for sampling and testing retired components
- Developing a long-term strategy for evaluating and mitigating a continuously aging asset
- Incorporating standardized components and technology innovations into replacement efforts

**Results to be achieved**

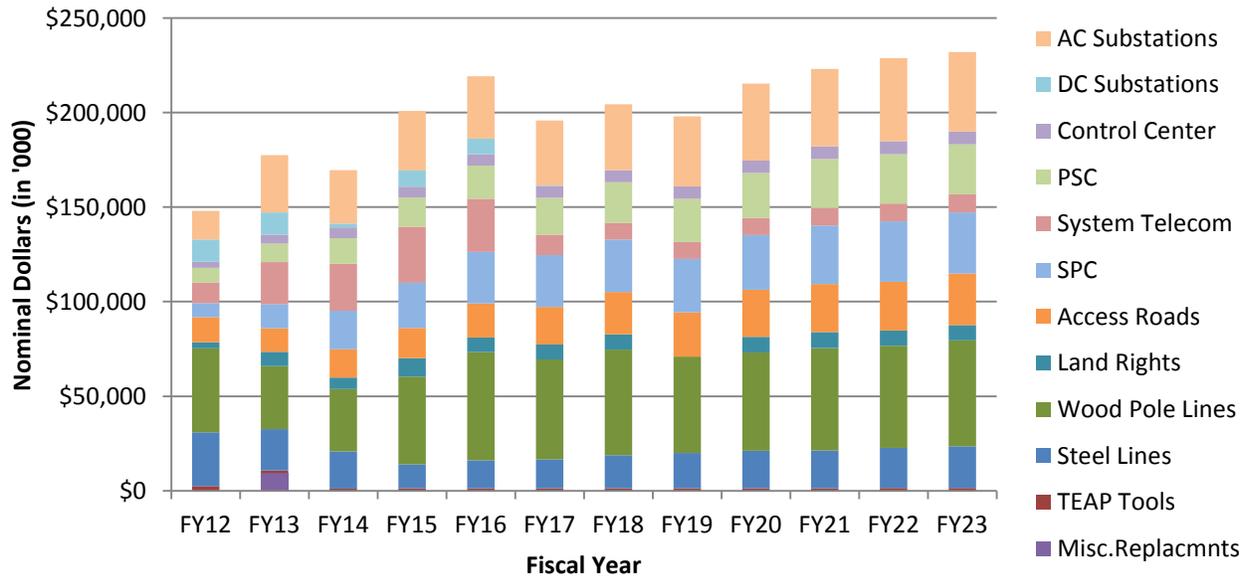
Transmission Services has adopted key transmission targets and system performance measures, or metrics, and to monitor the overall reliability, adequacy and availability of BPA’s transmission system (shown in the figure below). These system performance measures and targets are supplemented with asset program-specific metrics and targets contained in the sustain program strategies.

|                      | Performance Measures   | End Stage Targets   |
|----------------------|--|---|
| Reliability          | <p><b>System Average Interruption Duration Index (SAIDI) - Average duration of automatic outage minutes by BPA line category.</b><br/>Provides an indication of BPA's success at minimizing the duration of unplanned transmission line outages.</p>   | <p>No control chart violations per year for line importance categories 1-2.<br/>No more than 1 control chart violation per year for line importance categories 3-4.</p>   |
|                      | <p><b>System Average Interruption Frequency Index (SAIFI) - Average number of automatic outages by BPA line category.</b><br/>Provides an indication of BPA's success at minimizing the number of unplanned transmission line outages.</p>   | <p>No control violations per year for line importance categories 1-2.<br/>No more than 1 control chart violation per year for line importance categories 3-4.</p>   |
|                      | <p><b>Report of number of outages to transmission lines of all voltage levels caused by vegetation growing into the conductor or within flashover distance to the conductor. (Relates to vegetation growing from either inside or outside the BPA right-of-way)</b></p>                        | <p>No outages to transmission lines of all voltage levels caused by vegetation growth.</p>  |
| Adequacy             | <p><b>Flowgate Performance</b><br/>Number of excursion minutes that actual path flows are greater than the System Operating Limits (SOL). Indicates congested areas for which capacity expansion may merit consideration.<br/>Included in Transmission Services FY2014 balanced scorecard.</p> | <p>Flowgate annual excursion minutes for all of FY2014 are at or below the calculated control limit (110 minutes/flowgate) system-wide.</p>   |
| Availability         | <p><b>Availability for service of BPA’s most important transmission lines (Category 1 and 2)</b><br/>Included in Transmission Services FY2014 balanced scorecard.</p>  | <p>BPA’s most important transmission lines (Category 1 and 2) are available for service at least 97.39% of the time.</p>  |
| Process Improvements | <p><b>Asset Management Key Transmission Target</b><br/>Included in Transmission Service FY2014 balanced scorecard.</p>   | <p>Per the approved Asset Management Roadmap, processes, tools, and policies in support of asset register improvements; asset strategy development; and more successful project, portfolio and program delivery will be integrated and operationalized in the business organizations to enable effective Asset Management and planning.</p> |

**FY2014-2023 Sustain Capital Forecast**

The Transmission sustain capital program execution level has increased from approximately \$70M in FY2008 to \$177M in FY2013. An average of \$200M is planned for FY2014-FY2017 with a slight ramp up the out years. The annual level of investment is expected to increase and the determination of the optimal level needed to adequately address the backlog will continue to be analyzed.

**Sustain Capital FY2012-2013 Actuals and FY2014-2023 Ten Year Forecast**



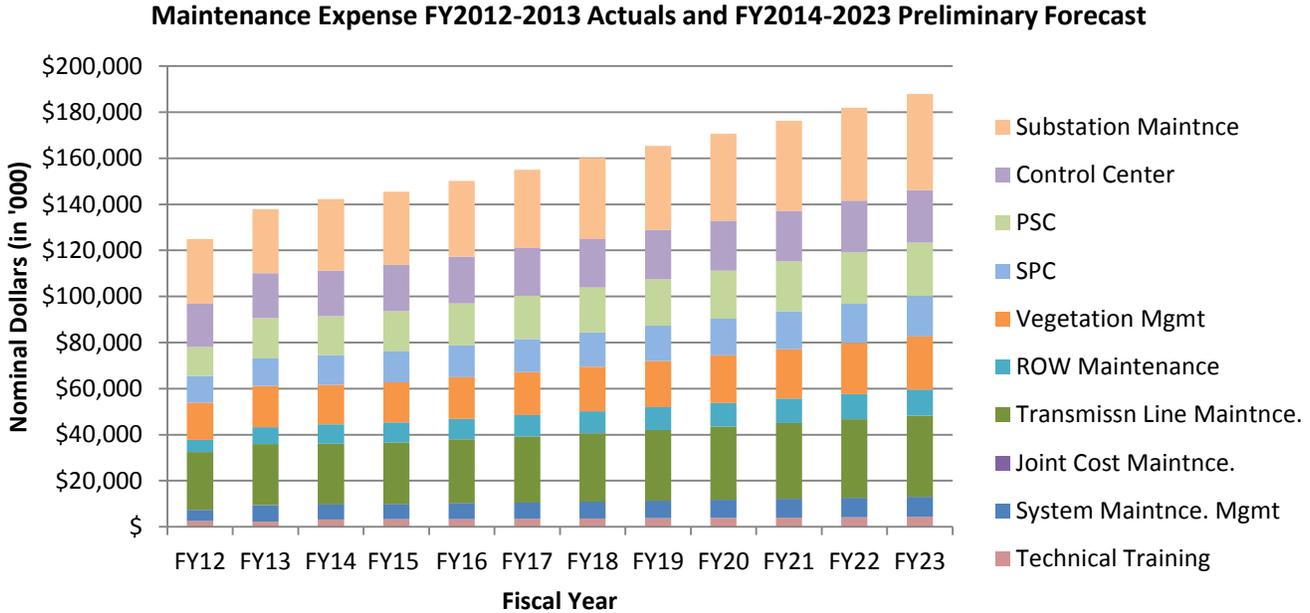
**Capital FY2012-2013 Actuals and FY2014-2023 Ten Year Forecast**

**Transmission Services – Sustain Programs**

Direct Capital only, Nominal Dollars in '000  
Actuals

| Program              | FY12           | FY13           | FY14           | FY15           | FY16           | FY17           | FY18           | FY19           | FY20           | FY21           | FY22           | FY23           | *Excludes<br>FY12-13<br>Total |
|----------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|-------------------------------|
| AC Substations       | 15,007         | 30,219         | 28,367         | 31,508         | 32,870         | 34,331         | 34,703         | 37,157         | 40,728         | 40,861         | 44,012         | 42,082         | <b>366,619</b>                |
| DC Substations       | 11,813         | 11,826         | 1,907          | 8,500          | 8,300          | 400            |                |                |                |                |                |                | <b>19,107</b>                 |
| Control Center       | 3,228          | 4,701          | 5,811          | 5,827          | 6,104          | 6,206          | 6,437          | 6,516          | 6,597          | 6,677          | 6,760          | 6,837          | <b>63,773</b>                 |
| PSC                  | 7,793          | 9,795          | 13,500         | 15,500         | 17,500         | 19,500         | 21,500         | 22,850         | 23,798         | 25,975         | 26,204         | 26,437         | <b>212,764</b>                |
| System Telecom       | 10,986         | 22,152         | 24,845         | 29,559         | 28,000         | 10,750         | 8,750          | 8,899          | 9,050          | 9,204          | 9,360          | 9,519          | <b>147,937</b>                |
| SPC                  | 7,280          | 12,877         | 20,350         | 23,898         | 27,284         | 27,420         | 27,814         | 28,252         | 28,897         | 31,036         | 31,946         | 32,310         | <b>279,208</b>                |
| Access Roads         | 13,422         | 12,491         | 15,000         | 16,000         | 18,000         | 20,000         | 22,500         | 23,500         | 25,000         | 25,425         | 25,857         | 27,297         | <b>218,579</b>                |
| Land Rights          | 3,134          | 7,551          | 6,042          | 9,790          | 7,778          | 7,910          | 8,045          | 8,181          | 8,321          | 8,462          | 8,043          | 8,180          | <b>80,751</b>                 |
| Wood Pole Lines      | 44,516         | 33,282         | 33,020         | 46,520         | 57,270         | 52,850         | 55,900         | 51,000         | 52,000         | 54,100         | 54,100         | 56,000         | <b>512,760</b>                |
| Steel Lines          | 28,407         | 21,881         | 19,603         | 12,625         | 14,865         | 15,276         | 17,449         | 18,623         | 19,741         | 20,024         | 21,200         | 22,074         | <b>181,479</b>                |
| TEAP Tools           | 2,410          | 1,369          | 1,176          | 1,200          | 1,224          | 1,248          | 1,273          | 1,299          | 1,325          | 1,351          | 1,378          | 1,406          | <b>12,880</b>                 |
| Misc.Replacmnts      |                | 9,349          |                |                |                |                |                |                |                |                |                |                |                               |
| <b>Sustain Total</b> | <b>147,995</b> | <b>177,493</b> | <b>169,622</b> | <b>200,927</b> | <b>219,195</b> | <b>195,892</b> | <b>204,371</b> | <b>206,277</b> | <b>215,455</b> | <b>223,115</b> | <b>228,862</b> | <b>232,143</b> | <b>2,095,858</b>              |

**FY2014-2023 Maintenance Expense Preliminary Forecast**



**Expense FY2012-2013 Actuals and FY2014-FY2023 Ten Year Forecast**

**Transmission Maintenance**

Nominal Dollars in '000

| Program               | Actuals        |                | SOY            | Rate Case      | FY16           | FY17           | FY18           | FY19           | FY20           | FY21           | FY22           | FY23           | Total            | Excludes FY12-13 |
|-----------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|------------------|------------------|
|                       | FY12           | FY13           |                |                |                |                |                |                |                |                |                |                |                  |                  |
| Substation Maintnce.  | 28,056         | 27,726         | 31,112         | 31,777         | 32,889         | 34,040         | 35,231         | 36,464         | 37,741         | 39,062         | 40,429         | 41,844         | <b>360,588</b>   |                  |
| SPC                   | 11,651         | 11,869         | 13,100         | 13,381         | 13,849         | 14,334         | 14,835         | 15,355         | 15,892         | 16,448         | 17,024         | 17,620         | <b>151,834</b>   |                  |
| PSC                   | 12,637         | 17,623         | 16,868         | 17,582         | 18,198         | 18,835         | 19,494         | 20,176         | 20,882         | 21,613         | 22,370         | 23,153         | <b>199,170</b>   |                  |
| Control Center *      | 18,686         | 19,398         | 19,708         | 20,024         | 20,344         | 20,670         | 21,000         | 21,336         | 21,678         | 22,025         | 22,377         | 22,735         | <b>211,896</b>   |                  |
| Line Maintnce.**      | 24,984         | 26,572         | 26,361         | 26,820         | 27,758         | 28,730         | 29,735         | 30,776         | 31,853         | 32,968         | 34,122         | 35,316         | <b>304,440</b>   |                  |
| ROW Maintnce.         | 5,243          | 7,298          | 8,429          | 8,597          | 8,898          | 9,210          | 9,532          | 9,866          | 10,211         | 10,568         | 10,938         | 11,321         | <b>106,276</b>   |                  |
| Vegetation Mgmt       | 16,141         | 17,928         | 17,135         | 17,471         | 18,082         | 18,715         | 19,370         | 20,048         | 20,749         | 21,476         | 22,227         | 23,005         | <b>189,571</b>   |                  |
| Technical Training    | 2,443          | 2,211          | 3,201          | 3,269          | 3,384          | 3,502          | 3,625          | 3,752          | 3,883          | 4,019          | 4,159          | 4,305          | <b>37,099</b>    |                  |
| System Maintnce. Mgmt | 4,879          | 7,076          | 6,434          | 6,574          | 6,804          | 7,042          | 7,288          | 7,543          | 7,807          | 8,081          | 8,363          | 8,656          | <b>74,592</b>    |                  |
| Joint Cost Maintnce.  | 146            | 123            | 1              | 1              | 1              | 1              | 1              | 1              | 1              | 1              | 1              | 1              | <b>10</b>        |                  |
| <b>Expense Total</b>  | <b>124,866</b> | <b>137,824</b> | <b>142,346</b> | <b>145,494</b> | <b>150,206</b> | <b>155,077</b> | <b>160,112</b> | <b>165,317</b> | <b>170,697</b> | <b>176,260</b> | <b>182,011</b> | <b>187,956</b> | <b>1,635,475</b> |                  |

**Caveats**

The basis for this 10 year forecast is the FY2015 rate case budget for labor and materials. A 3.5% inflation rate has been applied for FY2016-2023.

\*The Control Center forecast includes labor only and a 1.6% inflation rate has been applied for FY2014-2023.

\*\*Includes both Wood Pole and Steel Lines programs.

These forecasts are currently under review as part of the 2014 Integrated Program Review (IPR) process and will be updated in conjunction with the IPR timeline.

# **TRANSMISSION ASSET MANAGEMENT OVERARCHING STRATEGY**

## 1.0 STRATEGY BACKGROUND

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### 1.1 Business Environment

#### *Sustain existing assets*

Over the past few years, Transmission Services has been maturing its asset management program with a goal of sustaining its existing assets to meet reliability and availability targets at optimal lifecycle cost. Long-term asset strategies and asset plans for capital replacements and maintenance have been developed for:

- Alternating and direct current substations
- Control centers
- Power system control/telecommunications
- System protection and control
- Rights-of-way
- Wood lines
- Steel lines

Sustainment planning is asset driven and takes into account the condition of the assets and the demands placed on them. Each of the program strategies contains a representation of asset health and risk of failure to the system along with a strategy for mitigating any associated risks. The strategies provide the direction for addressing the most critical assets first while a corresponding plan has been developed to implement risks mitigation, slow down or eliminate capital replacement backlogs, and reach optimal lifecycle management.

#### *Expand the system*

BPA's transmission expansion program includes investments to add capacity and flexibility, increase operational output, improve reliability and meet load growth. The expansion program includes investments to interconnect generation, meet customer service requests and relieve transmission congestion. Projects range from minor upgrades and substation additions to major transmission line additions. Included are projects that are tariff driven or customer requested and that may be funded in part or wholly by customers or a third party.

Expand investments are divided into four groups:

- **Main grid**, consisting of 500-kilovolt (kV) transmission and substation facilities as well as some 345-kV and a few 230-kV facilities.
- **Area and customer service**, consisting of facilities, typically 230 kV and below, that function primarily to serve customer loads at their request.
- **Interregional paths**, consisting of 500 kV and some lower voltage lines and facilities that interconnect with transmission providers and generating resources outside the Pacific Northwest.
- **Upgrades and additions**, consisting of upgrades to substations, line capacity, hardware, software and other electrical equipment. This includes the multi-year project to modernize and upgrade the Celilo Converter Station and the Pacific Direct Current Intertie north of the California-Oregon border.

Transmission Services also funds capital investments in information technology, environmental work, nonelectric facilities, fleet, and security enhancements in support of the transmission program. These investments are addressed in separate asset strategies for these asset types due to the unique drivers behind the investments.

## 2.0 STRATEGY FOR MANAGING TRANSMISSION ASSETS

### 2.1 Current State

The majority of the transmission system and its high voltage power lines and substations are more than 40 years old. It was designed to move power from known points of dispatchable generation to stable predictable load centers. The environment has changed dramatically over the years and upgrades to the grid are now critical to keeping up with the demands. Insufficient modernization has been performed over the past two decades.

The challenges facing BPA’s transmission sustain programs include managing the risks associated with an aging infrastructure, including equipment failure and technological obsolescence risks, and managing funding, labor, outage availability and other constraints to implementation. These challenges are made worse by years of underinvestment in replacing and renewing the system. Some equipment, such as critical telecommunications components, is technologically obsolete. This means that interoperability problems are arising and vendor support and spare parts are less and less available. Some transmission assets are more than 25 percent past their design life, which puts the system’s reliability at risk.

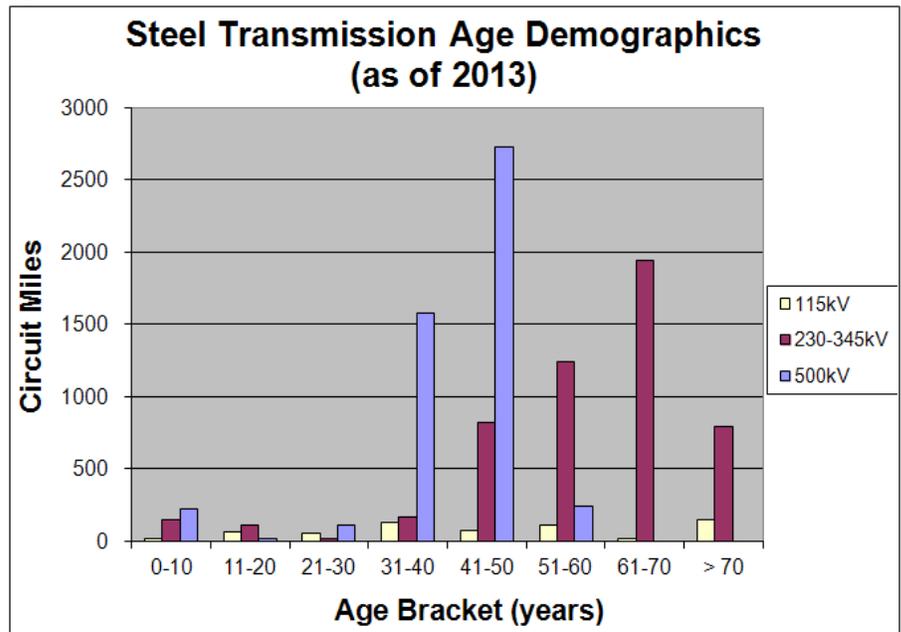
#### Aging infrastructure

Transmission assets generally have long expected lives. On BPA’s system, it’s not unusual to encounter transformers, structures or other components that are over 60 years old. Over the years, long asset lives have enabled BPA to push replacements farther and farther into the future. This provided BPA with flexibility to address expansion needs, budget and rate pressures, and unplanned contingencies. However, persistent delay of investment has resulted in a substantial backlog of replacement needs, higher maintenance expense and higher risk of equipment failure and obsolescence. To illustrate, Figure 1 indicates that an estimated 60% of steel lines are approaching theoretical end-of-life.

In 2010, BPA’s Transmission organization participated in a benchmarking study conducted by 1st Quartile that compared BPA’s line and substation assets and capital program with other North American utilities such as the Tennessee Valley Authority, National Grid and Pacific Gas & Electric. In general, the results showed that BPA’s substations are older than the substations of most other surveyed utilities. Overall, capital spending at BPA is lower than average, and the rate of replacement is lower than most other utilities benchmarked.

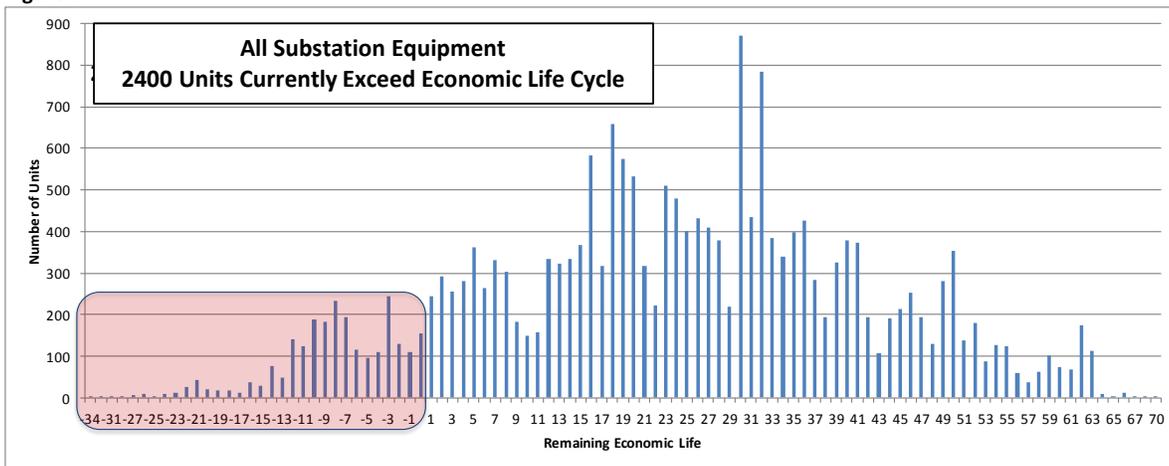
Leaving equipment on the system that is beyond its expected service life increases the likelihood of failures that could require costly outages with accompanying high emergency response costs.

Figure 1



An example of the volume of equipment determined to be past its optimal life cycle is shown in Figure 2. Failures may also lead to unplanned customer outages with regional implications. Many existing assets are also not designed or constructed to withstand potential operational, physical, cyber and natural disaster threats.

Figure 2



In order to target these priority replacements, it is vitally important to have a complete and accurate inventory of the age and health of transmission assets.

**Asset register progress**

Transmission Service’ asset register, known as the Transmission Asset System (TAS), forms the foundation for the Transmission asset management program by providing the data and information necessary to prioritize its maintenance and replacement programs. The past few years has been focused on defining the requirements and refining processes to support data gathering and analysis.

In FY2013, emphasis was placed on developing hardened business processes to ensure all incoming and outgoing asset data is processed in a manner that is consistent with good data management. Transmission Services created the Asset Data Management (ADM) organization to develop, manage, and drive continued improvement in support of this effort. Since its inception, the ADM group has been assessing the completeness and accuracy of the asset data that is stored in TAS. Multiple audits have been performed to understand the accuracy of current asset data. This has resulted in a better understanding of data completeness and accuracy and the development of a plan to address inaccuracies is in process. A standardized process for requesting changes to the assets or to the TAS system is in place to facilitate monitoring and categorizing the requests for asset changes, prioritization, resource assignments, and day-to-day work progress.

The database platform was enhanced in FY2013 and data was reconfigured to better meet the business needs for the system protection and control, substations, and power system control equipment. The program has now been extended to include transmission line assets and is interfaced with the Enterprise Geographic Information System (eGIS) for a geographical representation of those asset requirements.

**Asset Performance Analysis**

In addition to having accurate and complete asset data, development of a sound asset management strategy is contingent upon having the capability to analyze the data in order to trigger asset management life cycle activities, such as increased maintenance or deferral of replacements. A Reliability Centered Maintenance (RCM) group in Transmission Services is being established to serve this critical need. The scope of this function will be fully defined

once the ADM group has completed developing the requirements and processes for asset data collection for the specific programs. It is expected that improvements in analysis will result in a more robust preventative maintenance program thereby decreasing corrective maintenance and the higher costs associated with it.

Specifically, the RCM function will improve asset management through the

- ◆ Development of algorithms for criticality, health, and risk of equipment
- ◆ Determination of the balance of corrective vs. preventative maintenance
- ◆ Understanding of failure modes and for setting maintenance frequency and tasks
- ◆ Establishment of condition based maintenance triggers
- ◆ Monitoring of the efficiency and effectiveness of the maintenance program
- ◆ Application of maintenance tasks and triggers dependent on manufacturer and model, application and health as determined from predictive analysis

### *Operations and Maintenance*

Transmission Services' operations and maintenance (O&M) program is a critical and arguably the most costly phase of the assets' lifecycle. Continued improvement in aligning O&M activities with asset strategies is underway to ensure cost effective asset lifecycle management is achieved. Management and implementation of O&M activities are highly data dependent, and without good data can create a situation of either over spending by performing too much maintenance or increasing risks by under-maintaining. As mentioned previously, asset register data is being improved yet is not in the state needed to adequately inform O&M activities on a cost effective life cycle basis.

Once fully established, the ADM and RCM functions will provide the data and associated analytics required to determine the appropriate maintenance strategy based on criticality, health, and risk information.

### *Technological Obsolescence*

Transmission Services is faced with the challenge of rapidly evolving technology in several different programs such as system telecommunications, system protection and control, and control centers. BPA has generally lagged behind the industry and is starting to feel the effects of this delay. Maintaining system and equipment operability with multiple older vintages of equipment has increased the inventory of equipment needed for spare parts and creates additional instances of equipment failure and system mis-operations. Costs for maintenance and inventory are up substantially as a result. In addition, while some equipment may still be in fair or good condition, the lack of vendor support and replacement parts makes repairs very expensive and increases the potential for outages of unacceptable duration.

In addition, there are many new technologies that would provide Transmission Services with flexibility on the system for performing replacements and O&M activities without requiring an outage. Transmission Services is focused on identifying and implementing technologies that would reduce the number and the duration time of outages for maintenance, repair and replacement. While Transmission Services has begun initial efforts to partner with Electric Power Research Institute (EPRI) to develop a technology research and development roadmap, this effort is just beginning to reach a functional level.

### *Continuity of Operations*

BPA's electrical transmission system is located within the Cascadia Subduction Zone, widely recognized as a seismic hazard that can produce very large earthquakes of magnitude 9.0 or greater. This places transmission facilities at risk of potentially severe damage and loss of operation during seismic events. In order to mitigate this risk, BPA adopted a seismic design standard that specifies how to design and strengthen transmission facilities to withstand the hazards associated with seismic activity. The seismic standard provides design requirements that will enable essential electrical facilities to remain in service or be capable of being returned to service in a reasonable and

timely manner. Much progress has been made in improving the resiliency of the transmission system including the recent installation of a first-of-its-kind support system known as base isolation technology on a critical transformer on the Vancouver, Washington Ross Complex. This state-of-the-art technology will decrease the likelihood of damage and increase the likelihood of system availability during and after a major seismic event.

The continuity of operations program as applied to transmission assets is being implemented in the areas of critical business function redundancy, critical equipment anchoring, rigid bus riser replacement, and river-crossing mitigation. A building seismic strengthening program is included in the Facilities Asset Management Strategy. In addition, sparing strategies for critical equipment are being developed in conjunction with federal continuity directives.

**Managing congestion**

Currently, several transmission paths are at or near their capacity limits, which can force changes to the optimal dispatch of generating resources and lead to higher regional costs for delivered power. Further, a heavily loaded system constrains the BPA’s ability to schedule outage time for needed maintenance, repairs and replacements. Increased congestion requires that new capacity and flexibility be added to the system to meet tariff and regulatory requirements and provide adequate, efficient and reliable service.

**Prioritization of projects**

The backlog of underinvestment in the sustain program makes it imperative for the Transmission Asset Management Strategy to incorporate a solid approach for prioritizing its resources towards mitigating the most critical risks. Transmission Services is in the process of evaluating all sustain program strategic alternatives on the basis of reducing *total economic cost*. This leading-practice involves assessing the health condition of equipment, the likelihood of equipment failure and the potential for line derates and outages should equipment failure occur. The method produces a risk-informed prioritized program of replacements and internal process improvements designed to minimize BPA costs and customer value losses from equipment failures over time. An example of process for evaluating costs using this method that was completed during the development of the Integrated Control System Strategy (ICSS) is shown in Figure 3. This effort

resulted in a valuable integrated strategic approach for better coordinating the equipment replacement for power system control/system telecommunications, system protection and control, and associated control center assets.

Strategic alternatives using this method have been developed for remedial action schemes and alternating current substation assets. The steel lines, wood pole lines, and rights-of-way programs are currently undergoing evaluation in an integrated manner. The effort will be extended to the control centers in the 2014-2015 timeframe. Once all program strategies are developed on the same platform, it will provide Transmission Services with the ability to evaluate and prioritize sustain investments across all programs and make trade-off decisions to ensure the most critical replacements with the highest level of risk from an economic perspective are addressed first.

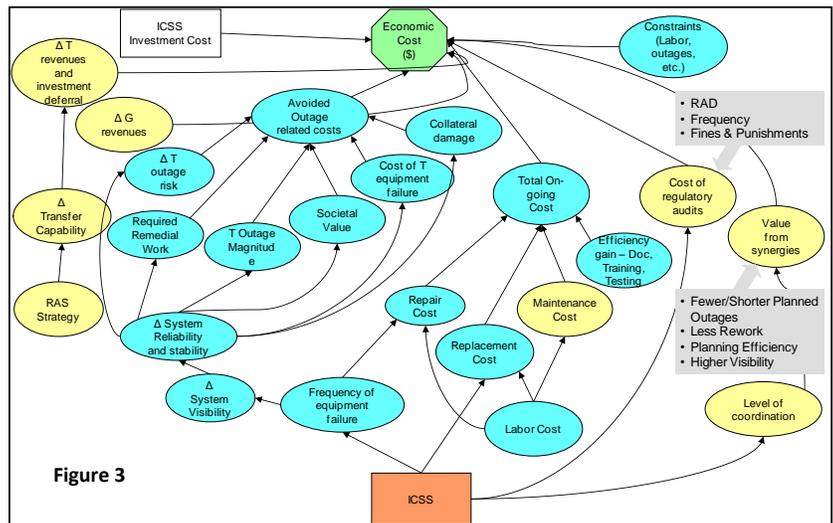


Figure 3

BPA has recently adopted the same method to prioritize all expansion projects across BPA, including transmission expansion projects. The initial effort, due to be completed in January 2014, will produce a portfolio of prioritized expand projects across all of BPA for the FY2015-2017 timeframe that provides the greatest economic value across the region.

### *Managing and implementing the portfolio of Transmission projects*

Given the current state of Transmission's assets, the people, processes, data, and tools needed to implement greater number of replacement projects is more important than ever. Transmission Services has been working steadily over the past few years to create the tools and processes needed to prioritize projects, identify resource levels, and manage all aspects of its total capital program from project identification through project execution. Improvements have been implemented and more are in the works. For example, the Demand Planning effort now provides visibility into the resources needed for projects on a three year horizon, yet obtaining the additional skilled resources to execute the sustain replacement plans at required levels continues to be a challenge.

The creation of the Contract Management Office (CMO) and its contractual relationship with an owner's engineer firm has increased the level of execution for large expansion projects over the past several years. Evaluations of how to expand the contracting capability to address sustain projects consisting of multiple replacements of smaller equipment across wide geographical areas are underway.

Over the past few years, improvements in project tracking and reporting tools have been made, but continue to be mostly independent of each other. Recognizing the importance of a visible cross-functional and comprehensive system, Transmission Service is currently working on the development of a prototype system to fill this need. The system will provide a centralized view of asset program information from planning through execution, alignment of data across multiple systems and sources, and customizable scenarios for views, modeling, and management.

### *Execution of sustain projects*

Although the past few years have seen the implementation of sustain projects slowly trending upwards, replacement has still lagged behind expansion projects, and investment in sustaining the existing infrastructure has still not caught up with depreciation. Since 2009, the rate of under-execution in the sustain programs has ranged from 9% to as much as 30%. The effects of this impact both the operation of the system and planned maintenance activities, and have contributed to a perpetual problem of emergency replacements and high maintenance costs.

Executing the sustain projects at optimal levels is a balancing act in many ways; between outage requirements and customer demand for availability, between resources that are shared by both expand and sustain programs, and between keeping rates low and reserving access to capital funding and spending what is necessary to replace assets based on recommended strategies. Recent focus, not only by Transmission Services but BPA as a whole, on ensuring sustainment of the system is driving the need to make tough choices in order to ensure the risks to BPA's transmission system and the Pacific Northwest region are minimized.

With the recognition and understanding of the critical impact of these constraints to the execution of most of the sustain programs, a focused effort towards improving program development, resource forecasting, and expediting project approval was undertaken in FY2013. Lessons learned and resulting improvements made early in FY2013 led to widespread acknowledgement among the planning and execution organizations that the changing nature of the capital program (from fewer large expand projects to many more small sustain projects) would accentuate known and anticipated pinch points during the execution phases of design, construction and commissioning. Gaps between planning and execution were highlighted and resource and other constraints restricting capital program delivery were made visible.

As FY2013 performance continued to lag projections, a team of managers and subject matter experts representing the engineering, planning, and operations organizations worked to reach consensus on the capital program improvements needed and an approach for closing gaps. The recommendation was approved by Transmission Services’ executives for ongoing focus and development of three initiatives directed towards "Getting Work Accomplished".

1. *Early Scope Development*

In recent years, Transmission Services has developed the detailed project scope during the early design phase. Problems discovered at this relatively late point in the project lifecycle delay execution of the specific project and all other dependent projects. Examples include:

- inadequate land rights
- insufficient substation yard and/or control house space
- delay in cultural resources review and environmental approval
- supporting infrastructure deficiencies such as station service, battery/charger capacity

2. *Additional Contracting Opportunities to address key resource constraints*

3. *More effective planning and utilization of outages*

The Get Work Accomplished (GWA) core team has identified additional hurdles to capital program delivery. These include:

- Environmental/Cultural Resources Approval
- Land Rights, Land Acquisition and Right of Way
- Levelize and more effectively manage workload
- Staffing

**2.2 Strategic Landscape**

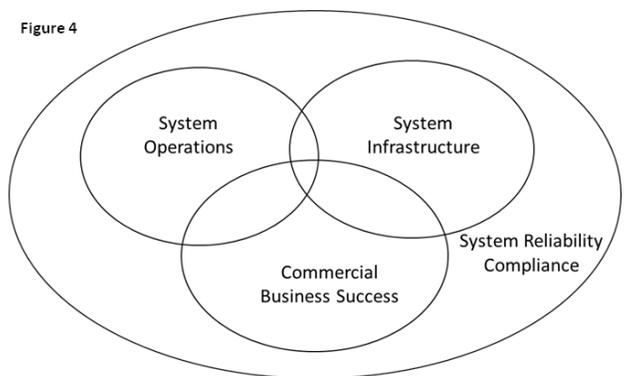
In FY2013, Transmission Services executives held several internal workshops to discuss and re-evaluate the strategic direction for the Transmission Services program, focusing on the next five years. In recognition of the demands and challenges placed upon Transmission’s assets, one of the focus areas was the Transmission system infrastructure. While key strategic landscape issues were categorized into four distinct areas, all of the areas are interlinked and improvements in any one must be aligned with the others in order to claim success.

The workshops resulted in the identification of a set of Transmission Strategic Priorities. The Transmission priorities are focused on improvements to better meet BPA and Transmission Services’ business objectives and address transmission and enterprise risks in the following areas:

- **System Infrastructure**
- **System Operations**
- **Commercial Success**

All three priorities above must be evaluated in the context of achieving the fourth priority of **System Reliability Compliance** (see Figure 4).

The **System Infrastructure** strategic priority is focused on addressing the challenges and issues currently being faced in the implementation of the asset management program and as such, forms the basis for this revision to the Transmission Asset Management Strategy.



The **System Operations** strategic priority specifies the need to sustain operational stability and enable system flexibility. It reflects the need to address the needs of commercial customers while supporting reliability. This is contingent upon having a platform of healthy assets. BPA must balance system reliability with an acceptable level of risk in order to ensure the infrastructure needed to support the operations of the transmission system is healthy.

Over the past few years, the electric utility industry has shifted to emphasize bulk transmission's commercial importance alongside reliability and the need for the **Commercial Success** strategic priority was identified in response. Transparency of system constraints and utilization, and understanding of customer needs, is fundamental to driving future decisions for products and services, system operations, system planning, system infrastructure, and new technology deployment.

New and ever-increasing regulatory compliance demands being placed on how BPA Transmission and other utilities create, operate, and maintain their transmission systems led to the need for the **System Reliability Compliance** strategic priority. This priority is directed towards embracing required compliance performance as a key means to enhanced transmission system reliability.

Transmission Services is in the early stages of developing the strategies and implementation plans for these strategic priorities. Particular attention is being paid to ensure the Transmission strategic priorities are in alignment to BPA's strategic objectives and enterprise risks, and are also integrated with each other to make certain that the outcomes of the priorities are achievable by staff through a *balance of workload and resources*, one of BPA's top enterprise risks.

## 2.3 Future State

Each of Transmission's Strategic Priorities contains business objectives to be achieved by 2018. The evaluation of key gaps to be closed and a detailed planning effort for how the key objectives and outcomes are to be reached are the focus of an FY2014 Key Transmission Target (KTT).

### 2.3.1 Key objectives

#### **System Infrastructure – Assets and Technology:**

*Significantly improved annual program delivery levels of 90% for Sustain and 80% for Expand, substantially advanced asset management quality and systems, robust project integration, and implemented technology strategy and governance, together preserve and enhance the reliability and availability of the existing and future transmission system infrastructure.*

#### **System Operations – Stability and Future Flexibility:**

*System reliability is preserved and enhanced, confidence in firm transmission delivery is increased, confidence in optimized available transfer capability (ATC) is increased, and abilities to proactively manage congestion and system events are improved, based on a platform of integrated analytical capabilities that advance operational planning, outage flexibility, system management, and alignment between system operations and internal and external parties.*

#### **Transmission is a Commercially Successful Business:**

*Transmission is a commercially successful business that delivers valuable products and services at cost-effective rates and demonstrates regional leadership.*

#### **System Reliability Compliance:**

*Zero violations of NERC compliance standards rated as high risk or as a severe or high severity level, and zero repeat violations, so that BPA's reputation and existing BPA Administrator authorities are preserved and enhanced.*

### 2.3.2 Program and Process Improvements

The future envisioned in the Transmission Strategic Priorities pushes Transmission Services towards a more integrated and comprehensive state where system reliability and compliance, availability, operational and commercial requirements are all balanced appropriately and supported by a well-planned system infrastructure. Towards this end, the system infrastructure strategic priority aims towards continued improvements in two main areas, program delivery and asset management.

### 2.3.3 Key Outcomes

The Transmission Strategic Priorities specify the key outcomes expected to be achieved by 2018.

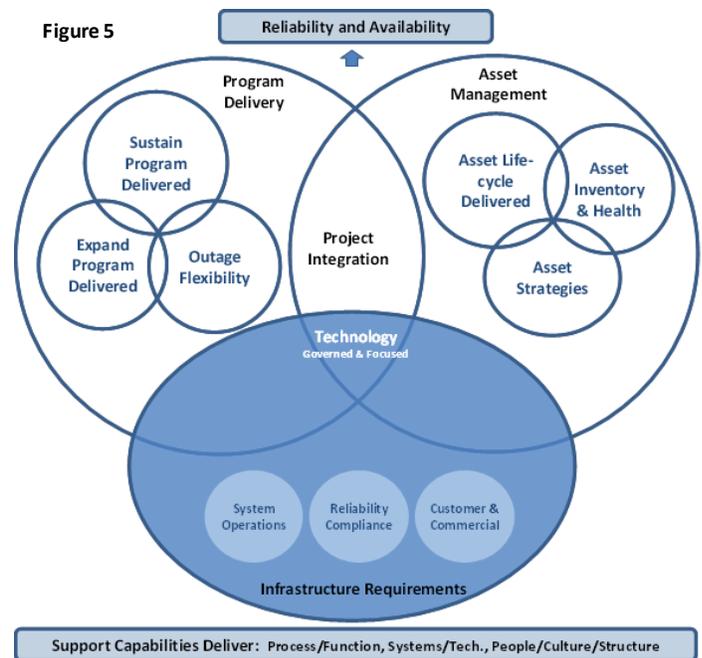
The **System Infrastructure** Transmission Strategic Priority provides the vision for the Transmission Asset Management program for the next three to five years. To substantially improve upon the state of the Transmission System Infrastructure will require significant progress in four overlapping areas, as illustrated by the diagram in Figure 5. Program delivery and asset management are two areas of focus for the 2018 vision of this strategic priority. These two areas are affected by, and affect the need to improve project integration and technology management.

**Program Delivery:** *Significantly improved program delivery levels of 90% for Sustain and 80% for Expand, with major progress in Sustain delivery that does not come at the expense of Expand, through a focus on comprehensive delivery.*

Key work will focus on reduction of constraints, be supported with approaches integrated across organizations, implemented effectively to advance across the immediate-, mid- and long-term timeframes. This key outcome is the central focus of the strategic priority for system infrastructure. The supporting work in asset management, project integration and technology must enable, not detract from or impact, the focus on delivery of the programs.

There are three sub-outcomes to be achieved to deliver this end-state:

1. **Sustain Program Delivered:** Measured by each program with delivery at 90% or better annually, scope metrics developed and implemented that are at 90% or better annually and milestones met 90% of the time or higher, with 100% of the work ready by July for the next fiscal year and additional work (reserve / shovel ready / move in – move-out) ready by October 1.
2. **Expand Program Delivered:** Measured by each program with delivery at 80% or better annually, scope metrics developed and implemented that are at 80% or better annually and milestones met 80% of the time or higher, with 90% of the work ready by July for the next fiscal year and additional work (reserve / shovel ready / move in – move-out) ready by October 1.
3. **Outage Flexibility:** Technology and other approaches are developed and implemented that support outage management approaches to reduce the impact and duration of outages and their effect on project timelines such that the metrics for program delivery are met.



Achieving these sub-outcomes will be based on significantly improved project integration that will improve coordination between planning and project execution, through more precise resource planning and work plan development, project management improvement, and process reduction. The improvements will be measured by changing from the current metrics of total capital program delivery, capital milestones, and Capital Allocation Board (CAB) targets, to more disciplined measures of delivery for each program, milestones as established by programs, and CAB targets.

Technology will impact the delivery of the outcomes in the longer term by improving the transmission technology roadmap through: effective investment in sustain technologies of field practices, and IT initiatives for project management resource planning and work plan development.

Delivery of the sustain and expand programs as a key outcome for the System Infrastructure strategic priority is based on several key aspects, but primarily on the increase in program requirements for work needed to address the aging system and the challenges to date in increasing delivery to meet that requirement. This has important implications across all the strategic priorities of System Operations, Reliability Compliance and Commercial Success.

While there are many key outcomes required for delivery of Transmission’s programs, the rationale for narrowing to these was based on reducing focus across many areas and investing in those assessed as having the largest impact in the three to five year timeframe of this strategy.

***Project Integration:*** *Broad, disciplined ownership and application of improved project prioritization, management, portfolio development, program integration and other standard practices, significantly improve Asset Management and Program Delivery.*

Improvement in project integration will address shortfalls in how projects are managed across the asset management program, plan, design, build continuum. Project integration ties Asset Management and Program Delivery together resulting in progress in addressing major gaps such as early and effective resource strategy planning and project scoping, management of BPA and contract resources, State and Federal permitting, and improvements in Plan-Design-Build throughput. Progress here will enable “shovel ready” projects and other approaches that will increase project efficiency.

While success in improvement efforts over the past few years has been realized such as development of the asset programs, the creation of the Contract Management Office (CMO) and Project Management Office (PMO), inspections, contracted panel construction, and resource planning, significant change continues to be needed in project coordination, scoping, and pre-construction activities.

***Asset Management:*** *A substantially improved Asset Management program achieves three key sub-outcomes: asset register is complete and of high quality, including asset inventory, performance and health; asset strategies and associated asset plans are informed, deliverable, measurable, and incorporate system needs, customer needs and priorities; and asset strategies are transparent, owned and supported by business processes resulting in a mature asset lifecycle approach that incorporates operations and maintenance. Maintenance, repairs and replacements are performed at the right time based on performance, cost and risk.*

There are three sub-outcomes to be achieved to deliver the end-state:

1. *Asset register*: Progress in this key sub-outcome is:
  - Asset inventory with determination of criticality is established and processes for maintaining are developed and functioning for 90 to 100% of assets
  - Asset health information is based on criticality and priority determination for two-thirds of assets
2. *Asset strategy quality*: Results in this key sub-outcome are:
  - Scenario and analysis capability that produces defined capital and O&M work lists based on Transmission system and health, such that the full range of analytical capabilities to support asset strategies is in use
  - Strategies that fully incorporate customer input, commercial, and economic aspects
3. *Asset life-cycle maturity*: The end-state in this key sub-outcome is:
  - Dictating RCM Program with standards so that O&M work is optimized
  - Accurate and complete asset trend analysis is fully utilized,
  - Asset strategies for core sustain are established through total economic cost modeling based on quality data and thorough analysis so that backlog is reduced to acceptable risk, allowing the optimization of maintenance and capital
  - Transmission asset management will be balanced against other BPA asset categories, resulting in a BPA level prioritized investment portfolio

These sub-outcomes will be delivered in the immediate- and mid-term timeframe through implementation of: the Transmission Asset System ; initiation of the Transmission Asset Portfolio Management (TAPM) project with initial operational capability set and achieved; and work practices improvements in areas such as strategic capability planning, demand planning, contract approaches, and project portfolio development. Technology investment to support this key outcome will invest in condition monitoring, inspection assessment, maintenance, and incorporating technology to reduce the number of outages and time needed for maintenance, repair and replacement activities.

Improvements in Asset Management will be measured by changing from the current metrics to more disciplined measures of critical asset data, actionable standards, and the measures for Program Delivery.

**Technology:** *Existing and emerging technologies are developed, integrated with Transmission business and asset strategies, and applied to improve the transmission system by leveraging the Transmission technology roadmap, central technology governance and partnerships with BPA Technology Innovation, EPRI and others.*

Progress in this key outcome will be in two areas:

1. Driving technology to meet needs by identifying areas in which new technologies are needed and bringing academia, industry and other Federal Agencies to the table to produce technologies that meet that need.
2. Much more effective utilization of existing technologies that are already available and have not yet been implemented with Transmission Services.

Results in this key outcome will enable Transmission to leverage existing technologies such as Phasor Measurement Units (PMU) and advance in new technologies, for example in emerging advanced electronic controls such as Inter-area Oscillation Damping Controls and Response-Based Voltage Stability Controls and moving to major operational tools such as Dynamic Line Rating and other cutting edge applications.

### **Impact to Other Transmission Strategic Priorities**

Overall progress in all four outcomes envisioned by the System Infrastructure Strategic Priority is supported by, and significantly impacts the outcomes of the other Transmission Strategic Priorities (System Operations, System Reliability Compliance and Commercial Success). As the outcomes for the System Infrastructure strategic priority are achieved, major progress will be made towards system reliability in many key areas due to advances in system health, maintenance and in system availability as a result of reduced unplanned outages, increased system flexibility, available transmission capacity, system operating limits, and expanded opportunities for commercial success.

## **3.0 STRATEGY IMPLEMENTATION PLAN**

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### **3.1 Implementation Plan - Strategic priorities and supporting initiatives**

Over the past few years, key initiatives have been initiated to close major existing gaps in Transmission Services program delivery and asset management capabilities. An asset management roadmap of key initiatives has been developed with a focus on alignment and integration. These initiatives are well underway and are expected to support meeting the outcomes of the System Infrastructure Strategic Priority. The progress of the key initiatives is being measured and tracked through a FY2014 KTT for Asset Management. Beyond these, the identification of a strategy and plan for fully meeting the outcomes of the Transmission Strategic Priorities is a focus for FY2014.

#### **3.1.1 Asset Management Roadmap Capabilities Initiatives**

**Initiative:** *Asset register development*

**Gap(s) being addressed:**

- Deficiency in asset information and systems
- Maintenance / replacement decisions
- Implementation of changes to maintenance standards
- Effective asset trend analysis

This initiative is focused on furthering the development in the Transmission Asset System (TAS) and the Asset Data Management (ADM) function towards the enhancement of the Transmission asset register. There are four main areas of focus over the next three years.

1. The initial focus is on continued development of a hardened business process to ensure all incoming and outgoing asset data is processed in a manner that is consistent with good data management.
2. The second area of focus is on the completeness and accuracy of the asset data that is stored in the TAS database. The plan includes identifying the accuracy of current asset data. The degree of accuracy and completeness will inform decisions on how to correct the inaccuracies. The approach could be a complete inventory or an approach that corrects the inaccuracy in the normal course of operation.
3. The third focus will be on understanding and prioritizing requests for additional functionality or data gathering requirements of the TAS system.
4. The fourth focus will be two fold, but done in parallel in order to maximize the return on effort.
  - a) Gain a better understanding of what information is needed that is collected external to TAS and how to connect those data sources with the TAS data.
  - b) Understand what new processes will be needed to either collect new data or use existing data differently.

The above focus is understood to be subject to the prioritization of the changing compliance environment and will need to be adaptable.

The goals of the ADM program for FY2014 are to:

- Establish metrics for accuracy of data and the volume of work queued up for the ADM group to process, also known as the “backlog.”
- Create a quality management plan for the ADM group.
- Document the rationale for defining and managing the maintenance activities for the highest risk/most critical asset type per asset category (Lines, Subs, SPC, PSC).  
Establish the process for reviewing and managing the change of the items in bullets 1 and 3.

**Initiative: *Maintenance Management Strategy***

**Gap(s) being addressed:**

- Maintenance / replacement integrated decision approaches
- Implementation of changes to maintenance standards

The Transmission Maintenance Program performs regularly scheduled inspections, testing and monitoring, preventative maintenance, and corrective maintenance as needed. Even so, it is recognized that a more robust maintenance strategy, fully aligned and integrated with the asset life cycle is needed. The plan to further develop the maintenance strategy must be sequenced with efforts to:

1. Develop policies, processes, and procedures needed to implement an accurate asset register. These policies, processes, and procedures are a prerequisite for an accurate asset register and are currently being implemented. They are expected to be substantively complete by the end of second quarter FY2014. The ADM organization should be operational using the above policies, processes, and procedures by the end of FY2014. The ability to maintain and modify transmission asset data accurately is the cornerstone needed to address both existing compliance requirements and maintenance strategies.
2. Establish a reliability centered maintenance function to conduct asset performance analysis that will inform asset management strategies.
3. Keep pace with the evolving compliance requirements work to develop a plan to deliver on the “System Reliability Compliance” strategic priority that is foundational to developing and integrating maintenance strategies. Current compliance requirements dictate specific maintenance requirements and Transmission Services’ ability to react to the changes that the industry is facing must be addressed for the long term. The plan development is expected to be completed by the end of FY2014.
4. Develop and integrate the asset strategies using the common platform based on reducing total economic cost currently underway (see TASI below). This effort not only will identify data requirements for the asset register but will also inform the maintenance strategies as a driver on repair/replace decisions.

With results from the above efforts, Transmission Services can begin to consolidate these requirements to guide in the development and integration of the asset management strategies.

**Initiative: *Transmission Asset Strategy Integration (TASI)***

**Gap(s) being addressed:**

- Need for a single asset plan that is aligned across Transmission
- Sustain programs are not integrated within and between programs
- Challenges in ensuring investment decisions incorporate market and customer aspects

In recent years, Transmission Services has employed an industry-recognized consulting firm to facilitate its sustain programs through the development of strategic alternatives using an economic value-based approach that not only address the risks facing BPA's transmission system, but the regional risks as well. The approach quantifies all failures, outages, and line derates and aggregates their associated costs so that equipment replacements can be prioritized based on total economic value. Included in the strategic alternatives are recommendations for process improvements that have been determined to add value and potentially cut costs.

Once completed for all sustain programs, the result will be an integrated model that provides Transmission Services with the ability to target the most costly risks across all programs. Currently the strategies and resulting planning models have been integrated for the system protection and control (SPC), power system control (PSC), system telecom, and remedial action scheme (RAS) equipment. Over the next two years, work will continue to build and integrate these models for the rest of the sustain programs. It is expected that by 2016 all sustain strategies will have been developed using this approach and the tool for aggregating all transmission assets will be available for use in making trade off replacement decisions.

Specific process improvements have been identified for the four programs that have been evaluated and are currently in the process of being implemented. The FY2014 KTT is tracking the progress and achievements in

- Improving the state of the equipment documentation in the field for PSC equipment
- Enhanced training for PSC staff
- More rigorous testing of PSC and SPC equipment prior to field installation
- Development of policy and plans for RAS automation
- Development of plans for addressing RAS complexity

**Initiative:** *Transmission Asset Portfolio Management (TAPM)*

**Gap(s) being addressed:**

- Need for a single asset plan that is aligned across Transmission
- Lack of a dynamic and adaptive work planning process
- Metrics that do not accurately forecast program delivery with sufficient lead times to resolve shortfalls
- Need to incorporate demand planning and capability planning as part of asset strategies, IPR budgets, and asset plans development

The TAPM initiative is focused on three primary areas of improvement:

1. The development of a comprehensive system that will compile forecasted work for program planning, approval and funding, execution planning and status reporting.
  - In FY2014-2015, the TAPM project team will be developing and testing a system prototype. This will be converted into an enterprise-level, IT project beginning in FY2015-2016.
2. Application of the Lean methodology to the capital project process, the business process for planning to execution of capital work.
  - Focus will be on streamlining processes and eliminating waste and non-value-added work from targeted sub-processes.
3. Continue improvements in the process to identify and analyze resource requirements for implementing asset plans, known as demand planning and strategic capability planning.
  - In FY2014, this effort will identify and deliver on improvement opportunities to support managerial use of demand planning scenarios and to further reduce the effort required to create demand planning scenarios. Improvements may include, but are not limited to: shaping demand, customizing capacity constraints, statusing work in progress, adjustable resourcing, scenario automation, integrations with project portfolio creation and work plan management and control.

**Initiative: *Improvement in Execution/Project Management Office capabilities*****Gap(s) being addressed:**

- Project management capability and the Plan, Design, Build (PDB) throughput required for project delivery.
- Program development that has not fully incorporated key resource constraints in both budgeting and delivery resources.
- Need to incorporate demand and strategic capability planning as part of asset strategies, IPR budgets, and asset plans development

Continued progress is planned for building the capabilities of the Transmission Project Management Office (PMO) to facilitate the successful execution of increasing number of projects. In FY2014, the PMO will focus on the following program elements:

- In coordination with improvements in demand and strategic planning, improve the accuracy of the annual resource availability forecast for existing groups and add other groups not currently reporting in the capacity planning tool
- Introduce the concept of Project Portfolio Management in order to improve the ability to deliver the maximum amount of productivity within the Transmission Capital Projects Organization (at large). This includes the transition away from managing smaller disparate work items, to delivering complete and integrated project solutions
- Improve “project team” related processes and performance, including targeted IT solutions for creating local effectiveness and efficiency
- Create an objective-driven PMO, staffed appropriately
- Implement a newer version of Microsoft Project to enable workflow + process integration
- Prototype enterprise-wide solutions for managing project delivery across the capital project organization

Focus for FY2015 and beyond:

- Identify and mitigate portfolio constraints and manage portfolio level risks through a centralized strategy and process
- Allow room for experimentation within the project management arena to establish a clearing house for best practices in terms of process systems and job aids.
- Create Communities of Practice and develop standards and best practices within these communities

**Initiative: *Get Work Accomplished (GWA) Initiative*****Gap(s) being addressed:**

- Project management capability and the Plan, Design, Build (PDB) throughput required for project delivery.
- Contracting approaches that were designed for larger expand projects, but do not meet the needs of the sustain program’s smaller projects
- Scope definition challenges as projects are planned and designed that impact build
- Major impact of outages, land, State and Federal permits and other constraints on project delivery
- Challenges in resourcing the work of planning, designing, and building with current BPA and contracted resources.

This initiative is in direct support of addressing the constraints impacting the ability to fully implement the sustain programs strategies as currently defined. Three specific areas are being focused on to close the execution gaps experienced by most of the sustain programs.

**1. *Early Scope Development***

Early scope development (ESD) will be conducted during the late planning phase, utilizing BPA staff and contracted owner’s engineer subject matter experts to identify and address gaps between planning and execution that reduce

efficiency and effectiveness, particularly in accomplishing the core sustain work. This will have the benefit of providing time to detect problems and apply mitigation when performed two to three years in advance of execution, thereby reducing delay and inefficiency during execution. In addition, by performing a “programming” step at this point in the project lifecycle to test dependencies and coordination with other projects in the portfolio related by location or systems integration will further reduce delay and re-work during execution. Applied over the long term, Early Scope Development and programming will provide the necessary integration and visibility to optimize and sustain these improvements.

Current ESD progress: Under the Transmission PMO’s guidance, BPA’s internal engineering forces and contracted engineers scoped the high priority FY2014 new start projects. Separately, the system telecommunications planning and design organizations joined forces to scope proposed telecommunication projects (e.g. radio stations.) The GWA core team observed scope development of projects by both BPA and contracted engineers to document the current effort, identify additional opportunities and prepare recommendations. It is expected that an organizational home, as well as clarification of roles, duties and performance expectations of the ESD and programming functions are to be determined in FY2014.

### *2. Pursuing additional contracting opportunities*

In FY2014, the GWA core team will be investigating several options for meeting program needs with additional contracting opportunities, such as contracts to manage multiple smaller projects and/or supplemental labor.

### *3. Outage Planning and Utilization*

The GWA staff will work with Transmission Operations on outage management with a focus towards:

- Master planning
- Coordination of outage requests
- Tools to assess outage risks

#### **Initiative:** *Critical spares strategy*

##### **Risk being addressed:**

- BPA enterprise risk of business continuity

To meet the mission essential function (MEF) of delivering power to load in a reliable manner, BPA needs the ability to restore service following disruptions to the grid. BPA can better meet the objectives of this MEF with the capability of knowing what critical spares are available, where they are located, and how to best deliver them to field sites during an emergency.

The FY2014 Asset Management KTT includes an initiative to develop a Transmission Critical Spares Strategy and create a unified way to access critical spares inventory information. This will serve to address BPA’s Continuity of Operations objectives and will increase BPA’s long-term ability to restore service following disruptions to the grid by ensuring critical spares are properly positioned with viable transportation alternatives. By the end of FY2014, it is expected that the Critical Spares team will have:

- Performed a gap analysis between the risk assessment completed by the Enterprise Risk Management group and the existing Emergency Minimum Stock (EMS) policies and created a strategy for closing the gaps
- Conducted and assessed a sample inventory at field sites and warehouses of critical spares/EMS to validate and determine accuracy of existing inventory data for count and location and incorporate results into the strategy

### 3.1.2 Process Performance Metrics

In addition to realizing improvements in program delivery and asset management fundamentals, results of many of the initiatives listed in the previous section are expected to yield greater efficiency and productivity of Transmission staff. Examples of the process performance metrics Transmission Asset Management will be monitoring and measuring include:

#### TAS Lines project

The purpose of this project is to improve upon the state of lines asset data and condition. Currently data on transmission line demographics, health, utilization, performance and costs is often incomplete, inconsistent in quality, or siloed between business functions. The project is directed towards providing a solution to support meaningful analysis on lines assets that will lead to better investments and maintenance decisions, reliability and availability of the system, and efficiencies in use of capital and staff resources.

The following labor benefits will be tracked and measured after the implementation of the TAS Lines project in FY2015.

| Benefit description   | Metric  | Baseline (current)                   | Target (goal)                 | Comments   |
|---|---|--------------------------------------|-------------------------------|--|
| Improved TLM labor efficiency from better access to information   | A gain of 1hr/wk per lineman in efficiency      | 2012 actual TLM labor costs = \$8.8M | Annual labor benefit = \$442K | .50 hr gain in efficiencies by the TLM craft and .50 hr gain by supporting staff (such as engineering) |
| TLM labor efficiency gains due to improved maintenance practices reflected in decreased cost/hr of work performed | 10% overall gain in labor efficiency            | 2012 actual TLM labor costs = \$8.8M | Annual labor benefit = \$880K | Precedent has been demonstrated in same metric for ITF assets.   |
| Improved RCM analysis results in efficiency gains in execution of maintenance program                             | \$880k labor savings over 7 year life of system | 2012 actual TLM labor costs = \$8.8M | Annual labor benefit = \$125k | Savings/Benefits evolve for 7 years to reach 100%.   |

#### Transmission Asset Portfolio Management System (TAPM)

This investment is needed to replace a patchwork of generic tools with one designed to manage asset portfolios. Today, each step along the asset management and planning process through the execution tracking process is supported with autonomous tools – typically MS-Access databases or MS-Excel spreadsheets. Transmission Services tracks thousands of projects and metadata over a 10- to 30-year life period. Data does not naturally flow from one step to another and people are forced to replicate and reconcile data every step of the way. It is also extremely difficult to track the progress of the asset programs from planning through execution. This is inefficient and error-prone, and it slows the pace at which work is prepared for execution and provides limited visibility to track program/project execution. These issues are some of the contributing factors to under-delivery of the planned capital program in recent years.

At the conclusion of this project, much efficiency is expected to be realized through time-saving processes and integrated systems. In preparation for the capital IT project that supports this effort, studies will be performed to determine the current labor requirements for analyzing and managing this vast amount of data. Metrics and targets

for the improvement in productivity of staff performing these tasks will be determined once these studies are completed.

### 3.1.3 Risks to meeting the objectives

The future state in the Transmission Strategic Priorities has specified an aggressive target to close many key gaps by 2018. While section 3.1.1 described the effort underway to close many of the gaps, many of the risks to achieving the recommended objectives reach across all of BPA. The following are a few of BPA's Top Enterprise Risks that will have an impact on when and how Transmission Services will meet the goals of the System Infrastructure Strategic Priority. Success is contingent upon the development of a BPA overarching approach for mitigating the effects associated with these risks.

- Addressing the changing business environment
- Workload and resource balance
- Talent adequacy
  - ◆ Succession planning for key positions
  - ◆ Hiring constraints for filling vacancies
- Regulatory and compliance continued evolution

While not insurmountable, other risks to the objectives will take substantial time to define and develop feasible mitigation plans.

- Dependencies with external agencies and organizations (Bureau of Land Management, US Forest Service, tribal partners, etc.) to meet regulatory needs such as permitting, in a timely manner for adequate project planning and implementation
- System operational impacts of needed outages to perform replacements in relation to availability requirements
- Asset register deficiencies and the time needed to correct may not fall into strategic timeframe.

# **ALTERNATING CURRENT SUBSTATION PROGRAM ASSET MANAGEMENT STRATEGY**

Jerry Almos, Program Manager  
December 2013

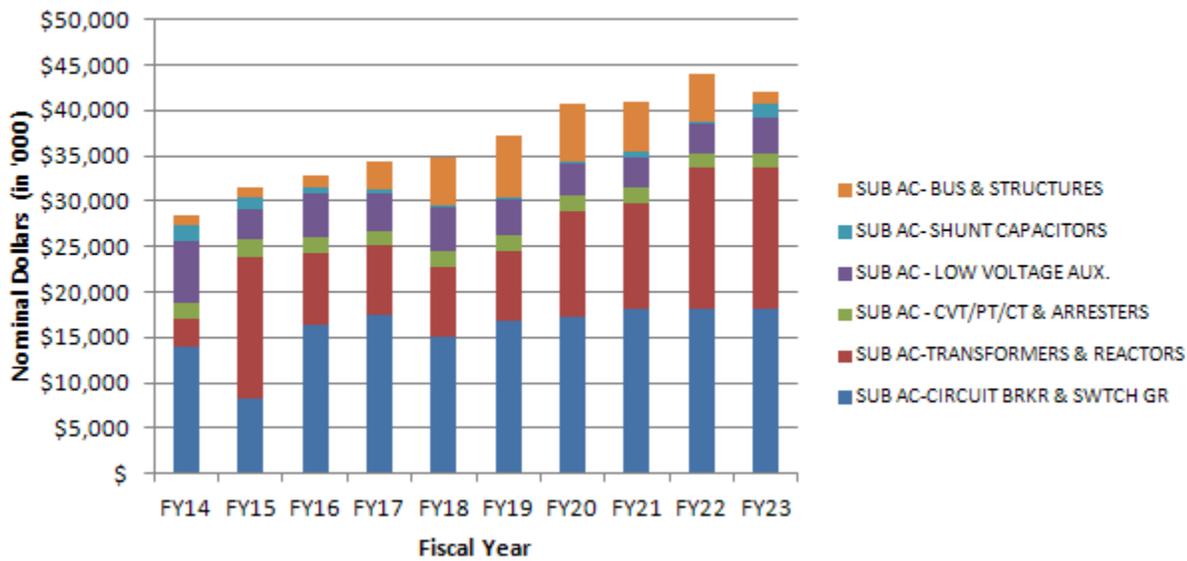
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## EXECUTIVE SUMMARY

### AC Substations program overview

- Approximately 298 alternating current (AC) Substations on the BPA system, over 50 operate at 500kV
- Approximately 27,000 major (serial numbered) pieces of high voltage electrical outdoor substation equipment and another 5,000 with limited attribute data
- Assets:
  - ◆ Power Transformers, Power Reactors, HV Transformer and Reactor Bushings, and Current Limiting Reactors
  - ◆ Power Circuit Breakers, Circuit Switchers and Disconnect Switches
  - ◆ Shunt Capacitors
  - ◆ Instrument Transformers
  - ◆ Arresters and Rod Gaps
  - ◆ Control Batteries and Chargers
  - ◆ Station Service (SS), SS Transfer Switches and Engine Generators
  - ◆ Control Houses, Foundations, Structures, Substation Bus and Insulators

**AC Substation Capital Forecast FY2014-2023**



### Key risks to be addressed

- Unplanned equipment replacements due to failures and failure rates
- Over or underinsuring caused by replacing too soon or too late in equipment life cycle
- Delays caused by planning, work processes, and work procedures
- Inadequate vendor support
- Spare parts availability or cost
- Technology obsolescence
- Work force availability and efficiency

**Strategy Elements**

Modeling and analyzing equipment replacement on a total economic cost basis revealed there is a large backlog of equipment beyond its economic lifecycle that will be now need to be addressed in this strategy timeframe. This drives the implementation of a strategy that includes:

- Replacement plans to address backlog are based on economic lifecycle
- Development and implementation of predictive analysis using information from relays, sensors and cameras, and information currently collected through inspections, SCADA and other maintenance data bases
- Improving work related processes
- Strategic placement of on-site spares for transformers and reactors

In the long run, this strategy will help:

- Set the pace of planned replacements that reduces the frequency of failures, which has an impact on preventative maintenance, corrective repairs and emergency replacements, thereby reducing the economic cost to BPA and to BPA's customers
- Reach a steady state, where most work is planned, there is stable and constant system reliability

**1.0 STRATEGY BACKGROUND****1.1. Business Environment****Customers and Stakeholders Served**

- Network Transmission Customers – Utilities (Public & Investor owned) & Generators (Independent Power Producers – IPP's & Federal Hydro)
- Delivery Customers – Small utilities (public), small IPP's (co-generation), Tribal PUD
- BPA Internal – System Protection and Control (SPC), Power System Control (PSC), Substation Operations, Substation Maintenance, Billing, Non Electric Plant (NEP) Facilities, Energy Efficiency; Environment, Fish & Wildlife

**Products and Services**

- Network Services: AC sustain enables interconnection/transfer Service (IOU's, PUD's)
- Generation Integration: (Hydro, Wind, Thermal, Coal, Co-Generation)
- Delivery Service: Radial service - Public utilities, small investor owned utilities (IOU's) (load service)
- Reactive Compensation: VAR Support, Available Transfer Capability, System Operating Limits
- Measurement & Indication (voltage & current) for System Protection & Control, Revenue Metering, Control Area & Interchange Scheduling, Automatic Generation Control
- Spare power transformer support for regional customers and nationally - member of EEI (Edison Electric Institute) STEP Program since 2006

**Strategic Drivers**

- Historically, BPA has primarily replaced AC substation equipment based on failures or failure rates, asset condition assessment, system upgrade (capability/capacity), and asset risk (failure and consequence)
- Long term vendor support is increasingly limited, which affects spare parts availability and cost
- Small Control Houses are lacking space for station upgrades and new equipment replacements which can take up more space due to increased capacity or redundancy required by regulations (NERC-CIP, etc.)
- Technology obsolescence
- Workforce availability - the loss of skilled/experienced workers through retirement and attrition is a major factor in maintaining older equipment

- Reporting requirements are increasing for substation equipment maintenance, equipment failure tracking/trending, and equipment ratings (thermal/continuous).

**Increasing Demands on AC Substation Assets**

- A key Transmission asset management goal is to make fuller, more optimal use of existing system capacity. Among other impacts, this goal may lead to:
  - ◆ Tighter margins on reliability and availability and ultimately equipment performance
  - ◆ Reduced tolerance for equipment failure
  - ◆ Reduced outage availability for maintenance
- Load growth is projected to continue putting increased demands on existing equipment in terms of loading (thermal ratings), fault duty (short circuit ratings) and decreased outage availability for maintenance or system disturbances (contingencies)
- Integration of generation, such as wind generation, is also growing. Existing substation equipment can accommodate, to some extent, integration of key wind and other generation resources. However, using up existing system capacity tends to:
  - ◆ Put increased demand on equipment (thermal and short circuit ratings)
  - ◆ Reduce operating margins that allow for system contingencies, and
  - ◆ Reduce maintenance and operational flexibility
- Generation is often connected radially which creates constraints on the availability of terminal equipment and line outages for maintenance.
- Increasing demand to monitor, test, and report on equipment condition, both for regulatory and program strategy purposes and ensure all data in the Transmission Asset System (TAS) is accurate for regulatory reporting.

**On the strategic radar are future opportunities in data collection:**

- Use of relays to collect data on CVT secondary voltages, breaker operation time, fault current interruption ( $i^2t$ ), and thorough fault information
- Automatic data collection for counters and temperature readings imported into TAS from PI (Plant Information System) rather than taking manual readings
- Import of data from TOA (Transformer Oil Analysis) and PowerDB (Battery Testing) into TAS

**1.2 Assets, Asset Systems and Criticality**

**AC Substation Assets**

Program Profile: Approximately 298 Substations and 32,000 major pieces of equipment

| Asset                     | Count | Description  |
|---------------------------|-------|--|
| Power Transformers        | 668   | Convert power (voltage and current) to maximize the efficiency in moving and delivering power between generation sources and load centers. All 500kV, 345kV and many 230kV power transformers are considered critical equipment.   |
| Power Reactors            | 120   | Serve two primary roles: 1- Controlling system over voltages, particularly during light load conditions; 2 - Reducing system currents caused by transient or fault currents. All 500kV reactors are considered critical equipment. |
| Current Limiting Reactors | 652   | Reduce transient and fault currents caused by normal switching and short-circuit system events to levels within the ratings of existing equipment.   |

| Asset   | Count   | Description  |
|---|---------|--|
| Fuses   | 1,569   | Protects power transformers in substations, by providing interruption of permanent faults.   |
| Power Circuit Breakers                                | 1,907   | Protect transmission lines and transformers by clearing system disturbances caused by events such as faults or lightening.   |
| Circuit Switches                                      | 214     | Primarily used to switch reactive equipment (Capacitors and Reactors) in and out of service. Circuit Switchers are also used on a limited basis to clear faults.   |
| Disconnect Switches                                   | 6,578   | An isolation device used to separate equipment or transmission lines from the transmission system for maintenance or replacement activities.   |
| Shunt Capacitor                                       | 226     | Provide reactive compensation to increases power transfer and boost system voltage during heavy load conditions. Small air core current limiting reactors are used in conjunction with multiple capacitor groups on the same bus to limit transient currents that can damage equipment while switching.  |
| Instrument Transformers                               | 7,080   | Provides the raw current and voltage data from the power system for protection and control relaying, revenue meter data, AGC, generation and stability control and condition monitoring  |
| Surge Arresters                                       | 3,695   | Protective devices that control over-voltages caused by voltage transients caused by switching or during system events such as lightning and faults.   |
| Rod Gaps  | Unknown | A crude form of surge protection against over-voltages. Upon each operation a line fault is created that must be cleared by a breaker thus de-energizing the line. This momentary outage can contribute to SAIFI and SAIDI.<br>Rod Gaps are actively being replaced with surge arresters.  |
| Control Batteries                                     | 283     | Provides uninterruptable power to relays, control, indication, security, and communication systems.  |
| Control Batteries Chargers                            | 538     |  |
| Station Service                                       | 1,063   | Supplies AC power to control cabinets, heaters, cooling equipment, station yard power and Non Electric Plant (NEP) facilities within substations.  |
| Transfer Switches                                     | 141     | Used to transfer the AC power between primary and secondary sources of AC station service. A reliable secondary source of AC station service can be provided by a separate source within the station, through local utilities or engine generators.  |
| Engine Generators                                     | 57      | Provides a reliable back up power for critical AC loads when the primary source is lost.   |
| Substation Bus, Structures, Foundations, Rigid Risers | Unknown | These supports and structures provide the required electrical clearances or spacing between energized equipment (phase-to-phase); energized equipment to ground, and safe working distances for personnel and HV electrical equipment to work and operate safely.<br>The replacement of rigid risers with flexible jumpers is done to prevent damage during a seismic event. |
| Control Houses  | ~250    | Contain batteries, relaying, control and indication, metering, SCADA and communication equipment.  |

**Criticality**

| Less Important                                   |                      | More Important            |                                   |
|--|----------------------|---------------------------|-----------------------------------|
| Substation Bus and structures                    | Rigid Risers         | Shunt Capacitors          | Power Transformers                |
| Station Auxiliary excluding DC control Batteries | Substation grounding | Disconnect Switches       | Power Circuit Breakers            |
|  |                      | Current Limiting Reactors | Circuit Switchers                 |
|  |                      | Instrument Transformers   | DC Control Batteries and Chargers |
|  |                      | Fuses                     | Surge Arresters                   |

As work continues to evaluate the criticality of equipment based on its impact to total economic cost, these criticality assumptions could possibly change.

## 2.0 THE STRATEGY

### 2.1 Current State

#### 2.1.1 Program Accomplishments for FY2012-2013

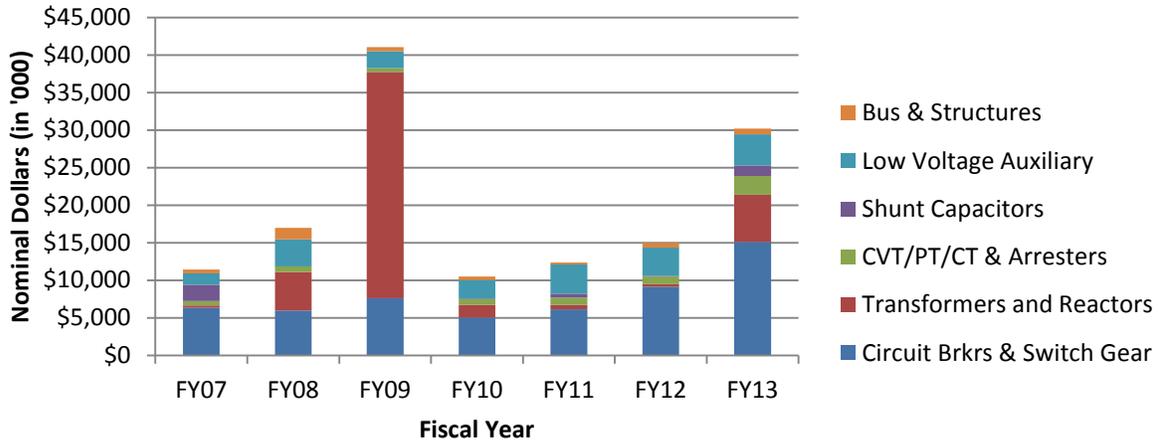
| Equipment                     | 2012   |           | 2013   |           |   |
|-------------------------------|--------|-----------|--------|-----------|---|
|                               | Design | Construct | Design | Construct |   |
| Arresters / Rod Gaps          | 30     | 73        | 184    | 136       | Emergency replacements - 15 in 2012, 14 in 2013             |
| Battery                       | 16     | 17        | 30     | 16        |   |
| Disconnect Switches           | 11     | 28        | 25     | 6         | Emergency replacements - 9 in 2012, 5 in 2013               |
| Instrument Transformers       | 43     | 32        | 44     | 40        | Emergency replacements - ALL                                |
| Power Circuit Breaker - 500kV | 14     | 3         | 2      | 5         | Emergency replacements - 1 in 2013                          |
| Power Circuit Breaker - Other | 9      | 20        | 19     | 13        | Emergency replacements - 1 in 2012, 4 in 2013               |
| Power Reactor - 500 kV        | 0      | 0         | 1      | 0         | One failure in 2013   |
| Reactor - Other               | 0      | 0         | 1      | 0         | One failure in 2013   |
| Rigid Risers                  | 9      | 5         | 12     | 13        |   |
| Shunt Capacitors              | 0      | 0         | 2      | 1         |   |
| Station Service               | 2      | 3         | 3      | 2         |   |
| Transformer Auto- 500kV       | 1      | 0         | 0      | 0         | One delivered and purchased in 2013 to be installed in 2014 |
| Transformer Auto - Other      | 1      | 0         | 0      | 0         | One delivered and purchased in 2013 to be installed in 2014 |
| Transformer - Other           | 0      | 0         | 1      | 0         |   |
| Totals                        | 136    | 181       | 324    | 232       |   |

### 2.1.2 Cost History

#### Historical Actuals - Capital

- Capital spend in 2009 ramped up significantly for Transformers & Reactors due to the purchase of five emergency spare transformers to reduce outage duration and to locate additional spares in regional locations to avoid transportation bottlenecks.
- In 2012-2013, completed the installation of five (5) 500kV circuit breakers and purchased material for the remaining nine (9) 500 kV circuit breakers which will be installed throughout 2014 .

**AC Substation Historical Actuals - Capital FY2007-2013**



#### Historical Actuals – Capital

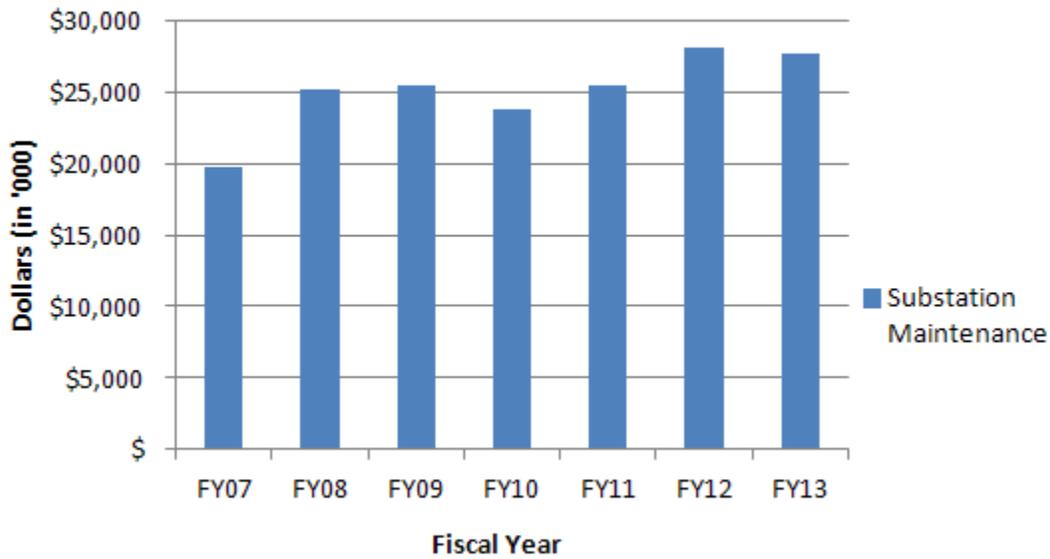
Dollars in '000

| Level 5 Node Name      | FY07            | FY08            | FY09            | FY10            | FY11            | FY12            | FY13            | Total            |
|------------------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|------------------|
| Circt Brkr & Switch Gr | \$6,352         | \$5,981         | \$7,609         | \$5,038         | \$6,123         | \$9,154         | \$15,137        | \$55,394         |
| Transfrmrs & Reactors  | \$292           | \$5,117         | \$30,139        | \$1,679         | \$633           | \$350           | \$6,233         | \$44,443         |
| CVT/PT/CT & Arresters  | \$618           | \$742           | \$514           | \$802           | \$959           | \$1,009         | \$2,535         | \$7,179          |
| Shunt Capacitors       | \$2,134         | \$30            | \$62            | \$496           | \$82            | \$1,386         | \$4,190         | \$4,190          |
| Low Voltage Auxiliary  | \$1,528         | \$3,592         | \$2,230         | \$2,442         | \$3,893         | \$3,783         | \$4,147         | \$21,615         |
| Bus & Structures       | \$506           | \$1,526         | \$551           | \$498           | \$266           | \$630           | \$782           | \$4,759          |
| <b>Total</b>           | <b>\$11,430</b> | <b>\$16,988</b> | <b>\$41,043</b> | <b>\$10,521</b> | <b>\$12,370</b> | <b>\$15,008</b> | <b>\$30,220</b> | <b>\$137,580</b> |

#### Notes:

- The actuals above reflect the addition in 2009/10 of many new capital replacement equipment categories for financial reporting and the transfer of projects from “miscellaneous” and “upgrades & additions” categories to the newer more specific equipment categories.

### Substation FY2007-13 Historical Actuals - Expense



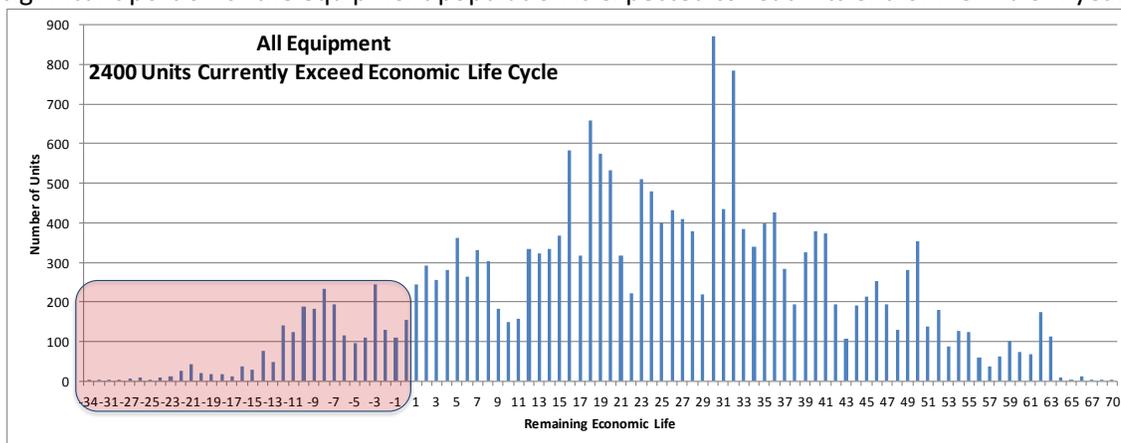
#### Historical Actuals - Expense

Dollars in '000

|                        | FY07     | FY08     | FY09     | FY10     | FY11     | FY12     | FY13     | Total     |
|------------------------|----------|----------|----------|----------|----------|----------|----------|-----------|
| Substation Maintenance | \$19,706 | \$25,154 | \$25,522 | \$23,809 | \$25,522 | \$28,056 | \$27,725 | \$175,496 |

### 2.1.3 Health of Current Assets (Current Condition & Performance)

The following histogram represents the number of substation equipment on BPA's system in terms of its economic life. As shown, there is a large backlog of equipment (i.e. equipment that is beyond its economic lifecycle), that should have been addressed before 2014 and will now lead to a spike in the number of replacements that will need to be done beyond 2014. There are also several asset "walls" in future years. An asset "wall" is defined as when a significant portion of the equipment population is expected to reach its end of life in a 3-4 year time period.



## 2.2 Future State

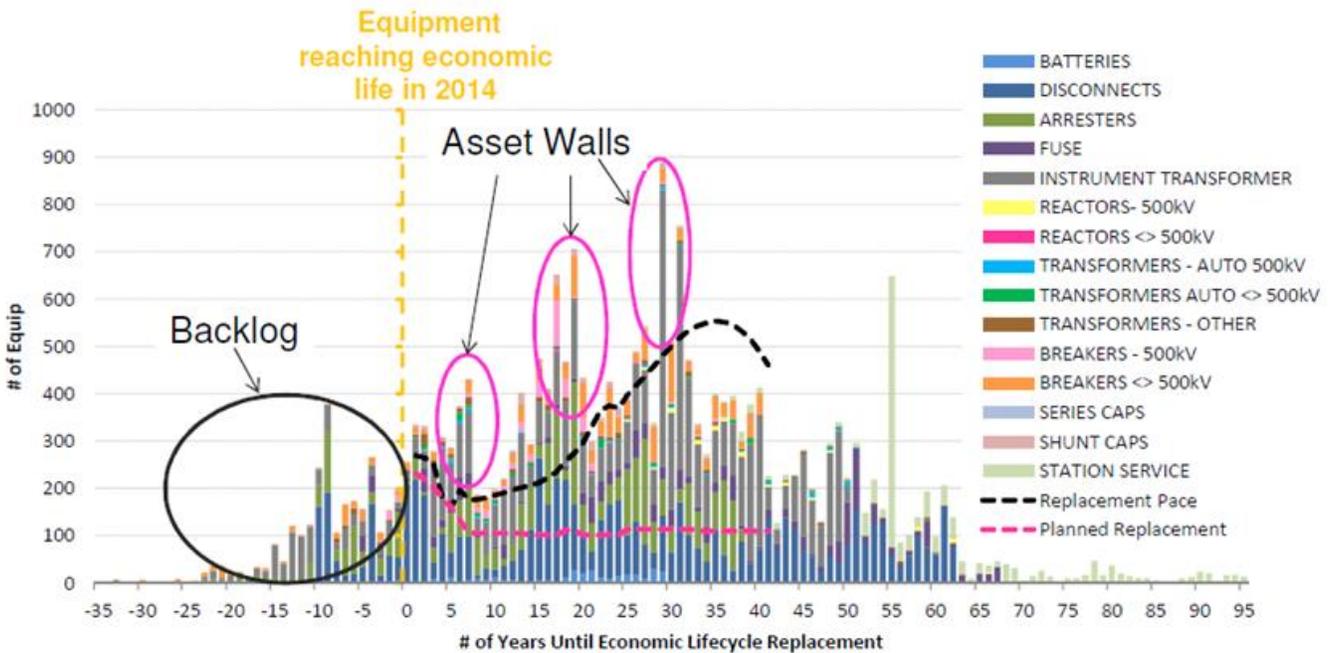
### 2.2.1 Key asset performance objectives, measures and targets

The AC Substations program has recently gone through the process of developing a risk-informed asset management strategic approach where substation assets are planned for replacement based on reducing total economic cost. This strategy includes a quantification of not only risks to BPA, but to BPA’s customers as well.

The plans for how to implement this strategy are currently in development. Once this occurs, performance objectives, measures and targets will be drafted to represent the approach that will be taken to implement this new strategic approach. It is expected that the detailed strategy planning phase will start in the middle of Q2 FY2014.



## 2.3 Asset Condition/Performance Gaps



BPA’s substation equipment has been determined to be older than many other utilities, which is a large contributing factor to the backlog and asset walls seen in the chart above. Additionally, the current state of substation equipment has been caused by:

- Delay of replacing some equipment, causing an increase to the backlog
- System capacity is increasing while equipment operating margins are decreasing due to effective age and/or effective life cycle

- Unplanned replacement of equipment due to failures and failure rates
- Delays caused by planning, work processes and work procedures
- Reduced vendor support
- Limited or inability to obtain spare parts and cost of the spare parts
- Technology obsolescence
- Workforce availability

As a result of the gaps listed above, there will be a higher risk probability and consequence to substation assets in the future until a steady state can be achieved. These assets include all of the “more critical assets” identified in section 1.2, such as transformers, circuit breakers, circuit switchers, batteries and chargers, surge arresters and shunt capacitors. According to the total economic cost modeling, a steady state can be achieved by FY2023 and will yield full benefits in ~40 years if the replacement pace (dotted black line in the chart) is met. This includes the ramp up of equipment replacements to eliminate the backlog of equipment beyond its economic life.

In addition to ramping up replacement pace, BPA has increased the amount of condition-based inspections (e.g. monitoring oil levels) to supplement age-based analysis. More automated approaches, such as temperature sensors for condition monitoring is detailed in section 2.4.1.

### 2.3.1 Risks to meeting objectives

The risks to meeting the objectives will be identified after performance objectives are developed in conjunction with the detailed strategy planning phase.

#### Execution constraints

The Substation program and the successful execution of the strategy rely heavily on asset data and performance analysis. The Asset Data Management (ADM) and Reliability Centered Maintenance (RCM) functions are critical for accurately capturing and analyzing the data derived from maintenance and condition assessments. As described in the Transmission Asset Management Overarching strategy, there is an effort underway to address the requirements for fully establishing these functions. These capabilities will enhance the planning and execution of the substation strategy through

- Better visibility in TAS of lines and transformer outages forced out of service by equipment such as instrument transformers, arresters and disconnect switches
- Mapping of the spare parts availability to equipment
- Determination of what information needs to be collected on Substation Operations inspections that will trigger actions
- Identification of information that needs to be collected on non-serial numbered equipment, such as foundations, pedestals, insulators, ground grid, etc.  
Application of standard inspection, maintenance, and replacement criteria to Substation Bus & Structures, including foundations, pedestals, insulators and substation bus

## 2.4 Strategic Approach to Closing Gaps

### 2.4.1 Strategic Approach

The strategic approach for managing Substation equipment, determined to offer the greatest economic value is a combination of an optimal replacement plan based on economic lifecycle, predictive analysis, process improvements, and the strategic location of spares.

It is expected that in the long run, this strategy will reduce the economic cost to BPA and BPA’s customers and levelize the program to a steady state of planned work and resources as well as stable and constant system reliability.

**Replacement plans based on economic lifecycle to address backlog:**

The economic lifecycle replacement determines the best interval of replacement based on the likelihood of failure and the economic impact of the failure based on the quantification of the following elements:

- Regulatory violations
- Unplanned and planned transmission and customer outage costs
- Ongoing business costs associated with operations and maintenance
- Change in cost of energy delivered, which is often a consequence congestion created by transmission de-rate and outages. It reflects the potentially higher generation costs (BPA cost) and higher electricity prices (non-BPA).
- The pace of planned replacement. This impacts the frequency of failure which has an impact on the repairs and premium for emergency replacements.

The following table gives the economic perspective of when equipment should be replaced based on total economic cost.

| Equipment                    | Current Practice (years equip stays on system) | Economic Lifecycle & Equip Replacement Per Year |              | PV Benefit of Economic Replacement (\$M) |
|------------------------------|--|---|--------------|--|
|                              |  | years   | replace / yr |  |
| Arresters/ Rod Gaps          | 47   | 38-39   | 97           | 211                                      |
| Power Transformer Other      | 80   | 67-75   | 4.9          | 62                                       |
| Disconnect Switches          | 57   | 64-67   | 102          | 51                                       |
| Power Circuit Breaker 500kV  | 35   | 41-46   | 8.4          | 41                                       |
| Power Circuit Breaker Other  | 55   | 41-46   | 35           | 28                                       |
| Power Transformer Other Auto | 70   | 72-80   | 2.4          | 13                                       |
| Series Capacitor             | 35   | 21-23   | 1            | 5  |
| Shunt Capacitor              | 35   | 34-35   | 6            | 2  |
| Batteries / Chargers         | 23   | 29-30   | 9.4          | 0+                                       |
| Instrument Transformers      | 47   | 52-54   | 134          | 0+                                       |
| Power Transformer 500 Auto   | 70   | 54-64   | 2.1          | 0+                                       |
| Power Reactor- 500kV         | Run until major problem                        | 72-79   | 1.3          |  |
| Power Reactor- Other         |  | 67-69   | 0.3          |  |
| Fuse Links                   |  | 72-73   | 23           |  |
| Station Service              |  | 100   | 18           |  |
| Substation Bus               |  | 78-79   | 10.1         |  |

As shown in the table, for most equipment categories, equipment was not being replaced on economic lifecycle. Switching to an economic lifecycle based replacement strategy will provide BPA with the ability to balance equipment replacement frequency against repair and the unplanned outage cost of a failure, thereby reducing cost to BPA and customers.

- Current practice is to replace equipment before it’s too old and likelihood of failure is too high.
- When replacements occur prior to economic life, this results in over-insuring. The equipment still has useful life and there is low risk of failure and unplanned customer outages.

- When replacements occur beyond the economic life, this results in under-insuring. When equipment is allowed to remain on the system beyond its economic life, there is a greater risk of failure, outages, increased maintenance, and emergency replacements.
- Replacing based on economic lifecycle creates value. Replacing arresters and disconnects create a high level of value due to their population and impact of failure.
- The pace of planned replacement impacts the frequency of failure, which has an impact on the repairs and premium for emergency replacements.
- The replacement pace also determines the total replacement cost i.e. the more frequently equipment is replaced, the higher the total replacement cost.

#### **Expanded predictive analysis:**

Predictive analysis reduces the number of equipment failures and time spent in planned and unplanned outages through better use of information from inspections as well as information from relays, sensors and cameras.

Predictive analysis will

- Reduce emergency repairs and replacements and can catch forced outages before they happen. Planned work reduces emergency premium.
- Increase equipment life through timely maintenance. Fewer equipment failures will be experienced due to reduction in the effective age of the equipment.
- Identify the equipment with the poorest health and target for replacement leading to better informed planned replacements.
- Provide cradle to grave information to help systematically increase the likelihood of targeting the worst condition equipment.
- Identify better positioning of on-site spares resulting in a reduction in the duration of unplanned outages. Cost of moving spares will be incurred less often.

#### **Implementing process improvements:**

The strategy recognizes the value from efficiencies that will be gained in the future through four main process improvements: continued coordination with expand projects, bundling across programs, prequalifying contract labor, and performing bay-to-bay maintenance and planned replacement work between assets and crafts. This will result in:

- Reduction in planned outage requirements
- Maintenance and replacement labor efficiency
- Increase in contract labor efficiency which alleviates BPA resource constraints
- Cost savings from competitive contractor bidding

#### **Substation upgrades and additions:**

Coordination with the upgrades and additions portion of the expand program resulted in the development of a programmatic approach for two critical substation components, control houses and engine generators. Space constraints found in many control houses were impacting the ability to make necessary equipment upgrades and replacements. In conjunction with the Facilities Asset Management group, an evaluation of alternatives was performed that resulted in the recommendation and approval to replace specific control houses with cost-effective modular facilities in a programmatic manner. It is expected that replacements will be targeted and performed over the next 10 years. Likewise, an evaluation of the engine generators used for substation back up power indicated deficiencies in reliability and meeting capacity requirements. A programmatic approach for upgrading and replacing critical engine generators has now been approved and will be implemented over the next 10 year timeframe.

**O&M Flex Program:**

The O&M Flex program has been established to identify projects that have the potential to reduce the number and severity of BPA Transmission System operational issues. A programmatic approach to recommend and develop the capital upgrade projects in BPA’s substations in response to these issues has been developed. It is expected that improvements resulting from these investments will further enhance system reliability by providing alternatives to planned outages to perform some operations, maintenance, and replacement activities.

**Addition and strategic location of on-site transformer and reactor spares**

By using predictive analysis to determine the placement of spares based on the likelihood of failure, it has been estimated that adding on-site spares for critical transformers and reactors at specific locations where the economic cost of an outage is higher, will result in cost savings in the long run.

### 3.0 STRATEGY IMPLEMENTATION PLAN

#### 3.1 10 year Implementation Plan

| Equipment                     | Ramp to get to Steady State |     |        |     |        |     |        |     |        |     |        |     |        |     |        |    |        |     |        |     |
|-------------------------------|-----------------------------|-----|--------|-----|--------|-----|--------|-----|--------|-----|--------|-----|--------|-----|--------|----|--------|-----|--------|-----|
|                               | FY2014                      |     | FY2015 |     | FY2016 |     | FY2017 |     | FY2018 |     | FY2019 |     | FY2020 |     | FY2021 |    | FY2022 |     | FY2023 |     |
|                               | D                           | C   | D      | C   | D      | C   | D      | C   | D      | C   | D      | C   | D      | C   | D      | C  | D      | C   | D      | C   |
| <i>Substations:</i>           |                             |     |        |     |        |     |        |     |        |     |        |     |        |     |        |    |        |     |        |     |
| Arrestors / Rod Gaps          | 150                         | 114 | 125    | 150 | 120    | 125 | 101    | 120 | 101    | 101 | 105    | 101 | 96     | 105 | 96     | 96 | 96     | 96  | 96     | 96  |
| Battery                       | 9                           | 31  | 10     | 9   | 10     | 10  | 10     | 10  | 9      | 10  | 10     | 10  | 9      | 10  | 10     | 10 | 10     | 10  | 10     | 10  |
| Transformer Auto- 500kV       | 1                           | 1   | 1      | 1   |        | 1   | 1      | 0   | 1      | 1   | 1      | 1   | 1      | 1   | 2      | 1  | 2      | 2   | 2      | 2   |
| Transformer Auto - Other      | 1                           | 1   | 1      | 1   | 2      | 1   | 1      | 2   | 1      | 1   | 2      | 1   | 1      | 2   | 2      | 1  | 2      | 2   | 2      | 2   |
| Transformer - Other           |                             | 1   |        | 0   |        | 0   |        | 0   | 1      | 0   | 2      | 1   | 3      | 2   | 5      | 3  | 5      | 5   | 5      | 5   |
| Power Reactor - 500 kV        |                             |     |        | 1   |        | 0   |        | 0   |        | 0   |        | 0   |        | 0   |        | 0  |        | 0   |        | 0   |
| Reactor - Other               |                             |     |        | 1   |        | 0   |        | 0   |        | 0   |        | 0   |        | 0   |        | 0  |        | 0   |        | 0   |
| Station Service               | 5                           | 13  | 4      | 5   | 5      | 4   | 4      | 5   | 3      | 4   | 3      | 3   | 2      | 3   | 4      | 2  | 5      | 4   | 4      | 5   |
| Power Circuit Breaker - 500kV |                             | 9   |        | 0   |        | 0   |        | 0   |        | 0   |        | 0   |        | 0   |        | 0  |        | 0   |        | 0   |
| Power Circuit Breaker other   | 18                          | 18  | 21     | 18  | 28     | 21  | 27     | 28  | 33     | 27  | 31     | 33  | 32     | 31  | 31     | 32 | 31     | 31  | 31     | 31  |
| Disconnect Switches           | 17                          | 22  | 40     | 17  | 45     | 40  | 44     | 45  | 56     | 44  | 70     | 56  | 90     | 70  | 102    | 90 | 102    | 102 | 102    | 102 |

#### 3.2 Program Forecast Planning

**FY2014-2023 Capital Forecast**

Direct Capital only, Nominal Dollars in '000

| Equip Category       | FY14            | FY15            | FY16            | FY17            | FY18            | FY19            | FY20            | FY21            | FY22            | FY23            | Total            |
|----------------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|------------------|
| Circt Brkr &Swtch Gr | \$14,023        | \$8,203         | \$16,462        | \$17,388        | \$15,084        | \$16,714        | \$17,295        | \$18,047        | \$18,211        | \$18,211        | \$159,638        |
| Transfrm & Reactor   | \$3,101         | \$15,678        | \$7,866         | \$7,746         | \$7,746         | \$7,842         | \$11,580        | \$11,751        | \$15,495        | \$15,416        | \$104,221        |
| CVT/PT/CT Arresters  | \$1,644         | \$1,920         | \$1,781         | \$1,635         | \$1,571         | \$1,631         | \$1,654         | \$1,618         | \$1,618         | \$1,618         | \$16,690         |
| Low Voltage Aux      | \$6,897         | \$3,330         | \$4,669         | \$4,158         | \$4,992         | \$4,047         | \$3,623         | \$3,462         | \$3,187         | \$3,868         | \$42,233         |
| Shunt Caps           | \$1,783         | \$1,365         | \$620           | \$367           | \$233           | \$135           | \$109           | \$512           | \$180           | \$1,539         | \$6,843          |
| Bus & Structures     | \$919           | \$1,012         | \$1,472         | \$3,037         | \$5,077         | \$6,788         | \$6,467         | \$5,471         | \$5,321         | \$1,430         | \$36,994         |
| <b>TOTAL</b>         | <b>\$28,367</b> | <b>\$31,508</b> | <b>\$32,870</b> | <b>\$34,331</b> | <b>\$34,703</b> | <b>\$37,157</b> | <b>\$40,728</b> | <b>\$40,861</b> | <b>\$44,012</b> | <b>\$42,082</b> | <b>\$366,619</b> |

**FY2014-FY2023 Expense Forecast**

Nominal Dollars in '000

| Maintenance Program | FY14     | FY15     | FY16     | FY17     | FY18     | FY19     | FY20     | FY21     | FY22     | FY23     | Total            |
|---------------------|----------|----------|----------|----------|----------|----------|----------|----------|----------|----------|------------------|
| Substation Mgmt     | \$31,112 | \$31,777 | \$32,889 | \$34,040 | \$35,231 | \$36,464 | \$37,741 | \$39,062 | \$40,429 | \$41,844 | <b>\$360,588</b> |

**Caveats**

*Forecast is currently under review as part of the 2014 Integrated Program Review (IPR) process and will be updates in conjunction with the IPR timeline.*

# **CONTROL CENTER PROGRAM ASSET MANAGEMENT STRATEGY**

Laurie Hansen, Program Manager  
December 2013

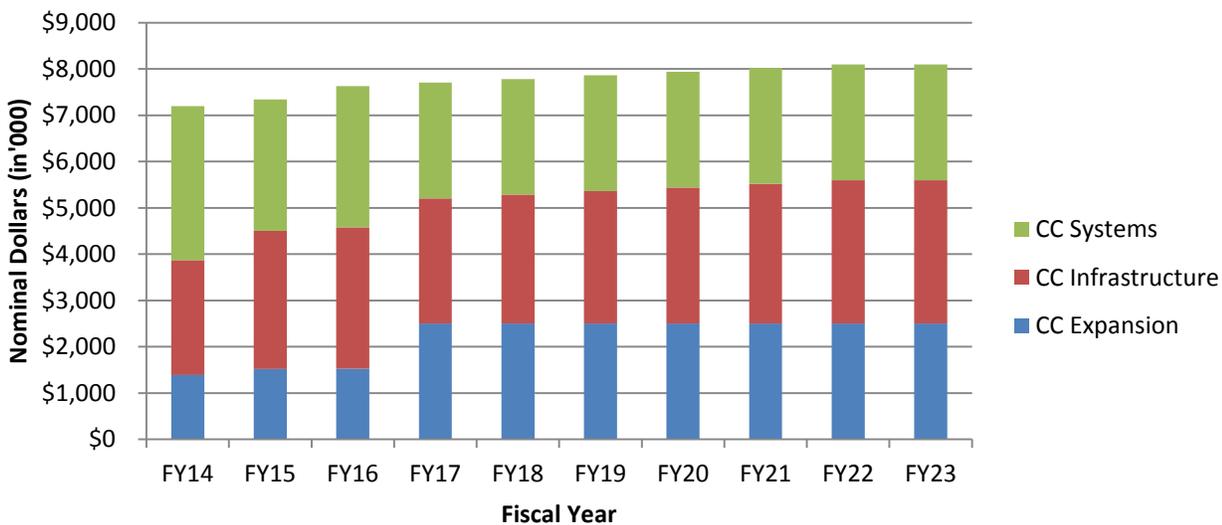
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## EXECUTIVE SUMMARY

### Control Center (CC) program overview

- Includes all the systems, tools, infrastructure and support services required to manage the Transmission Grid. Requires a 24/7 availability support model with redundancy both within the systems and between the two CC sites.
- Grid Ops system assets can be considered in the following layers:
  - ◆ Operations System Services (~37 systems)
  - ◆ RAS Systems (~6 systems)
  - ◆ Data Center Infrastructure & Support Services (~43 systems)

**Control Center Capital Forecast FY2014-2023**



### Key risk to be addressed

- Risks to system reliability and flexibility
- Wide range of evolving operational, regional market, industry, regulatory, and security related requirements
- Gaps in Governance and Support capabilities
- Staffing adequacy

### Strategy Elements

- Complete Lifecycle Plans for every system and update them at least annually. Ensure integration of the Program Asset Plan priorities management and Project Portfolio Management processes.
- Server and workstation lifecycle standards support determining system upgrade planning and risk methods. Other CC equipment lifecycle standards will be developed and incorporated into systems lifecycle planning.
- Complete Windows Migrations efforts for remaining OpenVMS systems
- Develop a CC Data Management Program and Strategy
- Develop business architecture and strategic “line of sight” to CC assets
- Develop visibility, tools, and processes to support more complete and proactive Demand & Capacity Management in the CC
- Strategically plan for CC asset information management improvements
- Establish plans for appropriately dedicating CC technology and architecture planning functions or roles

- Develop a cyber-security and risk management strategy towards evolving the current practices for system visibility, risk assessment, decision making and compliance response

In the long run, this strategy will help:

- Ensure replacement or maintenance actions result in no assets assessed as Critical Risk Level of failure, obsolescence, or noncompliance
- Critical systems meet their respective availability targets.
- Provide redundancy and deployment of the most important systems in a geographically diverse manner to help ensure continuity of operations in the event of loss of a control center.

## 1.0 STRATEGY BACKGROUND

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The System Operations organization (TO) is responsible for the safe, reliable, and open access operation and dispatch of the high voltage transmission system and interconnected generation. TO operates and manages two regional control centers, represents BPA on operations and other issues through participation in regional and national groups, and sponsors and supports Technology Innovation (TI) efforts within the operations arena. From an Asset Management standpoint, Operations includes 2 aspects – the “business” side that identify the needs and uses the asset system services, and the Operational Technology (OT) side that supports and manages the assets.

### 1.1. Business Environment

The assets-focused side of TO supports lifecycle activities for asset systems that maintain and improve the tools available for the reliable operation of BPA’s transmission system. System Operations is also responsible for the Grid Operations Information System Security Program (GO ISSP) which implements and maintains regulatory cyber security requirements applicable to Transmission Services’ information and cyber security systems used to operate, control and protect the transmission system.

#### Transmission Operations Strategy

There are significant emerging expectations for evolving operations and how BPA manages the grid, increasing visibility, reliability, and flexibility. A number of strategy efforts and initiatives have emerged that are attempting to define the business direction that should be driving the CC asset strategy (e.g., emerging SmartGrid initiatives, Technology Innovation Roadmaps, Remedial Action Schemes (RAS) strategy, Commercial Operations initiatives, and Energy Imbalance Market (EIM) assessment. Translating and clarifying these strategic needs for CC assets is paramount to plan for their lifecycle demands. The draft of the recently developed *System Operations Strategic Priority* outlines intended outcomes and related risks for the following aspects that will set requirements for CC system assets:

1. Reliability and Availability
2. Integrated Analytical Capability
3. Operational Planning
4. Outage Flexibility
5. Constraint Management
6. Event Management
7. Operations and Reliability Compliance Alignment
8. Operations and Commercial Alignment
9. Operations and Power Services (PS) Alignment
10. Operations and Systems Infrastructure Alignment

The detailed success factors identified for these outcomes will speak to the range of operational, regional market, industry, regulatory, and security related requirements that CC system assets will need to meet over the next 5-10 years. These include both sustaining the systems while implementing innovations and significant upgrades. Addressing the expectations for emerging these operational outcomes in time, and identifying the related workload, staff capacity, and budgets necessary will clarify the real Asset Strategy and Plan demands, offering BPA choices about how and by when to achieve them.

### **Cyber Security, Compliance, and System Risk Management**

CC system assets and lifecycle activities, must meet a wide range of security and reliability requirements, including, but not limited to:

- NERC Reliability requirements for Operations that dictates many requirements for system services
- NERC Critical Infrastructure Protection (CIP) standards regarding the implementation and management of Grid systems
- Federal Information Systems Management Act (FISMA) law requiring federal agencies to follow minimum National Institute of Science & Technology (NIST)-based security control standards
- NERC Emergency Operations (EOP-008) standards
- Federal Continuity Directive (FDC) setting requirements for the nation’s critical infrastructure of Mission Essential Functions (MEF)

The last five years have been focused on evolving NERC CIP standards implementation, and increasingly, the CC program is focusing on FISMA-based security requirements. Significant attention to EOP-008 standards has emerged this last year, and FDC related requirements will be getting more attention in the next couple years. The continuously evolving nature of these requirements has imposed a significant workload increase on the CC staff to meet them for system implementations, O&M, and support service activities. It is also imposing an increase in the number of systems, equipment, and in some cases, new support functions.

Perhaps a potential bright spot in this security and regulatory arena are Executive Directive-driven efforts to re-invent the NIST standards in an attempt to consolidate and refine the various regulations above towards more effective, industry-based, and smart grid-enabling standards. The goal of this effort is to move the focus to risk management versus compliance, and work with agencies and industry to innovate and make critical infrastructure security and protection more effective. Some of the key advances in this area include the following works:

- Electricity Subsector Cybersecurity Risk Management Process
- Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2)
- Executive Order for “*Improving Critical Infrastructure Cybersecurity*”
- NIST Discussion Draft for its Preliminary Cybersecurity Framework (August, 2013)

## **1.2 Assets, Asset Systems and Criticality**

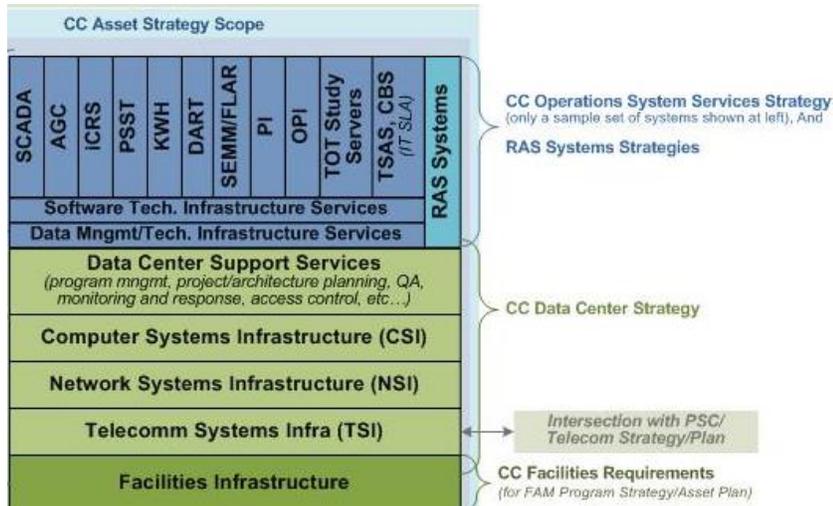
The CC Assets and supporting services include all the systems, tools, infrastructure and support services that are required to manage the transmission grid. High reliability expectations require a 24/7 availability support model, and redundancy is built into most systems, both within the systems, and between the two CC sites.

These assets and services span both control centers and are increasingly becoming identical at both CC sites. Increasing reliability and continuity requirements are continuing to drive all the aspects of the two control centers to be capable of mirroring operations in the event of an emergency or disaster. Today only a handful of less critical capabilities reside only at Dittmer.

**Control Center Assets:**

Grid Ops system assets can be considered in the following layers:

1. Operations System Services
2. RAS Systems
3. Data Center Infrastructure & Support Services.
  - Computing Systems Infrastructure
  - Network Systems Infrastructure
  - Telecommunications Systems Infrastructure
  - Physical Systems Infrastructure (“Operators”, set Facilities Asset Management (FAM) requirements)



**Program Profile:** These asset groups comprise a total of approximately\* 80-85 unique system assets that support specific ‘services’. A system asset is comprised of many layered components and the mix of these component lifecycles states (age and vendor support), business services demands, and security requirements determine their lifecycle replacement plans.

| Asset                      | Count       | Description   |
|----------------------------|-------------|---|
| Operations System Services | ~37 systems | Systems that directly enable management, monitoring, decision-support, and analysis of the grid. This first layer is comprised of the individual systems that directly serve Operations business users, or communications between the systems and customers. Each has its own service and set of functions it delivers. All of these systems transverse the other infrastructure layers for Data Center hardware, network, and communications support and/or components, but they are grouped here for the type of business services that they support. This section is most focused on the software and application side of the assets, and the strategies to better enable business functionality. While hardware lifecycle standards influence the specific lifecycle replacement plans for these systems, the unique mix of component and business needs of each system sets their specific lifecycle plan. |
| RAS Systems                | 6 systems   | Though the RAS systems have similar vertical layers as the other Ops Services systems, in this strategy the RAS systems are treated as a unique category as there are unique issues and requirements that drive RAS strategy, technology, lifecycle planning, and processes. More than most other Grid Ops systems, RAS is diversely shared across Transmission groups for asset strategy and lifecycle activities.   |
| Data Center Infrastructure | ~43         | The 2 Data Centers are tightly coupled with each highly secure CC site. It includes Data Center Infrastructure (i.e., computing hardware, telecomm, networks, and   |

|  |  |
|--|--|
| & Support Services   | critical facilities) and monitoring and management systems that support Ops Systems across the data centers. The Control System Monitoring (CSM) and other support functions offer 24x7 real-time monitoring and support for the dispatch functions. It also includes planning, testing, physical and electronic access control, procurement, asset management, quality assurance and other key support functions. Critical Facilities are increasingly supported by the FAM Program, but the CC still maintains ‘operator’ and ‘responder’ status and more hands-on for most of them, including critical and emergency power systems. |
| *Note: CC systems count is evolving as new and emerging systems are being deployed, retired, and/or reconfigured through the year. |  |

**Criticality**

The security categorization results for control center information and information systems are mandated by Federal Information Processing Standards (FIPS) 199. They are identified by using the steps outlined in *NIST SP 800-60 Guide for Mapping Types of Information and Information Systems to Security Categories*:

1. Identify Information Types
2. Select Provisional Impact Levels for Loss or Compromise
3. Review and Adjust/Finalize Impact Levels
4. Assign System Security Category

The table below lists the control center information types and the BPA final adjusted potential impact levels to BPA operations, assets, or individuals in the event of a loss of confidentiality, integrity, or availability based on the provisional impact levels established in NIST SP 800-60.

| Information Type                              | Potential Impact           |                      |                         |
|---|----------------------------|----------------------|-------------------------|
|   | Confidentiality<br>(L/M/H) | Integrity<br>(L/M/H) | Availability<br>(L/M/H) |
| 1. Energy Supply - Business                   | Moderate                   | Moderate             | Moderate                |
| 2. Energy Supply – Real-Time Control          | Moderate                   | High                 | High                    |
| 3. Energy Supply – Real-Time Dispatch Support | Moderate                   | Moderate             | Moderate                |
| 4. Energy Supply - Dispatch Training          | Moderate                   | Low                  | Low                     |
| 5. IT Infrastructure Maintenance              | High                       | Moderate             | Moderate                |
| 6. System Development and Maintenance         | Moderate                   | Moderate             | Low                     |
| 7. Security Management                        | Moderate                   | High                 | Moderate                |
| 8. Contingency Planning                       | Moderate                   | Moderate             | Moderate                |
| 9. Lifecycle/Change Management                | Low                        | Moderate             | Low                     |
| 10. System and Network Monitoring             | Moderate                   | Moderate             | Moderate                |

The FIPS 199 criteria for establishing potential impact levels are outlined as follows:

| Impact                | Control Center Primary Functions            | Asset Damage or Financial Loss | Harm to Individuals  |
|-----------------------|---|--------------------------------|--|
| High<br>[severe]      | Cannot perform one or more primary function | Major                          | Loss of life or life threatening injuries  |
| Moderate<br>[serious] | Effectiveness is significantly reduced.     | Significant                    | Significant but <b>does not</b> involve loss of life or life threatening injuries. |
| Low<br>[limited]      | Effectiveness is noticeably reduced.        | Minor                          | Minor  |

The system security category is assigned based on the highest potential impact of all the information types stored, processed, or passed through the information system. Note that based on the FIPS 199 criteria, there are currently no systems identified as ‘Low’ potential impact, though this is currently being reevaluated. \*Increasingly, however, based on evolving interpretations of the NERC CIP-002 and FISMA standards, more systems are being designated as “high” each year. This is in part due to the interdependencies between these systems for data, authentication, and operations coordination. Given this criticality schema, the following generally reflects importance of system types:

Criticality

| Less Important |  | More Important  |
|----------------|--|---|
| Low            | Moderate   | High  |
| n/a            | After-the-fact (versus real-time) analysis systems | Systems that offer real-time grid visibility and control                          |
|                | Systems that exchange data with other entities     | Systems that enable cross-CC and/or utility communications and data exchange      |
|                | Lightning monitoring and Fault location systems    | Data Center infrastructure, like networks, environment management and monitoring. |
|                | Training systems                                   |   |

Additionally, the NERC CIP process for identifying NERC “Critical Cyber Assets” or CCA’s, entails determining which systems are essential to the reliable operation of the Bulk Electric System (BES). If a system meets any one of the following criteria, it is considered a NERC CCA:

1. Used in supervisory or autonomous control impacting reliable operation of the Critical Asset?
2. Displays/transfers/contains information relied upon to make real-time decisions impacting reliable operation of the Critical Asset?
3. Loss, degradation or compromise impacts the reliable operation of the Critical Asset?

## 2.0 THE STRATEGY

### 2.1 Current State

One of the unique challenges with CC is that its system assets performance and lifecycles are more driven by business, industry, and regional evolving demands than they are failures or obsolescence. The CC program still has significant sustain-based workload and challenges keeping up with necessary, short-lifecycle upgrades, but these other demands are a key influencing factor in the actual performance expectations and lifecycle plans of each

unique system. Getting a better “line of sight” to this range of business demands all the way to the individual system service strategies and lifecycle plans is a key gap the CC program needs to fill.

As indicated below in section 2.1.1, the CC program has made some important progress in developing asset System Security Plans (SSP’s) for gaining system visibility and steps towards security risk assessments, and the lifecycle planning is now steadily evolving. However, until CC has these done, as well as the improved “line of sight” mentioned above, the true asset health, risk, and lifecycle demands priorities (capital and expense) picture is not complete. The current expectation is to complete this gap in FY2014 for a more complete Asset Plan and Risks picture.

Capital makes up a relatively small portion of the program focus and needs – not all of CC asset work is capital, and much of it ends up driven and/or funded outside of the CC capital budget. Upgrades sometimes get pushed out for other priorities and given the majority of the CC staff priority is on operations and maintenance, upgrade and project work takes second priority to O&M and urgent compliance initiatives.

### 2.1.1 Program Accomplishments for FY2012-2013

#### Fiscal Year 2012

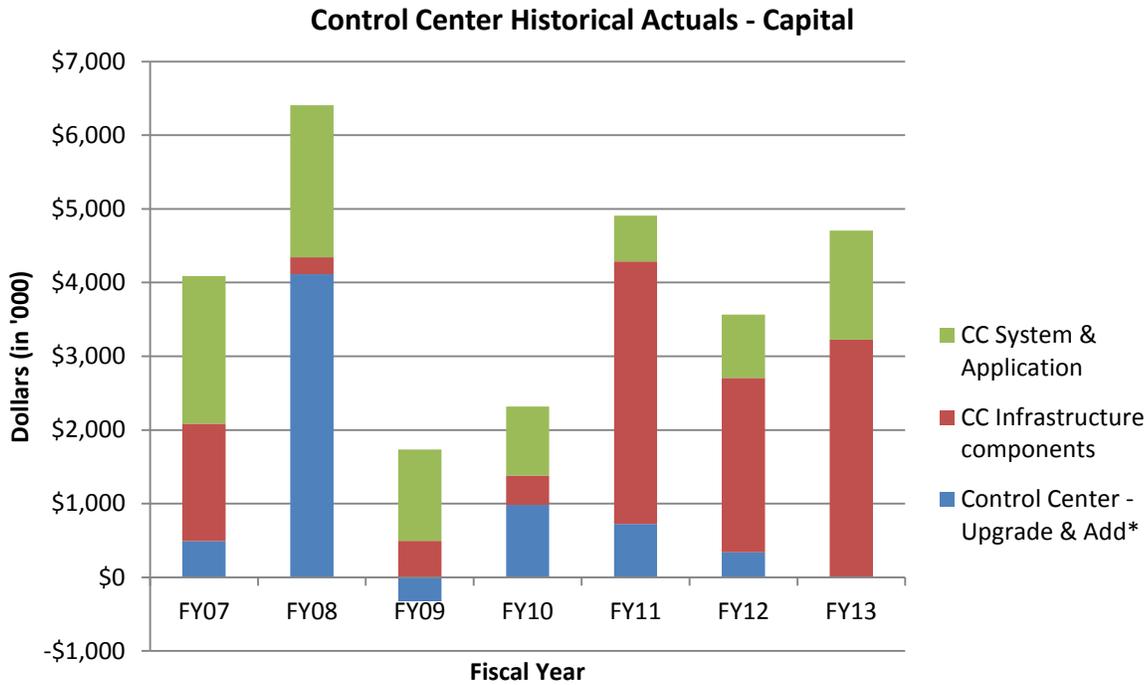
- Sustain projects focused on upgrades and standardization between sites, funded by the CC capital program
  - ◆ Integrated Curtailment & Redispatch System (iCRS) redundancy implemented at Munro Control Center (MCC).
  - ◆ Urgent SQL storage expansion to capture current system logs for new FERC Audit requirements
  - ◆ MCC Uninterruptable Power Supply (UPS) upgrade
  - ◆ MCC LAN desk deployment at Munro for standardized patching and compliance
  - ◆ WebFG Windows upgrade
  - ◆ Firewall system upgrade
- Expansion and/or Significant Upgrade Projects Funded by other Capital Programs
  - ◆ Real-time Operations Dispatch & Scheduling (RODS) system Retirement major deployment milestones met in FY2012, including Data Exchange (DEX) system implemented to replace the legacy system functionality.
  - ◆ Kickoff and early design stages of Synchrophasor through FY2012.
- Participation in the Integrated Control Systems Strategy (ICSS) development effort aimed at aligning the PSC, SPC, and CC asset programs.
- By the end of the year, CC *defined and kicked-off* a FY2013 Program Work Plan aimed at accomplishing the following key Asset Management Targets:
  - ◆ Significant Strategy revision/evolution
  - ◆ Asset Risk Assessment Initiative – developing System Security Plans (SSP’s) and system asset Lifecycle Plans towards creating a risk-based Program Asset Plan.
  - ◆ Outlined a draft *Strategic Asset Information Management (SAIM)* strategy - targets were to revise, approve, and identify a strategic roadmap in FY13
  - ◆ Defining the problems, objectives, and recommended improvement roadmap surround the CC’s Demand and Capacity management issues

#### Fiscal Year 2013

- Sustain projects focused on upgrades and standardization between sites, funded by the CC capital program
  - ◆ Dittmer Control Center (DCC) Generator Breaker replacement

- ◆ NERC EOP-008 required Emergency Ops implementations and test.
  - ◆ DCC Data Center Power Distribution Unit (PDU)-TLM Panel replacement
  - ◆ SCADA Inter-Control Center communication Protocol (ICCP) Windows upgrade
  - ◆ Video Wall Controller upgrade.
  - ◆ DCC Cell Phone Repeater upgrade
  - ◆ Active Directory upgrade
  - ◆ Network Device Authentication and management tools deployed.
- Expansion and/or Significant Upgrade Projects Funded by other Capital Programs
    - ◆ RODS Retirement - Energy Accounting system replacing RODS functionality.
    - ◆ RAS Direct Current (DC) - The second phase of RAS DC completed with the testing period, preparatory step for the installation of the RAS DC controllers in the next phase.
    - ◆ Synchrophasor – Completed Key Agency Target for archiving PMU data from substations and wind sites on the DCC Production PI Server and WECC’s backup Reliability Coordinator in Loveland, CO. Designed and implemented part of the new PMU Network management systems and functions required to support this new network.
    - ◆ OMET – Met target for completing the preliminary requirements and technology design and testing stages.
    - ◆ Munro Scheduling Center (MSC) – design and implementation engagement to support meeting the MCC building expansion targets.
- FY2013 Program Work Plan Accomplishments:
    - ◆ Completed significant revisions of the program strategy, better framing up the scope of the CC program, the asset system service strategies, and more significant analysis around governance & support strategies addressing key program risks.
    - ◆ Significant coordination with the FAM program towards joint asset planning for the CC Critical Facilities assets.
    - ◆ Completed about 63% of the System Security Plans targeted for 9/30/2013 – this is a ‘yellow’ progress indicator, but planned completion is expected to make 80-100 % (green) by the end of FY2014 Q1 as planned.
    - ◆ Evolved the system lifecycle plan templates, risk methods, and data collection process, and have begun to ramp up on coordination to complete them.
    - ◆ Evolved SAIM objectives internally. Additional achievements to consolidate some inventory data across the TO groups.

### 2.1.2 Cost History



#### Historical Actuals - Capital

Dollars in '000

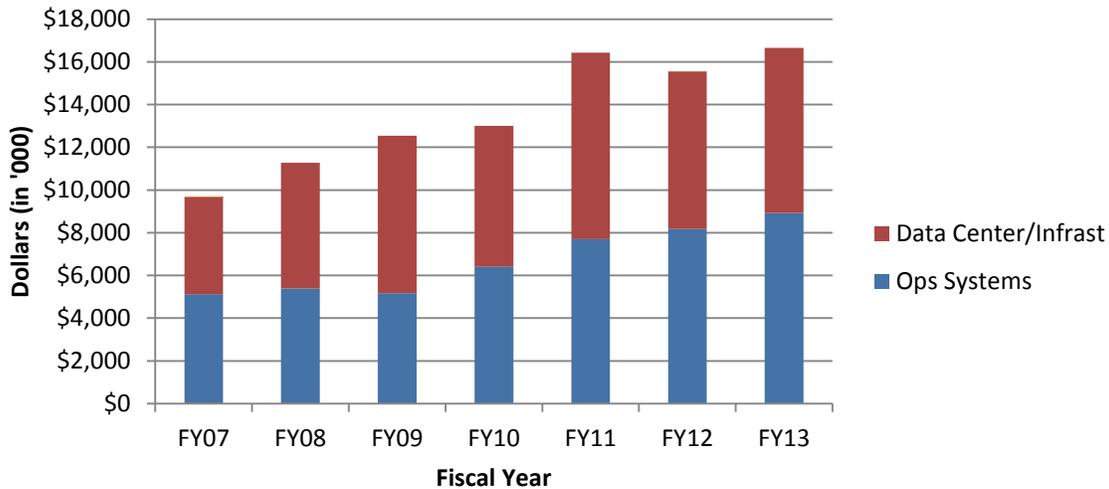
| Equipment Category      | FY07           | FY08           | FY09           | FY10           | FY11           | FY12           | FY13           | Total           |
|-------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|-----------------|
| CC - Upgrade & Add*     | \$490          | \$4,116        | -\$325         | \$981          | \$726          | \$339          | \$3            | \$6,330         |
| CC Infrastr components  | \$1,594        | \$225          | \$497          | \$400          | \$3,562        | \$2,365        | \$3,223        | \$11,866        |
| CC System & Application | \$2,003        | \$2,064        | \$1,239        | \$935          | \$619          | \$863          | \$1,478        | \$9,201         |
| <b>Total</b>            | <b>\$4,087</b> | <b>\$6,405</b> | <b>\$1,411</b> | <b>\$2,316</b> | <b>\$4,907</b> | <b>\$3,567</b> | <b>\$4,704</b> | <b>\$27,397</b> |

\*Expand Program Dollars

#### Historical Actuals - Capital

- Today, CC typically has the capacity to execute about \$5-7 million per year in capital work, depending on the amount of large infrastructure upgrade work occurring. Except for RAS work, projects are typically executed by all TO staff, so it is mostly a TO demand-capacity planning issue to complete capital work.

### Control Center Historical Actuals - Expense



#### Historical Actuals - Expense

Dollars in '000

| Equipment Category  | FY07    | FY08     | FY09     | FY10     | FY11     | FY12     | FY13     | Total    |
|---------------------|---------|----------|----------|----------|----------|----------|----------|----------|
| Ops Systems         | \$5,124 | \$5,393  | \$5,163  | \$6,408  | \$7,695  | \$8,173  | \$8,916  | \$46,872 |
| Data Center/Infrast | \$4,555 | \$5,887  | \$7,382  | \$6,590  | \$8,735  | \$7,373  | \$7,743  | \$48,265 |
| Total               | \$9,679 | \$11,280 | \$12,545 | \$12,998 | \$16,430 | \$15,546 | \$16,659 | \$95,137 |

#### Historical Actuals - Expense

- Note that expense costs above were extrapolated from organization budgets and accounts based on assumptions on asset-specific work (including security and compliance activities).
- Expense costs include labor and materials for a broad base of activities, such as:
  - ◆ Minor system enhancements and configuration changes
  - ◆ Minor system upgrades and additions (not capital eligible)
  - ◆ System requirements and preliminary design stage work (not capital eligible)
  - ◆ System break-fix and 24/7 real-time user support
  - ◆ Security-related monitoring, documentation, and projects
  - ◆ O&M work orders for standard system maintenance work
  - ◆ Compliance activities
  - ◆ Technology training and travel
  - ◆ Inter-site travel
  - ◆ Service contracts
  - ◆ Spares pool replenishment

### 2.1.3 Health of Current Assets (Current Condition & Performance)

As mentioned above, having a clear understanding of current condition, performance standards, and system lifecycle plans for improved, risk-based asset planning is not complete. The following reflects what is known at this time.

**Important Lifecycle Aspects of CC System Assets:**

- The rate of technology change has been accelerating resulting in equipment and infrastructure life spans are significantly shorter than in the past.
- Asset systems in the CC comprise multiple components: applications, operating systems, servers and in some cases, other hardware.
- The systems' components are frequently so interdependent, that the replacement of one component typically requires replacement of one or more of the other components.
- There are interdependencies between field and master component installations, requiring long-term planning and execution for replacement strategies. Many systems and technologies must be supported past their normal end-of-life to accommodate this, and often parallel support is required for both the old and new systems in the CC until field units are upgraded.
- Where possible, the CC uses commodity servers and hardware, and keeps spares available on-site.
- Most of the systems in the control centers operate on the MS Windows OS, and there is an effort to migrate most remaining systems to MS Windows where possible.
- Server and workstation hardware, and related operating system standards are an early guide towards lifecycle replacement at seven years (for Windows systems). This is usually the longest a CC system can operate without a significant upgrade of its components. This component standard is recognized in the data center hardware and software lifecycle management processes across the CC computing environment based on support and manageability, and is an initial guide to evaluating the remaining factors in a given system's lifecycle plan.
- A manufacturer's support of their software applications can be unpredictable – after purchasing of a software application the vendor can discontinue support without notice.
- Historically, long-term maintenance and support costs for new systems and infrastructure are not adequately assessed, planned, or allocated when the investments are approved.

**Lifecycle Plans**

Today, the lifecycle plan effort is evolving the assessment and scoring method to break down the various performance aspects of the systems, and more specific criteria for assigning risks scores towards meeting them. The sum of these scores will provide a more specific sense of relative 'Health' and risks of the assets. The risk scoring method is discussed further in sections below. With the absence of this visibility today, asset priorities are identified and prioritized in the project portfolio process, and are generally prioritized by most urgent compliance or upgrade to be addressed.

**Current Project Portfolio Priorities**

Today, the project portfolio is a growing list of projects that is in constant flux due to urgent priorities. The backlog of work is growing, and the most urgent projects are the ones that get priority by default. The prior asset strategies (and related risk priorities method) did not offer an effective way to incorporate the risk method into the project process or vice versa. The intent is that the new lifecycle planning, and the roll-up of identified priorities and funding/staff requirements, will offer a better way to consistently log, incorporate, and prioritize new pop-up projects, and offer better visibility of the relative importance and total demands of all those priorities.

Current projects identified in the fiscal year implementation plan as of 9/30/2013, and their asset risk drivers, are reflected in the *3.1 10 Year Implementation Plan* section below. The majority of the CC work is sustain based. A small portion of the work is categorized as expansion work and is typically comprised of upgrades necessary to meet compliance or policy driven requirements.

## 2.2 Future State

### 2.2.1 Key asset performance objectives, measures and targets

The CC Asset Performance & Management Objectives identified in FY2010 and still applicable are listed in the table below. While these sustain-focused objectives remain accurate and sufficient to the CC asset program, notions of the measures, end stage targets, and strategies to meet them are evolving.

| Asset Performance Objectives |   |   |  |
|------------------------------|---|---|--|
| Category                     | Performance Objective   | Measure   | End Stage Target   |
| Reliability & Compliance     | Replacement or maintenance actions result in no assets assessed as Critical Risk Level of failure, obsolescence, or noncompliance   | Assets that result in a combined Critical Risk Level rating per the CC Risk Assessment methodology*.    | No assets are assessed at a combined “Critical” Risk Level rating  |
| Availability                 | Critical systems meet their respective availability targets   | Annual average of scheduled and unscheduled outages of any one instance/site or component of the system | Currently, the following systems have targets set: <ul style="list-style-type: none"> <li>▪ SCADA: Available 99.95% per FY**</li> <li>▪ AGC: Available 99.975% per FY**</li> </ul> |
| Availability                 | In addition to being redundant, the <i>most important</i> systems are deployed in a geographically diverse manner to help ensure continuity of operations in the event of loss of a control center. | All NERC CIP Critical Cyber assets are fully redundant at both sites.                                   | Target currently met.  |

\*See Asset Health & Risk Assessment method and criteria outlined in section 2.3.1.

\*\* Measures include average total planned and unplanned outages per year, measured and accumulated weekly.

There may be a need to evolve the objectives in FY2014 to incorporate some of the following themes and issues:

- BPA strategies and business requirements for Operations are clarified such that asset service demands (their performance expectations) are planned for success.
  - ◆ *Beyond sustain, the CC systems need to be planned for all lifecycles activities, including BPA-driven expansion in Operations business capabilities and technology innovations. A significant portion of CC assets are being targeted for various forms of expansion and innovation within upgrades, and there is a need to understand this better to more fully balance the sustain and ‘transform’ aspects of the asset plans, and the related requirements it will take to achieve them within this largely O&M-focused organization.*
- Focus on “security” risk assessments, versus just compliance. Compliance reaction-based behavior does not typically focus on achieving the right practices for secure and managed assets.
  - ◆ *As discussed above, the feds and industry are focused on evolving and re-enforcing both innovation and rigor in this area to get Agencies focused on sound asset and risk management towards ensuring achievement of Federal and business objectives versus imposing multiple compliance drills. There is*

*heavy emphasis on enabling secure SmartGrid technologies. From a criticality and redundancy standpoint, need to clarify what the “most important” equate to and the criteria (i.e., may not be just CCA’s).*

- Identifying a more explicit itemization of the range of requirements each asset system is expected to meet in its performance expectations and lifecycle plans, including a range of regulatory and BPA requirements for:
  - ◆ *Cyber Security standards, including DOE directives, FISMA/NIST and NERC CIP*
  - ◆ *All NERC Reliability Requirements for Operations that are directly supported by systems, including Emergency Ops Procedures (EOP08).*
  - ◆ *Federal Continuity Directives (FCD Mission Essential Functions #23/24) requirements*
  - ◆ *BPA Transmission Technical Standards where appropriate for communication and control assets in the CC.*

### **2.3 Asset Condition/Performance Gaps**

An understanding of the following key items will drive clarification of asset performance objectives, system condition and performance expectations, and the related risks:

1. Strategic demand planning to connect BPA/Operations Strategy requirements to system services (System Lifecycle Plans for services expectations).
2. System Lifecycle Plans for system health and risk identification.
3. Clarify the need to expand on availability standards for other/more systems, and determine process requirements for monitoring against them.

The table of projects shown below in section 3.1 currently serves as the list of known performance gaps and issues, largely driven by the most urgent cyber security, compliance, and upgrade issues. As the above tasks are completed, data-driven current and future state risk maps will be enabled.

#### **Evolving Asset Assessment Methods**

The previous strategies contained an Asset Health Risk Assessment table and methodology that ranked risks of Obsolescence, Failure, and Noncompliance for each system, multiplied the sum of those by the impact severity level of loss of the system, and then prioritized them in order of risk scores. This was a rudimentary, gut-feel process for assigning scores and capturing reasoning and risks. The image below is a partial/sample snapshot of the resulting risks table. The evolving lifecycle plans and related risk scoring will enhance this described method. The expectation is that the asset health demographics, risks, and gaps will be better understood. The resulting Risk Assessment table shown below will be relatively similar, but with some improvements. Additionally, the CC program will be undergoing the *Total Economic Cost* evaluation of the risks associated with CC assets in the spring of 2014. This will result in potential new strategic alternatives and will drive a more quantified risk-informed strategy in the future.

| 2011 Health Assessment Scoring<br>Likelihood/Probability of<br>obsolescence, noncompliance, or failure<br>(H=3, M=3, L=1) |                 |                    |                |                     |                    | Critical = 15 - 21                        |                                    |
|---|-----------------|--------------------|----------------|---------------------|--------------------|---|------------------------------------|
|   |                 |                    |                |                     |                    | Moderate - High = 10 - 14                 |                                    |
|   |                 |                    |                |                     |                    | Low = <=9                                 |                                    |
| row   | CC System Asset | Obsolescence score | Failures score | Noncompliance score | Total Health Score | Impact of Loss (FIPS 199 severity rating) | Asset Risk Score (Health x Impact) |
| 1   | Cyber Asset #1  | 3                  | 1              | 3                   | 7                  | 3   | 21                                 |
| 2   | Cyber Asset #2  | 3                  | 1              | 3                   | 7                  | 3   | 21                                 |
| 3   | Cyber Asset #3  | 3                  | 1              | 3                   | 7                  | 3   | 21                                 |
| 4   | Cyber Asset #4  | 3                  | 3              | 1                   | 7                  | 3   | 21                                 |
| 5   | Cyber Asset #5  | 3                  | 2              | 1                   | 6                  | 3   | 18                                 |
| 6   | Cyber Asset #6  | 3                  | 3              | 3                   | 9                  | 2   | 18                                 |
| 7   | Cyber Asset #7  | 3                  | 1              | 2                   | 6                  | 3   | 18                                 |
| 8   | Cyber Asset #8  | 3                  | 1              | 1                   | 5                  | 3   | 15                                 |
| 9   | Cyber Asset #9  | 1                  | 1              | 3                   | 5                  | 3   | 15                                 |
| 10  | Cyber Asset #10 | 3                  | 2              | 2                   | 7                  | 2   | 14                                 |
| 11  | Cyber Asset #11 | 3                  | 1              | 3                   | 7                  | 2   | 14                                 |

- **Asset Health Assumptions include:**
  - ◆ Assets are given Health ratings that take into account all of their components and the various levels of compliance requirements for CC systems
  - ◆ Likelihood of failure are indicated by instances of component failures or intermittent system outages (i.e., a hard drive fails repeatedly).
  - ◆ Likelihood of obsolescence are indicated by loss of vendor or staff support, or problems with interoperability (i.e., vendor support is discontinued for a component, or component will not interoperate with other key components or systems).
  - ◆ Likelihood of noncompliance is indicated by technical feasibility of components or systems to comply with regulatory requirements, including NERC CIP, FISMA, EOP-008.
- **Impact Assumptions include:**
  - ◆ The FISMA-required FIPS 199 Classification (discussed in the *Criticality* section above) for each asset was used to set this score.
  - ◆ Catastrophic/High = 3 (includes all NERC CIP CCA’s, as well as others by this classification)
- **Risk Level = Health X Impact, reflected as Critical, Moderate-High, and Low**

### 2.3.1 Risks to meeting the objectives

In FY2010, the CC conducted a risk assessment survey to identify the biggest risks to meeting the identified objectives. The process completed the following steps per the BPA’s risk methodology:

- Risks to achieving asset management goals and objectives
- Risk identification/definition (23 total risks) by team
- SME analysis and surveyed prioritization of top 11
- Selection of top 5 for improvement

The most significant risks to achieving the objectives of the asset strategy are all related to constrained resources in light of skills and knowledge sustainability, O&M versus replacement and expand workload, and increase in competing priorities. These top 5 risks (listed in the table below) are still relevant today and paramount to address in the CC asset strategy.

| Results of Risk Assessment Survey |  |   | Likelihood X Impact |
|-----------------------------------|--|---|---------------------|
|                                   | Risk:  | Description:  |                     |
| 1                                 | Projects are approved and funded without a corresponding commitment to operations and maintenance, both in terms of expense dollars and support staff. | The control center has a finite number of staff with operational expertise. This staff must support both operations and maintenance as well as function as primary implementers of new projects. Continued growth in the number of systems requiring support will invariably necessitate less time dedicated to new project work, causing project delays.   | 20.45               |
| 2                                 | NERC/WECC and FISMA compliance effort.   | NERC/WECC and FISMA requirements continue to increase the workload on TO staff. This pertains to implementing standards, system monitoring, reporting, and audit preparation. Improper or incomplete NERC-CIP related processes or documentation leads to sanctions and/or new mitigation work. This work then competes with other projects for resources. This results in failure to meet established schedules, increased net costs and inability to spend capital funds per fiscal year budget.  | 19.71               |
| 3                                 | Commitments to new initiatives (e.g. WIT, Synchrophasor)   | Significant commitment to these programs leads to unanticipated expansion work, as well as long-term support work. This diverts staff from existing Control Center systems and operations work. These commitments typically have aggressive timelines.  | 18.24               |
| 4                                 | TO staff retire, quit or transfer before succession planning can occur.  | The skill set required to maintain, operate and implement Control Center systems is highly specialized. There is a heavy reliance on contracted retired BPA employees to meet many of these needs. Finding or training staff with the expertise needed would be difficult and time consuming (6-24 months) without the added constraints of a staffing cap. The result is a reduction in system support and delays in new project work. Increasing reliance on contracting staff is an additional risk to maintaining core systems knowledge. | 17.01               |
| 5                                 | The continued maintenance of a range of old and new technologies with current staff.   | Maintaining a range of old and new technologies increases the institutional knowledge and technical expertise required to support it. This impacts staff requirements, cross-training and re-usability of system components.  | 14.45               |

In FY2013 strategy development work, the CC strategy expanded the above risks to recognize gaps in “Governance & Support” capabilities (asset management “enablers”) that need to be addressed *over the long term*, summarized in the following areas:

- **Increasing BPA-wide demands on the CC assets and staff**, requiring more cohesive strategic direction and “line of sight” to those demands, and with visibility to the total range of demands and their relative priority to the strategic business goals.
- **Adopting a “Services” view to system requirements and service model planning** –with clear and documented current-day system demands and requirements. Evaluating the service model towards a “service delivery” focus will help identify key areas of needed efficiency, skills and staff planning expectations, and identifying the appropriate level of support needs (functions, processes, FTE) that impact CC workload and delivery capability. This includes clarifying system “Availability” expectations and related monitoring.
- **Enabling visibility and practices for more coordinated and proactive work demand & resource capacity management, supported by appropriate level of tools and staff** – there is need for visibility to the complete range of lifecycle activity demands being made for the CC assets and their support staff. Current processes and tools are not sufficient to support managed and cohesive receipt, characterizing, routing and prioritization of work requests in relation to staff capacity.
- **Enabling efficient access to accurate, complete and integrated CC asset information** sufficient to support proactive and compliant asset inventory, planning, risk management, and audit response. The CC program needs to define a path for maturing asset Configuration Management *practices and program support*, and

then integrating other basic lifecycle information for a more holistic view to asset health, risks, costs, and planning decisions. This is essential for maturing good asset management and security practices.

- **Establishing dedicated CC architecture planning functions** – the CC staff bandwidth is largely consumed by operations and maintenance activities, with a small percentage towards technology and architecture planning. CC is challenged with inadequate architecture staffing to spend sufficient time to plan future, cohesive architectures that ensure recognition of all the strategic and security requirements, and that are well coordinated with other groups, including through the Integrated Control Systems (ICS) Councils processes.
- **Implementing better practices and tools to plan for Communication & Control systems as complete systems** -- The CC, PSC, and SPC assets make up these closed-loop assets that really function as a ‘service’ for operations. Though coordination and efforts via the ICS Councils are aimed at improving this area, the data systems, planning and design processes, and compliance view to these systems are still relatively separate. The CC needs to provide leadership in this area to clarify the ‘service’ expectations and provide planning functions to bridge the architecture coordination gap that exists for these systems.
- **Adopting a risk management approach to system security** – Compliance tends to get the priority for staff work and interpretations for security implementation, and tends to be reactive. A new focus and cyber security strategy is needed to identify “security-first” based planning and implementations that will meet longer-term goals and demands and grow risk management practices around system services, versus short-term compliance requirement interpretations.
- **Establishing a CC data management program that establishes standards, architecture, and strategic service direction.** CC system data is in high demand by many at BPA. As new systems are added and evolve, the data interdependencies between systems becomes more complex and poses both risks as well as challenges to improving standardization, manageability, and service models. System inventory and configuration data is another aspect of CC data management challenges. Currently, the CC does not have a coordinated and recognized data management program to establish CC-wide data standards, plan sound and consistent data architectures, and offer cohesive and streamlined data management services to meet the range of demands.
- **Identifying and “institutionalizing” clear organizational asset strategy and planning processes that drive and better integrate project portfolio management priorities and activities.** Completion of the lifecycle and program asset plan, as well as completing the strategic demand planning, will better define asset service expectations. As this work is completed, processes and roles to better integrate more formal CC methods for asset strategy and planning management need to be established.

#### Other uncertainties

- Major change initiatives such as the Energy Imbalance Market decisions and direction, changing security and continuity requirements, and other regional process and innovation expectations will be taken into account as the CC strategy evolves.

## **2.4 Strategic Approach to Closing Gaps**

In summary, the asset performance objectives are:

- *Replacement or maintenance actions result in no assets assessed as Critical Risk Level of failure, obsolescence, or noncompliance*
- *Critical systems meet their respective availability targets*
- *In addition to being redundant, the most important systems are deployed in a geographically diverse manner to help ensure continuity of operations in the event of loss of a control center*

The following strategic approach and identified targets will get the CC program closer to achieving this future state and improving asset management practices, including the evolution of the full asset demands (beyond sustain) that are expected from CC assets.

### 2.4.1 Strategic Approach

#### Asset Life Cycle & Performance Strategies

1. **Complete Lifecycle Plans for every system and update them at least annually.** The lifecycle plans development was a target of FY2013, and are targeted to be complete for all systems before the end of FY2014 Q3. A new expanded element of this picture will include an understanding of the various lifecycle activity demands and gaps, including O&M, minor enhancements, upgrades, and major expansion work. Reflecting these lifecycle activities in relation to the expected performance, including demands to expand those assets to meet evolving business needs, must be identified in the asset performance picture for these short-lifecycle assets.
  - The risk assessments will be consistent with BPA's risk management policies.
  - Lifecycle Planning, including risk assessments, will be refreshed at least annually.
  - The lifecycle plans culminate to the Program Asset Plan, which identifies all the asset risk priorities before they become projects and supports more proactive and visible priority management, as well as strategic capability planning.
  - This work is also expected to support the Transmission Asset Strategy Integration (TASI) project work scheduled for CC focus in FY2014 Q3.
2. **Server and workstation lifecycle standards support determining system upgrade planning and risk methods.** This component standard is recognized in the data center hardware and operating system lifecycle management processes across the CC computing environment based on support and manageability, and is an initial guide to evaluating the remaining factors in a given system's lifecycle plan.
  - These standards pose as risk indicators in the CC Lifecycle Plan risk scoring scheme, supporting priority setting to those systems nearing hardware EOL.
  - **Upgrades** - Server hardware end of life is considered 7 years; where optimal, any given system will complete a major upgrade (hardware and software) by the 7<sup>th</sup> year of the hardware life. The same is true for workstations, but on a 5 year cycle. These will be identified in the CC equipment database and in every system lifecycle plan developed in FY2014.
3. **Other CC equipment lifecycle standards will be developed and incorporated into systems lifecycle planning.** Other Data Center Programs (Network, Telecomm, and Physical Infrastructure) are in the process of defining equipment lifecycle standards for all equipment. Telecomm will be tying in and coordinating with the PSC Program strategies. The Facilities Asset Management (FAM) team will be creating and coordinating these standards and condition assessments for the CC Physical Infrastructure with CC staff, and will set targets through their asset program.
4. **Complete Windows migrations efforts for remaining OpenVMS systems.** Many of the systems now rated at High Risk Level due to obsolescence and support risks that will be migrated to Windows platforms to reduce the range of technology support, improve compliance management, and increase interoperability.
  - Three Energy Management Systems (EMS) are left to migrate, currently planned over the next two years,
  - Three others are targeted to be planned and migrated in the next 2-3 years.

- Software obsolescence and issues is identified as in the risk scoring scheme as an additional weighted item; the combination of both equipment and software risks and related support issues, as well as their high *Impact* scores weights these system migration projects as high-risk priorities.
5. **Develop a CC data management program and strategy** – Support current data infrastructure staff in developing and evolving a CC Data Management Program and Strategy to identify:
- Program function, roles, goals, and outcomes desired
  - Identify strategies and plans to achieve the goals for an improved data management program, including setting standard, technology direction, and optimal data solution approaches.
  - Identify future tie-in with Configuration & Change Management processes and data, architecture design standards, data flows, and asset planning.

### Closing capability gaps – Governance & Support strategies

6. **Develop enterprise architecture and strategic “line of sight” to CC assets**, refining a service view to their respective service strategy, performance objectives, and lifecycle demand requirements by developing the following capabilities:
- **Strategic Demand Planning** - Clarify BPA/Transmission desired outcomes, strategy business architecture, and priorities in relation to Operations direction and asset needs. Partner with other efforts around BPA (Transmission Strategy development, Tech Innovation, Commercial Ops initiatives, etc.) to help develop the Enterprise Architecture for the operations business direction.
  - **Clarify system services requirements and strategies** – identify system requirements, performance and service expectations and in relation to Strategic Demand.
  - **Identify use and practices around availability standards** for systems, possibly creating a tiered class approach.
  - **Clarify the various continuity and disaster recovery requirements** and capabilities expected of each CC system. Identify any gaps to be addressed.
7. **Establish dedicated CC technology and architecture planning functions** or roles to enable standards development, future-looking and comprehensive architecture plans, and a higher level of coordination across CC and other groups.
- Ensure CC Operations system service expectations are clarified, and integrated master, remote, and telecomm technology and replacement plans are planned as part of the complete service.
  - Identify the relationship and coordination requirement with the Integrated Control Systems’ functions of the PSC and SPC Technology Evaluation and Test councils and test teams.
8. **Strategically plan for CC asset information management** improvements to ensure that information on CC assets is accurate, complete, secure, and readily accessible to those who need it. Specifically, as outlined in the preliminary draft Strategic Asset Information Management (SAIM) plan:
- An Asset Configuration Management Program (supporting system inventory, configuration, architecture, changes, and service performance expectations) is established with clear service expectations, process, roles and responsibilities, and has sufficient staffing and system solutions to support the process and identified stakeholder needs.
9. **Develop visibility, tools, and processes to support more complete and proactive Demand & Capacity Management** in the CC to identify both sustain and expansion workload and skill requirements, allocate existing staff to greatest benefit, and anticipate where staff needs to be added.
- Outline alternative approaches to completing identified work

- Identify minimum requirements for Expense budget that is sufficient to support current systems lifecycle activities.

10. **Develop a cyber security and risk management strategy** towards evolving current practices for system visibility, risk assessment, decision making and compliance response.

**FY2014 Strategy Targets**

| FY2014 Target  | Measure:  |
|--|---|
| <p><b>1. Complete Lifecycle Plans for every system and update them at least annually.</b></p> <p><b>Target:</b> Complete an initial version of all CC system lifecycle plans, and culminate into a Program Asset Plan rollup, by the end of FY2014 Q3.</p>   | <p>Every identified CC system, and or program of systems, has a version 1.0 lifecycle plan document with a preliminary risk score and an FY needs plan (\$'s/FTE).</p>  |
| <p><b>2. Server and workstation lifecycle standards support determining system upgrade planning and risk methods.</b></p> <p><b>Target:</b> All systems lifecycle plans have the CC Equipment Database EOL recognized and part of the risk scores and lifecycle plan by the end of FY2014.</p>   | <p>CC Equipment database is updated to indicate EOL for all Servers and workstations for every system, and the hardware EOL is incorporated into every lifecycle plan risk score.</p> <p>CC Equipment database generates a periodic report of EOL risks.</p>  |
| <p><b>3. Other CC equipment lifecycle standards will be developed and incorporated into systems lifecycle planning.</b></p> <p><b>Targets:</b></p> <p>3.1 Network and Telecomm Programs will identify lifecycle strategies and EOL standards as appropriate for their equipment types by end of FY2014.</p>  | <p>Equipment types population will be determined.</p> <p>CC Equipment database is updated with the equipment and to indicate EOL for the identified population. EOL risks are identified in the related subsystem lifecycle plans.</p> <p>CC Equipment database generates a periodic report of EOL risks.</p> |
| <p><b>4. Complete Windows Migrations efforts for remaining OpenVMS systems.</b></p> <p><b>Targets:</b></p> <p>4.1 Projects are currently underway to address the Windows migration of the 3 remaining Energy Management Systems (EMS): SCADA, AGC, and PSM.</p> <p>4.2 Projects are expected to begin replacement planning for the 3 remaining systems in FY14: KWH, SEMM/FLAR, and Microwave Monitor (MWM) Masters, with intent to replace over the next 2-3 years.</p> | <p>Current Project Delivery Years:<br/>                     SCADA – FY2015 Q1<br/>                     PSM – FY2015 Q1<br/>                     AGC – FY2016 Q1</p> <p>Preliminary Plans are expected to be identified and approved for the KWH, SEMM FLAR, and MWM Masters by the end of FY2014.</p>         |
| <p><b>5. Develop a CC Data Management Program and Strategy.</b></p> <p><b>Target:</b> Appropriate TO staff is identified and charged with coordinating and developing a proposed CC Data Management Program and Strategy for TO management review, input, and approval by the end of FY14.</p>   | <p>A DM Program Plan and Strategy is drafted sufficient for TO management serious review and consideration. Strategy should recommend next steps and targets to be approved.</p>  |

| FY2014 Target   | Measure:  |
|---|---|
| <p><b>6. Develop enterprise architecture and strategic “line of sight” to CC assets, refining a service view to their respective service strategy, performance objectives, and lifecycle demand requirements.</b></p> <p><b>Target:</b> Outline a plan for a Strategic Demand Planning effort towards creating mechanisms for “line of sight” to Asset Strategy for TO and TPO management review by the end of FY2014 Q1.</p>   | <p>Plan available for TO/TPO management review by the end of FY2014 Q1. Plan to include goals, plan and approach, expected resources, and progress milestones.</p> <p><i>Leadership and analysis for the effort will be a focus of the CC Program manager.</i></p>  |
| <p><b>7. Establish dedicated architecture and technology planning functions or roles. Evaluate objectives and options for roles and staffing for enhancing and enabling CC architecture and technology planning function(s).</b></p> <p><b>Target:</b> Through Transmission Operations strategic planning, the TASI project, and other efforts as appropriate, identify a strategic functional approach and next steps by the end of FY2014.</p>  | <p>A simple plan and approach is outlined and steps for proceeding are approved by the TO Manager.</p> <p>The plan will identify the relationship to the PSC and SPC Technology evaluation and test Councils and Test Team functions.</p>   |
| <p><b>8. Strategically plan for CC asset information management improvements to ensure data on CC assets is accurate, complete, secure, and readily accessible to those who need it. Specifically, as outlined in the preliminary draft Strategic Asset Information Management (SAIM) strategy:</b></p> <p><b>Target:</b> Per the preliminary SAIM Strategy approved on 3/31/2013, achieve the first 2 recommended steps by the end of FY2014 Q1:</p> <p><b>8A. Designate a Tier III or above Manager to own* and champion the strategy development</b> and implementation planning.</p> <p><b>8B. Determine staff and/or an approach to effectively support the Strategy development effort</b> for project management, analysis, and/or consulting. Set subsequent targets for progress based on the decisions.</p> | <p>A simple plan and approach is outlined and steps for proceeding are approved by the TO Manager.</p> <p><b>*“Owner” Expectations include:</b></p> <ul style="list-style-type: none"> <li>■ Accountable to ensuring the strategy development is supported and managed for progress.</li> <li>■ Ensures the Strategy effort is defined, structured, and all appropriate stakeholders are identified.</li> <li>■ Ensures all the related sub-efforts are in alignment, prioritized and managed against the strategy – monitors both short-term efforts and long-term vision development.</li> <li>■ Garner agreement at the TO management team level for final strategy and implementation plan – ensures all perspectives and concerns are incorporated.</li> </ul> |

### 3.0 STRATEGY IMPLEMENTATION PLAN

#### 3.1 10 year Implementation Plan

The current three-year view for priority projects identified as of 9/30/2013 is outlined below. In summary, this work plan will experience some flux and new priorities, for which the most urgent compliance and upgrades will get priority.

| Project                                      | Expected Work Plan FY Start | Expected Completion | Sustain/Expand | Main Project Driver (Risk)                            |
|--|-----------------------------|---------------------|----------------|---|
| <b>Control Centers (Expansion)</b>           |                             |                     |                |   |
| RAS AC/West Side Controller Expansion        | FY2013                      | FY2015              | Expand         | Policy-Interconnection commit.                        |
| CSM Room Expansion                           | FY2014                      | FY2014              | Expand         | Compliance/Policy- Support current growing systems    |
| CC Security and Event Log Consol.            | FY2014                      | FY2015              | Expand         | Increased Security/Compliance, Agency KAT             |
| Centralized Backup Phase 2                   | FY2015                      | FY2016+             | Expand         | Compliance/Policy-Disaster Recovery                   |
| Dispatch Line Fault Indic Tool Imp           | FY2015                      | FY2016+             | Expand         | Discretionary-Dispatch visibility, reduce outage time |
| <b>CC Infrastructure (Sustain)</b>           |                             |                     |                |   |
| DCC-MCC Network True Up                      | FY2012                      | FY2014              | Sustain        | Site to site standardization, compliance              |
| CC Network Mngmt Tools Upgrade               | FY2012                      | FY2014              | Sustain        | Upgrade/EOL, site/tools standardization               |
| CCN DMZ Update                               | FY2013                      | FY2015              | Sustain        | Upgrade/EOL, imminent compliance issues               |
| Security Scanners                            | FY2013                      | FY2015              | Sustain        | Upgrade, compliance, standardization, efficiency      |
| IDS/IPS Upgrade                              | FY2014                      | FY2015              | Sustain        | Upgrade/EOL, improved security, standardization       |
| MCC Dispatch Modernization                   | FY2015                      | FY2015              | Sustain        | Upgrades, site to site standardization, EOP008        |
| DTF Dispatch Modernization                   | FY2015                      | FY2016+             | Sustain        | Upgrade room and tools to current dispatch needs      |
| CC Public Key Interface (PKI)                | FY2015                      | FY2016+             | Sustain        | compliance, security enhancement/consolidation        |
| <b>CC Systems and Applications (Sustain)</b> |                             |                     |                |   |
| SCADA EMP 2.5 Upgrade                        | FY2011                      | FY2014              | Sustain        | Upgrade/EOL, Window's Migration strategy              |
| CC OPI App Web Server Upgrade                | FY2012                      | FY2014              | Sustain        | Upgrade/EOL, capacity/performance issues              |
| EMS Systems Replacement Phase 3              | FY2013                      | FY2016              | Sustain        | Upgrade/EOL, Window's Migration strategy              |
| CCA NERC CIP Compliance Upgrade              | FY2014                      | FY2015              | Sustain        | Upgrades, Imminent compliance issues                  |
| Automated Patch Management                   | FY2014                      | FY2015              | Sustain        | Upgrades, compliance improvements, efficiencies       |
| PI Upgrade                                   | FY2015                      | FY2015              | Sustain        | Upgrade/EOL, compliance issues                        |
| DART Upgrade                                 | FY2015                      | FY2016              | Sustain        | Upgrade/EOL, compliance issues                        |

EOL = "End of Life"; EOP-008 = "NERC Emergency Operations Requirements"

CC typically has the visibility to plan about 2-3 years out. The expectation is that Lifecycle plans, and the roll-up of identified priorities and funding/FTE requirements, will offer a somewhat longer-term and comprehensive view to the program needs. Improvements towards consistently incorporating new pop-up projects into the Asset Plan will offer mechanisms to manage the priorities and see the relative importance and total demands of those priorities. The plan is to develop methods to incorporate this analysis into the asset priorities before they become projects, and support more proactive and visible priority management.

### 3.2 Program Forecast Planning

#### FY2014-2023 Capital Forecast

Direct Capital only, Nominal Dollars in '000

| Equip Category    | FY14           | FY15           | FY16           | FY17           | FY18           | FY19           | FY20           | FY21           | FY22           | FY23           | Total           |
|-------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|-----------------|
| CC Expansion      | \$1,389        | \$1,517        | \$1,526        | \$2,500        | \$2,500        | \$2,500        | \$2,500        | \$2,500        | \$2,500        | \$2,500        | \$21,932        |
| CC Infrastructure | \$2,479        | \$2,987        | \$3,052        | \$2,706        | \$2,783        | \$2,861        | \$2,939        | \$3,019        | \$3,094        | \$3,094        | \$29,014        |
| CC Systems        | \$3,332        | \$2,840        | \$3,052        | \$2,500        | \$2,500        | \$2,500        | \$2,500        | \$2,500        | \$2,500        | \$2,500        | \$26,724        |
| <b>Total</b>      | <b>\$7,200</b> | <b>\$7,344</b> | <b>\$7,630</b> | <b>\$7,706</b> | <b>\$7,783</b> | <b>\$7,861</b> | <b>\$7,939</b> | <b>\$8,019</b> | <b>\$8,094</b> | <b>\$8,094</b> | <b>\$77,670</b> |

#### FY2014-FY2023 Expense Forecast

Nominal Dollars in '000

| Maintenance Program | FY14     | FY15     | FY16     | FY17     | FY18     | FY19     | FY20     | FY21     | FY22     | FY23     | Total            |
|---------------------|----------|----------|----------|----------|----------|----------|----------|----------|----------|----------|------------------|
| Control Center      | \$19,708 | \$20,024 | \$20,344 | \$20,670 | \$21,000 | \$21,336 | \$21,678 | \$22,025 | \$22,377 | \$22,735 | <b>\$211,896</b> |

#### Caveats

Forecast is currently under review as part of the 2014 Integrated Program Review (IPR) process and will be updated in conjunction with the IPR timeline.

# **POWER SYSTEMS CONTROL ASSET MANAGEMENT STRATEGY**

Jeff Cutter, Program Manager  
December 2013

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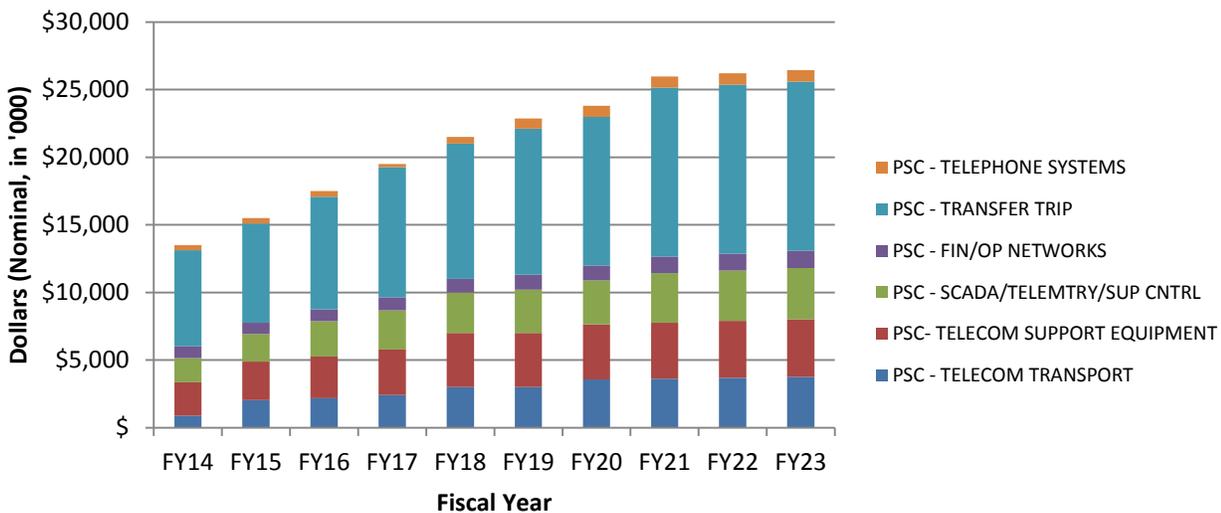
## EXECUTIVE SUMMARY

### Power System Control (PSC) program overview

Power System Control assets are the substation controls and the telecommunications equipment that help maximize capacity on the transmission system. Equipment includes:

- Telecom Transport
- Telecom Support Equipment
- SCADA/Telemetry/Supervisory Control
- Field Information Network (FIN)/Operational Networks
- Telephone Systems
- Transfer Trip
- Remedial Action Scheme (RAS)
- System Telecommunications
- Fiber Optic Cable

**PSC Capital Forecast FY2014-2023**



### Key risks to be addressed

- Unplanned equipment replacements due to failures
- Outage risks and high economic costs due to equipment failure
- Technology interoperability issues
- Technology obsolescence and evolution
- Costly re-work caused by inadequate testing, lack of needed coordination with System Protection and Control (SPC) and Control Center (CC) programs
- Lack of manufacturer support
- Changing power system operations needs and evolving regulatory requirements

### Strategy Elements

By using the total economic cost analytical approach, this strategy reflects the identification of a replacement plan that provides the greatest opportunity to reduce risks and therefore cost to BPA and its customers. This drives the development of a strategy that includes:

- Focus on replacing critical, at-risk equipment first

- Less critical and risky equipment is allowed to run to failure
- Accumulated backlog of replacements is planned based on economic lifecycle
- Preparation for future technology
- Work process improvements
  - ◆ More robust testing
  - ◆ Documentation clean up and management
  - ◆ Enhanced training
  - ◆ Coordination with SPC program for replacements

In the long run, this strategy will help:

- Set the pace of planned replacements that reduces the frequency of failures, which has an impact on preventative maintenance, corrective repairs and emergency replacements, thereby reducing the economic cost to BPA and to BPA’s customers
- Overcome the backlog of replacement and reach a steady state to better manage risks, costs, and resources
- The PSC program be better positioned to respond to market changes
- Make PSC staff more efficient and effective

## 1.0 STRATEGY BACKGROUND

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### 1.1. Business Environment

The Power System Control (PSC) assets are critical control components for the transmission system. The program is highly driven by emerging technologies and regulatory compliance and must be positioned to respond to changes. Much of the equipment has a short lifecycle due to its technology type and often external forces drive the availability of spare parts and continued support from the manufacturer.

### 1.2 Assets, Asset Systems and Criticality

**Program Profile:** 732 sites, including 111 radio sites, 482 BPA and customer-owned substations, and 139 other sites such as power houses, maintenance buildings, and control centers.

**Assets:** Equipment is categorized into six groups and is described in the table below:

| Asset  | Description   |
|--|---|
| Telecom Transport                                    | This equipment includes analog and digital microwave radio, analog and digital multiplex, fiber optic terminal equipment and UHF radios. The combination of these systems creates an extensive, system-wide communications network, with over 10,000 telecom circuits (primarily data and control circuits) |
| Telecom Support Equipment                            | This equipment includes alarm systems, batteries/chargers, DC-DC converters, engine generators, UPS systems, timing systems, fault locators, miscellaneous support systems, and towers and grounds.   |
| SCADA/Telemetry/Supervisory Control                  | This equipment includes Supervisory Control And Data Acquisition Remote Terminal Units (RTUs), supervisory control systems, and telemetering systems.   |
| Field Information Network (FIN)/Operational Networks | This equipment includes FIN network equipment, operational network equipment, network management system equipment, and modems.  |

| Asset             | Description  |
|-------------------|--|
| Transfer Trip     | This equipment includes protection units and Remedial Action Scheme (RAS) communication units.   |
| Telephone Systems | BPA maintains an extensive internal Dial Automatic Telephone System (DATS) for daily operation and maintenance activities. This equipment includes DATS switches and supporting systems, key system and telephone equipment, and teleprotection systems. |
| Fiber Optic Cable | This includes approximately 3,000 miles of fiber optic cable.  |

**Criticality**

| Less Important        |                      | More Important              |                         |
|-----------------------|----------------------|-----------------------------|-------------------------|
| Misc. support systems | Telephone systems    | VHF/mobile/portable radios  | RAS                     |
|                       | Telephone protection | UHF                         | Transfer trip           |
|                       | FIN network          | DATS                        | SCADA                   |
|                       |                      | Multiplex                   | Fiber cable             |
|                       |                      | Power line carrier          | Comm batteries/chargers |
|                       |                      | Telemetry                   | SONET/MW radios         |
|                       |                      | Operational networks/NMS    |                         |
|                       |                      | Supervisory control systems |                         |
|                       |                      | UPS                         |                         |

## 2.0 THE STRATEGY

### 2.1 Current State

Over the years, multiple generations of PSC equipment have been installed on BPA’s transmission system and the increasing risks of PSC equipment failure has become a key driver for the development of a strategy to mitigate the impacts.

Some of the equipment is technologically obsolete as a result of the rapid evolution of technology in the marketplace and older vintage equipment is often without vendor support or spare parts or both. As a result, interoperability problems across equipment vintages are being experienced. This causes unnecessary deratings, outages and other risks. Maintenance is time consuming and complicated leading to backlogs, long repair times and higher than expected costs. This has created an excessively large and expansive spare parts inventory.

In the last 10 years, BPA has under-invested in telecomm transport, telephone systems, telecomm support, SCADA and telemetry and transfer trip replacements as a result of many of the constraints being addressed in the Transmission Asset Management Overarching strategy. This has resulted in a backlog of replacements in the PSC/System Telecom programs.

In recent years, the PSC/System Telecom programs have gone through an evaluation of strategic alternatives based on reducing risks and total economic costs. In addition, to ensure investments in PSC equipment replacement were coordinated with the associated replacements in system protection and control (SPC) assets, Transmission Services initiated the development of an effort to integrate the two programs, along with associated control center (CC) assets. This effort, known as the Integrated Control System Strategy, resulted in the evaluation and development of

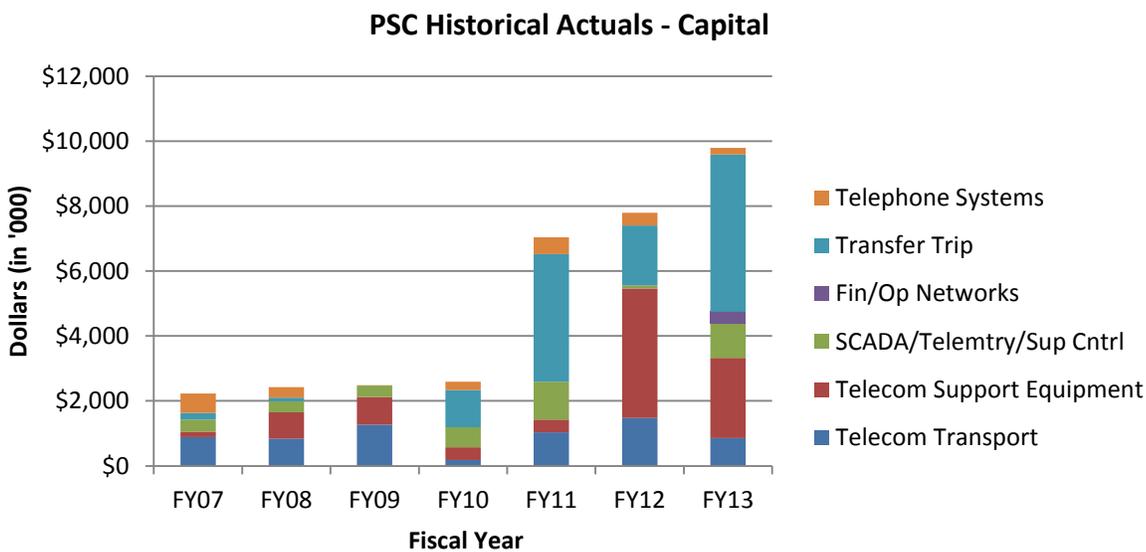
a strategic approach that ensures the most valuable investments, based on reducing total economic cost, are focused on first, regardless of the program. This allows Transmission asset management to make important trade-offs based on mitigating the most costly risks.

### 2.1.1 Program Accomplishments for FY2012-2013

Execution of projects to move the analog to digital migration initiative forward:

- Completed #YC01 digital fiber/radio ring
- Buried approximately 2.5 miles of problematic fiber optic cable at Silver Butte.
- Construction commenced on the #BC radio system.
- #KC Phase 2 Project (\*K06 and \*K16) became operational, allowing circuits to begin moving from the analog microwave along the COI to fiber and digital radio.
- Completed 60% of EACC circuit cutovers
- Completed replacement of:
  - ◆ 30 communications batteries/chargers
  - ◆ 10 MW radio replacements
  - ◆ 13 SCADA RTUs
  - ◆ 14 UHF radios
  - ◆ 40 analog communications alarm RTUs and FIN RTUs
  - ◆ 8 antenna systems
  - ◆ 12 KTS and 2 DATS telephone switches
  - ◆ 30 analog Transfer Trip/RAS units
- Completed design to upgrade over 300 miles of fiber optic cable on the Ross-Schultz fiber project.
- Completed design and started construction of the #WC radio/fiber system.
- Received approval for Mobile Radio Replacement Project and started equipment selection.
- Received approval for the Optical Multi-gigabit Ethernet Transport (OMET) and have begun design and testing of equipment
- Completed the development of new test lab
- Began actively addressing the documentation backlog

### 2.1.2 Cost History

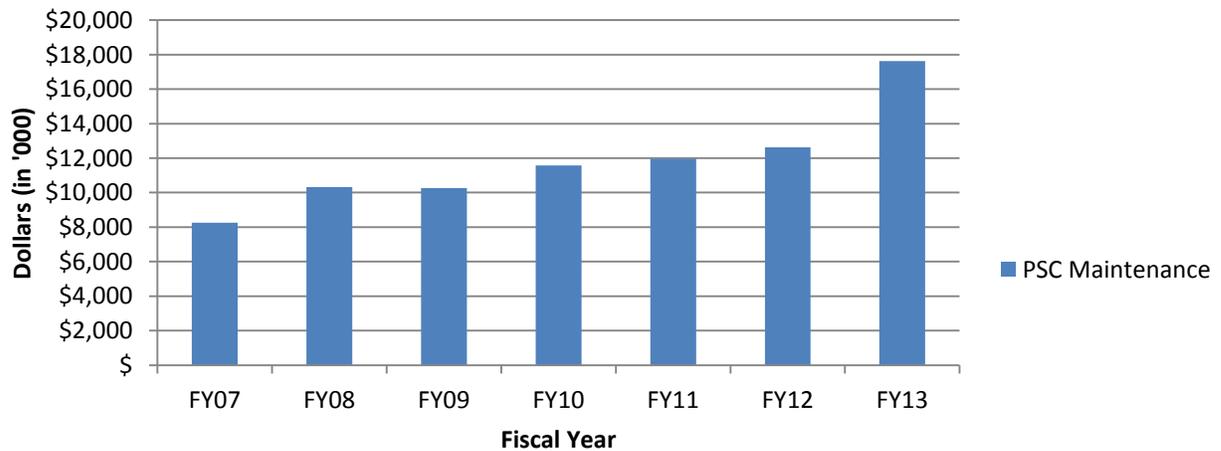


**Historical Actuals - Capital**

Dollars in '000

| Equipment Category        | FY07           | FY08           | FY09           | FY10           | FY11           | FY12           | FY13           | Total           |
|---------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|-----------------|
| Telecom Transport         | \$890          | \$834          | \$1,266        | \$183          | \$1,029        | \$1,471        | \$856          | \$6,529         |
| Telecom Support Equip     | \$166          | \$813          | \$855          | \$392          | \$401          | \$3,990        | \$2,468        | \$9,085         |
| SCADA/Telemetry/Sup Cntrl | \$371          | \$338          | \$353          | \$611          | \$1,157        | \$100          | \$1,052        | \$3,982         |
| Fin/Op Networks           |                |                |                |                |                |                | \$373          | \$373           |
| Transfer Trip             | \$204          | \$116          | -\$1           | \$1,148        | \$3,929        | \$1,845        | \$4,841        | \$12,082        |
| Telephone Systems         | \$596          | \$324          | \$10           | \$258          | \$526          | \$388          | \$205          | \$2,307         |
| <b>Total</b>              | <b>\$2,227</b> | <b>\$2,425</b> | <b>\$2,483</b> | <b>\$2,592</b> | <b>\$7,042</b> | <b>\$7,794</b> | <b>\$9,795</b> | <b>\$34,358</b> |

**PSC Historical Actuals - Expense**



**Historical Actuals - Expense**

Dollars in '000

| Program | FY07    | FY08     | FY09     | FY10     | FY11     | FY12     | FY13     | Total    |
|---------|---------|----------|----------|----------|----------|----------|----------|----------|
| PSC     | \$8,248 | \$10,328 | \$10,271 | \$11,579 | \$11,958 | \$12,637 | \$17,632 | \$82,642 |

### 2.1.3 Health of Current Assets (Current Condition & Performance)

#### Lifecycle Assumptions by Equipment Type

| EQUIPMENT TYPE   | Lifecycle (Yrs) | # of Units | Average Age |
|--|-----------------|------------|-------------|
| SCADA  | 13              | 212        | 15          |
| Transfer Trip  | 12              | 846        | 14          |
| RAS  | 14              | 666        | 15          |
| Fiber Cable  | 25              | 3000 miles |             |
| Mobile   | 15              | 1480       | 13          |
| VHF Repeater   | 12              | 65         | 19          |
| 7 Year Lifecycle (Comm Alarm Systems, VRLA Batteries)  | 9               | 715        | 9           |
| 20 Yr Batteries (Flooded Cell Batteries)               | 22              | 248        | 11          |
| DC Power 15 (Chargers, DC-DC Converters)               | 18              | 546        | 13          |
| Misc 10 Year (Fiber Patch Panels; Fiber Drivers, etc.) | 12              | 422        | 10          |
| UHF Radios   | 11              | 109        | 11          |
| Telemetry  | 18              | 578        | 12          |
| Telephone (Key Systems, etc.)                          | 12              | 720        | 17          |
| Engine Generators                                      | 22              | 80         | 20          |
| SONET Other (Fiber nodes)                              | 12              | 261        | 8           |
| DATS   | 12              | 14         | 7           |
| SONET Ancillary (digital multiplex, digital microwave) | 10              | 635        | 7           |

As the equipment ages, these assets require a significant level of resources to maintain, repair and operate. These expenses are expected to continue to grow as the system gets larger and becomes increasingly more complex until obsolete equipment is removed and replaced (e.g. analog to digital), and strategy process improvement initiatives reach steady state.

## 2.2 Future State

### 2.2.1 Key asset performance objectives, measures and targets

#### Critical equipment replacement plan:

*Aggressively reduce risks of asset failure, interoperability, and technological obsolescence*

- Accomplish conversion from analog equipment to digital within 7-9 years
- Replace critical analog Transfer Trip and RAS equipment within five years (accelerate from the current pace of 17-19 years)
- Develop and implement a long-term strategy for moving off SONET

#### Process improvement initiatives:

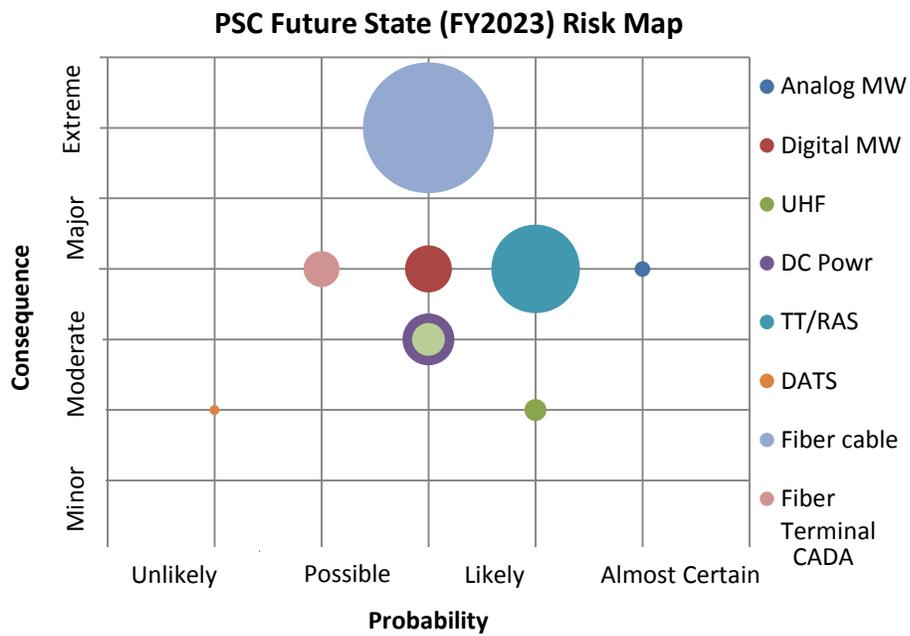
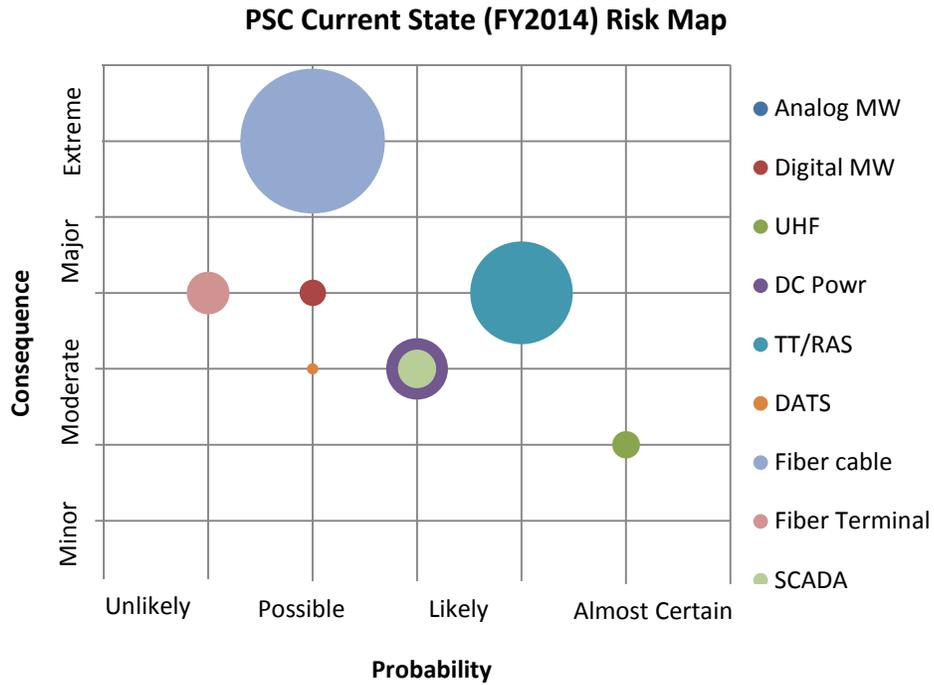
*In addition to equipment performance measures, targets have been established for implementing valuable process improvements to enhance program delivery. These are being tracked through the FY2014 Asset Management Key Transmission Target.*

The target for FY2014 is to achieve key planned milestones per the Integrated Control System (ICS) detailed strategy plan by focusing on providing training to accommodate increased staffing levels, reducing backlog of PSC documentation and maintaining accurate documentation.

By the end of FY2014,

- At least 21% of PSC documentation backlog has been completed
- Implementation of a second training room is ready for use by the third quarter of FY2014.
- FY2015 training schedule for both training rooms is developed.

### 2.3 Asset Condition/Performance Gaps



See Appendix G for definitions of Consequence and Probability Scales

## Gaps between Current and Future State

### Fiber cable:

BPA's first fiber cables were installed in the early 1990s. Plans are in place to replace some of the early cables that are in poor shape. The current plan is to replace 100 miles per year, which does not meet the system's needs. At 3,000 miles and growing, the replacement rate should also grow with an average lifecycle of 25 years. Therefore, over the next ten years the miles will need to increase or the risk will grow. A fiber cable failure has the highest consequences in the PSC program.

### Transfer Trip (TT) and RAS

The number of TT and RAS units continues to grow. The current state shows that the replacement rate has not met the need in many years. The average age of the asset for both RAS and TT exceeds its lifecycle. Over the next ten years the plan is to increase the replacement rate to required level but still will come short in meeting system needs. Without an increase in the annual level of replacement, the risk will continue to increase and the number of failures per year could rise. The equipment life is being pushed to hazardous levels. Effort to increase the volume of replacement continues.

### Analog Microwave

The number of analog radios continues to decrease. Most will be off the system in ten years. Those that remain will be in very poor condition. The risk of failure will be high but the impact should be minimal.

### Digital Microwave

The number of digital radios will continue to increase. The average age of the radio is less than 10 years old, which is less than the expected lifecycle. Given the shorter lifecycle, equipment will need to be replaced more frequently. The future state map assumes some level of risk of failure due to replacement rate needing to rise at levels greater than can currently be executed today.

### Fiber Terminals

The number of new SONET terminals is not expected to increase greatly. Most of the terminals are still young. The biggest issue is software, firmware and hardware compatibility. There are already boxes that cannot upload the latest software. Therefore, they need to be replaced even though there are no reliability issues. The scale of the problem is unknown at this time. Finally, more and more manufacturers are going to packet-based networks and SONET will become eventually obsolete. It is still unknown how long SONET will be manufactured and supported.

### SCADA

The SCADA replacement is on schedule and will be complete this year. Delays were incurred due to need to coordinate with building replacements or other similar issues.

### DATS

The last of the new KTS will be installed in FY2014-FY2016. The program then begins a new cycle. The new cycle should be completed by 2023. No significant issues are expected.

### DC Power

BPA is currently on schedule with the battery and charger replacements. The biggest issue has been quality. The equipment was produced in the early 2000s and is experiencing early failure. The next few years will be focused on emergency or urgent replacements.

## UHF

Most of the analog UHF radios have been removed. The rest will be removed in the next few years. The existing and new digital UHF radios are of lesser quality than previous equipment and interference and other issues have arisen. The future of this equipment is uncertain at this time, but the frequency band is needed since other bands are being lost. The direction of this program is very uncertain at this time.

### 2.3.1 Risks to meeting the objectives

#### **Execution constraints:**

The primary risk to successful execution of the strategy is the insufficient number of resources for designing and executing PSC projects. Transmission Services is currently working on an overarching plan to address these gaps.

## 2.4 Strategic Approach to Closing Gaps

### 2.4.1 Strategic Approach

#### **There were four innovations used for the PSC/Telecom asset strategy.**

- The first was “Quantification of regional (societal) costs as well as BPA-incurred costs”. This estimates the value of transmission reliability and the cost to the region when equipment fails and a customer outage occurs.
- The second is “comprehensive modeling of cost (and avoided cost) uncertainties”. This is a leap forward in quantifying risks and is based on historical actuals and extensive coordination with SMEs.
- The third is a new model that will enable work to be prioritized to reduce reliability risk and exposure and reduce economic cost. This is done while also taking into account capital funding, outage availability, resource availability, and other constraints.
- Finally, the fourth is a structured approach to implementation planning. It is based upon constraint assumptions, data, and a vetted model. The replacements and maintenance are prioritized in greater detail with redesigned and bolstered processes, including test and evaluation program, technical training, and asset documentation practices. Resources are allocated as needed.

The overall goal was minimize long-term economic cost to BPA and the Region.

#### **Several key working assumptions underlie the development of the model and implementation plan.**

- Low impact equipment is repaired until it reaches terminal failure, then replaced (run to fail) rather than having a time-based replacement cycle.
- Replacement cycles are driven by equipment type, technology and market lifecycles, experience with similar technologies, ability to repair in-house and availability of spares. Adjusted lifecycles by equipment type and extended whenever appropriate.
- Assume all failures will be repaired to restore service prior to a replacement decision being made, and terminal failure rate is between 2% and 10%.
- Equipment groupings are based on similarities in system impact, cost, and life cycle.
- Analog to Digital (A/D) replacements turned to retirements (eliminated duplication between A/D and SONET categories).
- Outage risk reassessed for different sizes of outages. High MW/high cost outages are a much lower risk than low MW/low cost outages.

### **Rolling Technology Strategy**

The PSC/Telecom strategy is focused on reducing the risks of asset failure, interoperability, and technological obsolescence.

*The PSC program is working to ensure PSC and telecom equipment will support BPA in delivering on its strategic initiatives, such as:*

- Technological innovations that enable grid operators to “see” the grid more accurately, intermittent generation to be forecast more accurately, and grid operations to be controlled more precisely
- Scheduling and product design innovations that increase access and enable fuller use of existing capacity
- Balancing authority consolidation (or partial consolidation) should the region decide to consolidate

In addition, BPA will continue to deploy synchrophasors over the next 3-7 year period. This will be consistent with WECC’s program direction. Other PSC equipment will also be deployed consistently with the synchrophasor project plan for engineering, control center, and real-time response-based control applications.

*Design and conduct a comprehensive, integrated testing program –“Test twice, install once”:*

- Enhance existing selection and testing programs by adding a field testing phase to the current pre-qualification testing
- Install enough terminals of a new technology to test for technology interoperability, system limits for timing, geographic distribution, circuit type limitations
- Coordinate the testing of system components so that roll-outs are efficient and pose minimal risk to system stability
- Ensure that reliability risk is reduced , time-consuming and expensive re-do’s are minimized, and scarce FTE are deployed efficiently

*Benchmarking with other west coast utilities will be performed to learn how they manage their PSC assets and develop and implement resourcing strategy by:*

- Identifying core skill requirements
- Determining the number, composition of required staffing levels (BFTE, CFTE, Service Contractors)
- Determining recruiting sources/approach (coordinate with HCM/Unions)

*The strategy analytics will be updated on a recurring basis to better inform strategy and implementation plan development:*

- Update asset health risk assessments
- Update prioritization of work activities – directed at maximizing total economic value

*Finally, BPA will develop and implement training program.*

- To ensure productive, high quality work by the large influx of new staff
- To ensure currency of skills for the technologies being introduced

### **The Integrated Control System (ICS) effort, evaluated a number of strategic alternatives:**

- *Reference*  
Current state execution of strategies based on resource limitations and associated funding
- *Approved Strategy*  
SPC, PSC, and Control Center strategies as presented and approved by BPA
- *Active Coordination*

Continue with the originally approved PSC/Telecom/SPC strategies and improve upon them with increased coordination between PSC, SPC and CC programs for equipment replacements and process improvements

- *Enhanced Fault Location (EFL)*  
Reduce the restoration time of transmission outages/derates through better and faster fault location on all voltage levels; extend fault location to approximately 125 sites on sub-grid, replace the FLAR master.
- *Relay Functionality Optimization (RFO)*  
Use full capability of microprocessor relays to perform transfer trip, SCADA, digital fault recording, and sequential events recording functionalities, and eliminate selected PSC and SPC equipment types everywhere.

Based on the optimal approach for reducing total economic cost, it was recommended BPA implement all facets of the *Active Coordination* strategy. This strategy will:

- Create synergy by developing a disciplined process for coordination of planning, planned outages, and execution.
- Expand the PSC council to cover all equipment and coordinate current and future technologies across PSC/System Telecom/SPC/CC. The ICSS council will manage the technologies and pre-deployment equipment testing.
- Create and act on an appropriate staffing strategy.
- Replace equipment based on economic lifecycle (i.e. based on impact to the total economic cost). Improve documentation and pre-deployment testing.
- Develop the ability to adjust the replacement plans based on observed failure rates.
- Set a process to monitor strategy execution performance.
- Identify opportunities to shorten planned outages, specifically fiber, where the work could potentially be performed in half the time.
- For fiber replacement, the feasibility of using two crews to reduce the planned outage duration by 40% with approximately the same FTE cost is being investigated.
- Consider a limited targeted spares kits strategy for PSC and SPC in high impact areas to reduce outage times.

### 3.0 STRATEGY IMPLEMENTATION PLAN

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The PSC/telecom model used to develop the implementation plan takes into account equipment age, expected life, condition and technological change. Failure-probability curves derived from actual BPA PSC equipment failures coupled with SME judgment, were prepared for each of 24 equipment types to compare age with probable end of life. The model also takes into account the optimal time to repair or replace based on outage risk and exposure.

This information drives the identification of the 10 year equipment replacement plan included in the following page.

### 3.1 10 year Implementation Plan

| Equipment                            | Current Strategy Impl. Plan - Steady State of equip needing to be replaced per year | Ramp to get to Steady State |   |        |    |        |    |        |    |        |    |        |    |        |    |        |    |        |    |        |    |    |    |  |  |
|--------------------------------------|---|-----------------------------|---|--------|----|--------|----|--------|----|--------|----|--------|----|--------|----|--------|----|--------|----|--------|----|----|----|--|--|
|                                      |   | FY2014                      |   | FY2015 |    | FY2016 |    | FY2017 |    | FY2018 |    | FY2019 |    | FY2020 |    | FY2021 |    | FY2022 |    | FY2023 |    |    |    |  |  |
| D=Design C=Construct                 |   | D                           | C | D      | C  | D      | C  | D      | C  | D      | C  | D      | C  | D      | C  | D      | C  | D      | C  | D      | C  | D  | C  |  |  |
| <b>PSC Program:</b>                  |   |                             |   |        |    |        |    |        |    |        |    |        |    |        |    |        |    |        |    |        |    |    |    |  |  |
| <b>TelecomTransport</b>              |   |                             |   |        |    |        |    |        |    |        |    |        |    |        |    |        |    |        |    |        |    |    |    |  |  |
| UHF Radio Replacement                | 10  | 0                           |   | 0      | 0  | 4      | 0  | 6      | 4  | 8      | 6  | 10     | 8  | 10     | 10 | 10     | 10 | 10     | 10 | 10     | 10 | 10 | 10 |  |  |
| Microwave Radio Replacement          | 32  |                             |   | 8      |    | 12     | 8  | 16     | 12 | 20     | 16 | 24     | 20 | 28     | 24 | 30     | 28 | 32     | 30 | 32     | 32 | 32 | 32 |  |  |
| SONET Node Replacement               | 32  | 6                           |   | 10     | 6  | 14     | 10 | 18     | 14 | 20     | 18 | 22     | 20 | 24     | 22 | 26     | 24 | 28     | 26 | 30     | 28 | 30 | 28 |  |  |
| <b>Telecomm Support</b>              |   |                             |   |        |    |        |    |        |    |        |    |        |    |        |    |        |    |        |    |        |    |    |    |  |  |
| 1 year projects                      |   |                             |   |        |    |        |    |        |    |        |    |        |    |        |    |        |    |        |    |        |    |    |    |  |  |
| Engine Generator Replacement         | 4   | 6                           |   | 5      |    | 5      |    | 5      |    | 5      |    | 4      |    | 4      |    | 4      |    | 4      |    | 4      |    | 4  |    |  |  |
| Battery Replacement                  | 20  | 15                          |   | 15     |    | 12     |    | 12     |    | 13     |    | 15     |    | 16     |    | 18     |    | 20     |    | 20     |    | 20 |    |  |  |
| Charger Replacement (sets)           | 20  | 8                           |   | 10     |    | 13     |    | 13     |    | 13     |    | 15     |    | 16     |    | 18     |    | 20     |    | 20     |    | 20 |    |  |  |
| <b>SCADA/Telemetry Support</b>       |   |                             |   |        |    |        |    |        |    |        |    |        |    |        |    |        |    |        |    |        |    |    |    |  |  |
| SCADA Replacement                    | 14  | 8                           |   | 8      | 8  | 8      | 8  | 8      | 8  | 8      | 8  | 10     | 8  | 12     | 10 | 14     | 12 | 14     | 14 | 14     | 14 | 14 | 14 |  |  |
| Telemetry Replacement                | 30  | 6                           |   | 8      | 6  | 10     | 8  | 12     | 10 | 16     | 12 | 18     | 16 | 20     | 18 | 20     | 20 | 22     | 20 | 24     | 22 | 24 | 22 |  |  |
| <b>FIN/Op Networks</b>               |   |                             |   |        |    |        |    |        |    |        |    |        |    |        |    |        |    |        |    |        |    |    |    |  |  |
| 1 year projects                      |   |                             |   |        |    |        |    |        |    |        |    |        |    |        |    |        |    |        |    |        |    |    |    |  |  |
| FIN/NMS Replacement                  | 30  | 18                          |   | 30     |    | 30     |    | 30     |    | 30     |    | 30     |    | 30     |    | 30     |    | 30     |    | 30     |    | 30 |    |  |  |
| RS Station Service Replacement       | 2   | 1                           |   | 1      |    | 1      |    | 1      |    | 1      |    | 1      |    | 1      |    | 1      |    | 1      |    | 1      |    | 1  |    |  |  |
| Communication Alarms RTU Replacement | 15  | 10                          |   | 10     |    | 10     |    | 10     |    | 10     |    | 11     |    | 12     |    | 13     |    | 14     |    | 15     |    | 15 |    |  |  |
| <b>Transfer Trip and RAS</b>         |   |                             |   |        |    |        |    |        |    |        |    |        |    |        |    |        |    |        |    |        |    |    |    |  |  |
| Transfer Trip Replacement            | 55  | 35                          |   | 40     | 35 | 45     | 40 | 45     | 45 | 45     | 45 | 47     | 45 | 50     | 47 | 52     | 50 | 55     | 52 | 55     | 55 | 55 | 55 |  |  |
| RAS Replacement                      | 45  | 15                          |   | 20     | 15 | 20     | 20 | 25     | 20 | 25     | 25 | 28     | 25 | 30     | 28 | 28     | 30 | 30     | 28 | 35     | 30 | 30 | 30 |  |  |
| <b>Telephone Systems</b>             |   |                             |   |        |    |        |    |        |    |        |    |        |    |        |    |        |    |        |    |        |    |    |    |  |  |
| DATS Telephone System replacement    | 3   | 0                           |   | 0      | 0  | 0      | 0  | 2      | 0  | 5      | 2  | 5      | 5  | 5      | 5  | 5      | 5  | 5      | 5  | 5      | 5  | 5  | 5  |  |  |
| KTS Telephone System replacement     | 10  | 12                          |   | 12     | 12 | 12     | 12 | 9      | 12 | 0      | 9  | 0      | 0  | 0      | 0  | 0      | 0  | 0      | 0  | 0      | 0  | 0  | 0  |  |  |
| GPS Receivers (Expense)              |   |                             |   | 2      | 2  | 2      | 2  | 2      | 2  | 2      | 2  | 2      | 2  | 2      | 2  | 2      | 2  | 2      | 2  | 2      | 2  | 2  | 2  |  |  |
| Telephone Protection (Expense)       |   |                             |   | 5      | 5  | 5      | 5  | 5      | 5  | 5      | 5  | 5      | 5  | 5      | 5  | 5      | 5  | 5      | 5  | 5      | 5  | 5  | 5  |  |  |

### 3.2 Program Forecast Planning

#### FY2014-2023 Capital Forecast

Direct Capital only, Nominal Dollars in '000

| Program - Equipment Category   | FY14            | FY15            | FY16            | FY17            | FY18            | FY19            | FY20            | FY21            | FY22            | FY23            | TOTAL            |
|--------------------------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|------------------|
| PSC - TELECOM TRANSPORT        | \$877           | \$2,039         | \$2,188         | \$2,407         | \$3,000         | \$3,000         | \$3,560         | \$3,620         | \$3,682         | \$3,744         | \$28,117         |
| PSC- TELECOM SUPPORT EQUIPMENT | \$2,486         | \$2,855         | \$3,063         | \$3,370         | \$4,000         | \$4,000         | \$4,068         | \$4,137         | \$4,207         | \$4,279         | \$36,465         |
| PSC - SCADA/TELEMTRY/SUP CNTRL | \$1,775         | \$2,039         | \$2,625         | \$2,889         | \$3,000         | \$3,200         | \$3,254         | \$3,661         | \$3,723         | \$3,787         | \$29,955         |
| PSC - FIN/OP NETWORKS          | \$870           | \$816           | \$875           | \$963           | \$1,000         | \$1,100         | \$1,119         | \$1,220         | \$1,241         | \$1,262         | \$10,466         |
| PSC - TRANSFER TRIP            | \$7,102         | \$7,342         | \$8,313         | \$9,630         | \$10,000        | \$10,800        | \$10,984        | \$12,509        | \$12,509        | \$12,509        | \$101,697        |
| PSC - TELEPHONE SYSTEMS        | \$391           | \$408           | \$438           | \$241           | \$500           | \$750           | \$814           | \$827           | \$841           | \$856           | \$6,065          |
| <b>TOTAL</b>                   | <b>\$13,500</b> | <b>\$15,500</b> | <b>\$17,500</b> | <b>\$19,500</b> | <b>\$21,500</b> | <b>\$22,850</b> | <b>\$23,798</b> | <b>\$25,975</b> | <b>\$26,204</b> | <b>\$26,437</b> | <b>\$212,764</b> |

#### FY2014-FY2023 Expense Forecast

Nominal Dollars in '000

| Maintenance Program | FY14     | FY15     | FY16     | FY17     | FY18     | FY19     | FY20     | FY21     | FY22     | FY23     | Total     |
|---------------------|----------|----------|----------|----------|----------|----------|----------|----------|----------|----------|-----------|
| PSC                 | \$16,868 | \$17,582 | \$18,198 | \$18,835 | \$19,494 | \$20,176 | \$20,882 | \$21,613 | \$22,370 | \$23,153 | \$199,170 |

#### Caveats

Forecast is currently under review as part of the 2014 Integrated Program Review (IPR) process and will be updated in conjunction with the IPR timeline.

# **SYSTEMS PROTECTION AND CONTROL**

## **ASSET MANAGEMENT STRATEGY**

Curtis Michael, Program Manager  
December 2013

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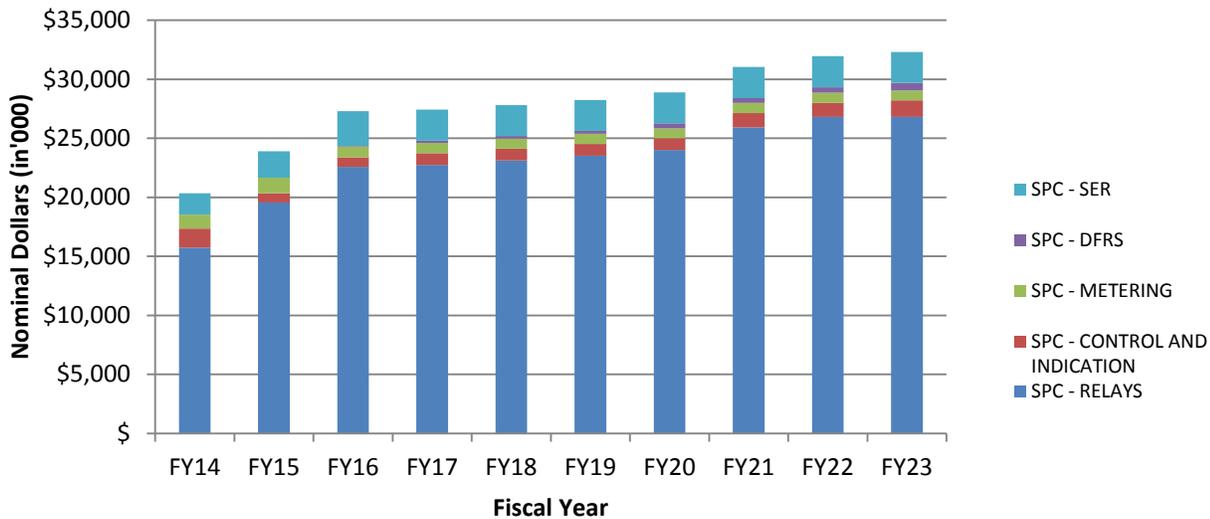
## EXECUTIVE SUMMARY

### System Protection and Control (SPC) program overview

SPC systems provide critical support to the primary circuit elements by preserving equipment integrity, maintaining overall reliability, gathering and storing operational data and ensuring public safety.

- Over 28,000 units of equipment in approximately 956 locations, including all BPA substations and many customer-owned substations, power houses, maintenance buildings and control centers.
- Assets:
  - ◆ Protective relaying
  - ◆ Sequential events recorders (SER)
  - ◆ Fault recorders (DFR)
  - ◆ Revenue and interchange metering
  - ◆ Control and indication equipment

**SPC Capital Forecast FY2014-2023**



### Key risks to be addressed

- Lack of Original Equipment Manufacturer (OEM) support for most SPC equipment due to advanced age
- Risks associated with poor health condition of older SPC equipment
- Decreasing skill set to maintain older equipment as SPC employees retire
- Increased corrective maintenance workload to maintain older equipment in poor health
- Increase in higher cost emergency repairs

### Strategy Elements

The SPC strategy and implementation plan were developed using a risk-informed evaluation of strategic alternatives with a goal towards reducing total economic costs. This strategy includes:

- Targeting replacement of high risk-high economic cost non-microprocessor relays over a 10 year horizon
- Replace older DFRs then subsequently managing units on a 15-18 year lifecycle
- Actively coordinate with PSC program to replace all Beta SERs with SER/SCADA standard
- Replace majority of at-risk revenue and interchange meters over the next 10 years
- Control & Indication - develop a lower cost mini console replacement and begin replacing old units

- Process improvements include:
  - ◆ Formalized coordination with PSC for specific replacements
  - ◆ Bundle work with other sustain and expand programs for more efficient use of resources and planned outages

In the long run, this strategy will help:

- Improve reliability and lower economic cost by replacing critical at-risk equipment
- Develop the ability to adjust the replacement plans based on observed failure rates
- Address outage management needs and availability targets through expected reduction in outages

## 1.0 STRATEGY BACKGROUND

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### 1.1 Business Environment

#### Customers and stakeholders served

- Stakeholders of all BPA power system components require isolation of equipment during fault conditions to prevent equipment damage and protect personal safety
- BPA operations and control center personnel require system control and monitoring to operate and maintain the power system
- BPA internal billing and scheduling organizations and external customers require accurate meter data
- Maintenance personnel use fault and event data to locate, troubleshoot and correct system failures
- BPA external power and transmission customers require reliable power; SPC equipment contributes to that reliability

#### Products and services

- Fast isolation of faulted or failed power system components provides system stability and prevents further equipment damage
- Ability to monitor and control the power system both locally and remotely
- Accurate meter data for scheduling and billing of energy exchange
- Fault data for troubleshooting and evaluating system operation and health
- Remedial action schemes ensure greater system stability allowing more energy transfer across a given path

#### Strategic environment

- Regulatory and legal standards
  - ◆ FERC, NERC and WECC regulation and standards are continually evolving; the trend is toward more understandable and specific standards that in turn may require modification of relay setting and maintenance practices and require more detailed documentation of SPC work
  - ◆ Recently implemented relay setting standards have initiated many relay replacements
  - ◆ Forthcoming equipment and maintenance standards have potential to influence where certain equipment must be installed and how equipment is maintained
  - ◆ There is always regulatory pressure to improve relay setting coordination and reduce relay misoperations
- Complexity of protection schemes
  - ◆ Complexity of the power system being protected has direct impact on the magnitude of challenges the protection engineer faces when developing the protection scheme or relay settings

- The high degree of flexibility in programming modern digital relays has led to challenges in coordinating protection schemes that span across utility boundaries; each utility has developed their unique means of implementing a particular type of relay so compromises and adjustments must be made when coordinating with other utilities
- Generation integration
  - ◆ Wind generation is frequently interconnected in the middle of a transmission line requiring complicated protection schemes
- Commodities
  - ◆ Many types of existing SPC equipment are no longer supported by the manufacturer and replacements parts are not available
  - ◆ Shorter life expectancy of new digital equipment will result in a faster replacement tempo than has been seen with the electro-mechanical relays
- Integrated Control System Strategy (ICSS)
  - ◆ A strategy to better coordinate the SPC, Power System Control (PSC) and Control Center programs will realize efficiencies through optimization of equipment upgrades.
- Staffing and other constraints
  - ◆ Balancing FTE resources between expansion projects and maintenance and replacement efforts
  - ◆ SPC inventory has many types of legacy and modern equipment requiring a huge knowledge base for engineers and craftsmen

## 1.2 Assets, Asset Systems and Criticality

**System Protection and Control assets include the following equipment types:**

### Protective Relays

- Protective relays are of three different technology eras: electro-mechanical, electronic and microprocessor based
  - ◆ Electromechanical relays - installed up to 1983 with a 30 year life expectancy
  - ◆ Electronic relays - installed 1980 through 1995 with 15 to 20 year life expectancy
  - ◆ Digital relays - installed 1987 to present with 15 to 20 year life expectancy

### Sequential Events Recorders

- SERs maintain a historical record of all equipment operations and alarms in a substation and interface with station SCADA to provide remote monitoring capability to the control centers

### Fault Recorders

- Digital fault recorders record voltage and current waveforms during system faults; the data is used by SPC engineers to validate proper power system response to faults, troubleshoot equipment misoperation (internal and external to the BPA system) and improve relay setting coordination

### Revenue and Interchange Meters

- Data from revenue meters is used by BPA's billing organization to account for power entering and leaving the BPA power system
- Interchange meters measure power entering or leaving the BPA balancing authority area
- Some revenue meters and all interchange meters provide data for automatic generation control (AGC)

### Control and Indication Equipment

- The SPC program has responsibility for a variety of substation control and indicating equipment

- Control equipment includes auto sectionalizing, dead bus clearing, auto synchronizing schemes and synchronous control units (SCU)
- Indicating equipment includes phasor measurement units (PMU), panel meters, control consoles, transformer temperature monitors, recording voltmeters, battery voltmeters, battery ground monitors, SCADA transducers, relay communication processors, and interconnecting wiring

System Protection and Control Asset Criticality:

| Less Important               |                   |                  |  | More Important     |
|------------------------------|-------------------|------------------|--|--------------------|
| Load-shedding relays         | DFR               | RAS              |  | Transformer relays |
| Indicating meter transducers | Control equipment | Reactive relays  |  | Bus relays         |
| Relay communications         |                   | Revenue metering |  | Line relays        |
|                              |                   | SER              |  | Breaker relays     |

## 2.0 THE STRATEGY

### 2.1 Current State

#### Capital Replacement Program in Recent Years

- Capital replacement funds have been focused on failing and obsolete equipment that could no longer be maintained
- Overall, SPC equipment has been replaced at a much slower rate than it is aging toward obsolescence and poor condition
- See section 2.1.3 below for detail the current state of SPC equipment categories

#### 2.1.1 Program Accomplishments to Date

##### Targets vs. Performance

###### FY2011-2013 Targets

- Program Cost: Cumulative total direct capital costs between \$33M and \$47.2M
- Program Scope/Capability:
  - ◆ Complete 80% or more of the work plan (all three years)
  - ◆ Protective Relay Reliability - Relay Malfunction: <0.5% of Relay operations reported in Outage Analysis and Reporting System (OARS) each year, where the relay failed to operate for a fault inside its zone of protection due to relay equipment malfunction.
  - ◆ Protective Relay Reliability - Relay Setting: <0.2% of Relay operations reported in OARS each year, where the relay failed to operate for a fault inside its zone of protection due to relay setting error.

###### FY2011-2013 Performance

- Program Cost: Cumulative total direct capital costs = \$25.9 M
- Program Scope/Capability:
  - ◆ Project completion (as of 9/30/2013) - 42%
  - ◆ Protective Relay Reliability - Relay Malfunction: 0.009%
  - ◆ Protective Relay Reliability - Relay Setting: 0.055%

**Lessons Learned / Performance Contributors**

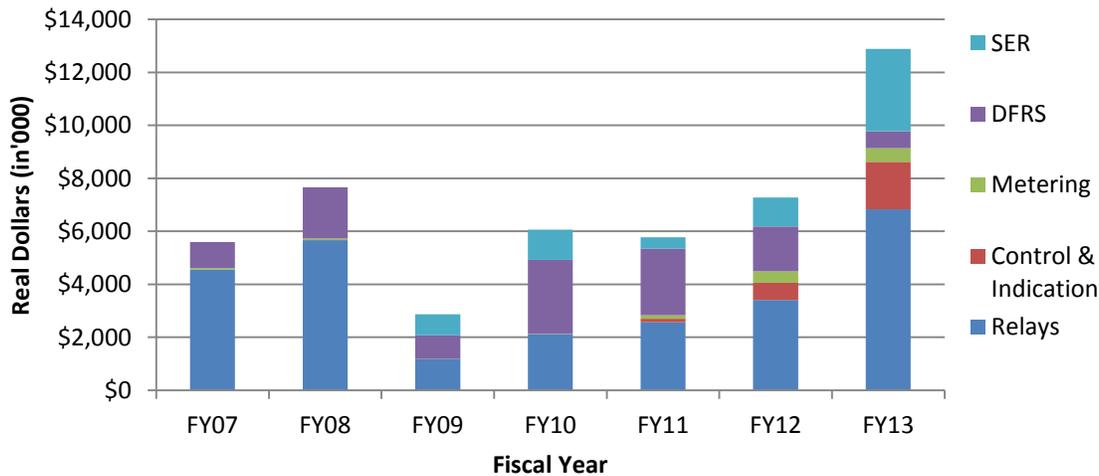
The Contract Management Office (CMO) delivery model is being improved to optimize delivery of the type of work in the SPC program. This delivery method will double the capability of the SPC replacement program in the near term. The CMO delivered approximately \$5M in FY2013 for SPC and is scheduled to deliver \$9M-\$10M in FY2014 for SPC.

Project scoping is a key factor in the delivery equation. This is being resolved by utilizing the Program Manager's (PgM) 10 year planning tool, early PgM/district involvement to ensure proper scoping, as well as utilization of improved processes. Design groups are currently being utilized to scope projects for next year to ensure that there are no show-stopping issues. If there are show-stopping issues, there will be time to resolve them and still get the designs done on time or to remove them from the work plan and replace them with another project.

Early in FY2012, SPC project estimates were updated and are now more accurate, reflecting actual project costs better than ever before.

**2.1.2 Cost History**

**Historical Actuals - Capital**



**Historical Actuals - Capital**

Dollars in '000

| Equipment Category   | FY07           | FY08           | FY09           | FY10           | FY11           | FY12           | FY13            | Total           |
|----------------------|----------------|----------------|----------------|----------------|----------------|----------------|-----------------|-----------------|
| Relays               | \$4,552        | \$5,668        | \$1,189        | \$2,114        | \$2,567        | \$3,407        | \$6,828         | \$26,325        |
| Control & Indication |                |                |                |                | \$136          | \$656          | \$1,790         | \$2,582         |
| Metering             | \$60           | \$55           | \$1            | \$8            | \$128          | \$423          | \$523           | \$1,198         |
| DFRS                 | \$984          | \$1,940        | \$889          | \$2,803        | \$2,517        | \$1,696        | \$637           | \$11,466        |
| SER                  |                |                | \$797          | \$1,141        | \$431          | \$1,098        | \$3,102         | \$6,569         |
| <b>Total</b>         | <b>\$5,596</b> | <b>\$7,663</b> | <b>\$2,876</b> | <b>\$6,066</b> | <b>\$5,779</b> | <b>\$7,280</b> | <b>\$12,880</b> | <b>\$48,140</b> |

**Replacement Cost History**

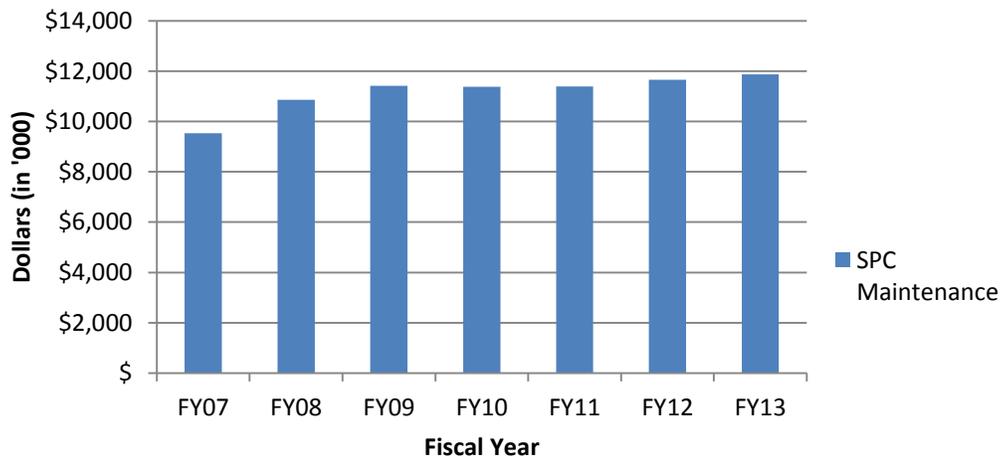
SPC equipment replacement costs shown below and used in program funding development are based on:

- Typical direct costs from like projects provided by project Transmission Planning Estimating group
- Reflect 2013 dollars

- Assumes labor, both in-house and supplemental, is used for the entire project – design through construction and Test & Evaluation (T&E)
- Contract Management Office (CMO) estimates use the same type of data, but are based on CMO contractors for work completion

| Equipment Type          | Typical Replacement Cost per terminal (in \$'000) |
|-------------------------|---|
| 500kV Line Relay w/TT   | 450   |
| 115kV Line Relay w/o TT | 200   |
| Bus Differential Relay  | 275   |
| DFR                     | 225   |
| SER                     | 250   |
| Revenue Meter           | 27  |

**SPC Historical Actuals - Expense**



**Historical Actuals - Expense**

Dollars in '000

| Program         | FY07    | FY08     | FY09     | FY10     | FY11     | FY12     | FY13     | Total    |
|-----------------|---------|----------|----------|----------|----------|----------|----------|----------|
| SPC Maintenance | \$9,535 | \$10,864 | \$11,419 | \$11,377 | \$11,388 | \$11,651 | \$11,869 | \$78,103 |

**2.1.3 Health of Current Assets (Current Condition & Performance)**

**Protective Relays**

Protective relays fit into two groups related to their technology characteristics

- Non-microprocessor based
  - Includes electro-mechanical (E/M) and electronic relays
  - By nature of their design these relays tend to drift out of calibration and therefore require more frequent maintenance (every 36 months)
  - With age, wiring insulation becomes brittle potentially compromising circuitry when the relays are handled for maintenance or repair; aging components also result in setting drift so in some instances these relays cannot be maintained within calibration limits

- ◆ In many cases spare component parts are no longer available
- ◆ BPA has traditionally assumed E/M relays to have a 30 year life expectancy; E/M relays on the system are 28 to 48 years old
- ◆ Electronic relays have a shorter operating life of 15 to 20 years; BPA’s electronic relays are 18 to 29 years old
- ◆ Electronic relays employed on the BPA system are much more complex than the E/M relays; they require extensive training for personnel to maintain, troubleshoot and repair them
- ◆ One model of electronic relay employed at BPA, the INX5 bus differential relay, has an added vulnerability of being employed as single layer protection; that means if one of these relays fails the substation bus is without protection and must be deenergized.
- ◆ Manufacturing support is no longer available for electronic relays or for many models of E/M relays
- Microprocessor based (digital)
  - ◆ Digital relays do not drift out of calibration like E/M and electronic relays so maintenance intervals are extended (every 60 months)
  - ◆ The modern microprocessor based relays are intelligent electronic devices (IED) meaning they have the capability to communicate and share data with other substation equipment providing opportunity for better substation automation and implementation of Smart Grid technologies
  - ◆ BPA’s oldest digital relays are 25 years old
- The electronic relay technology was applied primarily to protect 500kV transmission lines and 115-500kV substation buses
- E/M relays continued to be used in the most protection categories until the advent of digital relays in the late 1980’s
- Of the approximately 1300 non-microprocessor based relays approximately 1150 are E/M, 150 are electronic line and bus differential relays

| Relay Terminals by Category and Type (Nov 2013)             |                     |                 |
|---|---------------------|-----------------|
| Relay Category  | Non-micro processor | Micro processor |
| Line, bus-tie, bus differential, breaker failure, reclosing |                     |                 |
| 500kV   | 302                 | 563             |
| 57-345kV  | 448                 | 944             |
| <57kV   | 206                 | 38              |
| Shunt Capacitors and Reactors                               |                     |                 |
|   | 59                  | 255             |
| Transformers  |                     |                 |
| <50MVA  | 41                  | 6               |
| >50MVA  | 181                 | 49              |
| Under Frequency Load Shedding                               |                     |                 |
|   | 25                  | 21              |
| Total:  | 1262                | 1876            |

**Remedial Action Schemes**

- RAS are special protection schemes within the protective relay category
- For RAS components under the umbrella of the SPC sustain program, the equipment is supported and/or replacement parts are readily available

**Sequential Events Recorders**

- Today the standard equipment for new or replacement SER installations is a GE D20

| Model             | Number in operation | Approximate period of installation |
|-------------------|---------------------|------------------------------------|
| BETA 512          | 83                  | 1987 to 1994                       |
| BETA 4100         | 62                  | 1994 to 2009                       |
| BPA custom design | 3                   | 2002 to 2005                       |
| Misc              | 5                   | unknown                            |
| D20               | 4                   | 2008 to present                    |
| Total:            | 157                 |                                    |

- BETA 512
  - ◆ The BETA 512 is no longer supported by the manufacturer so there are no new spare parts available
  - ◆ Since no new parts are available for these units a SPC policy has been established that requires replacement of a BETA 512 SER when a substation expansion project requires expansion of the SER unit
  - ◆ The oldest of these units are approximately 25 years old and have reached their life expectancy
- BETA 4100
  - ◆ The BETA 4100 is no longer supported by the manufacturer so there are no new spare parts available
  - ◆ Since no new parts are available for these units a SPC policy has been established that requires replacement of a BETA 4100 SER when a substation expansion project requires expansion of the SER unit
  - ◆ The oldest of these units are 15 years old
- D20 – current BPA SER standard
  - ◆ The D20 has the capability of accomplishing both SER and SCADA functions
  - ◆ BPA is now using the D20’s capability to combine SER and SCADA function into one unit thus gaining efficiency in construction and maintenance
  - ◆ The D20 also makes a large stride forward in BPA’s ability to share information between the various substation equipment providing opportunity for improved substation automation and implementation of Smart Grid technologies

**Digital Fault Recorders**

- An aggressive replacement program is in place to retire the remaining old technology DFR’s by the end of FY2017
- The new technology DFR’s are well supported by the manufacturer; SPC expects this equipment will meet system needs and not require replacement until approximately 2020

**Revenue and Interchange Meters**

- BPA has approximately 1600 meters at 1340 different locations
- Approximately 1250 of the meters are old technology and have no manufacturer support.

**Control and Indication**

- The 4 general types of control equipment are listed below with the number on the BPA system
  - ◆ Dead bus clearing schemes – 64
  - ◆ Auto synchronizing schemes – 18
  - ◆ Auto sectionalizing schemes – 10
  - ◆ Synchronous control units (SCU) – 30
- There are several types of indicating equipment including:

- ◆ Phasor measurement units (PMU)
  - ◆ Relay communication processors
  - ◆ Panel meters
  - ◆ Control consoles
  - ◆ Recording volt meters
  - ◆ SCADA transducers
  - ◆ Battery volt meters and ground detectors
- The SCU's and "mini" control consoles are obsolete and require replacement at this time
  - The replacement of a mini console would require a control house expansion in all cases on the BPA system (11 remain). This is a costly replacement, at approximately \$2M+ for the building expansion and rack design/construction.
  - The analog panel meters are obsolete; they are being replaced in conjunction with other capital work such as relay replacements or using a corrective work order when a failure occurs
  - Additional condition assessment is required on the control and indication equipment in order to develop a thorough 10 year asset strategy

The following tables show overall health demographics at the major component level for SPC Equipment (as of June 2013).

| Overall Component Health Demographics      |                 |      |      |              |      |      |              |  |
|--|-----------------|------|------|--------------|------|------|--------------|--|
| Major SPC Component                        | Maintainability |      |      | Obsolescence |      |      | Asset Health |  |
|  | Good            | Fair | Poor | Good         | Fair | Poor |              |  |
| <b>Electro-Mechanical Relays</b>           |                 |      |      |              |      |      |              |  |
| 500kV                                      |                 |      |      |              |      |      | Impaired     |  |
| 230-345kV                                  |                 |      |      |              |      |      | Impaired     |  |
| 69-169kV                                   |                 |      |      |              |      |      | Impaired     |  |
| <69kV                                      |                 |      |      |              |      |      | Impaired     |  |
| Transformer & Reactive                     |                 |      |      |              |      |      | Impaired     |  |
| Special Protection & Control Schemes (RAS) |                 |      |      |              |      |      | Fine         |  |
| <b>Electronic Relays</b>                   |                 |      |      |              |      |      |              |  |
| 500kV                                      |                 |      |      |              |      |      | Poor         |  |
| 230-345kV                                  |                 |      |      |              |      |      | Poor         |  |
| 69-169kV                                   |                 |      |      |              |      |      | Poor         |  |
| <69kV                                      |                 |      |      |              |      |      | Poor         |  |
| Transformer & Reactive                     |                 |      |      |              |      |      | Poor         |  |
| Special Protection & Control Schemes (RAS) |                 |      |      |              |      |      | Poor         |  |

| Overall Component Health Demographics      |                 |      |      |              |      |      |              |  |
|--|-----------------|------|------|--------------|------|------|--------------|--|
| Major SPC Component                        | Maintainability |      |      | Obsolescence |      |      | Asset Health |  |
|  | Good            | Fair | Poor | Good         | Fair | Poor |              |  |
| <b>Digital Relays</b>                      |                 |      |      |              |      |      |              |  |
| 500kV                                      |                 |      |      |              |      |      | Fine         |  |
| 230-345kV                                  |                 |      |      |              |      |      | Fine         |  |
| 69-169kV                                   |                 |      |      |              |      |      | Fine         |  |
| <69kV                                      |                 |      |      |              |      |      | Fine         |  |
| Transformer & Reactive                     |                 |      |      |              |      |      | Fine         |  |
| Special Protection & Control Schemes (RAS) |                 |      |      |              |      |      | Good         |  |
| <b>SERs</b>                                |                 |      |      |              |      |      |              |  |
| BETA 512                                   |                 |      |      |              |      |      | Poor         |  |
| BETA 4100                                  |                 |      |      |              |      |      | Impaired     |  |
| D20  |                 |      |      |              |      |      | Good         |  |
| <b>DFRs</b>                                |                 |      |      |              |      |      |              |  |
| Rochester                                  |                 |      |      |              |      |      | Poor         |  |
| BEN  |                 |      |      |              |      |      | Good         |  |
| <b>Revenue Meters</b>                      |                 |      |      |              |      |      |              |  |
| Electronic                                 |                 |      |      |              |      |      | Fair         |  |
| Digital                                    |                 |      |      |              |      |      | Good         |  |
| Remote Metering System                     |                 |      |      |              |      |      | Impaired     |  |

## 2.2 Future State

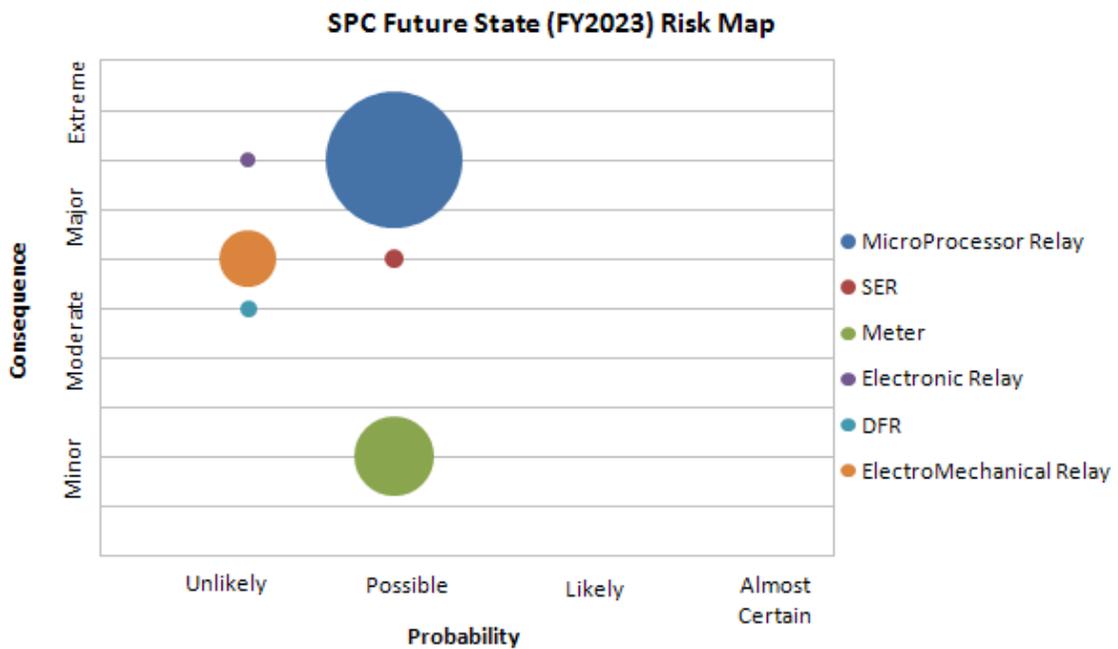
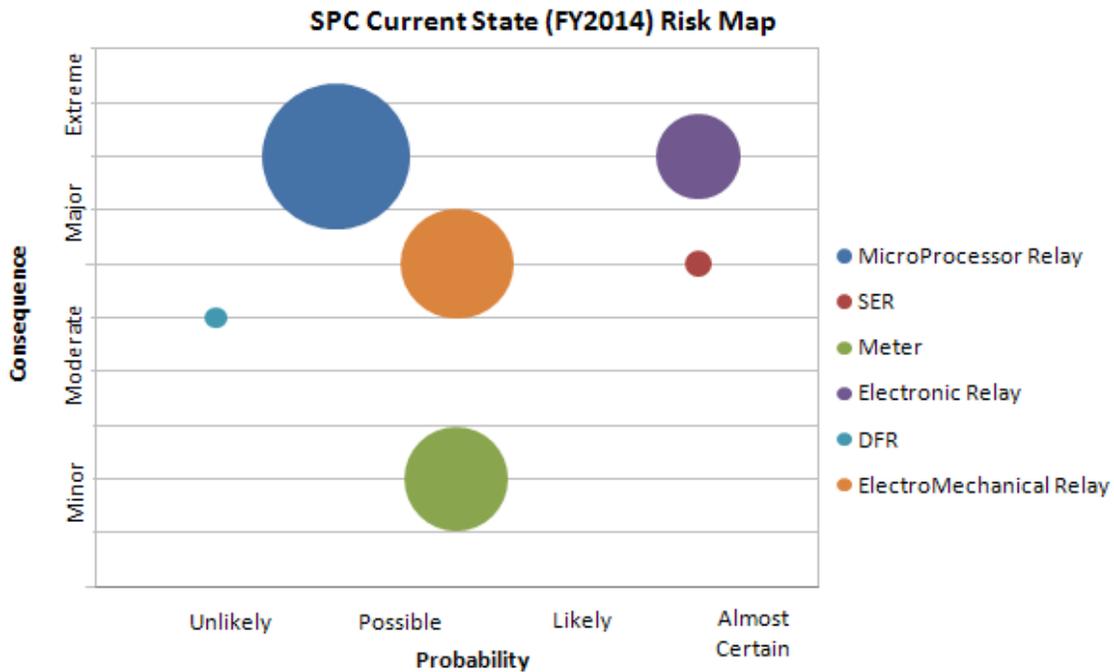
### 2.2.1 Key asset performance objectives, measures and targets

| Category   | Performance Objective   | Measure  | End Stage Target   |
|--|---|--|--|
| Protective Relay Reliability                         | Relays and other critical SPC equipment are at low risk of failure or obsolescence  | <ul style="list-style-type: none"> <li>▪ Standardization and frequency of condition assessment for SPC equipment</li> <li>▪ Percent of SPC equipment that are assessed to be in poor health condition based on maintainability and obsolescence</li> </ul> | <ul style="list-style-type: none"> <li>▪ Health condition of SPC equipment is assessed consistently with (1) condition-based standards, (2) standardized inspection protocols (including schedule), and (3) standardized risk assessment criteria</li> <li>▪ By the end of FY2016, no more than 5 percent of total protective relays and no more than 20 percent of SERS are in poor health condition</li> </ul>   |
|  | Protective relays clear power system faults sufficiently fast to prevent primary equipment damage or power system instability and ensure personnel and public safety                                  | Number of relay misoperations reported in the Outage Analysis and Reporting System (OARS)  | <ul style="list-style-type: none"> <li>▪ 0.5% or less of relay operations reported in OARS each year are a result of relay malfunction (not setting trouble) where the relay failed to operate for a fault inside of its zone of protection</li> <li>▪ 2.0% or less of relay operations reported in OARS each year are a result of relay setting trouble where the relay failed to operate for a fault inside of its zone of protection</li> </ul>   |
| Protective Relay Security                            | When no fault is present and under normal operating conditions, relays should not initiate a trip as a result of component or equipment failure within the relay                                      | Number of relay misoperations reported in the Outage Analysis and Reporting System (OARS)  | <ul style="list-style-type: none"> <li>▪ 0.5% or less of relay operations reported in OARS each year are a result of relay malfunction (not setting trouble) where the relay operated for a fault outside of its zone of protection or operated when there was no fault on the system</li> <li>▪ 1.0% or less of relay operations reported in OARS each year are a result of relay setting trouble where the relay operated for a fault outside of its zone of protection or operated when there was no fault on the system</li> </ul> |
| Sequential Events Recorder Accuracy                  | All events that occur on monitored and in-service substation equipment are recorded and time stamped within the accuracy of the GPS clock   | Number of reported loss of synchronization alarms  | SER is synchronized with the station GPS clock to facilitate coordination of SER data with data from other time synchronized substation data recording devices   |
| Sequential Events Recorder Availability/ Reliability | SER data is readily available to field and control center personnel in electronic & hardcopy at the sub for monitoring the operation and health of the system and to analyze or troubleshoot problems | Number of reported SER trouble alarms (no system is presently in place to automatically monitor and collect instances of SER trouble alarms)   | Chronologically continuous substation event data is recorded by the SER and is immediately available for use by operations and maintenance personnel locally and remotely where access exists  |

### 2.3 Asset Condition/Performance Gaps

The following two charts show the risk to the SPC equipment types listed. Over the next ten years:

- The population of electromechanical and electronic relays will be reduced as those units are replaced with microprocessor relays.
- The risk due to microprocessor relays will increase. The replacement of this class of relays will be delayed until the electromechanical and electronic relays are totally removed from the system.
- The risk due to the other SPC equipment types will be reduced as the average population age lowers due to replacement of old equipment with new equipment.



### 2.3.1 Risks to meeting the objectives

SPC equipment failure rates are at an unacceptable level and the number of corrective work orders is increasing. Equipment failures are due to

1. A backlog of obsolete equipment in need of replacement
2. System interoperability issues as a result of integrating new technologies with old, obsolete equipment and
3. New regulatory requirements on equipment and communications.

For SPC equipment the number of corrective actions has increased dramatically over the last eight years and with it the risk of a significant power system outage event.

#### **Execution Constraints**

In addition to risks resulting from the current state of SPC assets, there are execution constraints that present risks to fully implementing this strategy.

**Resource requirements:** The primary risk is associated with resources. This has been recognized across Transmission Services and is being addressed through the Transmission Asset Management Overarching strategy. Specific to the SPC program is the need for:

- Adequate Control Engineering design resources
- Execution resources with the appropriate skill level to meet the replacement work plan and maintenance requirements

**Planned Outages:** As the capital replacement program ramps up based on the requirements of the several asset program strategies, ability to obtain outages for construction (based on system operational constraints) has the potential to impact the rate of capital replacement.

**Equipment procurement:** This poses two potential risks; delivery of new equipment and replacement parts for existing old equipment

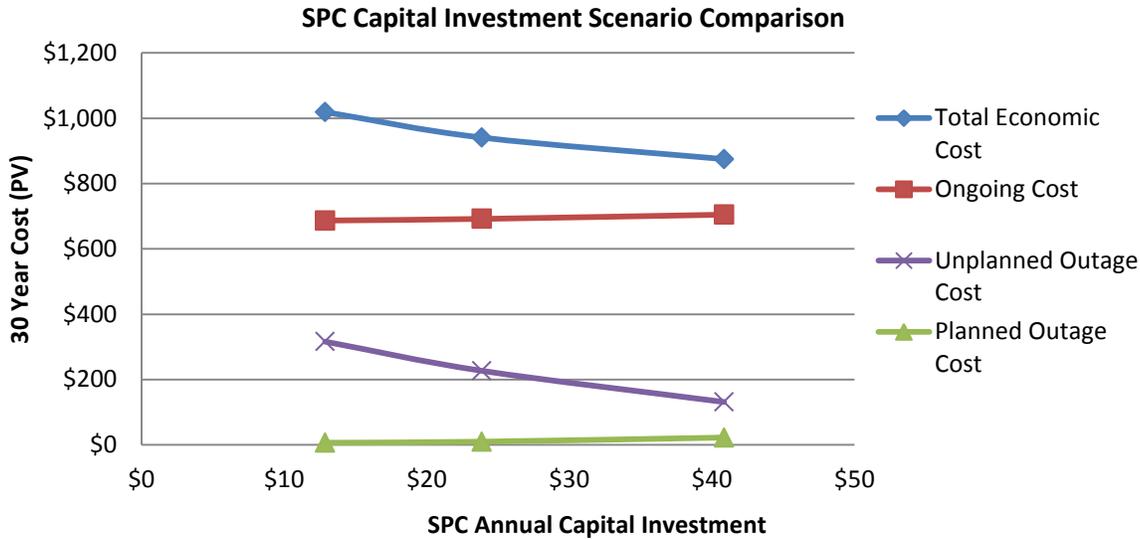
- a) Vendor business decisions to discontinue equipment models and no longer provide support which leads to having unsupported equipment on the system with inadequate parts and repair capability.
- b) Inadequate testing and training facilities

Asset register improvements: Work on the Transmission Asset System (TAS) is underway to populate the tool with more accurate and complete asset data. In the meantime, replacements will be planned based on best available information at that time.

#### **Risks of under-executing on the Program**

If the SPC Sustain program execution continues to be less than the strategy level:

- Asset condition will continue to deteriorate, while risk of equipment failure escalate
- Maintenance costs will increase as more corrective work is required
- Emergency capital replacements will become the norm and will disrupt planned work
- Reliability of the power system will be compromised
- Every year of delay to reach program steady state will cause the potential loss of \$5M in value.
- The Total Economic Cost of the SPC Program will be much higher as shown by the table and graph below.



All Values in \$M over a 30 year lifecycle

| Annual Investment          | Investment Scenarios |              |              |
|----------------------------|----------------------|--------------|--------------|
|                            | \$13                 | \$24         | \$41         |
| Ongoing Cost               | \$687                | \$692        | \$697        |
| Unplanned Outage Cost      | \$316                | \$227        | \$105        |
| Planned Outage Cost        | \$7                  | \$10         | \$23         |
| <b>Total Economic Cost</b> | <b>\$1,019</b>       | <b>\$941</b> | <b>\$851</b> |

## 2.4 Strategic Approach to Closing Gaps

### 2.4.1 Strategic Approach

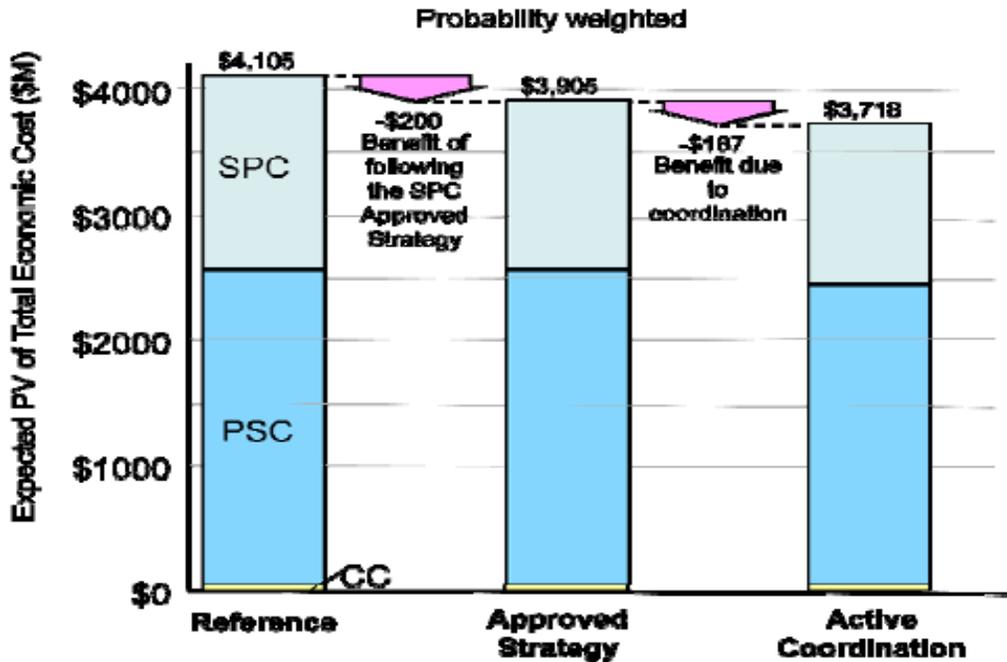
The Integrated Control System (ICS) strategy evaluated several different strategy alternatives. The overall result of the evaluation indicated that the SPC strategy as originally developed is the correct replacement strategy, based on reducing total economic costs. By not executing per the strategy, economic value is being left on the table. In addition, the potential to save cost and add more value to the programs can be achieved through specific, formalized coordination with the PSC and CC programs in the way of reductions in re-work optimization of resources, and better outage planning.

The recommendation of an “Active Coordination Strategy” specifically includes:

- Development of a disciplined process for coordination of planning, planned outages, and execution.
- Expansion of the PSC council to cover all equipment and coordinate current and future technologies across PSC/SPC/CC. The ICS council will manage the technologies and pre-deployment equipment testing.
- Creation and action on an appropriate staffing strategy.
- Replacement of equipment based on economic lifecycle (i.e. based on impact to the total economic cost).
- Addition of limited targeted spares kits for PSC and SPC in high impact areas.
- Improvement to documentation and pre-deployment testing.
- Development of the ability to adjust the replacement plans based on observed failure rates.
- Determination of a process to monitor strategy execution performance.
- Identification of opportunities to shorten planned outages

- Monitoring of sign posts to keep two other ICS options on the radar at no additional cost:
  - ♦ *Enhanced Fault Location (EFL)*
    - Reduce the restoration time of transmission outages/derates through better and faster fault location on all voltage levels; extend fault location to approximately 125 sites on sub-grid, replace the FLAR master.
  - ♦ *Relay Functionality Optimization (RFO)*
    - Use full capability of microprocessor relays to perform TT, SCADA, DFR, and SER functionalities, and eliminate selected PSC and SPC equipment types everywhere.

The financial benefits of Active Coordination are shown below:



**Final Results – Active Coordination contribution to the Total Economic Cost as compared to current state (PV over 30 years)**

The replacement strategy for SPC assets is as follows:

**Protective Relays with poor health assessment**

- A significant number of protective relays are assessed to have poor asset health
- Of all SPC equipment, relays in this condition pose the largest risk to system reliability
- Protective relays in poor asset health are unacceptable so this equipment should be replaced as quickly as possible; based on projected replacement rates this will take 8-10 years.
- Relays assessed in poor health based on maintainability and obsolescence are listed in the following table
- Projected replacement rates to accomplish this objective with projects on 2 year work plans:
  - ♦ 5 lines per year (10 relay terminals, replacing relays at both ends of each line)
  - ♦ 5 bus differential relays per year
- The INX5 bus differential relay package has no redundancy therefore replacement with the new standard relay package provides the additional benefit of redundant protection where it presently does not exist

| Voltage   | Protected Equipment | Electronic Relay Model            | Number of Relay Terminals |
|-----------|---------------------|-----------------------------------|---------------------------|
| 500kV     | Line                | RALDA, RALZA, RALZB, RAZFE, LZ96  | 63                        |
| 500kV     | Line                | LCB II                            | 7                         |
| 230kV     | Line                | LCB II                            | 9                         |
|           |                     | <b>Total Line Relay Terminals</b> | <b>79*</b>                |
| 500kV     | Bus                 | INX-5                             | 2                         |
| 115,230kV | Bus                 | INX-5                             | 38                        |
|           |                     | <b>Total Bus Relay Terminals</b>  | <b>40**</b>               |

\* 16 in Progress (Design or Construction as of 10/16/2013)

\*\* 15 in Progress (Design or Construction as of 10/16/2013)

**Protective Relays with impaired health assessment**

- A large number of protective relays are assessed to have impaired asset health
- These are electro-mechanical relays that are obsolete and becoming more difficult to maintain because of aging components and a dwindling supply of spare parts
- In order to prevent these relays from slipping into poor health prior to replacement, relays assessed in impaired health based on maintainability and obsolescence are listed in the table on the following page; the table includes average replacement rates on a 10 year plan for each category
- Cost, criticality of protected equipment, and ability to get outages for construction vary widely across this relay category

| Electro-Mechanical Relays (Impaired asset health) |                      |                           |                                       |
|---|----------------------|---------------------------|---------------------------------------|
| Voltage   | Protected Equip      | Number of Relay Terminals | Replacements per year on 10 year plan |
| 500kV   | Line                 | 30                        | 4                                     |
| 69-345kV  | Line                 | 275                       | 28                                    |
| <69kV   | Feeder               | 123                       | 13                                    |
|   | <b>Total Line:</b>   | <b>428</b>                |                                       |
| 500kV   | Bus Differential     | 19                        | 2                                     |
| 69-345kV  | Bus Differential     | 86                        | 9                                     |
| 69-345kV  | Bus Tie/Section      | 25                        | 3                                     |
|   | <b>Total Bus:</b>    | <b>105</b>                |                                       |
| >50MVA  | Transformer          | 176                       | 18                                    |
| <50MVA  | Transformer          | 40                        | 4                                     |
|   | <b>Total Xfm:</b>    | <b>216</b>                |                                       |
| All   | Shunt Caps & Rectors | 57                        | 6                                     |
|   | <b>Grand Total:</b>  | <b>806</b>                | <b>81</b>                             |

**Sequential Event Recorders with poor health assessment**

- The BETA 512/4100 sequential event recorders are assessed to be in poor health primarily due to their obsolescence

- Although poor asset health is not considered acceptable the urgency of replacing these SER's is less than for relays in the same condition based on lower system impact in the event of failure
- At the projected replacement rate, these obsolete pieces of equipment will be on the BPA system for another 14-16 years.

#### **Digital Fault Recorders with poor health assessment**

- Seven Rochester DFR's are in operation and all are assessed to be in poor condition
- Five have been funded and are replacement is in progress (construction phase)
- The remaining 2 are scheduled for replacement by FY2017

#### **Revenue and Interchange Meters with fair health assessment**

- The analog JEM1 meters are still able to be maintained and are not expected to slip into an impaired or poor health rating within the next 5 years
- To prevent the JEM1 meters from deteriorating to poor health prior to replacement, SPC recommends replacement of these meters on a 12 year plan
- Focus will be on replacing interchange and AGC meters due to the combined obsolescence of the meter and the integral EXJ register
- RMS units assessed in impaired condition are a minor unit in the Plant Catalog; SPC has a standard "plug and play" replacement so these units are being replaced using expense funds when the units fail prior to meter replacement

#### **Control and Indication:**

- While further condition assessment of this equipment is underway, \$500k/yr is recommended for replacement of the SCU's and \$2.5M/yr for mini control consoles, unless a lower cost alternative can be designed. This is being worked on by the design groups.

The SPC sustain/replacement program addresses the factors and challenges relating to the complexity of protection schemes in three ways:

1. Replacing the old non-standard equipment will reduce the number of equipment models, enabling a more focused approach for the SPC Engineers and Craftspeople regarding training and proficiency.
2. Replacing the old non-standard schemes with consistent and standardized schemes, assures more effective protection and control of the transmission system. As retirement of the complex, hard to maintain and understand schemes occurs, the SPC field personnel will be able to reduce outage durations caused by unplanned equipment performance/failure.
3. By using standard equipment and schemes in the replacement program, the process will become streamlined from design templates through the switchboard shop and into the field for final construction and the T&E process. This will reduce the cycle time for equipment replacements including the planned outage required.

### 3.0 STRATEGY IMPLEMENTATION PLAN

Note that at this time the SPC program is ramping up at a much slower pace than identified in the ICS evaluation. The implementation plan has been modified with the understanding that it will impact the value received from the SPC Program. The modifications are necessary due to resource (staffing) constraints. Efforts to address the implementation hurdles are underway at the Transmission Services level.

#### 3.1 10 year Implementation Plan

| Equipment            | Current Strategy Impl. Plan - Steady State of equip needing to be replaced per year | Ramp to get to Steady State |   |        |     |        |     |        |     |        |     |        |     |        |     |        |     |        |     |        |     |
|----------------------|---|-----------------------------|---|--------|-----|--------|-----|--------|-----|--------|-----|--------|-----|--------|-----|--------|-----|--------|-----|--------|-----|
|                      |   | FY2014                      |   | FY2015 |     | FY2016 |     | FY2017 |     | FY2018 |     | FY2019 |     | FY2020 |     | FY2021 |     | FY2022 |     | FY2023 |     |
| D=Design C=Construct |   | D                           | C | D      | C   | D      | C   | D      | C   | D      | C   | D      | C   | D      | C   | D      | C   | D      | C   | D      | C   |
| <i>SPC Program:</i>  |   |                             |   |        |     |        |     |        |     |        |     |        |     |        |     |        |     |        |     |        |     |
| Protective Relays    | 200   | 155                         |   | 145    | 155 | 152    | 145 | 154    | 152 | 158    | 154 | 168    | 158 | 169    | 168 | 174    | 169 | 177    | 174 | 177    | 177 |
| Control & Indication | 10  | 8                           |   | 21     | 8   | 8      | 21  | 10     | 8   | 10     | 10  | 10     | 10  | 10     | 10  | 12     | 10  | 12     | 12  | 14     | 12  |
| Metering             | 100   | 100                         |   | 50     | 100 | 50     | 50  | 50     | 50  | 50     | 50  | 50     | 50  | 50     | 50  | 50     | 50  | 50     | 50  | 50     | 50  |
| DFR                  | 4   | 0                           |   | 0      | 0   | 1      | 0   | 1      | 1   | 1      | 1   | 2      | 1   | 2      | 2   | 2      | 2   | 3      | 2   | 3      | 3   |
| SER                  | 10  | 10                          |   | 10     | 10  | 10     | 10  | 10     | 10  | 10     | 10  | 10     | 10  | 10     | 10  | 10     | 10  | 10     | 10  | 10     | 10  |

#### 3.2 Program Forecast Planning

##### FY2014-2023 Capital Forecast

Direct Capital only, Nominal Dollars in '000

| Program - Equipment Category | FY14            | FY15            | FY16            | FY17            | FY18            | FY19            | FY20            | FY21            | FY22            | FY23            | TOTAL            |
|------------------------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|------------------|
| SPC - RELAYS                 | \$15,740        | \$19,556        | \$22,592        | \$22,740        | \$23,126        | \$23,519        | \$24,000        | \$25,934        | \$26,799        | \$26,799        | \$230,805        |
| SPC - CONTROL AND INDICATION | \$1,600         | \$800           | \$800           | \$1,000         | \$1,000         | \$1,000         | \$1,000         | \$1,200         | \$1,200         | \$1,400         | \$11,000         |
| SPC - METERING               | \$1,195         | \$1,312         | \$923           | \$850           | \$850           | \$850           | \$850           | \$850           | \$850           | \$850           | \$9,379          |
| SPC - DFRS                   | \$              | \$              | \$45            | \$209           | \$214           | \$260           | \$423           | \$429           | \$474           | \$638           | \$2,692          |
| SPC - SER                    | \$1,816         | \$2,230         | \$2,925         | \$2,622         | \$2,623         | \$2,623         | \$2,623         | \$2,623         | \$2,623         | \$2,623         | \$25,332         |
| <b>TOTAL</b>                 | <b>\$20,350</b> | <b>\$23,898</b> | <b>\$27,284</b> | <b>\$27,420</b> | <b>\$27,814</b> | <b>\$28,252</b> | <b>\$28,897</b> | <b>\$31,036</b> | <b>\$31,946</b> | <b>\$32,310</b> | <b>\$279,208</b> |

##### FY2014-FY2023 Expense Forecast

Nominal Dollars in '000

| Maintenance Program | FY14     | FY15     | FY16     | FY17     | FY18     | FY19     | FY20     | FY21     | FY22     | FY23     | Total            |
|---------------------|----------|----------|----------|----------|----------|----------|----------|----------|----------|----------|------------------|
| SPC                 | \$13,097 | \$13,381 | \$13,849 | \$14,334 | \$14,835 | \$15,355 | \$15,892 | \$16,448 | \$17,024 | \$17,620 | <b>\$151,834</b> |

##### Caveats

Forecast is currently under review as part of the 2014 Integrated Program Review (IPR) process and will be updated in conjunction with the IPR timeline.

# **RIGHTS OF WAY PROGRAM**

## **ASSET MANAGEMENT STRATEGY**

Chuck Sheppard, Vegetation Program Manager  
Ron Burnett, Access Roads Program Manager  
Steve Goff, Land Rights Program

December 2013

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## EXECUTIVE SUMMARY

### Right of way (ROW) program overview

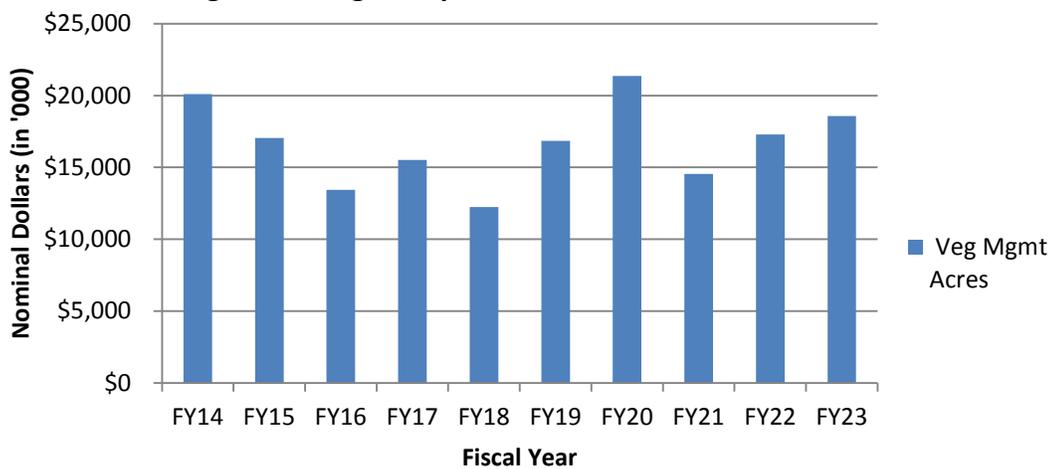
The overall ROW asset management strategy covers corridors that contain transmission lines, access roads established for the maintenance of transmission lines, and communications sites. Assets included in 195,600 acres of BPA maintained ROW corridors are:

- 319 corridors, 423 transmission lines, and 368 communication sites
- 11,861 miles of access roads, including roads, bridges, culverts, trails and gates
- ~ 80,000 tracts of easement for the corridors and access roads

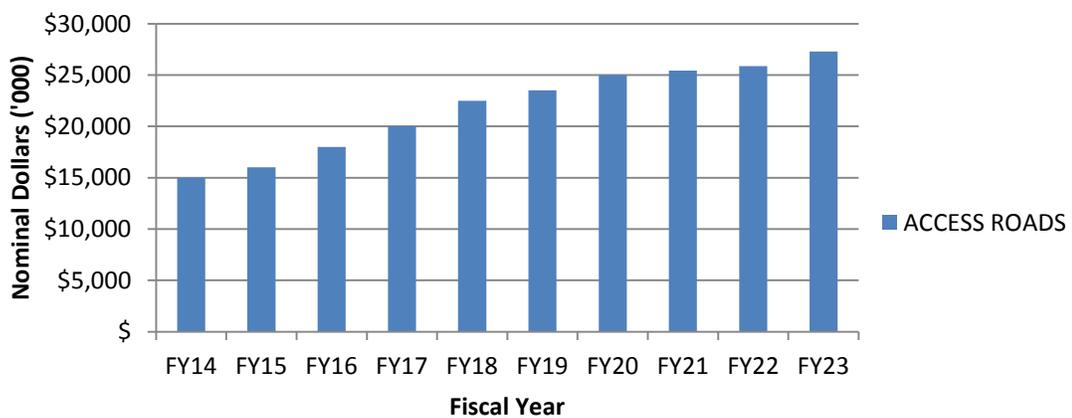
Three components are included in the strategy that enable BPA to safely access, construct, operate and maintain its transmission facilities. Each is managed by a different group and information about each will be grouped under these headings:

- Vegetation - Control and Manage Vegetation
- Access Roads - Maintain and Improve Access Roads
- Land Rights - Acquire and Manage Land Rights

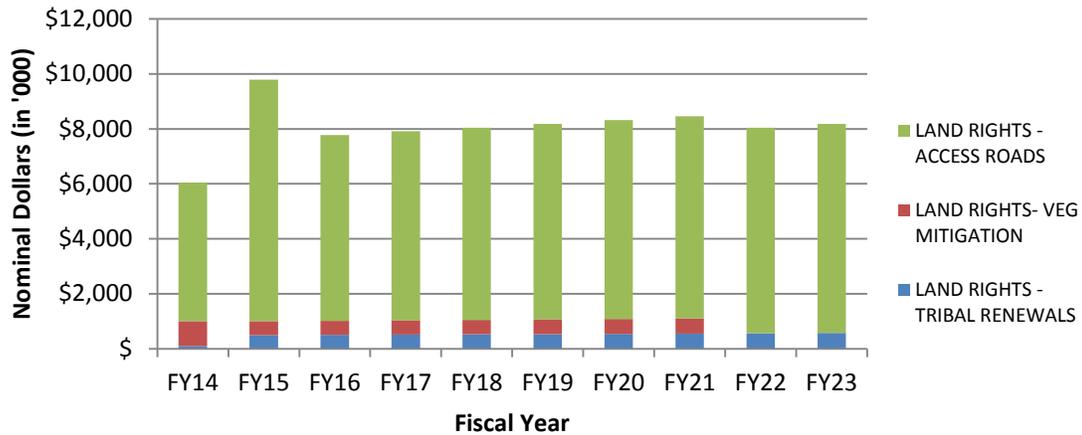
**Vegetation Mgmt Expense Forecast FY2014-2023**



**Access Roads Capital Forecast FY2014-2023**



### Land Rights Capital Forecast FY2014-2023



#### Key risks to be addressed

- Reliability risks due to vegetation growth in rights of way
- Regulatory and environmental noncompliance
- Impact on line projects implementation due to inadequate or illegal access to transmission lines
- Emergency access to transmission lines and structures is impeded Affect on relationships with tribes and other landowner agencies

#### Strategy Elements

##### Vegetation Management

- Ensure clearing and maintenance of land within transmission corridors. Supported through implementation of integrated vegetation management (IVM) practices.

##### Access Roads

- Complete all necessary construction access road work prior to line work associated with wood poles and steel lines projects
- Move from a reactive to a systematic approach to access roads project identification
- Provide adequate access to remote sites in support of System Telecom strategy
- Perform access road ‘stand alone’ upgrades (includes fish passage culverts, bridges, site specific reconstruction to restore access to isolated structures, and relocation/reconstruction of access roads to reduce/eliminate stream sedimentation)
  - ◆ To meet regulatory and environmental compliance
  - ◆ To address transportation system deterioration throughout the transmission system.

##### Land Rights

- Ensure legal access is provided in advance of construction dates by beginning all necessary land rights acquisition work a minimum of one year in advance of access road construction associated with wood poles and steel lines, and stand-alone projects.
- Renew rights to tribal property for ROW
- Orchard buy-back program to keep rights of way clear of vegetation and compliant with WECC/NERC regulations.

In the long run, this strategy will help:

- Ensure rights of ways are safely and legally accessible to transmission paths and remote sites and meet environmental regulations.

- Ensure BPA is compliant with all regulatory authorities
- Support BPA’s relationship with landowner agencies

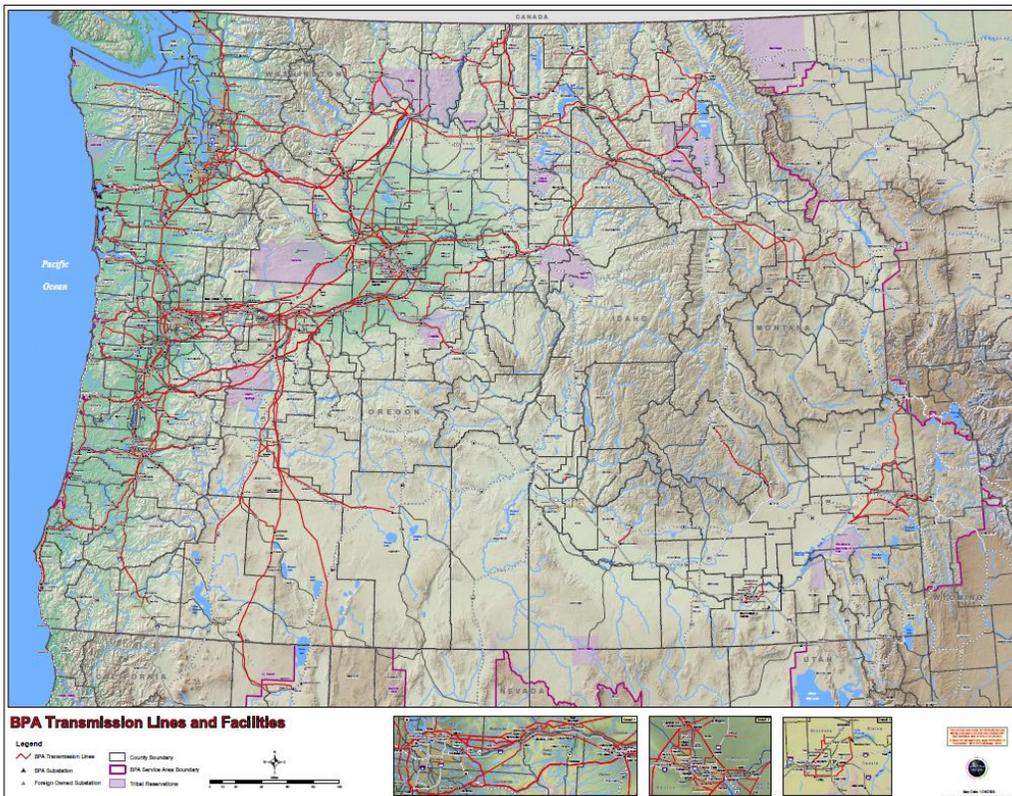
## 1.0 STRATEGY BACKGROUND

### 1.1. Business Environment

The ROW asset program has begun the process of developing and evaluating potential new strategic alternatives using the Total Economic Cost approach mentioned in the Transmission Asset Management Overarching strategy. This evaluation is being done in conjunction with the Wood Pole Lines and Steel Lines sustain programs to ensure alignment and necessary coordination of the ROW work as it supports the Lines sustain programs.

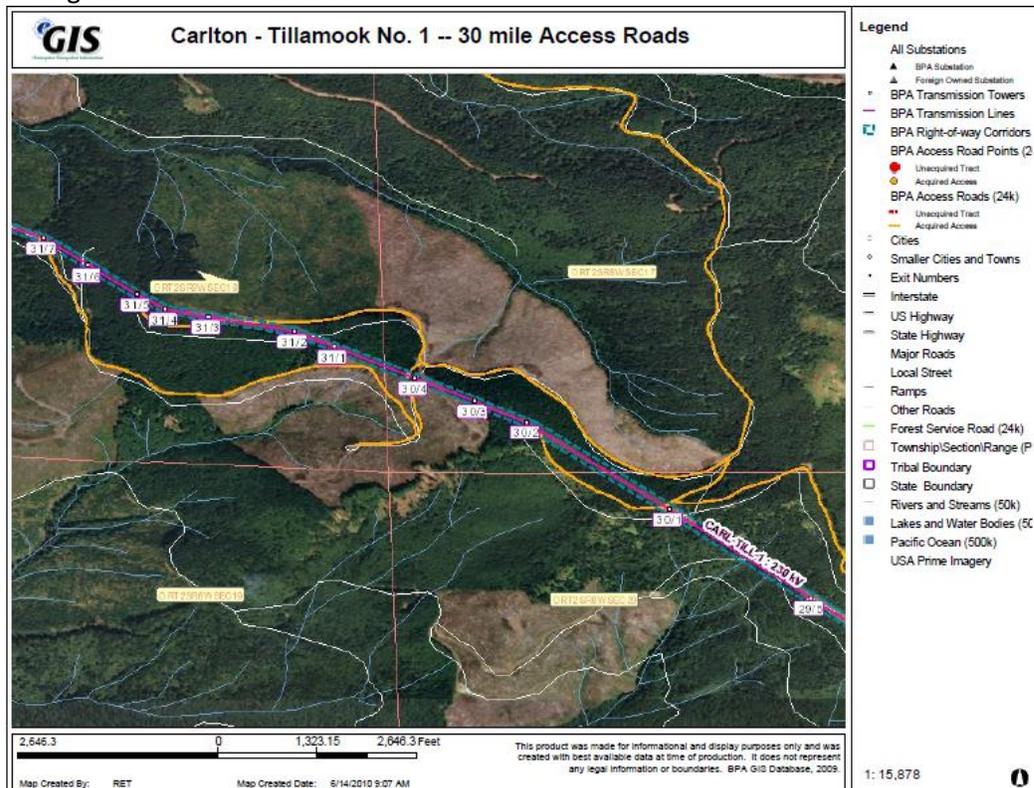
#### Vegetation - Control and Manage Vegetation

- Historically, the approach to ROW management has been to react to events rather than apply a proactive, planned life-cycle cost and risk approach.
- Costs to maintain the ROW are primarily expense activities focused on vegetation clearing and maintaining existing access roads.
- The 2008 vegetation-caused line outage resulted in remedial work costing over \$20 million.
- Environmental mitigation has been required to address impacts that could have been avoided with design adjustments to ROW management activities i.e., changes in vegetation management prescriptions. The often urgent, reactive nature of ROW activities these past 2-3 years has left little planning time.



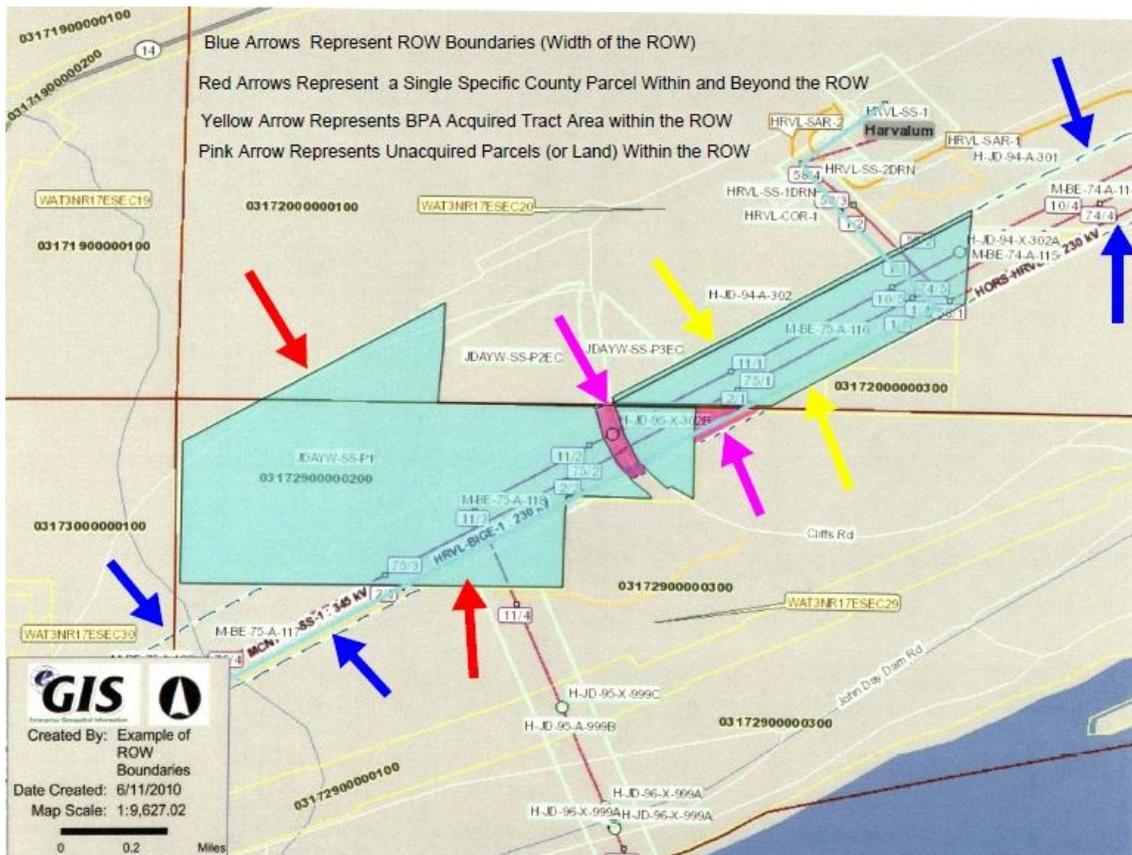
### Access Roads – Maintain and Improve Access Roads

- Access roads provide access to and through transmission corridors throughout BPA’s service area. They are an essential component of the Transmission Sustain program, supporting and aligning with BPA’s strategic priority to preserve and enhance the transmission assets and the economic, environmental and operational value they produce for the region.
- Access roads provide the transportation backbone that allows BPA crews to access BPA’s transmission system. The system includes more than 15,000 miles of high-voltage power lines, a dependable network of transmission highways that deliver electricity across the Pacific Northwest and into California, Canada and Montana.
- Access road projects support Wood Pole and Steel Lines sustain programs as well as environmental compliance and regulatory projects. Many access road projects serve to support land and water acquisition and restoration activities that improve fish and wildlife habitat.
- Because they provide the means for BPA crews to access the transmission system, access roads are a key component in ensuring that BPA Transmission assets are meeting a wide range of reliability standards that have steadily increased since 2007. An Access Roads Work Request System (ARWRS) has been developed and is being used to identify and prioritize access roads projects throughout the transmission system.
- Access roads are critical assets in terms of BPA meeting its environmental stewardship responsibilities both within and outside the Columbia River Basin. BPA’s transportation system must be compliant with all aspects of the Endangered Species Act (ESA) and the National Environmental Policy Act (NEPA). Many AR projects address fish passage, habitat preservation/restoration, and stream sedimentation issues throughout BPA’s service area.



### Land Rights – Acquire and Manage Land Rights

- Encroachments are an ongoing issue that is managed on a reactive basis.
- The Access Road Maintenance System (ARMS) and eGIS data indicate that formal easements are lacking on many currently utilized access roads. These roads will need to be reviewed to determine which require acquisition.
- Closer coordination with the Wood Pole Lines, Steel Lines and more importantly the AR program will help ensure that land rights are secured prior to construction so the projects are not delayed.
- The addition of critical required Real Property Services resources will allow for timely acquisition of required land rights.
- To address the current situation, a more strategic and centrally coordinated approach and tools are needed to manage ROW corridors (instead of individual lines) to support data-driven and risk-informed decision-making.



## 1.2 Assets, Asset Systems and Criticality

### Overall Rights of Way

ROW is comprised of corridors that contain transmission lines and the access roads established for the maintenance of transmission lines. An additional element that is covered is access roads to communications sites. Working with federal, state, and local agencies, private land owners, and other interested parties, BPA manages 195,600 acres of transmission line corridor rights of way.

This strategy covers maintenance work to control vegetation, maintenance work and improvements to roads; and acquisitions and perfecting of easement rights to enable BPA to access and manage existing transmission facilities.

This strategy does not cover the clearing of vegetation, building of roads, or acquiring of land or easement rights to support construction of new lines and facilities. These activities are instead covered by individual expansion-related projects.

### Vegetation - Control and Manage Vegetation

Program profile:

| Asset           | Count   | Description   |
|-----------------|---------|---|
| Gross ROW Acres | 195,600 | Total ROW corridor acres that need to be maintained |

- BPA inspects and observes vegetation on all 195,600 acres of transmission line corridors
- Approximately 52 percent (144,500 acres) require cyclical vegetation control while 48 percent (122,100) do not because they are managed for agricultural purposes
- Vegetation is also managed at the substation and communication sites
- 30% (80,761) of Transmission ROW acres have vegetation agreements (comprised of 22% agriculture; 53% landscaping; 17% tree orchards and Christmas trees; 8% individual tree agreements)
- The annual number of land management cases is up to 3,030 of which approximately 570 are closed annually

### Criticality

| Less Important | More Important |
|----------------|----------------|
|                | All Acres      |

Due to the potential impact of vegetation to corridors, all acres are determined to be equally critical.

### Access Roads – Maintain and Improve Access Roads

#### Assets

Program Profile: 11,861 Miles, 27,225 Asset components

| Asset        | Count     | Description   |
|--------------|-----------|---|
| Access Roads | 11,861 mi | Roads that provide the transportation system to and through transmission corridors. |
| Bridges      | 325       | Bridges provide access across streams and rivers.                                   |
| Culverts     | 10,100    | Culverts provide access across streams, frequently requiring fish passage design.   |
| Gates        | 16,800    | Gates restrict access across private property and into transmission corridors.      |

- Access roads service the corridors and communication sites
- Access roads are critical to execution of the Wood Lines, Steel Lines, and the communication sites portion of the System Telecom programs. They are critical in providing safe, environmentally compliant legal access to transmission assets.
- Environmental clearance and Land Rights acquisition are critical components of execution of the Access Roads Program.
- Priority for Access Roads Projects are based on:
  - ◆ Priorities from Wood and Steel Lines programs
  - ◆ Environmental degradation or compliance issues identified by working patrols or other agencies
  - ◆ District priorities to obtain access for critical maintenance work

Criticality

| Less Important |            | More Important |  |
|----------------|------------|----------------|--|
| Road Surface   | Road Prism | Bridges        |  |
| Gates          |            | Culverts       |  |

**Land Rights – Acquire and Manage Land Rights**

Assets

Program Profile: ~ 80,000 tracts of easement for the corridors and access roads

| Asset     | Count  | Description                         |
|-----------|--------|-------------------------------------|
| Easements | 52,115 | Line ROW and Access Roads Easements |
| Fee       | 1,507  | Facilities and Substations          |
| Permit    | 709    | City, State, and Federal agreements |
| Lease     | 9      |                                     |
| Options   | 83     |                                     |
| Neither   | 3,851  |                                     |

- Land rights are critical to execution of the Access Roads, Wood and Steel Lines programs. Without legal access, Access Roads, Wood and Steel Lines Programs cannot be executed.
- Types of rights include perpetual easements (vegetation, access), term easements (vegetation, access), fee properties, special use permits, and revocable permits

Criticality

| Less Important |  |  | More Important   |
|----------------|--|--|------------------|
|                |  |  | Perpetual Rights |
|                |  |  | Permits          |
|                |  |  | Leases           |
|                |  |  | License          |

## 2.0 THE STRATEGY

### 2.1 Current State

#### Vegetation - Control and Manage Vegetation

Vegetation Management Transmission Corridor System Performance

- Off-ROW\* fall-into caused outages are identified as Category 3 and are not sanctionable
- July 2007 grow into outage was on 500kV circuit
- June 2008 grow into outage was on 230kV circuit
- WECC response – issued a Remedial Action Directive (RAD) on July 3, 2008 ordering BPA to do a comprehensive inspection on all 8,500 corridor miles (approximately 15,000 circuit miles) within 90 days, costing roughly \$6.4 million
- Moving forward, goal is for zero On-ROW vegetation-related outages

| Year | On ROW | Off ROW* |
|------|--------|----------|
| 2013 | 0      | 3        |
| 2012 | 0      | 13       |
| 2011 | 0      | 6        |
| 2010 | 0      | 5        |
| 2009 | 0      | 6        |
| 2008 | 1      | 7        |
| 2007 | 1      | 80       |
| 2006 | 0      | 43       |

\*Off ROW vegetation related outages are sanctionable when there is grow-into contact

2007 represents a high storm activity year

(no sanctionable / grow-into Off ROW vegetation related outages recorded between 2006 and 2009)

#### Access Roads – Maintain and Improve Access Roads

A large portion of the transportation assets within BPA’s service area are in poor health. Decades of deferred maintenance and underinvestment in maintaining and upgrading the asset base has resulted in a large backlog of needed work. Maintenance has been deferred to the point that most of the system requires substantial capital investment to meet the objectives outlined in the Future State section of this strategy.

#### Land Rights – Acquire and Manage Land Rights

- Legal rights to access roads
  - ◆ A history of completing many past projects utilizing temporary licenses left a significant amount of work remaining to secure the permanent land rights. Many access road right deficiencies are also the result of system acquisitions that did not have adequate permanent rights and also the result of land subdivisions. Many times, when land is subdivided, BPA’s legal access is not transferred to the new owners.
  - ◆ Permits from city, state, and federal agencies are sometimes expired or non-existent and a history of not renewing those permits when identified sometimes creates delays in obtaining the rights needed. Identification of affected landowners and/or public entities early in the process allows possible identification of an alternate route saving acquisition time. These issues are usually uncovered during the scoping phase of the project.

- Tribal
  - ◆ All tribal transmission line right of way agreements are current with the exception of the Muckleshoot tribe agreement which expired in 2012. Negotiations to bring the agreement up to date are currently underway. Since the cost and timing of this is unknown, there is no provision for it in the budget. Rights to access roads on tribal lands are acquired as identified.

### 2.1.1 Program Accomplishments to Date

#### Vegetation - Control and Manage Vegetation

##### FY2012 Program Accomplishments

- Vegetation Program
  - ◆ Vegetation Grow-In Outages = 0
    - Continue to drive down locations requiring corrective maintenance
    - Focus goal developed to drive behaviors to reduce the number of Danger Brush (DB) / Danger Tree Grow into and reduce number of High Brush (HB)
  - ◆ 5 vegetation program improvements identified
    - Washington Department of Natural Resources (WDNR) Memorandum of Agreement (MOA) implemented
    - Access road work request system established
    - Summer readiness district outreach
    - Program metrics established
    - Aerial tree trimming project demonstrated
  - ◆ Vegetation Health Dashboard developed
    - Reduction in DB / HB chart
    - Conversion of maintenance / cost charts
  - ◆ Summer readiness completed by 5/15/12
  - ◆ Scheduled cutting activities completed
- Financial Perspective
  - ◆ Met financial goals for program
- Internal Operations
  - ◆ Compliance
    - Completed the compliance mitigation actions
    - Successful FERC audit
    - Completed compliance-driven FAC-003 patrol (NERC's reliability standard for VM) on schedule
- Industry Recognition
  - ◆ Article in T&D World - *BPA Employs Aerial Tree Trimming*, September 2012
  - ◆ Electric Energy - *Finding the "Sweet Spot" with BPA's Vegetation Management Program*, January 2012

##### FY2013 Program Accomplishments

- Vegetation Grow-In Outages = 0... 64 Months and running since the last event
- Research on the impact of the Aerial Tree trimming project
- DOE Office of Inspector General Audit – waiting for final report

- WECC Audit – success No Findings
- BPA recognized as an Industry Example of Excellence for LiDAR usage identified by NATF (May 2013)
- 100% of corrective actions completed due by 5/31/13
- 97% Scheduled maintenance work scope completed
- Met financial goals for ROW program
- Closed out WECC mitigation plan

### **Access Roads – Maintain and Improve Access Roads**

#### FY2012 Program Accomplishments

- Completed Construction on 13 of 13 projects in support of Steel, Wood and Stand Alone upgrades
- Completed Design on 19 of 19 projects in support of Steel, Wood and Stand Alone upgrades

#### FY2013 Program Accomplishments

- Completed Construction on 9 of 9 projects in support of Steel, Wood and Stand Alone upgrades
- Completed Design on 13 of 13 projects in support of Steel, Wood and Stand Alone upgrades

### **Land Rights – Acquire and Manage Land Rights**

#### FY2012 Program Accomplishments

- Initiated comprehensive plan and processes to identify and acquire needed land rights at least a year in advance of road or line construction. Eight projects were initiated in support of this effort.

#### FY2013 Program Accomplishments

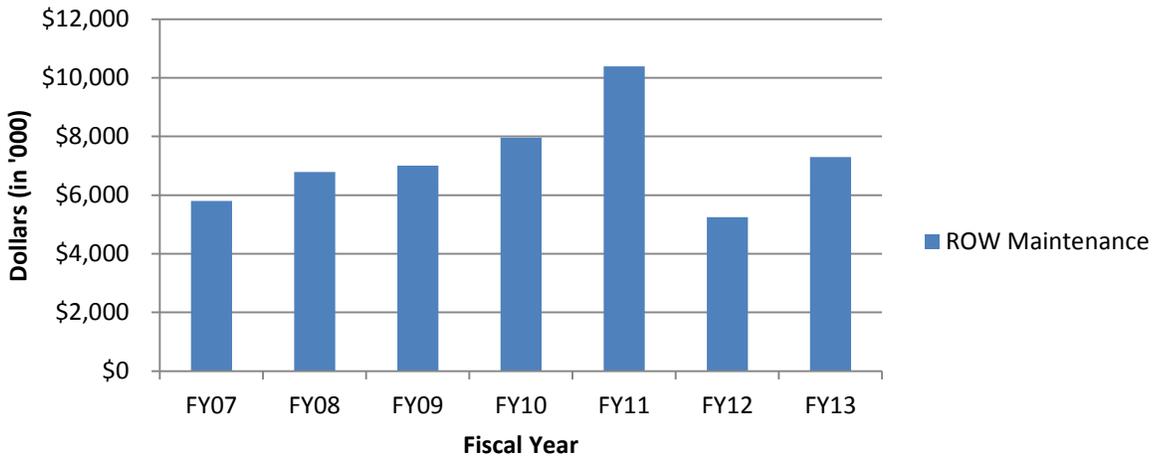
- In continuing to support the plan and processes to identify and acquire needed land rights at least a year in advance of the road or line construction, 29 scoping projects were initiated.
- Completed 45 Orchard buy back mitigations in FY2013. The annual target is 20 mitigations per year.
- Completed and recorded acquisition of land rights to 462 tracts in FY2013.

## **2.1.2 Cost History**

### **Overall ROW Maintenance**

Expense is tracked at an overall ROW level, while capital is tracked at the individual program level, with the exception of Vegetation which is all expense work.

**Overall ROW Maintenance - Historical Actuals - Expense**



Historical Actuals – Expense

Dollars in '000

| Program         | FY07    | FY08    | FY09    | FY10    | FY11     | FY12    | FY13    | Total    |
|-----------------|---------|---------|---------|---------|----------|---------|---------|----------|
| ROW Maintenance | \$5,798 | \$6,787 | \$7,003 | \$7,965 | \$10,386 | \$5,243 | \$7,298 | \$50,480 |

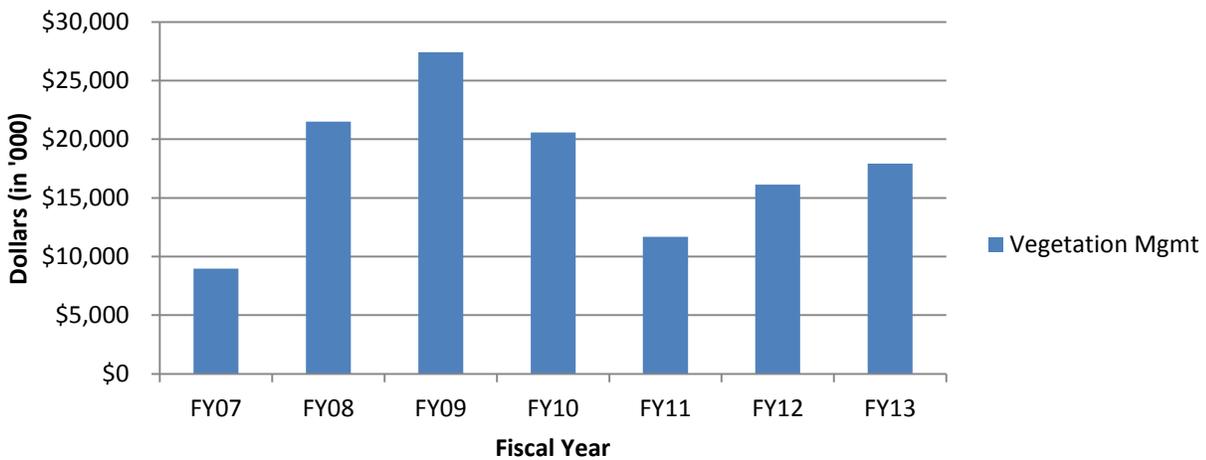
- The above chart and table represents overall ROW maintenance for Vegetation Management, Access Roads and Land Rights.

Historical Actuals - Capital

- Historical Actuals for capital are not available for overall ROW, as Vegetation Management is expense only. Historical Actuals for capital will be represented in the AR and LR sections below.

**Vegetation - Control and Manage Vegetation**

**Vegetation Historical Actuals - Expense**



Historical Actuals - Expense

Vegetation

Dollars in '000

| Program         | FY07    | FY08     | FY09     | FY10     | FY11     | FY12     | FY13     | Total     |
|-----------------|---------|----------|----------|----------|----------|----------|----------|-----------|
| Vegetation Mgmt | \$8,982 | \$21,514 | \$27,414 | \$20,583 | \$11,696 | \$16,141 | \$17,928 | \$124,258 |

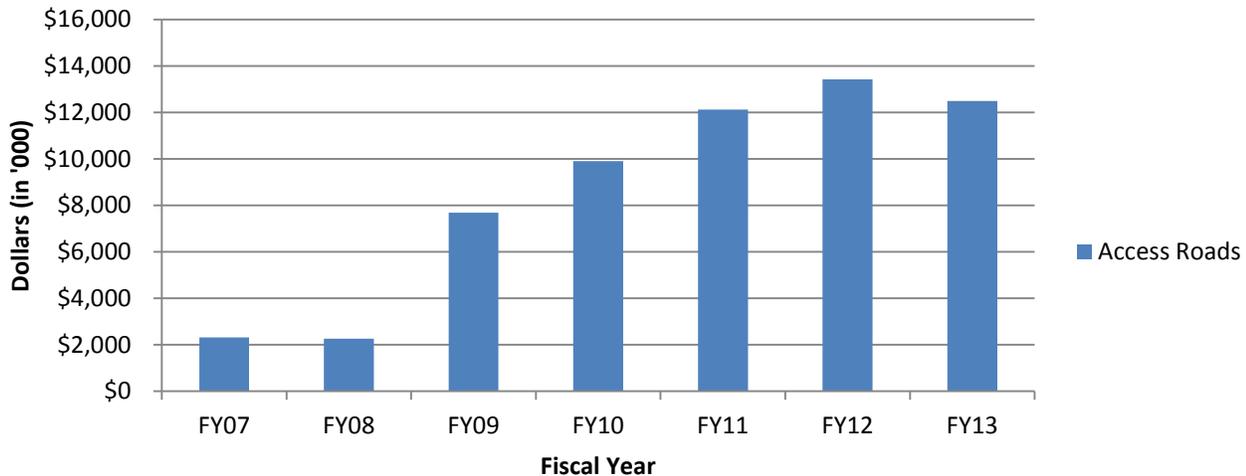
- In response to a transmission line vegetation-related outage in 2008 and self report to WECC, expenses related to vegetation management have ramped up dramatically for remedial work
- Vegetation management funding levels for prior years were determined to be inadequate to keep up with annual vegetation growth within and along the rights-of-way
- Costs for service contracts are expected to continue to be higher during the transition from corridors with many danger brush and high brush reports to corridors cleared of brush issues and maintained with low growing plant communities

Historical Actuals - Capital

- Capital is not applicable to the Vegetation Program

**Access Roads – Maintain and Improve Access Roads**

**Access Roads Historical Actuals - Capital**



Historical Actuals - Capital

Access Roads

Dollars in '000

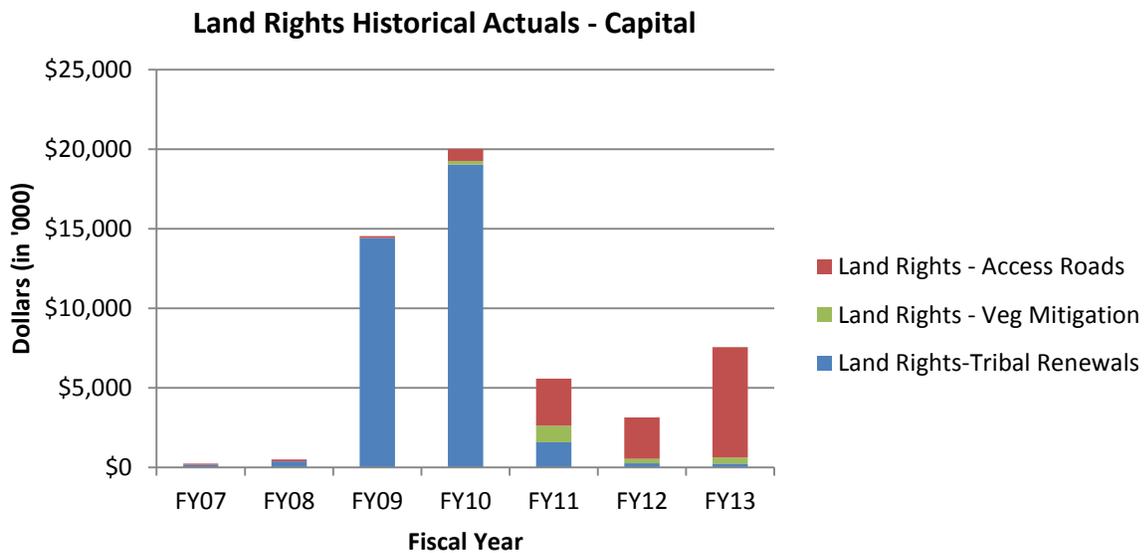
| Program      | FY07    | FY08    | FY09    | FY10    | FY11     | FY12     | FY13     | Total    |
|--------------|---------|---------|---------|---------|----------|----------|----------|----------|
| Access Roads | \$2,313 | \$2,259 | \$7,683 | \$9,900 | \$12,114 | \$13,422 | \$12,491 | \$60,182 |

Historical Actuals - Expense

- FY2013 is the only year that can be provided specifically for the Access Roads (AR) maintenance as previous years' expenditures were bundled with other programs.

- ◆ AR maintenance = \$1,100,007 in FY2013
- Maintenance of access roads has historically been completed as emergency repair work due to competing priorities.
- Expense activities include emergency repairs caused by slides, surface rocking, gate repairs, cleaning out, repairing and replacing culverts and working patrols documenting access road conditions.
- Current levels of funding for AR maintenance are designated at \$50K annually for each of the 13 Districts in the BPA Service Area. An additional \$500K is held in reserve to address emergency work or high priority repairs.
- In FY2013, AR maintenance activities increased to a level of ~\$1.5M.
- Current discussions with the Vegetation Management organization are focused at ramping up AR maintenance dollars so that preventive maintenance cycles can be implemented throughout the system as well as corrective maintenance to address immediate problems identified by District Patrols.
- Stable predictable funding level required is estimated at approximately \$4.0M per year in 2013 dollars.

**Land Rights – Acquire and Manage Land Rights**

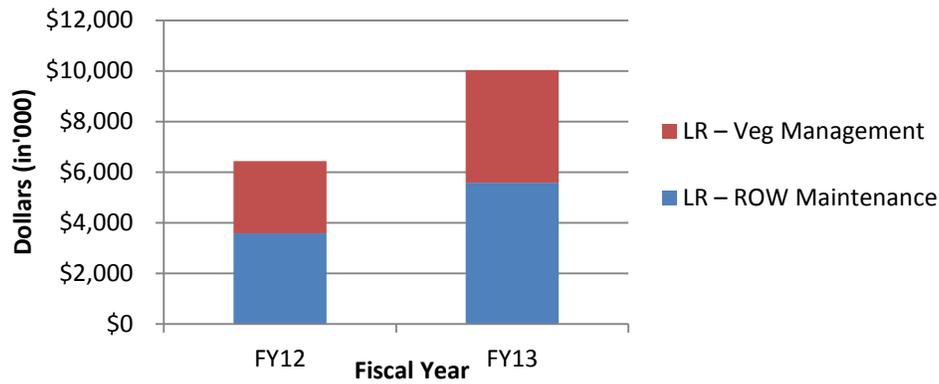


Historical Actuals - Capital

Dollars in '000

| Program              | FY07         | FY08         | FY09            | FY10            | FY11           | FY12           | FY13           | Total           |
|----------------------|--------------|--------------|-----------------|-----------------|----------------|----------------|----------------|-----------------|
| LR - Tribal Renewals | \$145        | \$380        | \$14,420        | \$19,025        | \$1,577        | \$251          | \$238          | \$36,036        |
| LR - Veg Mitigation  |              |              |                 | \$234           | \$1,027        | \$276          | \$374          | \$1,911         |
| LR - Access Roads    | \$77         | \$103        | \$106           | \$760           | \$2,958        | \$2,606        | \$6,939        | \$13,549        |
| <b>Total</b>         | <b>\$222</b> | <b>\$483</b> | <b>\$14,526</b> | <b>\$20,019</b> | <b>\$5,562</b> | <b>\$3,133</b> | <b>\$7,551</b> | <b>\$51,496</b> |

### Land Rights Historical Actuals - Expense



#### Historical Actuals - Expense

Dollars in '000

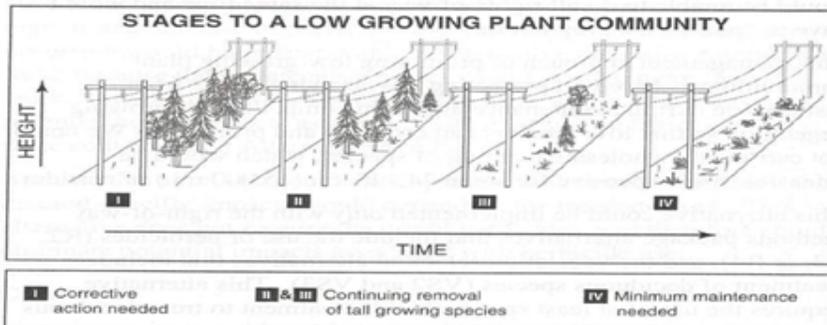
| Program                    | FY12    | FY13     | Total    |
|----------------------------|---------|----------|----------|
| LR – ROW Maintenance       | \$3,582 | \$5,579  | \$9,161  |
| LR – Vegetation Management | \$2,855 | \$4,458  | \$7,313  |
| Total                      | \$6,437 | \$10,037 | \$16,474 |

- Historical Actuals for expense in the LR program was not available until FY2012, which is why FY2007-11 is not represented.

### 2.1.3 Health of Current Assets (Current Condition & Performance)

#### Vegetation - Control and Manage Vegetation

##### Definition of Stages to a Low Growing Plant Community



Calculate stage based on stem density, height, and type of vegetation

- Stage 1: Correction action needed
  - 0-24% desirable forbs and grasses
- Stage 2: Continuing removal
  - 25-49% desirable forbs and grasses
- Stage 3: Continuing removal
  - 50-75% desirable forbs and grasses
- Stage 4: Minimum maintenance (prevention)
  - 76-100% desirable forbs and grasses

**Vegetation Overall Component Health Demographics**

| Major Component | Corridor Health- Low Growing Plant Community |         |         |         | Asset Health |
|-----------------|--|---------|---------|---------|--------------|
|                 | Stage 4                                      | Stage 3 | Stage 2 | Stage 1 |              |
| 800 kV          | 100%   |         |         |         | Good         |
| 500 kV          | 82%  | 15%     | 3%      |         | Good         |
| 345 kV          | 81%  | 19%     |         |         | Good         |
| 287 kV          | 100%   |         |         |         | Good         |
| 230 kV          | 82%  | 14%     | 4%      |         | Good         |
| 161 kV          | 100%   |         |         |         | Good         |
| 138 kV          | 46%  | 54%     |         |         | Fine         |
| 115 kV          | 77%  | 19%     | 4%      |         | Good         |
| Under 115 kV    | 57%  |         | 43%     |         | Impaired     |

**Condition Assessment:**

- 319 corridors
- Currently – On average, the breakdown of Low Growing Plant Community stages per corridor is:
  - ◆ 0% of the corridor is in Stage 1
  - ◆ 3% of the corridor is in Stage 2
  - ◆ 15% of the corridor is in Stage 3
  - ◆ 82% of the corridor is in Stage 4
- Approximately 55% of the corridor acres require cyclical, preventive vegetation maintenance to ensure achievement of clearance standards
- Conditions are markedly improved. Four (4) years ago, the breakdown of Low Growing Plant Community stages per corridor was:
  - ◆ 20% of the corridor is in Stage 1
  - ◆ 40% of the corridor is in Stage 2
  - ◆ 20% of the corridor is in Stage 3
  - ◆ 20% of the corridor is in Stage 4

Assessment based on the experience and judgment of the Natural Resource Specialist (NRS)

**Access Roads – Maintain and Improve Access Roads**

**Access Roads Overall Component Health Demographics**

| Major Component | Physical Condition |      |      | Obsolescence |      |      | Remaining Life |       |     | Asset Health |
|-----------------|--------------------|------|------|--------------|------|------|----------------|-------|-----|--------------|
|                 | Good               | Fair | Poor | Good         | Fair | Poor | >20            | 10-20 | <10 |              |
| AR Surface      |                    |      |      |              |      |      |                |       |     | Impaired     |
| Bridges         |                    |      |      |              |      |      |                |       |     | Good         |
| Culverts        |                    |      |      |              |      |      |                |       |     | Poor         |
| Road Prism      |                    |      |      |              |      |      |                |       |     | Impaired     |
| Gates           |                    |      |      |              |      |      |                |       |     | Fine         |

NOTE: This is an across-the-board quantitative assessment based on qualitative data.

- Condition information is captured during working patrols and line maintenance activities; the data is stored in TLM Apps and input in the ARWRS (Access Road Work Request System).
- An Access Roads Work Request System (ARWRS) has been developed by Transmission Field Services for district maintenance crews and is being used to identify and prioritize access roads projects system-wide.

- In late FY2012, a GIS data collection system was developed by the Access Roads Engineering group for use in designing and delivering AR projects in support of wood, steel, and stand-alone upgrades. The system allows data collected to be uploaded into an eGIS layer. In this manner, each project becomes a data point in identifying the health of the transportation asset.
- Condition varies greatly across the system depending on terrain, weather, public access, etc.:
  - ◆ 90% of the roads are adequate for access to patrol transmission lines with light duty vehicles, *but* current data collected in FY2013 indicates that 60% of the access road system requires minor to major capital improvement to support the heavy equipment that is needed for line repair, replacement, and other construction work
  - ◆ As of September 2013, 975 miles of roads have been identified to upgrade and improve in support of wood and steel lines projects and stand alone upgrade projects. This mileage will continue to increase as additional projects come on line and are developed to support sustain and stand-alone efforts.

### Land Rights – Acquire and Manage Land Rights

- ARMS: The Access Road Management System mapped all roads used by BPA, including acquired roads and roads where use is by verbal agreement only and the data was migrated to eGIS in 2011.
- Access roads easement rights fall into two categories: formal, documented rights vs. informal, undocumented rights.
  - ◆ Undocumented rights present potential access issues
  - ◆ The exact number of undocumented rights is unknown
- Trends indicate that Land Management Cases (encroachments and land use applications) have increased in number by 48% over the last 4 years
  - ◆ The increase of 48% is primarily attributable to land use applications. Landowners and developers recognize the benefit of potentially using the ROW to promote development on and off the ROW, especially where land availability is limited, and BPA's ongoing outreach programs may be successful in encouraging coordination with BPA prior to initiating any activities.
  - ◆ Adding supplemental labor support over the last couple of years has helped to increase the number of Land Management Cases closed per year
  - ◆ The backlog of cases continues to grow since staff cannot keep up with the increased workload
- To date the Natural Resource Specialists have identified 161 orchards that are not in compliance with BPA's vegetation clearance standards.
- Health of existing land rights is sufficient for current use in most cases. As gaps are identified, they are evaluated by stakeholders and mitigated.
- BPA has promoted collaborative relationships and trustworthy stewardship with landowners. Statistics show that the percentage of parcels condemned has decreased over time. BPA strives to use condemnation as a last resort, and to ensure that all reasonable efforts have been made towards successful negotiations between the parties.

## 2.2 Future State

### 2.2.1 Key asset performance objectives, measures and targets

#### Vegetation - Control and Manage Vegetation

| Category   | Performance Objective   | Measure   | End Stage Target   |
|--|---|---|--|
| Reliability –<br>SAIFI-related,<br>frequency of<br>unplanned outages | Maintain a safe clearance zone and a stable low-growing plant community | <p>Measure 1 (Lagging): Frequency of Line Outages caused by vegetation growth</p> <p>Measure 2 (Leading): Complete the corrective maintenance work identified Danger Brush (DB), High Brush (HB) and Danger Tree Grow in to (DTG) by the due date established in the Standard-Procedure-Instruction-Information (SPIFS)</p> <p>Measure 3: Comply with NERC/WECC requirements (FAC-003-02) Transmission vegetation program</p> | <p>End Stage Target 1: Zero grow into tree-related outages</p> <p>End Stage Target 2: 5% reduction each year over the next 5 years in the number of DB</p> <p>End Stage Target 3: 100% compliance with FAC-003-02, no significant findings</p> |

#### Access Roads – Maintain and Improve Access Roads

| Category  | Performance Objective   | Measure   | End Stage Target  |
|---|---|---|---|
| Reliability –<br>SAIDI-related,<br>duration of<br>unplanned<br>outages                              | Provide safe and reliable road access to transmission assets  | <p><b>Measure 1 (Leading):</b><br/>Number of Access Roads Project Upgrades completed to support Wood and Steel lines Sustain Programs.</p> <p><b>Measure 2 (Leading):</b><br/>Restore physical access to isolated structures.</p> | <p><b>End-stage Target 1:</b> All projects are on track to support of Wood and Steel lines project milestones for FY2013, FY2014, and FY2015.</p> <p><b>End-stage Target 2:</b> By 2015, physical access has been restored to 123 of 123 isolated structures.</p> |
| Environmental Compliance-<br>Compliance with Federal Regulations and Environmental Impact Statement | Maintain transmission corridors and access roads in accordance with KEP/Federal environmental standards and Final Environmental Impact Statement DOE/EIS-0285 | Number of Access-related Environmental Compliance projects completed  | By Q4 of 2015, complete 32 of 32 identified Environmental Compliance projects   |

| Category  | Performance Objective   | Measure  | End Stage Target   |
|---|---|--|--|
| Safety –<br><br>Lost-time accidents and fatalities; activities performed safely | BPA transmission corridors and access roads are maintained and operated in a way that limits risk to health and safety of employees working on the lines. | Frequency of lost-time accidents due to unsafe access. | Lost-time accident frequency rate ≤ 1.5 per 100,000 hours worked, no fatalities occur to BPA employees or contract employees working on BPA facilities as a result of unsafe access. |

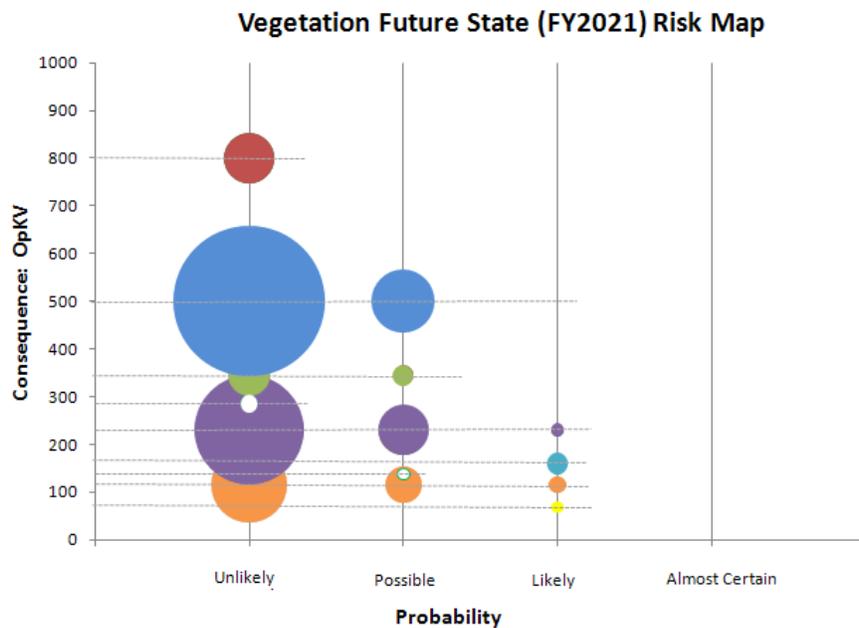
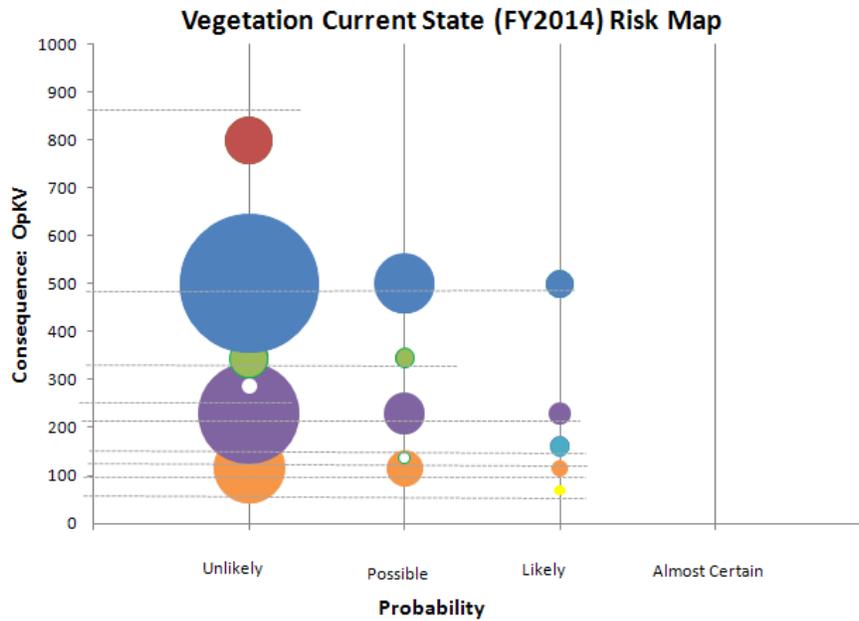
**Land Rights – Acquire and Manage Land Rights**

| Category  | Performance Objective   | Measure   | End Stage Target  |
|---|---|---|---|
| Stakeholder/L and Owner and Land Management –<br><br>Compatible uses of Rights of Way | Ensure that rights-of-way are maintained so that all uses are safe and do not present an interference with BPA's activities | <p><b>Measure 1:</b> Number of the encroachments per rating</p> <p><b>Measure 2:</b> Number of Outreach Programs scheduled</p> <p><b>Measure 3:</b> Number of Land Management Cases, for Orchards, closed</p> <p><b>Measure 4:</b> Number of vacant and underutilized rights-of-way scheduled for survey and marking ROW edge</p> | <p><b>End-stage Target 1:</b> 100% of the highest rated encroachments have action taken towards mitigation.</p> <p><b>End-stage Target 2:</b> 100% of Outreach Program schedules are met</p> <p><b>End-stage Target 3:</b> Within 5 years of 9/30/2010, half of the 129 orchards reported as incompatible with BPA's Vegetation Clearance Standards will have long term mitigation completed, and all will be mitigated within 10 years; any new orchards reported after 9/30/2010 will be mitigated within 2 years</p> <p><b>End-stage Target 4:</b> 100% of plan for vacant and underutilized rights-of-way met</p> |
|   | Legal access to transmission facilities is provided   |   | Develop plan to (1) identify the roads in the eGIS data base where land rights have not been acquired by December 2013; (2) the Access Road Team will identify and prioritize which roads need to be acquired, and which roads need to be eliminated from the eGIS data base by December 2014; (3) develop estimates for the cost to acquire the necessary land rights; (4) the Access Road Team will set a schedule based on the number of roads, and available funding to acquire the land rights for these access roads.   |

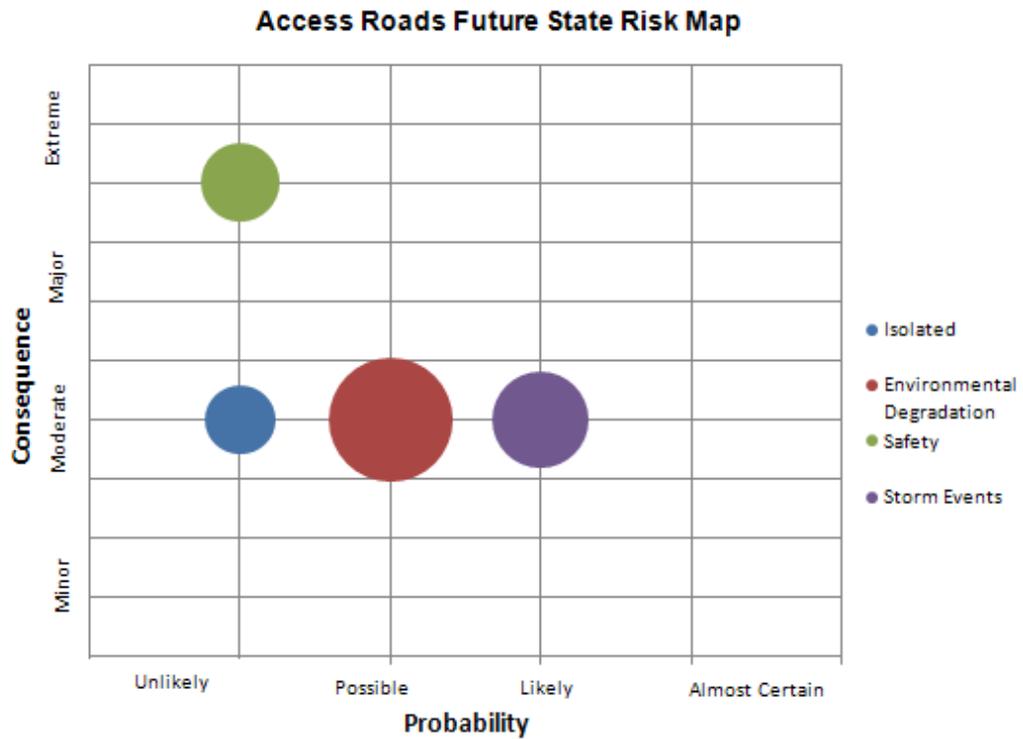
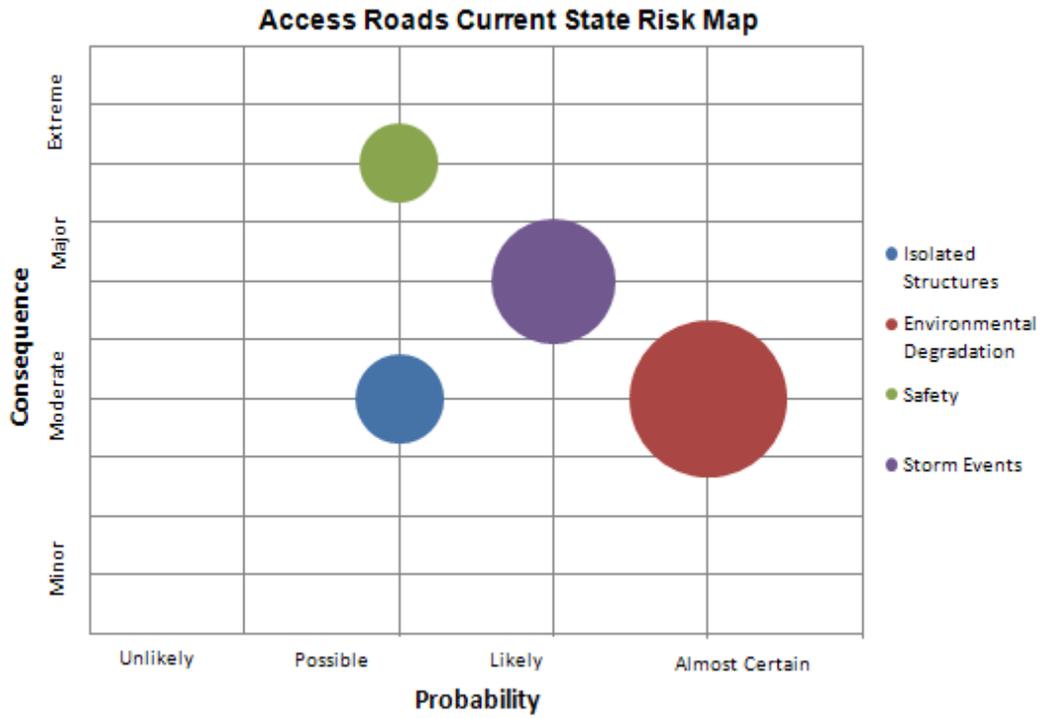
### 2.3 Asset Condition/Performance Gaps

#### Vegetation - Control and Manage Vegetation

The bubbles in the maps below show the number of acres and their condition for the specific voltage class (consequence y-axis), where “Unlikely” represents the Stage 4 - low growing plant community. The size of the bubble represents the volume of acres in the particular voltage class with respect to the ROW health in terms of percent of tall growing vegetation density (see chart in section 2.1.3 Stages to A Low Growing Plant Community.) Future state represents what the conditions would look like after the next maintenance cycle between 3 – 8 years.



**Access Roads – Maintain and Improve Access Roads**



\*See Appendix A for definitions of Access Roads Probability and Consequence scales

## **Gaps between AR Current and Future State Risk Maps**

### Isolated Structures

In the current state, there are over 100 isolated structures. Due to incomplete information on the transportation system the number is probably much higher and as data is collected project by project the information will become more accurate. The future state shows that most structures have become un-isolated and both the probability and consequence of encountering this condition have been reduced because of capital improvements and preventative or corrective maintenance.

### Environmental Degradation

In the current state, the transportation system has high exposure to triggering environmental damage due to lack of maintenance. A simple plugged culvert or blocked ditch can trigger catastrophic failure of the road prism or drainage structure and inject large amounts of sediment into streams. The future state shows a reduction in both exposure and relative consequence because of capital improvements and preventative or corrective maintenance.

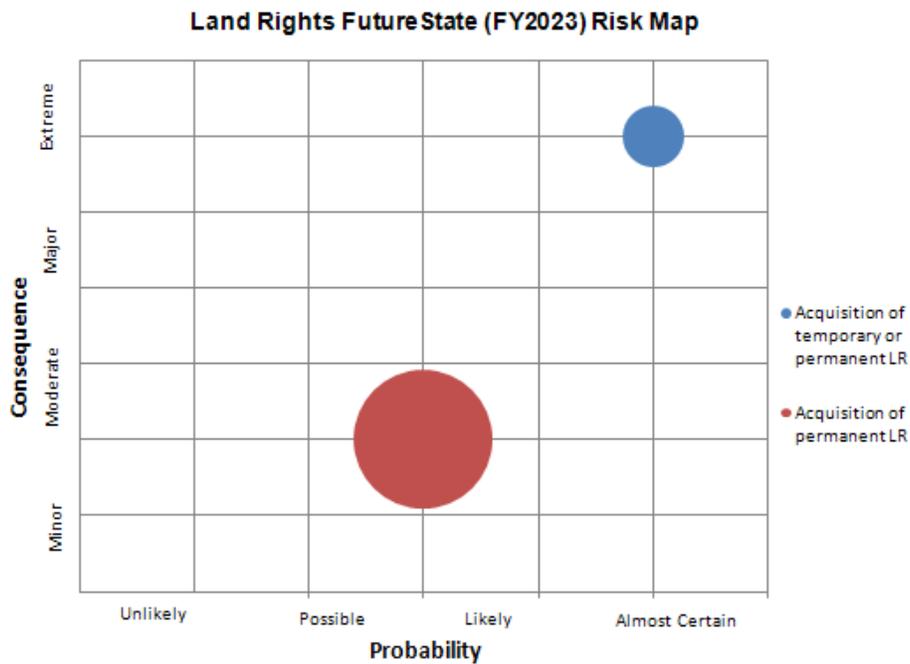
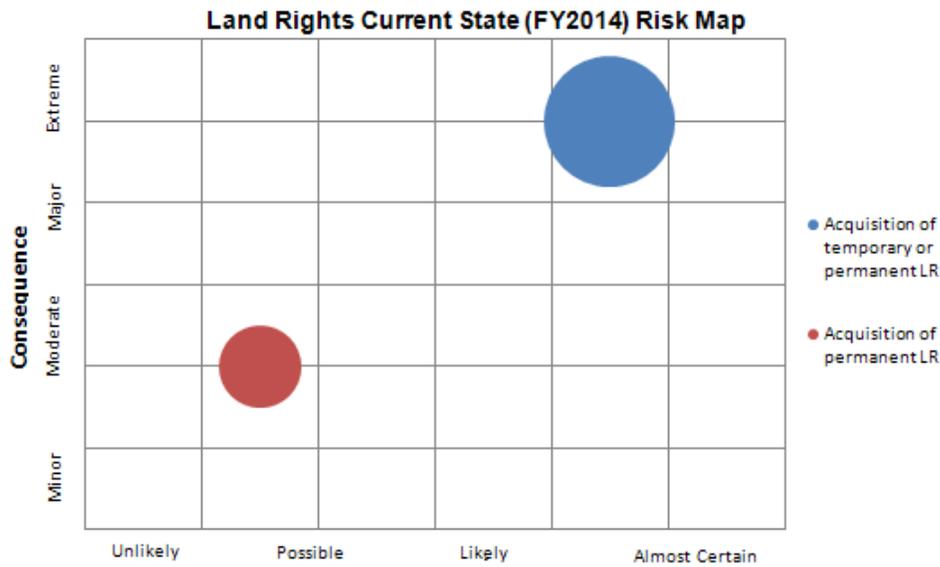
### Storm Events

In the current state, the transportation system has high exposure to triggering catastrophic environmental damage due to lack of maintenance. A simple plugged culvert or blocked ditch can trigger catastrophic failure of the road prism or drainage structure and inject large amounts of sediment into streams, killing fish and destroying habitat. Although the future state has the same level of probability for storm events, the relative consequence and degree of exposure is reduced because of capital improvements and preventative or corrective maintenance.

### Safety:

In the current state, the transportation system has some exposure to safety issues due to deteriorating road conditions and narrow roads that won't accommodate modern equipment. In the future state, while the consequence remains extreme, the exposure and probability have been reduced.

**Land Rights – Acquire and Manage Land Rights**



\*See Appendix H for consequence and probability definitions

**Gaps between LR Current and Future State Risk Maps**

- Meeting the need of supporting Wood, Steel, and Access Roads programs can be done temporarily by providing legal access for construction. That does not provide permanent access but does reduce or eliminate construction delays. In that case the Real Property Services goal of obtaining permanent rights still remains, even if it is long after construction is complete. Not completing the permanent rights acquisition before construction increases the work to be done because the permanent land rights must ultimately be acquired in addition to the temporary land rights.

- Risks to obtaining either temporary or permanent rights include uncooperative land owners, city, and state agencies, and resource or policy constrained federal agencies.
- Consequences to encountering these obstacles are always the same; it takes more time and costs more to obtain the required land rights. Alternatives are temporary rights when possible, reviewing alternative reroutes, or condemnation when no options remain.

**2.3.1 Risks to meeting the objectives**

**Vegetation - Control and Manage Vegetation**

| Category     | Risk   | Probability  | Consequence  |
|--------------|--|--|--|
| Reliability  | Vegetation Program does not comply with FAC-003-2 Standard   | Unlikely: Recently implemented process control and quality assurance, revisions to patrol and clearance standards, and increase in vegetation data   | Major: WECC sanctionable violation   |
|              | Danger Tree Grow-into (DTG) are present in one or more corridors   | Unlikely: Recently implemented process control and quality assurance, revisions to patrol and clearance standards, and increase in vegetation data   | Major: WECC sanctionable violation   |
|              | Unplanned transmission line outage due to vegetation in or on the edge of the corridor falling into a line   | Unlikely: Minor amount of corridor acreage that is not being actively managed for fall into situations; likelihood changes to unlikely if FAC-003-2 is implemented (clarifies “actively maintained rights-of-way”) | Major: WECC sanctionable violation and subsequent mitigation (~\$12MM, or more)  |
|              | Insufficient resources to complete all necessary vegetation corrections and planned maintenance              | Unlikely: On Rights-of-Way vegetation management activities are a high priority to fund and staff  | Major: Violation of TVMP (Transmission Vegetation Management Plan), WECC violation, possible outage, possible accrual of deferred maintenance, potential safety hazard to the public and BPA staff |
| Availability | Ineffective planning and / or limited funding to maintain vegetation clearance standards requires additional | Almost Certain: Some level of Vegetation outages are necessary to perform certain cyclical maintenance activities  | Minor ~ 105-205 planned outages for vegetation management activities have been required in a normal year, has not impacted the   |

| Category                 | Risk  | Probability   | Consequence  |
|--------------------------|---|---|--|
|                          | planned outages.  |   | BPA availability target  |
| Environmental Compliance | Vegetation management work does not comply with environmental standards: FEIS (Final Environmental Impact Statement – DOE/EIS - 0285) | Unlikely (scheduled maintenance activities) – environmental evaluations are completed for all maintenance projects and the prescriptive maintenance can be adjusted to minimize impact, Medium (corrective maintenance). Need to react quickly may limit mitigation options | Moderate: remedial mitigation after the fact, notice of violation, out of compliance with vegetation EIS, spread of noxious weeds along and outside of corridors |
| Safety                   | Vegetation Management, or Realty BPA staff, contractor, or public injury or fatality  | Unlikely - may be caused by inadequate safety training, weather/natural disaster, lack of proper checks and balances, or unqualified workers  | Extreme – injury or loss of human life, possible fire  |

**Execution Constraints - Vegetation Management**

A corridor assessment must be completed on the 319 corridors in order to complete a comprehensive risk assessment and risk map.

- Currently there is no comprehensive data set
- Dependencies: Implementation of Vegetation Management system that stores corridor profile and health data
  - ◆ COTS (commercial off the shelf) or in-house solution being evaluated by BPA’s IT department in FY2014
  - ◆ Will require capturing corridor health data through patrols and LiDAR
- Easement data resides in LIS (Land Information System) and Application Extender Tract ID can be associated with a corridor

**Access Roads – Maintain and Improve Access Roads**

| Category                 | Risk  | Probability  | Consequence  |
|--------------------------|---|--|--|
| Reliability              | Cannot access most important transmission lines (Category 1 and 2) and structures that have roads leading to them – due to physical conditions of the roads                           | Almost Certain: Will happen ~ every other year depending on storm conditions and intensity   | Minor to Moderate  |
|                          | Cannot access most important transmission lines and structures that have roads leading to them due to culvert failure   | Almost Certain: ~6 reported failures every year (road washout or road is impassible)   | Moderate: Environmental issues such as siltation of stream   |
|                          | Cannot access most important transmission lines and structures that have roads leading to them due to bridge failure  | Probability: Almost Certain – 3-4 Issues every year (bridge no longer meets load carrying standard)  | Minor to Moderate: increased time to conduct maintenance activities, increased outage duration if outage occurs.   |
| Environmental Compliance | Environmental degradation due to lack of maintenance creates stream siltation resulting in violations of the Clean Water Act and Landowner agency reluctance to approve BPA projects. | Likely: without a systematic cyclic preventative maintenance program, storm events and even normal rainfall and snowfall will trigger minor to catastrophic failure within BPA’s transportation system.                                    | Moderate: Loss of trust/working relationships with Landowner agencies, loss of reputation, potential citations from State/Federal Agencies.  |
|                          | Drainage crossings have not been upgraded to meet current Federal and State regulations for fish passage.   | Almost Certain: BPA’s transportation system is under increased scrutiny from Landowner Agencies as they become responsible to comply with Federal Endangered Species Act (ESA) requirements, State Regulations, and Legislative direction. | Moderate to Major: Many Landowner Agencies have removed any non-compliant drainage structures they encounter on their property because they don’t have sufficient funds to correct the installations. This isolates transmission structures and prevents ground access for maintenance, inspections, and construction. To restore access, BPA must upgrade the installations to meet current environmental regulations at a high cost. |

| Category | Risk  | Probability  | Consequence                       |
|----------|---|--|-----------------------------------|
| Safety   | BPA, contractor, or public injury or fatality due to deteriorating Access Road conditions and/or substandard width and/or excessive grades. | Unlikely – low travel speeds and the physical constraints of the system are more likely to result in stranded vehicles rather than injuries. | Extreme – Potential loss of life. |

**Execution Constraints - ROW program**

The Access Roads and Land Rights portions of the ROW program are subject to many of the constraints identified in the Transmission Asset Management Overarching strategy with regards to specific resource requirements. Forthcoming improvements in this area will support the ROW program in meeting its strategic objectives.

**Execution Constraints - Access Roads**

*Unanticipated Access Roads Program Demands (The “Front Log”)*

Since 2012, the AR support for the Steel Lines program has grown from less than \$1M/year to \$10M - \$15M per year. The ramp up to support Insulator Replacement projects has resulted in a substantial increase in miles of access roads required to be upgraded. Typically, the sections of line identified with the worst insulator conditions are also the sections where access is most difficult, environmental issues are most critical, and land rights are lacking. While information to understand the full impact of insulator replacement projects on the AR program is not currently known, it is expected that the insulator replacement program will drive funding requirements beyond originally planned levels for FY2014-2017.

In addition, AR Program support for Wood Lines is proving more costly than previously estimated due to complex un-maintained road systems in environmentally sensitive areas on unstable ground. As a result, road mileages to be upgraded and improved are much higher than previously estimated because Wood and Steel Lines projects are identified in many places where the terrain and topography are steep and difficult, requiring extensive ‘in and out’ for the transportation system to provide access to the transmission corridors.

All of the above factors and accelerating the ramp up to get the AR program ahead of Wood and Steel Lines programs has dramatically increased the need to execute a greater volume of AR work than originally forecasted. In order to meet these increased demands, the Environmental Clearance and Land Rights must be attained in a timely fashion to meet Wood and Steel program schedules. Once the path is cleared for roads work, Transmission Services may need to re-prioritize funding to cover additional costs to fully execute the AR plan in support of the lines programs.

*Environmental Clearance (includes NEPA documents, permits, and environmental studies/surveys)*

As mentioned in the Transmission Asset Strategy Overarching strategy, focus has been placed on the need to provide timely environmental clearance on many sustain projects. Many projects cross state and federal lands and BPA must rely on “cooperating agencies” to review environmental documents and permits in a timely manner. Additionally, BPA projects are increasingly coming under Landowner agency scrutiny with regards to environmental concerns on their property.

*Land Rights*

There are federal constraints on how much the government can pay a landowner for a given parcel, and the BPA culture is to avoid condemnation. Since the original construction of the system, land ownership has become much more complex, and relationships with both public and private landowners can sometimes be challenging.

**Land Rights – Acquire and Manage Land Rights**

| Category                 | Risk  | Probability       | Consequence  |
|--------------------------|---|-------------------|--|
| Reliability              | Blocked access by landowner   | Certain to happen | Delays access for emergency and routine maintenance  |
| Reliability              | Expired Permit, License, or Easement or new owner to an existing, unrecorded right.   | Very Likely       | Obtain temporary license if landowner is cooperative, pursue alternative if they are not.                  |
| Environmental Compliance | Crews or contractors may use access that BPA does not have legal rights to that is in an environmentally or culturally sensitive area.                        | Likely            | Fines, penalties, delayed work, compensation to landowner or agency.                                       |
| Safety                   | Crews are at risk from angry landowners if rights are not maintained as they do not know if a right has expired on property with a difficult or new landowner | Certain to happen | Delays access, risks damage to BPA equipment from vandalism, possible bodily harm to staff or contractors. |

**Execution Constraints – Land Rights**

Scoping projects in advance of the acquisition projects provide an accurate scope of the work that is required. It is clear from the four scoping efforts completed, that there are significant tracts of land rights to acquire. Budget level estimates completed at the end of the scoping effort total \$7.6M and exceed the entire Land Sustain Program budget originally forecasted for FY2014. There are currently 35 more scoping projects identified and underway that will identify even more work to be completed. This will place additional pressure on already identified resource and funding capacity.

**2.4 Strategic Approach to Closing Gaps**

The following section describes the actions and analysis needed to implement the ROW Program’s strategic objectives.

**2.4.1 Strategic Approach**

**Overall ROW**

Integrating ROW Strategy – Linking the strategies

- Synchronized planning and scheduling of ROW work schedules with long-range plans for tribal renewals, line projects, vegetation management cycles, and access roads projects. (Transmission Asset Plan tool is facilitating this effort between Access Roads and Realty)
- Strategy components
  - ◆ Vegetation Management – Integrated Vegetation Management (IVM)
  - ◆ Access Roads – Proactive Asset Renewal

- ◆ Land Rights – Proactive
  - Support IVM strategy for vegetation management and proactive strategy for Access Roads
- Software solutions are being pursued to manage data
- The Wood and Steel Lines programs along with the ROW programs are being taken through the economic value modeling process in FY2014 to identify and evaluate strategy alternatives that incorporate the integration of the programs towards reducing total economic costs.

## **Vegetation - Control and Manage Vegetation**

### IVM (Integrated Vegetation Management)

IVM is a system of managing plant communities whereby managers set objectives, identify compatible and incompatible vegetation, consider action thresholds, and evaluate, select and implement the most appropriate control method or methods to achieve set objectives. The choice of control method or methods should be based on the environmental impact and anticipated effectiveness along with site characteristics, security, economics, current land use and other factors.

- Pros: Maximum efficiency in utilization of resources and budget dollars; lowest risk; costs based on desired results; supports demand planning; industry best management practice ANSI A300 (part 7); supports compliance with FAC-003-1
- Cons: Highest level of planning required; requires more advanced tools (data management and tracking tools); requires higher skill level employees (Utility Arboriculture knowledge)

### Components of IVM System

- Understanding the pest and ecosystem dynamics
- Setting management objectives and tolerance levels
- Compiling treatment options
- Accounting for economic and ecological effects of treatments
- Site – specific implementation of treatments
- Adaptive management and monitoring

## **Access Roads – Maintain and Improve Access Roads**

### Proactive Asset Renewal

A proactive strategy will be used to create healthy access road assets. The assets will be upgraded incrementally in a systematic and proactive manner driven by:

- Transmission Sustain priorities from Wood Lines, Steel Lines and portion of System Telecom programs,
- Environmental/Regulatory compliance, and
- District Operation and Maintenance standards.

Condition data on the transportation system will be collected based on priorities identified above. Conditions will be evaluated against the future state to determine the level of effort and cost to upgrade the transportation assets to meet the future state. This effort will provide a continuously updated health indicator for the transportation system as a whole, based on the real time condition data collected.

Concurrently, as capital investments upgrade the transportation asset, appropriate maintenance cycles will be evaluated and implemented to protect the capital investment based on life cycle costs. This will result in an incremental increase in expense funds directed at the transportation assets throughout the system.

The development of the Transmission Asset Plan (TAP) is facilitating good synchronization between AR, Land Rights, and the Wood and Steel Lines Programs, because it allows Program Managers to look across programs, review schedules, and update cost information essentially in real time.

### **Land Rights – Acquire and Manage Land Rights**

#### Proactive

Develop a long-term plan to meet program objectives / targets, which includes reducing backlogs. Use long-term asset plans from access roads, vegetation, and wood and steel lines to define workload for upcoming years. Prioritize needs for rights (alternative routes, risk of complaints/litigation/trespass violations, criticality of the line, tribal renewals).

- Pros: Know where all of the issues are across the system – comprehensive view; supports long term work and budget planning
- Cons: Cost and resource intensive

The Vegetation Mitigation Process in the Orchard Buy Back program will result in a Mitigation Action Plan which could result in:

- Entering into a new Vegetation Agreement or modifying an existing Vegetation Agreement (reducing height and/or changing species), would require the Land Management Case remain active.
- Raising towers, and entering into a new Vegetation Agreement or modifying an existing Agreement, would require the Land Management Case remain active.
- BPA purchasing the right to control vegetation within the rights-of-way and removing the vegetation, or any combination of the three actions, would allow the Land Management Case to be closed.

### 3.0 STRATEGY IMPLEMENTATION PLAN

#### 3.1 10 year Implementation Plan

##### Vegetation - Control and Manage Vegetation

10 Year Work Plan

| Program Category | Current Target | FY14   | FY15   | FY16   | FY17   | FY18   | FY19   | FY20   | FY21   | FY22   | FY23   | Total   |
|------------------|----------------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|---------|
| Veg Mgmt Acres   | 45,000         | 67,000 | 55,000 | 42,000 | 47,000 | 36,000 | 48,000 | 59,000 | 39,000 | 45,000 | 47,000 | 485,000 |

Target acres based on maintenance cycles, may be adjusted to meet changing conditions on the ROW

##### Access Roads – Maintain and Improve Access Roads

10 Year Work Plan

| Program Category  | Current Target | FY14 | FY15 | FY16 | FY17 | FY18 | FY19 | FY20 | FY21 | FY22 | FY23 | Total |
|-------------------|----------------|------|------|------|------|------|------|------|------|------|------|-------|
| AR Sustain Miles  | 180            | 135  | 179  | 180  | 161  | 183  | 190  | 204  | 206  | 210  | 222  | 1870  |
| AR Upgrades Miles | 70             | 50   | 21   | 44   | 89   | 89   | 104  | 109  | 109  | 113  | 119  | 847   |
| Total             | 250            | 185  | 200  | 224  | 250  | 272  | 294  | 313  | 315  | 323  | 341  | 2717  |

\*Future Target will be set as an output of the Total Economic Cost Strategy for ROW, Vegetation Management, AR, Wood and Steel Lines, and Land Rights

##### Land Rights – Acquire and Manage Land Rights

10 Year Work Plan

| Program Category  | Current Target | FY14 | FY15 | FY16 | FY17 | FY18 | FY19 | FY20 | FY21 | FY22 | FY23 | Total |
|-------------------|----------------|------|------|------|------|------|------|------|------|------|------|-------|
| Tribal            | As Needed      | 5    | 5    | 5    | 5    | 5    | 5    | 5    | 5    | 5    | 5    | 50    |
| Veg (Orchard BB)  | 20             | 20   | 25   | 33   | 20   | 20   | 20   | 20   | 0    | 0    | 0    | 158   |
| Land Acquisition  | As Needed      | 34   | 30   | 30   | 30   | 30   | 30   | 30   | 30   | 30   | 30   | 304   |
| Land Access Roads | As Needed      | 50   | 60   | 50   | 50   | 50   | 50   | 50   | 50   | 50   | 50   | 510   |
| Total             |                | 109  | 120  | 118  | 105  | 105  | 105  | 105  | 85   | 85   | 85   | 1,022 |

#### 3.2 Program Forecast Planning

##### Vegetation - Control and Manage Vegetation

###### Capital Forecast

Not applicable to the Vegetation Management Program

###### Expense Forecast

##### FY2014-FY2023 Expense Forecast - Vegetation Management

Nominal Dollars in '000

| Maintenance Program | FY14     | FY15     | FY16     | FY17     | FY18     | FY19     | FY20     | FY21     | FY22     | FY23     | Total     |
|---------------------|----------|----------|----------|----------|----------|----------|----------|----------|----------|----------|-----------|
| Vegetation Mgmt     | \$17,135 | \$17,471 | \$18,082 | \$18,715 | \$19,370 | \$20,048 | \$20,749 | \$21,476 | \$22,227 | \$23,005 | \$198,278 |

Drivers of change for Vegetation Management costs

- Vegetation Management service contracts being reduced over time due to
  - ◆ Conversion of corridors to low growing plant communities that require less costly maintenance
    - Moving from reclamation activities (Heavy equipment mowing, and tree removal) to a targeted herbicide application represents an 82% reduction in costs
    - Significant reduction in the amount of corrective maintenance required
  - ◆ Process efficiencies gained by transitioning from a highly reactive approach to predominantly planned, preventive maintenance
- Low growing plant communities reduce the time required to complete working patrols
  - ◆ Easier to access and observe conditions
  - ◆ Reduced number of items (Danger Brush / High Brush) to report
- Staffing levels right-sized
  - ◆ Reduced reclamation work scope, maintenance project size, and corrective maintenance will drive the reduced need for Natural Resource Specialist Staff
- Increase the VM program to integrate new data management tool
- Move Access Roads program from emergency repairs to programmatic scheduled preventative maintenance and corrective maintenance.
- Increase the Realty expense to accelerate the resolution of existing non-compliant orchards and tree agreements, this includes both the staff costs associated with negotiations and costs associated with buying back rights.
  - ◆ Increased pressure from WA Department of Natural Resources to subsidize maintenance costs (to State standards) on BPA use of roads on WA state lands (595 miles)

**Access Roads – Maintain and Improve Access Roads**

Capital Forecast

**FY2014-2023 Capital Forecast - Access Roads**

Direct Capital only, Nominal Dollars in '000

| Program Category   | FY14     | FY15     | FY16     | FY17     | FY18     | FY19     | FY20     | FY21     | FY22     | FY23     | Total            |
|--------------------|----------|----------|----------|----------|----------|----------|----------|----------|----------|----------|------------------|
| AR Sustain /Upgrds | \$15,000 | \$16,000 | \$18,000 | \$20,000 | \$22,500 | \$23,500 | \$25,000 | \$25,425 | \$25,857 | \$27,297 | <b>\$218,579</b> |

Capital Cost Estimate Assumptions:

- Access roads capital required for services reflects the growth of the internal and external design resources and external construction contracts.
- Out year projections are based on providing synchronized design and construction of AR to support wood and steel lines projects and stand-alone upgrade projects.
- Increased construction services costs for inspection in the wood pole replacements program is anticipated
- Capital estimate includes approximately \$2M each year for environmental support for upgrades and the wood and steel programs. These costs are currently being incurred by the ROW program. It is expected these costs will increase as the identification of work associated with environmental compliance becomes better known.
- The forecasts support wood and steel sustain programs as identified in the respective line sustain strategy in the years they are needed.

Expense Forecast

**FY2014-FY2023 Expense Forecast - ROW Maintenance (Land and Access Roads)**

Nominal Dollars in '000

| Maintenance Program | FY14    | FY15    | FY16    | FY17    | FY18    | FY19    | FY20     | FY21     | FY22     | FY23     | Total           |
|---------------------|---------|---------|---------|---------|---------|---------|----------|----------|----------|----------|-----------------|
| ROW Maintenance     | \$8,429 | \$8,597 | \$8,898 | \$9,210 | \$9,532 | \$9,866 | \$10,211 | \$10,568 | \$10,938 | \$11,321 | <b>\$97,342</b> |

**Land Rights – Acquire and Manage Land Rights**

Capital Forecast

**FY2014-2023 Capital Forecast – Land Rights**

Direct Capital only, Nominal Dollars in '000

| Program Category   | FY14    | FY15    | FY16    | FY17    | FY18    | FY19    | FY20    | FY21    | FY22    | FY23    | Total           |
|--------------------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|-----------------|
| LR Tribal Renewals | \$100   | \$500   | \$509   | \$517   | \$526   | \$535   | \$544   | \$553   | \$563   | \$572   | \$4,918         |
| LR Veg Mitigation  | \$900   | \$500   | \$509   | \$517   | \$526   | \$535   | \$544   | \$553   | \$      | \$      | \$4,584         |
| LR Access Roads    | \$5,042 | \$8,790 | \$6,761 | \$6,876 | \$6,993 | \$7,112 | \$7,233 | \$7,356 | \$7,481 | \$7,608 | \$71,249        |
| Total              | \$6,042 | \$9,790 | \$7,778 | \$7,910 | \$8,045 | \$8,181 | \$8,321 | \$8,462 | \$8,043 | \$8,180 | <b>\$80,751</b> |

Expense Forecast

**FY2014-FY2023 Expense Forecast - ROW Maintenance (Land and Access Roads)**

Nominal Dollars in '000

| Maintenance Program | FY14    | FY15    | FY16    | FY17    | FY18    | FY19    | FY20     | FY21     | FY22     | FY23     | Total           |
|---------------------|---------|---------|---------|---------|---------|---------|----------|----------|----------|----------|-----------------|
| ROW Maintenance     | \$8,429 | \$8,597 | \$8,898 | \$9,210 | \$9,532 | \$9,866 | \$10,211 | \$10,568 | \$10,938 | \$11,321 | <b>\$97,570</b> |

**Caveats**

*All expense forecasts are currently under review as part of the 2014 Integrated Program Review (IPR) process and will be updated in conjunction with the IPR timeline.*

# **WOOD POLE LINES PROGRAM**

## **SUSTAIN ASSET MANAGEMENT STRATEGY**

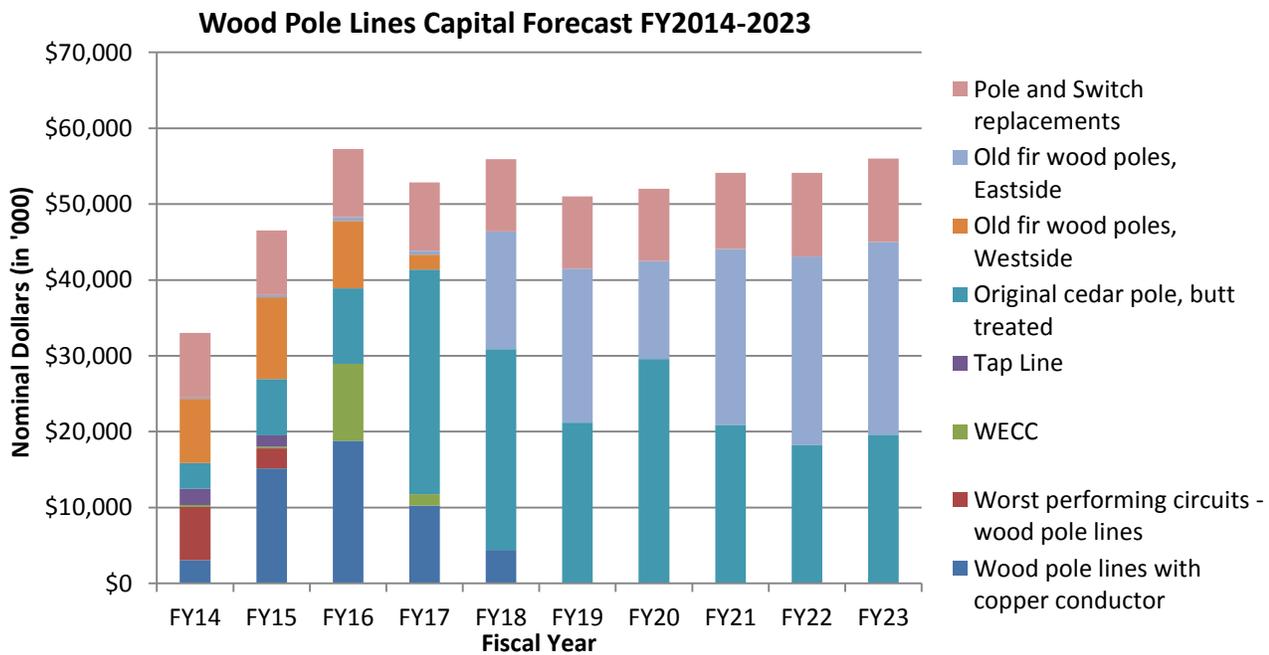
Rob Ochs, Program Manager  
December 2013

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## EXECUTIVE SUMMARY

### Wood lines program overview

- Covers 4,774 miles of wood pole transmission lines
- Assets:
  - ◆ Wood poles
  - ◆ Wood equivalent steel poles
  - ◆ Guy assemblies
  - ◆ Guy anchors
  - ◆ Cross arms
  - ◆ Cross braces
  - ◆ Insulator assemblies
  - ◆ Various types of conductor
  - ◆ Overhead ground wire
  - ◆ Fiber optic cable assemblies
  - ◆ Obstruction warning devices
  - ◆ Line disconnect switches
  - ◆ Various associated hardware.



### Key risks to be addressed

- Reliability risks from unplanned outages due to failed components
- Higher costs and inefficient practices of working on the same line multiple times for various replacements
- Risk to meeting availability targets due to wood pole asset replacement or maintenance
- Compliance risks and potential sanctions
- Safety risks to linemen and public

## Strategy Elements

The strategy for Wood lines has shifted from individual components of the line, like wood poles, to an Asset Lifecycle Strategy, which combines life extension and systematic replacement of aged, poorly performing wood pole lines. This strategy is based on a three year project schedule to better account for the time needed to complete all preliminary work such as land rights, environmental clearance, etc.

- The life extension portion of the program includes
  - ◆ Continuing the danger pole and priority pole replacement program.
  - ◆ Expanding the danger pole replacement work to include replacing all of the aged components on the structure, not just the wood poles.
- The systematic wood line replacement element of the sustain program places priority on rebuilding wood lines that are assessed as the worst performing, poorest condition, highest maintenance cost, and have significant safety risk to lineman and the public.

In the long run, this strategy will help:

- Decrease safety and liability risks associated with deteriorating components and abandoned wood pole lines
- Reduce the risk of unplanned outages due to component failures other than poles
- Address the growing backlog of lines well beyond their expected service life
- Increase efficiency in line work as result of replacing all components at the same time

## 1.0 STRATEGY BACKGROUND

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### 1.1. *Business Environment*

The asset management strategy for Bonneville Power Administration's (BPA's) wood pole transmission lines addresses 4,774 circuit miles of lines, located throughout the Pacific Northwest service area of Oregon, Washington, Idaho and Western Montana. There are approximately 336 individual transmission lines that are classified as wood pole lines (including tap lines, service lines, de-energized lines and leased lines) that BPA currently owns, operates and maintains. The wood pole transmission lines serve a variety of customers and system needs including the following:

- ◆ NW Utility Customers
- ◆ Regulatory Agencies: Western Electricity Coordinating Council (WECC), North American Electric Reliability Corporation (NERC), Federal Energy Regulatory Commission (FERC)
- ◆ Independent power producers, wind generation integration
- ◆ Tribes
- ◆ Private communication network service providers
- ◆ Extra regional customers
- Products and Services provided are
  - ◆ Network service
  - ◆ Generation integration
  - ◆ Point-to-point service
  - ◆ Intertie service
  - ◆ Communications services for operations of the transmission system and private networks.

## 1.2 Assets, Asset Systems and Criticality

### Program Profile:

BPA’s Wood Pole transmission lines make up approximately 1/3 of BPA’s 15,276 total circuit miles of transmission lines. The total wood line mileage is comprised of approximately 336 lines that vary from 200 feet to over 100 miles in length, and contain approximately 73,500 wood poles in 37,250 structures. These lines are located throughout BPA’s service area and are typically 115 and 230kV, with some 69, 138, and 161kV.

### Program Components Age:

Over 2,000 miles of BPA’s wood pole transmission lines were built in the late 1930’s through late 1950’s. The older wood lines are comprised of a variety of designs, legacy and obsolete components, wood species types, and a wide range of age and degree of deterioration.

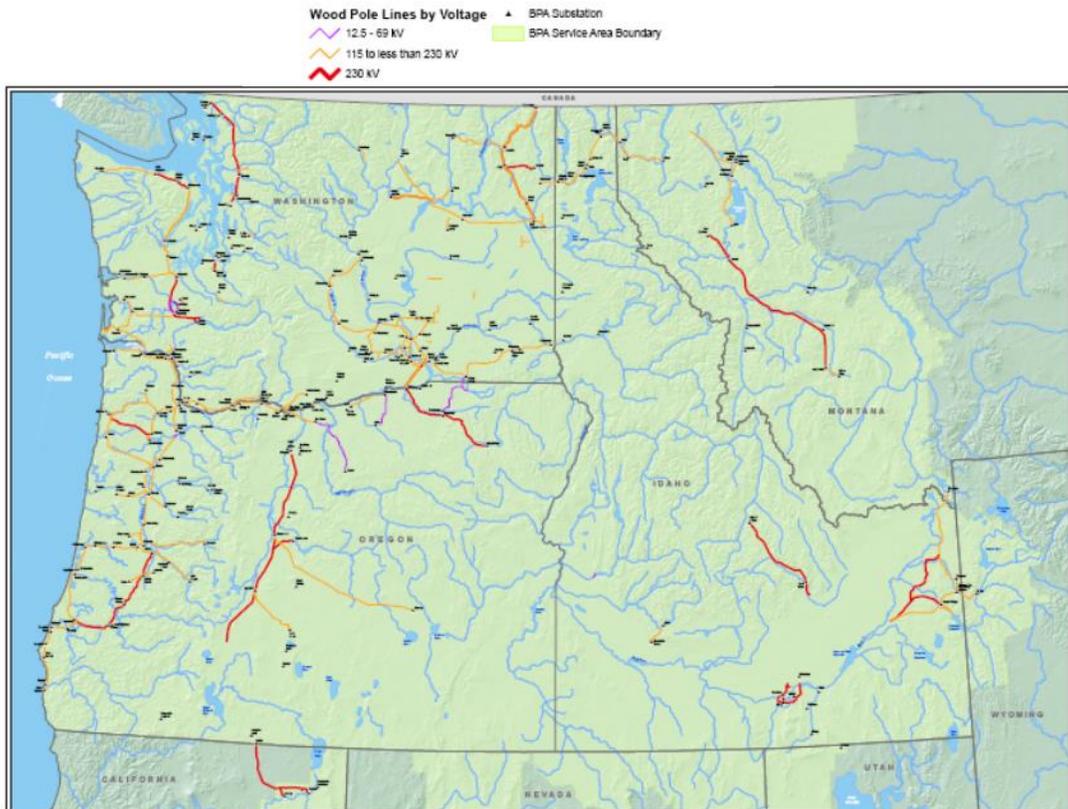
Wood Pole line assets consist of: All wood pole and light duty steel pole lines and line sections and all associated hardware and components:

| Assets   | Description  |
|--|--|
| Wood Poles   | Treated Cedar or Fir, primary structure component in support for overhead conductors   |
| Light Duty (wood equivalent) Steel Poles                       | Galvanized or Weathering steel poles sized similarly to comparable wood poles  |
| Guying systems: guy anchors, rods, guy strands, guy insulators | Provide strength needed to support conductor loads on angle and dead-end structures  |
| Cross Arms   | Wood or steel crossing member of a wood pole structure that supports the insulators for the conductor                                      |
| Cross Braces   | Wood or steel brace installed between poles to strengthen a structure  |
| Conductor Insulator Assemblies & associated hardware           | Insulator string (ceramic, glass, polymer), suspension shoes, armor rod, vibration dampers, jumpers and jumper attachment hardware, shunts |
| Ground Wire and associated hardware                            | Protective wire strung above conductors to shield them from lightning and fiber optic cable assemblies                                     |
| Fiber optic cable assemblies                                   | Hardware to attach fiber optic cable to structures   |
| Conductor  | Numerous all aluminum, aluminum with steel reinforcing core, and copper  |
| Obstruction Marking: Airway Lighting, Marker Balls             | Devices installed according to FAA regulations to designate flight hazards   |
| Line Disconnect Switches                                       | Manually or motor operated switch for changing connections in a circuit or isolating a circuit from the source of power                    |

Wood Pole line asset systems consist of:

- Network significant equipment transmission lines
- Generation interties
- Key points of interconnection with many of BPA’s customers

## BPA Wood Pole Transmission Lines



### Wood Pole Line Criticality and Prioritization

- About 40% of the wood pole transmission lines are identified as significant equipment in the BPA Operating Bulletin No. 19
- The wood pole transmission lines are primarily of importance rank 3 and 4, with some of the 230kV wood lines ranked as importance 2
- The operation and maintenance of BPA’s wood pole transmission lines are subject to a number of regulatory compliances and agencies, including FERC, NERC, and WECC
- Line criticality will be refined over time using Transmission’s evolving project prioritization and line criticality criterion, along with the Total Economic Cost Model currently being developed

A more comprehensive database on component condition is being amassed as part of the Transmission Asset System (TAS) lines effort. In the meantime, wood pole condition, outage history, and TLM observations is the basis for prioritizing work efforts. Currently, the Wood Line Sustain program, along with the Steel Line and Rights-of-Way sustain programs are undergoing the evaluation of risk-informed strategic alternatives, based on total economic cost. This effort will take most of FY2014 to complete, but will provide additional guidance in the criticality and prioritization of projects.

### Classification of Wood Lines

To facilitate strategy development and establishing priorities around inspection, test and treat, replacement and rebuild, these lines were grouped based on line components, age and condition as follows:

| Grouping Name                         | Definition   |
|---------------------------------------|--|
| Lines 20 to 40 years old              | Transmission lines that are 20 to 40 years of age with majority of components in good to excellent condition. No known performance issue with the line.  |
| Rebuilt Wood Pole lines <20 years old | Transmission lines that are no older than 20 years of age and are meeting performance objectives   |
| Original cedar pole, butt treated     | Transmission lines with a large percentage of wood poles that exceed 55 years of age and are original cedar, butt treated  |
| Old Fir Wood Poles, Westside          | Transmission lines located east of the Cascades with a large percentage of wood poles that exceed 45 years of age and are old fir, butt treated  |
| Old Fir Wood Poles, Eastside          | Transmission lines located west of the cascades with a large percentage of wood poles that exceed 45 years of age and are old fir, butt treated  |
| Steel lines with wood poles           | Transmission lines that predominately have steel structures supporting conductor, high voltage (230, 345 and 500kV), and have a few wood poles in certain locations along the line to support the conductor. |
| Wood pole lines with copper conductor | Transmission lines with any type of wood pole but have some portion or all of the line consist of copper conductor   |
| Worst Performing Circuits             | Transmission lines that have been assessed through actual performance and condition assessments by SME's to pose an unacceptable risk of component failures and sustained unplanned outages.                 |
| Other                                 | Other includes lines with fewer than 50 wood poles, short segments, tie lines, service lines and taps. These lines could have any species of wood pole, including old fir and original cedar.                |

**Line-Wood Pole Groupings**

The following table provides line miles and number of wood poles for each of the groupings as of September 2013.

| <b>Transmission-Wood Pole Line Classifications</b>     | <b>Line Miles</b> | <b>Number of Wood Poles</b> |
|--|-------------------|-----------------------------|
| Wood Pole Lines 20 to 40 Years old                     | 1,300             | 19,000                      |
| Rebuilt wood pole lines <20 Yrs                        | 586               | 8,893                       |
| Original cedar pole, butt treated                      | 1,137             | 17,672                      |
| Old fir wood poles, Westside                           | 288               | 4,462                       |
| Old fir wood poles, Eastside                           | 338               | 5,400                       |
| Steel lines with wood poles                            | NA                | 1,800                       |
| Wood pole lines with copper conductor                  | 463               | 7,180                       |
| Worst performing circuits - wood pole lines            | 209               | 2,755                       |
| Other Wood Pole Lines - service lines, PSC, taps, etc. | 454               | 6,418                       |
| <b>Total</b>   | <b>4,775</b>      | <b>73,580</b>               |

**2.0 THE STRATEGY**

**2.1 Current State**

Over 2,000 miles (40%) of the wood pole lines are over 50 years old; average expected life of a wood pole transmission line is approximately 60 years. On average, approximately 1/3 of the wood poles on lines over 50 years of age have been replaced at some point in time, but the other line components are original vintage and reaching end-of-service-life condition.

**2.1.1 Program Accomplishments to Date**

Since early 2010, BPA's Line crews have replaced a total of 3,818 wood poles as part of the life extension portion of this strategy, 1,278 poles in FY2010, 852 poles in FY2011, 899 in FY2012, and 789 in FY2013. This represents replacing approximately 1,900 wood pole structures. The transition from single pole replacements to complete structure rebuilds resulted in an initial decline in the total number of poles replaced per year. The current rate should remain fairly steady, but may change upon the completion and implementation of the total economic cost modeling effort.

The systematic replacement portion of the program has been implemented with a total of 23 Wood Pole line rebuild projects initiated to date. As of the end of September 2013, nine projects have been completed, totaling 290 miles of wood pole transmission lines that have been rebuilt. Many of these projects are contracted out via the Contract Management Office (CMO).

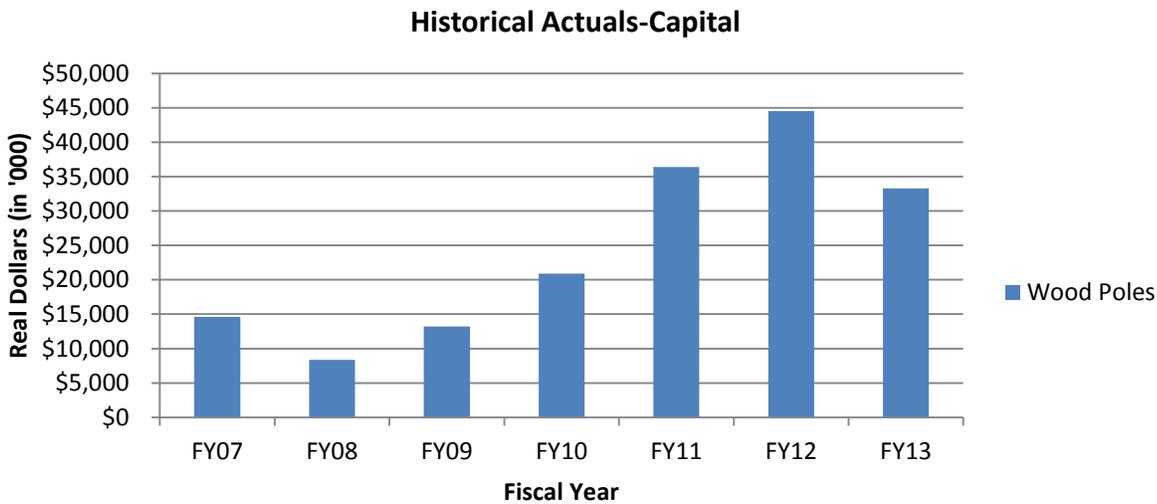
Line Rebuild Project specific status is as follows:

1. Chehalis-Raymond No. 1 (Chehalis-PeEll section, 18.4 miles) – (CMO) The design was completed during winter and spring of 2010 and construction took place over the summer and fall of 2010.
2. Albany-Eugene No. 1 (30.9 miles) – (CMO) The design is complete, and the project is currently under construction. Construction is expected to be completed in November 2012.
3. Bandon-Rogue No. 1 (46 miles) – (CMO) The design was completed in FY2010-2011, and the project is completed as of end of calendar year 2011.
4. Walla Walla-Tucannon River No. 1 (46.7 miles) – (CMO) The design was completed during FY2010-2011. Construction is completed and the rebuilt line was energized on November 1, 2011.
5. Colville-Republic No. 1 (Colville-Kettle Falls Tap section, 13.2 miles) – (CMO) The design was started and completed in FY2011. Construction started on August 15, 2011, and was completed on November 08, 2011. The remaining 31 miles of this line is a radial feed to the town of Republic that is being rebuilt by the Bell TLM crew. The crew has been rebuilding 6 to 8 miles per year, and is expected to complete the project by 2015.
6. Alvey-Fairview No. 1 (97.4 miles) – (CMO) The design was started in FY2011 and construction was included in the 2012 IPR forecast for FY2013 and FY2014, but has been delayed to FY2014 and FY2015 due to land and environmental compliance issues.
7. Creston-Bell No. 1 (53.8 miles) – (CMO) The design was completed in FY2011. The construction was completed and the line was re-energized in November 2012.
8. Midway-Benton No. 1 (28.8 miles) – (CMO) Design work was completed. BPA negotiated with the tribes and DOE to relocate the line to avoid sacred areas. Construction was completed and the line was re-energized in June of 2013.
9. Cardwell-Cowlitz No. 1 (7.7 miles) – (CMO) The design was completed in FY2011, and the project was completed by calendar year end 2011.
10. Benton-Othello No. 1 (11.0 miles) – (CMO) The design was completed in FY2012. The construction was completed and the line was re-energized in April 2013.
11. Keeler-Forest Grove No. 1 (10.5 miles) – (CMO) The design is complete, construction has been delayed to FY2014 due to land and environmental compliance issues.
12. Forest Grove-Tillamook No. 1 (47.4 miles) – (CMO) The design is complete, construction has been delayed to FY2014 due to land and environmental compliance issues.
13. Salem-Albany No. 1 (23.9 miles) – (CMO) The design is underway with construction scheduled for FY2016.
14. Salem-Albany No. 2 (27.9 miles) – (CMO) The design is underway, with construction scheduled for FY2015.
15. Palisades-Swan Valley No. 1 (12.4 miles) – (CMO) The design is underway, with construction scheduled for FY2014.
16. Maupin-Tygh Valley No. 1 (3.2 miles) – (BPA) Design in underway, with construction scheduled for FY2014.
17. Grand Coulee-Creston No. 1 (28.3 miles) – (CMO) The design is underway, with construction scheduled for FY2015.
18. Midway-Moxee No. 1 (34.0 miles) – (CMO) The design is underway, construction is being delayed in order to bundle the construction with expansion work on Midway-Grandview No. 1 due to Tribal concerns.
19. Cowlitz Tap to Chehalis-Covington No. 1 (6.3 miles) – (CMO) The design is underway, construction is scheduled for FY2014.
20. Kalispell-Kerr No. 1 (41.4 miles) – (BPA) The design is just starting, with construction scheduled for FY2016.

- 21. Vera Tap to Trentwood-Valley Way (3.8 miles) – (BPA) The design is underway, with construction scheduled for FY2015.
- 22. Lane-Wendson No. 1 (41.3 miles) – (CMO) The design is underway, with construction scheduled over two construction seasons in FY2016-2017.
- 23. Hills Creek-Lookout Point No. 1 (24.8 miles) – (CMO) The design is just getting started, with construction scheduled for FY2016.

The FY2010-2013 program targeted rebuilding 420 miles of line or more by the end of FY2013. As of September 30, 2013, the systematic replacement portion of the program rebuilt 290 miles of line (4250 poles). The life extension portion of the strategy has replaced over 3,818 poles under the priority pole replacement program, which includes replacing all of the danger poles in accordance with the BPA work standards and regulatory requirements. By the end of this construction season, the program will have removed over 110 miles of obsolete copper conductor. The sustain program is meeting its intended objective, however the execution rate of the line rebuild projects is a little behind schedule due to the program initially being planned around the assumption of a two year project schedule.

### 2.1.2 Cost History

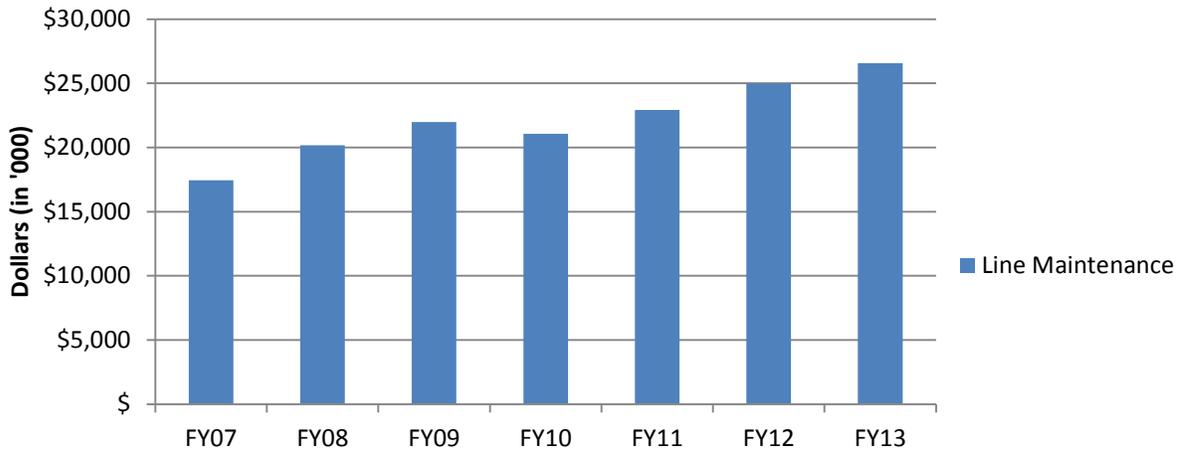


#### Historical Actuals - Capital

Dollars in '000

| Capital Program      | FY07     | FY08    | FY09     | FY10     | FY11     | FY12     | FY13     | Total     |
|----------------------|----------|---------|----------|----------|----------|----------|----------|-----------|
| Wood Poles - sustain | \$14,616 | \$8,382 | \$13,196 | \$20,912 | \$36,391 | \$44,516 | \$33,282 | \$171,295 |

**Lines\* Historical Actuals - Expense**



\*This chart represents expense historical actual for the Line Maintenance Program, which includes Wood Pole Line maintenance.

**Historical Actuals - Expense**

Dollars in '000

| Maintenance Program | FY07     | FY08     | FY09     | FY10     | FY11     | FY12     | FY13     | Total     |
|---------------------|----------|----------|----------|----------|----------|----------|----------|-----------|
| Line Maintenance    | \$17,442 | \$20,182 | \$21,983 | \$21,076 | \$22,921 | \$24,984 | \$26,572 | \$155,159 |

A major component of this expense is labor hours to inspect and maintain lines. Costs exclude right-of-way maintenance, access roads and vegetation management.

Wood pole maintenance costs vary greatly by line

- Wood pole lines in relatively poor condition cost more to maintain than wood pole lines that are new and in good condition. Maintenance cost per mile varies greatly. Here are some selected examples:

**Sample of Annual Maintenance Costs by Line**

| Adno | Line Name                       | Op Kv | Circuit Miles | Pole Count | FY 2004 | FY 2005 | FY 2006 | FY 2007 | FY 2008 | FY 2009 | FY 2010 | FY 2011 | Total Cost | Average Cost per Mile |
|------|---------------------------------|-------|---------------|------------|---------|---------|---------|---------|---------|---------|---------|---------|------------|-----------------------|
| 7410 | BANDON-ROGUE NO 1               | 115   | 46            | 597        | 14,069  | 13,789  | 17,253  | 18,230  | 22,422  | 20,348  | 23,433  | 21,909  | 151,453    | 3,292                 |
| 9210 | BENTON-FRANKLIN NO 1            | 115   | 21            | 305        | 2,215   | 1,989   | 3,142   | 2,638   | 3,975   | 2,110   | 4,093   | 3,760   | 23,921     | 1,137                 |
| 9211 | BENTON-FRANKLIN NO 2            | 115   | 21            | 298        | 2,638   | 1,889   | 10,502  | 50,147  | 7,717   | 2,531   | 5,039   | 2,360   | 82,803     | 3,937                 |
| 7140 | ALLSTON-ASTORIA NO 1            | 115   | 41            | 560        | 10,554  | 159     | 38,382  | 7,210   | 42,187  | 53,438  | 39,126  | 30,808  | 221,864    | 5,369                 |
| 7305 | ALBANY-EUGENE NO 1              | 115   | 40            | 688        | 68,923  | 38,904  | 34,854  | 22,895  | 26,974  | 28,203  | 13,468  | 11,447  | 245,498    | 6,167                 |
| 6104 | ALBENI FALLS-SAND CREEK NO 1    | 115   | 30            | 601        | 10,019  | 5,445   | 11,261  | 27,973  | 9,896   | 27,110  | 15,461  | 27,439  | 134,606    | 4,537                 |
| 6136 | COLVILLE-REPUBLIC NO 1          | 115   | 44            | 728        | 14,129  | 35,535  | 29,292  | 35,488  | 41,860  | 28,539  | 15,578  | 19,404  | 219,835    | 4,943                 |
| 7236 | KEELER-TILLAMOOK NO 1           | 115   | 58            | 988        | 36,067  | 24,677  | 35,723  | 30,435  | 64,303  | 61,346  | 51,289  | 59,456  | 363,295    | 6,284                 |
| 9290 | WALLA-WALLA-TUCANNON RIVER NO 1 | 115   | 48            | 646        | 24,140  | 37,857  | 48,369  | 14,716  | 19,675  | 13,390  | 13,798  | 7,010   | 178,956    | 3,720                 |

- Maintenance savings can be achieved by keeping wood pole transmission lines in good condition, but that alone doesn't justify a complete rebuild of a wood pole transmission line. Safety and performance of the line also needs to be a consideration.

**2.1.3 Health of Current Assets (Current Condition & Performance)**

As with all of the sustain programs, asset health is the driver for the wood lines sustain program. When addressing asset health concerns on the wood lines, system expansion needs are considered and addressed when possible.

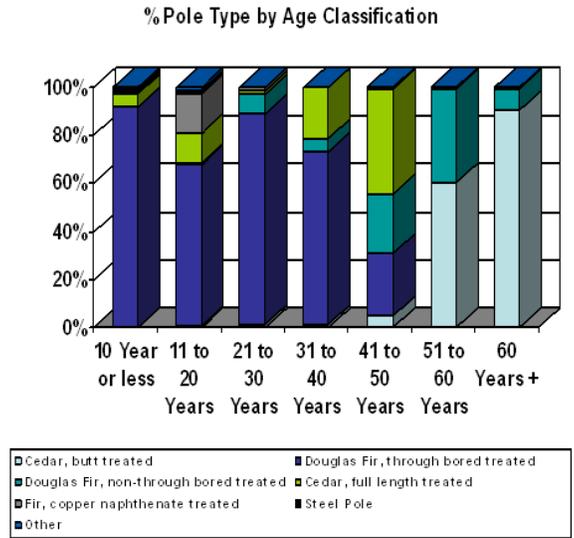
Overall performance of these lines has been acceptable, but performance risks are increasing as they continue to age and deteriorate

- Oldest lines typically have the original hardware, insulators, guying and counterpoise in place and condition of these assets in many cases is unknown
- Over 500 miles of lines have obsolete copper conductor that is difficult to repair and replace once it fails
- Approximately 18,000 wood poles are classified for priority replacement due to condition and/or age
- According to the BPA Aging Asset Report of 2007, the 115-161kV significant equipment system was rated as Fair to Impaired overall, with the lines essentially evenly split between Good, Fair, and Poor asset health due primarily to wood pole replacement issues. For the significant 230kV lines, 6% were rated as Poor, mainly due to the backlog of wood poles that have reached the end of their service life. The overall asset health assessment for the 115kV and 69kV grid was rated impaired, with the primary degradation driver being wood poles requiring replacement. The overall asset health assessment for the 230kV grid was rated fine, with the primary degradation driver being wood poles requiring replacement. Other degradation drivers which keep downward pressure on the health demographics of the wood pole transmission system include insulators, dampers, and connectors.

Wood poles are the only component of the wood lines for which the asset condition has been consistently assessed. Information on other line components including hardware, insulators, guying and counterpoise is lacking and antidotal at best. Other line components that are identified during patrols as posing a risk to the structure or transmission system are noted in the TLM Apps data base, and brought to the attention of transmission engineering. The current data base has extremely limited sort and filter capabilities for these notes making them difficult to identify and manage at a later date. This issue is being addressed by the expansion of the Transmission Asset System (TAS) which will allow the collection and data management of asset health for lines.

#### Wood pole condition assessment

- Approximately 73,250 wood poles on 4,775 miles of wood pole transmission lines
- Expected service life of 60 years
- 13% of wood poles exceed 60 years of age (over 9,508 poles). This is an increase from 2 years ago. Older poles tend to be butt treated cedar. The condition of these poles is identified as “sound” in the TLM apps database, but a lab study indicated that these poles are subject to strength loss with age due to sap wood weathering, creating some uncertainty as to their reliability.
- Pole strength and capability declines with age
- Loss of 1/3 of original strength = need to replace-pole; no longer meets standards.
- As of the end of FY2013, a total of approximately 9,350 wood poles have been replaced on the BPA system as part of the Wood Pole Lines sustain program.



**Wood poles in the highest risk condition**

- Approximately 25% (17,947) of the wood poles are classified for priority replacement.
- Danger poles, classified in priority 1, must be replaced within 12 months after being classified as a danger pole.
- The majority, 15,606, are classified as priority 5, which is based on age – Original Cedar 55 years or older and Original Fir, 45 years or older.
- Issue: Uncertainty on actual condition of priority 5 poles. If not replaced, some of these may become future danger poles and have to be replaced within 12 months.

| Replacement Priority as of October 2013 |               |
|---|---------------|
| Priority – Type of Poles                | Pole Count    |
| Priority 1 – Danger Poles               | 498           |
| Priority 2 – Danger Pole Candidates     | 562           |
| Priority 3 – Evaluated                  | 359           |
| Priority 4 – Minor Decay                | 922           |
| Priority 5 – OC Sound                   | 9,355         |
| Priority 5 – OF-45                      | 6,251         |
| <b>TOTAL</b>                            | <b>17,947</b> |

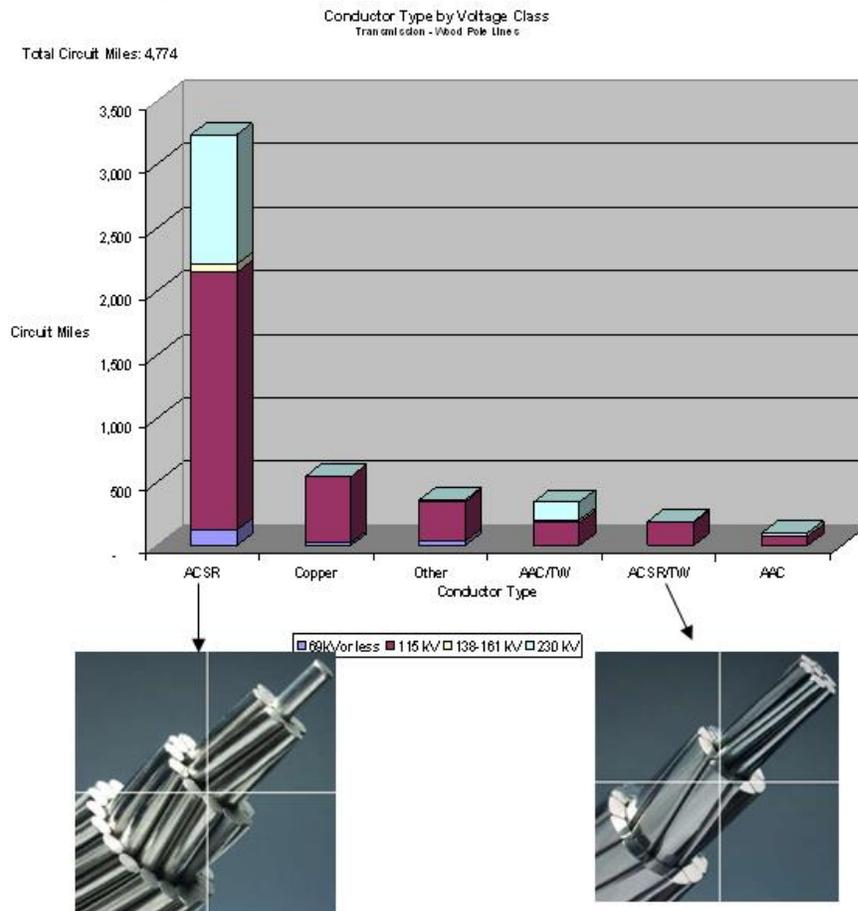
**Wood Line Forced Outage History**

- Wood Pole Transmission Line System Performance
  - ◆ Forced outages caused by line material failure: such as conductor, insulator, pole, other structure failure
  - ◆ Wood lines with majority of wood poles original cedar, butt treated and lines with copper conductor have almost 90% of the forced outage minutes and represent about 40% of line miles. The System Automatic Interruption Duration Index (SAIDI) represents the total duration of unplanned outages (in minutes) per line per year.
    - For example, over the 10 year period of 2002-2011, there were 21 forced outages totaling over 21,000 minutes due to failures on wood poles lines with copper conductor

- To address the aging asset issue, planned line outages went up significantly in FY2010 and 2011 for critical maintenance work and line rebuild/construction.
- Prior to FY2010, the majority of the planned outages were for maintenance type activities. With the plan to rebuild approximately 100 to 150 miles of wood lines each year BPA expects this trend will level off starting in 2014 and remain fairly level until the need for line rebuild activity declines.

Conductor condition assessment

- For all transmission lines, the type and vintage of conductor is known, but lack adequate condition assessments.
- Various retired line components are collected and tested in the BPA lab to identify component issues and establish base-line and benchmarking data. This data is currently available for limited components. The TAS system will provide consistent data collection for all components of concern. This data along with the total economic cost model will provide better information for adjusting the future pace and priority of line rebuild and component replacement activities.
- Based on current progress of TAS for lines, the system will be available to go live in 2014, and data collection and system verification will begin.



**2.2 Future State**

The vision for the wood lines sustain program is to restore the health of the wood lines transmission system to a state of long-term functionality and reliability and establish a proactive and economical strategy for assessing, tracking and mitigating the aging wood line assets over time.

2.2.1 Key asset performance objectives, measures and targets

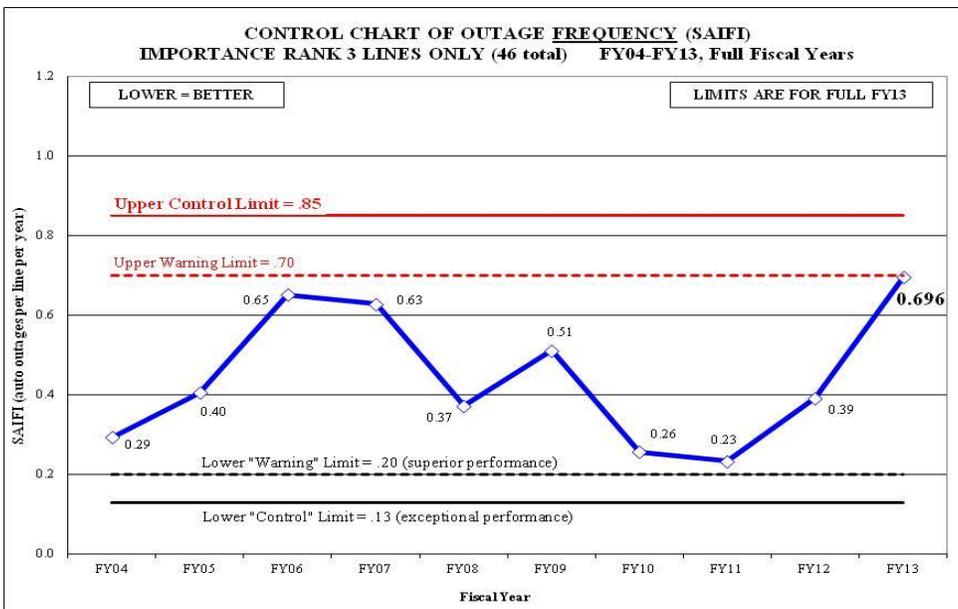
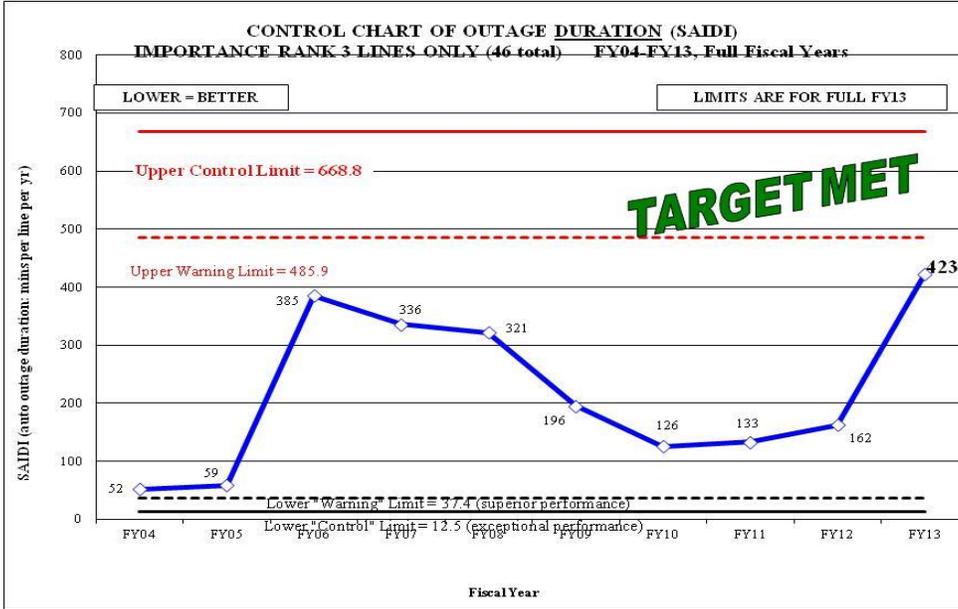
| Category     | Performance Objective   | Measure  | End Stage Target   |
|--------------|---|--|--|
| Reliability  | Frequency of Planned Outages - Minimize the number of unplanned transmission line outages on the most critical wood pole transmission lines (categories 1 through 4, 1 being most critical).    | System Average Interruption Frequency Index (SAIFI) – average number of automatic outages by BPA Line Category   | Control Chart violation per year: No more than 1 control chart violation per year for Wood Pole Transmission classified lines (typically line importance categories 3 and 4).  |
|              | Duration of Unplanned Outages - Minimize the duration of unplanned transmission line outages on the most critical wood pole transmission lines (categories 1 through 4, 1 being most critical). | System Average Interruption Duration Index (SAIDI) – average number of automatic outage minutes by BPA Line Category   | Control Chart violation per year: - No more than 1 control chart violation per year for wood pole transmission classified lines (typically line importance categories 3 and 4).  |
| Availability | Optimize availability of service from BPA’s wood transmission lines.  | Line availability percentage (includes planned and unplanned outages)  | BPA’s most important transmission lines (Category 1 and 2) are available for service at least 97.39% of the time.<br>BPA’s next most important transmission lines (Category 3 and 4, and generally primarily wood pole structure type) are available for service at least (X) percent of the time. No percentage has been established for this target. |
| Compliance   | Maintain and inspect wood pole transmission lines in accordance with NERC/WECC requirements.  | Transmission Maintenance & Inspection Plan (TMIP) is reviewed and revised annually; Wood pole lines are maintained in accordance with the TMIP; Maintenance records are maintained as required by the TMIP | No instance that BPA wood pole line maintenance & inspection practices fail to comply with NERC/WECC standard PRC-STD-005-1  |
| Safety       | No public safety event or injuries caused by failing wood pole structures or wood line components.  | Number of fatalities or injuries caused by failing wood pole structures or wood line components  | No BPA or contracted employee fatalities or injuries caused by failing wood pole structures or wood line components.   |

The control charts for the category 3 and 4 lines show that BPA is meeting the compliance objective, but the category 3 lines show an increasing trend to approaching the upper control limits for both SAIDI and SAIFI. The spike in FY2013 is primarily the result of a storm related unplanned outage in November and December on the Forest Grove-Tillamook No. 1 line. It should be noted that the design for this line rebuild project started in FY2011 and is currently scheduled for construction in FY2014.

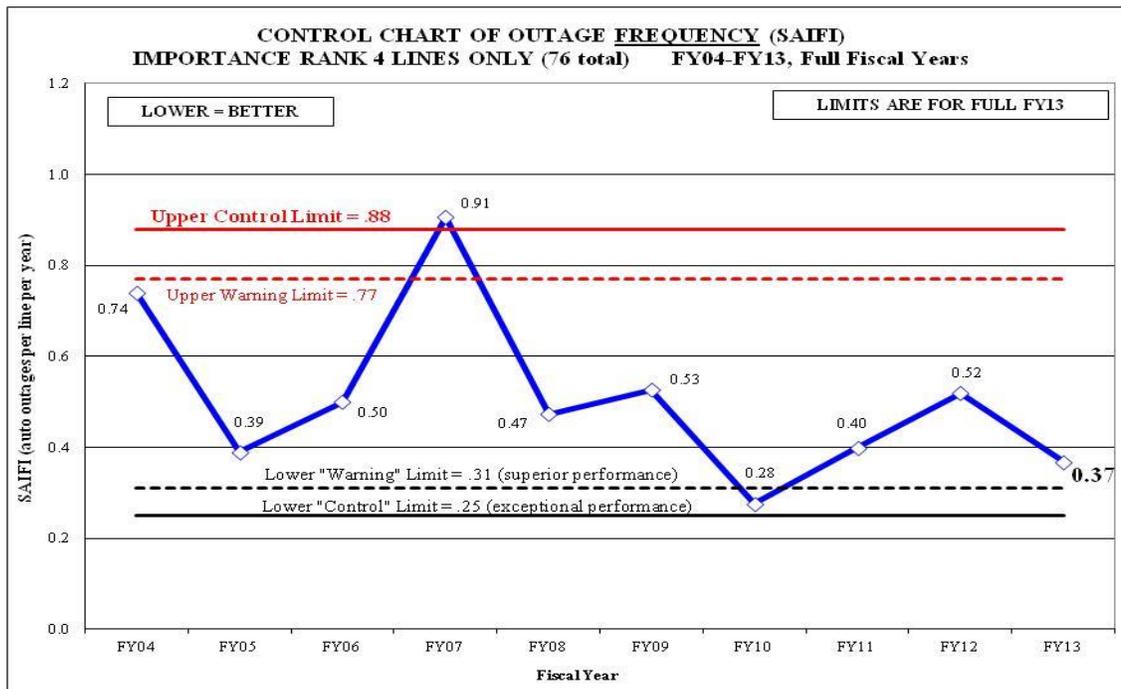
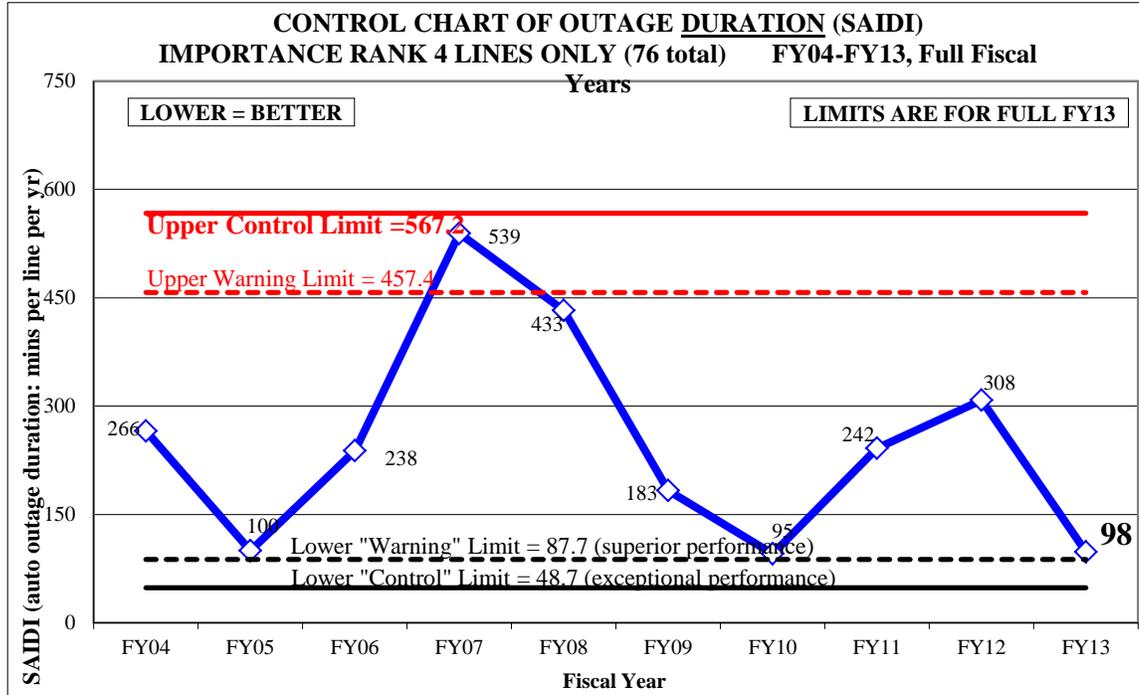
For both SAIFI and SAIDI, a control chart violation is defined as follows:

- Latest fiscal year above the Upper Control Limit (short-term degradation)
- 2 of last 3 fiscal years above the Upper Warning Limit (mid-term degradation)
- Continuous worsening trend in the last six fiscal years (long-term degradation)

**Control Charts - Line Importance 3**



**Control Charts – Line Importance 4**



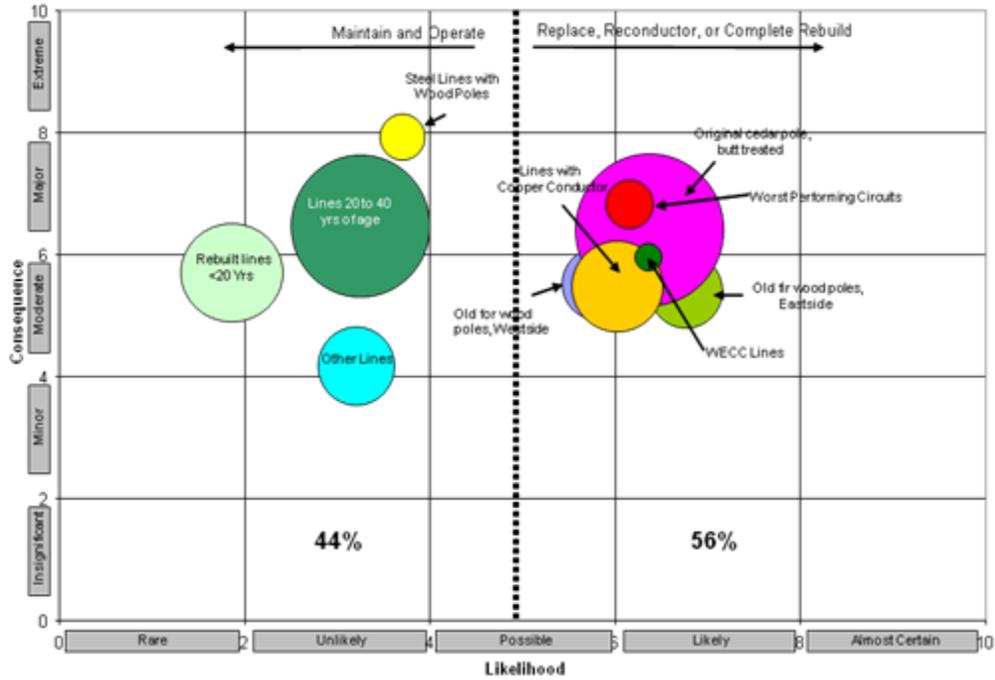
### 2.3 Asset Condition/Performance Gaps

The wood pole transmission lines are “linear assets,” made up of a series of structures, which consist of many components, which support the conductor that transmits the power. The failure of any one structure or individual component can result in a line outage, or failure of the line asset. The probability of failure for a wood line asset depends on the condition of the asset and the historical performance of its components, and the population of components in a compromised condition. For example, a line with a high percentage of poles prioritized for replacement is more likely to experience an outage than a line with few or no poles prioritized for replacement. In the same manner, a line with obsolete or older components is more likely to experience an outage than a line comprised of newer or standard components. The line groupings identified in section 1.2, grouped the wood lines by line components, age, and condition. Based on historical component performance, a probability of failure scale was developed. *(See Appendix B)*

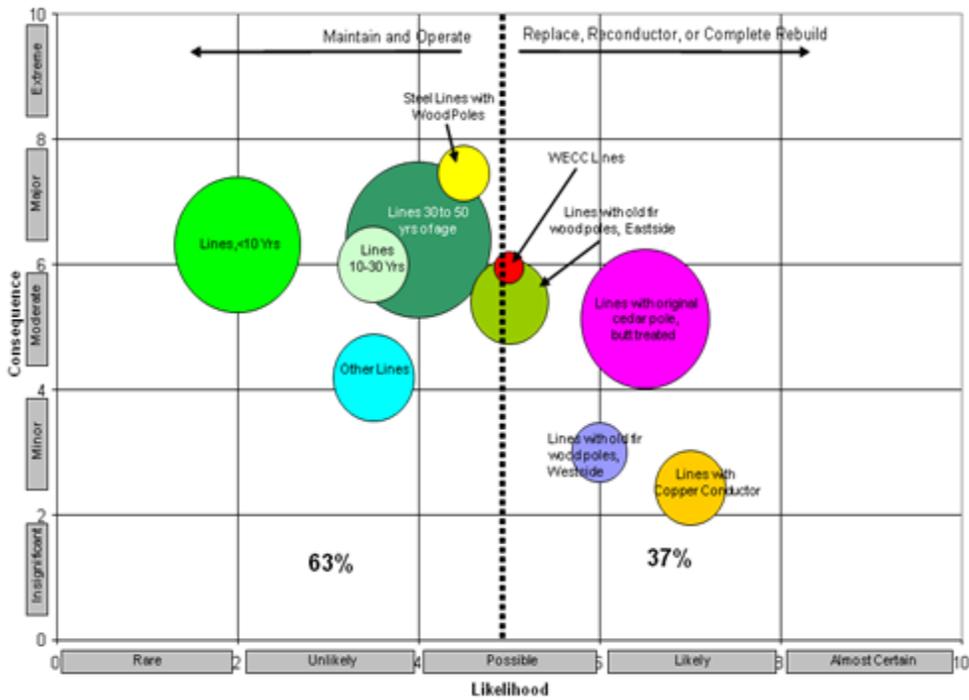
The consequence of a wood line failure is a measure of the impact of a transmission line outage and is based on the line rating, priority ranking, and number of taps on the line. This information was used to develop a consequence scale for the wood lines. *(See Appendix C)*

This information was used to develop the risk map which gives a graphical representation of the overall risk presented by the population of line groupings. As can be seen in the current state risk map, there is a fairly well defined space between the cluster of bubbles on the right side of the map and the remaining bubbles on the left side of the map. The line groups on the left side of the risk map are considered to be in good health and will remain in a status of operate and maintain. The line groups on the right side of the map are of greater concern, and are candidates for rebuilding, based on their individual health and performance history.

**Current State Risk Map (FY2014)**  
 (Bubble size represents volume of poles in each grouping)



**Future State Risk Map (FY2023)**  
 (Bubble size represents volume of poles in each grouping)



Under the current program strategy, the wood lines are performing at an acceptable level overall and meeting their performance objectives with no SAIDI/SAIFI control chart violations. Several line rebuild projects have been completed, reducing the population of lines in the groupings on the right side of the map, and the life extension portion of the strategy (priority pole replacements) are keeping the line groupings out of the “almost certain” likelihood of failure category.

### 2.3.1 Risks to meeting the objectives

- **Transmission Reliability Performance Objective:** Minimize the number of unplanned transmission line outages on the most critical wood pole transmission lines.
  - ◆ **Risk:** Components (conductor, wood structure, insulator, or hardware) that have reached the end of their service life begin to fail and continue to fail at increasing numbers, resulting in an increased likelihood of unplanned outages.
  - ◆ **Likelihood:** Possible to Likely. A number of components fail due to a variety of causes on the wood transmission lines every year.
  - ◆ **Consequence:** Moderate to Major as frequency of failures increase.
    - In small or irregular instances it is inconsequential but in the case of a radial feed line it could result in customers going dark for a short period of time until crews can be dispatched to restore service.
    - Reliability of the operating line will decrease
    - SAIFI and SAIDI end-stage targets will increasingly not be met
    - Failing components could result in extended line outages
    - Station equipment will experience increased duty with increasing automatic outages
    - Staff will be diverted from implementing planned program work
  - ◆ **Mitigation:** The aging component issue is being addressed under the priority pole replacement program, but this is still primarily driven by the wood pole condition. The program is currently engaged in an effort to more accurately determine the health of overhead assets and at the same time replace the most likely candidates for near term failure.
  
- **Transmission Availability Performance Objective:** Ensure BPA’s wood pole transmission lines meet availability targets.
  - ◆ **Risk:** The anticipated increase of transmission line maintenance and replacement work will lead to an increasing frequency of planned outages resulting in decreased transmission line availability.
  - ◆ **Likelihood:** Likely. Currently encountering planned outage restrictions that limit the amount of work that can be completed on certain lines every year. Without a systematic approach to preemptive replacement, the failure rate will likely be unmanageable from a maintenance perspective.
  - ◆ **Consequence:** Significant
    - Maintenance backlog will increase to an unsustainable level.
    - A lack of planned outage availability for required replacement work could result in future unplanned outages resulting in poorer reliability as well as availability.
    - Performing repairs under emergency conditions will be less economical than scheduled replacements.
  - ◆ **Mitigation:** The aging component issue is being addressed under the priority pole replacement program, but this is still primarily driven by the wood pole condition. In addition, the wood line rebuild portion of the program is focused on replacing the lines in poorest health. Once a line rebuild project is complete, it requires very little, if any maintenance other than patrols for 20 years.
  
- **Transmission Compliance Performance Objective:** Inspect, and maintain the wood transmission lines in accordance with NERC and WECC requirements
  - ◆

- ◆ **Risk:** Being found out of compliance with NERC/WECC standard PRC-STD-005-1 through self report or during NERC/WECC audit leads to mandatory emergency remediation with possible financial penalties that result in increased expense costs and loss of reputation.
  - ◆ **Likelihood:** Low
    - BPA currently has a TMIP in place,
    - Maintenance is performed in accordance with the TMIP
    - Maintenance records are maintained as required by this Standard
  - ◆ **Consequence:** Moderate – There are possible fines for non-compliance and BPA could be ordered to take expensive corrective actions within a short time frame.
  - ◆ **Mitigation:** BPA currently maintains inspection and maintenance history for the wood pole transmission lines in the TLM Apps data base. The TAS lines system will greatly facilitate compliance.
- **Transmission Safety Performance Objective:** Maintained and operated the wood pole transmission lines in a way that limits risk to health and safety of maintenance employees and the public.
    - ◆ **Risk:** Age-related deterioration of a wood pole structure or line component results in a failure during maintenance activities, storm events, etc, leading to injury or death.
    - ◆ **Likelihood:** Low. Wood poles and line hardware are usually replaced before they get in a condition that would pose a safety hazard to employees and the public.
    - ◆ **Consequence:** Significant – Potential injury or loss of human life
    - ◆ **Mitigation:** Safety is the most compelling driver. When there is a safety concern about a specific line or component, replacing it becomes a high priority for the Sustain program and for TEL.

The strategy for wood lines, as well as steel, includes improvements in asset information, e.g., component condition, line performance and cost.

#### Execution constraints

There are gaps that have been encountered in the execution of the strategy which pose additional risks to meeting the programs strategic objectives. The gap and approach to mitigating the issue are as follows:

- **Gap:** Minor resource constraints in completing priority pole replacements has the potential to become a problem if a large increase in the amount of required annual priority pole replacement work is encountered.
  - ◆ **Mitigation:** Continue use of the CMO for large projects to reduce the demand on BPA internal engineering resources, and work with the contracting office to supplement engineering staff with A&E contractors. Contract out priority pole replacement work on lines with large quantities of work. In addition, consider bundling lines with smaller quantities or priority pole replacements into one contract where feasible.
- **Gap:** Delays in completing priority pole replacement work due to outage availability will become a greater problem if the amount of line rebuild work and /or priority pole replacement work is ramped up.
  - ◆ **Mitigation:** Coordinate with operations as early as possible, and have alternate work available in the event of a cancelation. Take advantage of other scheduled outages when possible. Continue to develop Live Line maintenance resources.
- **Gap:** Delays in the execution of rebuild projects due to land acquisitions not being completed on schedule.
  - ◆ **Mitigation:** Utilize the project schedule information in the Transmission Asset Plan (TAP) system and initiate land rights reviews earlier in the process.

- **Gap:** Delays in execution of rebuild projects due to the Environmental Process (NEPA) not being completed on schedule. Delays can be experienced in the process from both internal and external (outside agencies) sources.
  - ◆ **Mitigation:** Utilize the project schedule information in TAP and initiate NEPA process and cultural surveys earlier in the process. Make sure that outside entities have adequate time to fulfill their environmental review requirements.
- **Gap:** Last minute deliveries on long lead time materials have the potential for delaying projects.
  - ◆ **Mitigation:** Utilize long term material forecasts to provide early identification of future material demands. Continue working closely with BPA's Supply Chain organization and hold quarterly material summits. Continue to explore the use of commercial off-the-shelf items by adopting industry standards where practical.
- **Gap:** While near term (5 to 8 years) line rebuild project priorities are clearly evident, there is some uncertainty in identifying long term program requirements in terms of volume and location of work.
  - ◆ **Mitigation:** Complete the development of the TAS system and ensure that sustain program critical data is captured during inspections and is adequate and available to Program Managers and the Reliability Centered Maintenance group.

## 2.4 Strategic Approach to Closing Gaps

Prior to the development of the Wood Pole Sustain Program, the former wood pole replacement program focused on replacing poles in the 60 year age range that were compromised by rot or another form of physical damage. It was recognized that this approach did not address the entire problem. BPA had made a significant investment in some lines, and they were still experiencing repeated planned and unplanned outages resulting from line component failures and maintenance issues. Continuing this strategy would have eventually posed a significant risk to the reliability and availability of the wood pole transmission system.

The current sustain program is an Asset Lifecycle Strategy, which combines life extension and systematic replacement of the worst performing and highest consequence of failure for existing lines assets. The life extension portion of the strategy consists primarily of the priority pole replacement work. The work is identified by the pole inspection data stored in the Transmission Line Maintenance Applications (TLM Apps) database. When an old wood pole structure is identified as having a pole prioritized for replacement, the entire structure is rebuilt, eliminating the need to make repetitive trips to the same structure year after year to address maintenance issues. The systematic replacement portion of the program now feasibly reflects rebuilding approximately 100 miles of wood pole transmission lines per year. The lines to be rebuilt are selected based on their overall health condition (TLM Apps data), performance (outage history) and criticality.

### 2.4.1 Strategic Approach

The Asset Lifecycle Strategy consists of systematic replacement of aging line assets that pose an unacceptable risk to meeting the key asset performance objectives. The asset replacement program evolved from a wood pole condition-centric program to a comprehensive approach that considers line criticality, line performance, and health of additional wood line components. The strategic approach involves:

- **Priority Pole Replacements.** When poles fail to meet the required strength and their condition has deteriorated to the point that it poses a risk to individual component failure, i.e. classified as a danger pole, then these poles are scheduled for replacement within 12 months.

- **Full Transmission Line Rebuilds.** When the overall condition and performance of a line deteriorates to the point that it poses an unacceptable risk to meeting asset objectives, the lines is targeted for future replacement. The targeted transmission lines are then prioritized for replacement based on condition, performance, line importance rating, and criticality.
- **Timely and comprehensive line inspections.** Line working patrols are conducted annually on all transmission lines. Working patrols are conducted per the BPA Transmission Line Maintenance standards and guidelines. TLM standards and guides are being updated to include the gathering of additional component inspection data in support of the TAS system.
- **Managing backlog of line conditions.** Proactively manage backlog of conditions (problems) found through working patrols and logged for later repair or replacement. To date, conditions that have been identified and are being addressed include:
  - ◆ Poor cross arm replacements
  - ◆ Stubbed pole replacements
  - ◆ Compromised cross braces and guy assemblies
- **Replacement of obsolete components.** Take advantage of opportunities to replace obsolete components with standard components in conjunction with other scheduled work and replacement opportunities are taken advantage of.
- **Standardization of replacement components.** Standardization of structures, conductor, insulators and other components when rebuilding. Utilizing standard components improves ability to maintain stocking levels and facilitates faster restoration of service in the event of an unplanned outage.
- **Utilize Owner/Engineers.** Design work for line rebuild projects will be contracted to Owners/ Engineers when the workload for design exceeds what can be done with BPA design resources.
- **Contract construction of line rebuild projects.** With the exception of small rebuild jobs, most of this work will be performed by contractors utilizing PC contracts where feasible.
- **Identify additional asset health data needs and develop a short term process to collect, store and analyze the data.**
  - ◆ A short-term, limited component effort plan was developed to address critical data gaps around crossarms and stubbed poles. The effort to expand this process to collect additional component data was cut short as resources were directed to focus on completing the TAS system for line assets.
- **Develop a long-term plan for collecting asset condition assessment data for all line components.** The Sustain Program Managers are working closely with the TAS development team and the Transmission Line Design Data (TLDD) database stewards to ensure that the program needs are met. The initial field trial is complete, and user comments are being incorporated for the next release.
- **Fiber optic cable replacement and maintenance.** In conjunction with partial and major line rebuild projects, fiber optic cable, if present, will be evaluated and assessed for replacement.
- **Retirement of old assets.** Abandoned wood pole lines pose a safety and liability risk. These lines present a maintenance responsibility that is an expense to BPA. Abandon wood pole lines will be retired and removed, materials will be recycled if possible, and disposed of properly.

### 3.0 STRATEGY IMPLEMENTATION PLAN

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The strategy implementation plan for the wood lines sustain program involves rebuilding approximately 100 miles of transmission lines (3 to 4 individual lines) per year under the systematic replacement portion of the program, and completing all of the priority pole replacements under the life extension portion of the program (approximately 400 structures). Variations in the miles of line rebuilt each year are a result of the actual line lengths that are identified for replacement. Similarly, the number of priority pole structure replacements varies per year as a result of prior year pole inspections. The danger pole structures must be completed, but the volume of additional structure

replacements must be balanced with other component replacement and maintenance needs, and available resources.

### 3.1 10 year Implementation Plan

#### 10 Year Implementation Plan

| Miles rebuilt/line grouping                   | FY14        | FY15         | FY16         | FY17         | FY18         | FY19         | FY20         | FY21         | FY22         | FY23         |
|---|-------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| <b>LINE REBUILD PROJECTS</b>                  |             |              |              |              |              |              |              |              |              |              |
| Wood pole lines w/ copper conductor           | 2.0         | 39.1         | 56.2         | 41.0         | 21.0         | 0.0          | 0.0          | 0.0          | 0.0          | 0.0          |
| Worst performing circuits                     | 32.8        | 25.0         | 0.0          | 0.0          | 0.0          | 0.0          | 0.0          | 0.0          | 0.0          | 0.0          |
| WECC  | 0.0         | 0.0          | 25.0         | 16.4         | 0.0          | 0.0          | 0.0          | 0.0          | 0.0          | 0.0          |
| Tap Line                                      | 3.3         | 6.8          | 0.0          | 0.0          | 0.0          | 0.0          | 0.0          | 0.0          | 0.0          | 0.0          |
| Orig. cedar pole, butt treated                | 0.0         | 21.0         | 32.8         | 62.4         | 0.0          | 66.8         | 76.6         | 0.0          | 66.0         | 66.0         |
| Old fir wood poles, Westside                  | 25.0        | 52.0         | 34.8         | 10.0         | 96.8         | 0.0          | 0.0          | 58.0         | 0.0          | 0.0          |
| Old fir wood poles, Eastside                  | 0.0         | 12.4         | 0.0          | 0.0          | 40.0         | 45.0         | 42.8         | 65.0         | 70.0         | 70.0         |
| <b>Total miles rebuilt</b>                    | <b>63.1</b> | <b>156.3</b> | <b>148.8</b> | <b>129.8</b> | <b>157.8</b> | <b>111.8</b> | <b>119.4</b> | <b>123.0</b> | <b>136.0</b> | <b>136.0</b> |
| <b>POLES/STRUCTURES REPLACED BY TLM CREWS</b> |             |              |              |              |              |              |              |              |              |              |
| Switch replacements                           | 4           | 4            | 4            | 4            | 4            | 4            | 4            | 4            | 4            | 4            |
| Priority Pole Structure Replmt's              | 400         | 400          | 450          | 450          | 500          | 500          | 500          | 550          | 650          | 650          |

The current implementation plan shows a fairly substantial variance in the amount of line rebuild work completed per year during the FY2014 through FY2018 period. Many of the projects in this time frame are currently underway, and the implementation plans represents the most up-to-date project schedule information. Projects were initially scheduled out at a fairly consistent level, but the construction phase of some of the individual projects has been delayed one or two years due to land acquisition for off right-of-way access roads and the NEPA and Cultural Resource compliance process. Here are a few key points to keep in mind when reviewing the implementation plan:

- Construction work that has been delayed a year or two ultimately falls in a year with other projects that are on schedule. The result is an increase in the miles of line constructed in the out year, and a decrease in the miles of line constructed in the current year.
- The implementation plan is based on BPA’s fiscal year, so the miles of transmission line rebuild work completed at the end of a construction season (October and November) are reported in the following fiscal year.
- Large projects like Alvey-Fairview (97 miles) are typically scheduled over a two year period, and the miles of line completed are influenced by the ability to sectionalize the line, and not split 50/50.

These factors account for the jump in miles of line rebuilt between FY2014 and FY2015-2018. The program is expected to be in a more steady state from FY2019 on, with slight increases in mileage and priority pole structure replacements.

### 3.2 Program Forecast Planning

#### FY2014-2023 Capital Forecast

Direct Capital only, Nominal Dollars in '000

| Group   | FY14            | FY15            | FY16            | FY17            | FY18            | FY19            | FY20            | FY21            | FY22            | FY23            |
|---|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|
| <b>LINE REBUILD PROJECTS</b>                  |                 |                 |                 |                 |                 |                 |                 |                 |                 |                 |
| Wood pole lines with copper conductor         | \$3,060         | \$15,140        | \$18,790        | \$10,250        | \$4,400         | \$0             | \$0             | \$0             | \$0             | \$0             |
| Worst performing circuits - wood pole lines   | \$7,010         | \$2,670         | \$0             | \$0             | \$0             | \$0             | \$0             | \$0             | \$0             | \$0             |
| WECC  | \$270           | \$190           | \$10,140        | \$1,500         | \$0             | \$0             | \$0             | \$0             | \$0             | \$0             |
| Tap Line                                      | \$2,110         | \$1,520         | \$40            | \$0             | \$0             | \$0             | \$0             | \$0             | \$0             | \$0             |
| Original cedar pole, butt treated             | \$3,400         | \$7,400         | \$9,900         | \$29,600        | \$26,500        | \$21,200        | \$29,600        | \$20,900        | \$18,200        | \$19,600        |
| Old fir wood poles, Westside                  | \$8,500         | \$10,800        | \$8,900         | \$2,000         | \$0             | \$0             | \$0             | \$0             | \$0             | \$0             |
| Old fir wood poles, Eastside                  | \$170           | \$300           | \$500           | \$500           | \$15,500        | \$20,300        | \$12,900        | \$23,200        | \$24,900        | \$25,400        |
| <b>Total</b>                                  | <b>\$24,520</b> | <b>\$38,020</b> | <b>\$48,270</b> | <b>\$43,850</b> | <b>\$46,400</b> | <b>\$41,500</b> | <b>\$42,500</b> | <b>\$44,100</b> | <b>\$43,100</b> | <b>\$45,000</b> |
| <b>POLES/STRUCTURES REPLACED BY TLM CREWS</b> |                 |                 |                 |                 |                 |                 |                 |                 |                 |                 |
| Pole and Switch replacements                  | \$8,500         | \$8,500         | \$9,000         | \$9,000         | \$9,500         | \$9,500         | \$9,500         | \$10,000        | \$11,000        | \$11,000        |
| <b>PROGRAM TOTAL</b>                          | <b>\$33,020</b> | <b>\$46,520</b> | <b>\$57,270</b> | <b>\$52,850</b> | <b>\$55,900</b> | <b>\$51,000</b> | <b>\$52,000</b> | <b>\$54,100</b> | <b>\$54,100</b> | <b>\$56,000</b> |

The program shows some significant variations in the required budget from year to year. This is the result of several factors encountered primarily in the execution of the line rebuild projects.

- The size and total cost of line rebuild projects are a direct function of the length of the individual lines. An effort is made to evenly spread the work across the years as lines are prioritized and selected for replacement, but they never total up to the same distance every year. This results in an irregular distribution of required funding from year to year.
- The construction phase of a line rebuild project typically accounts for 80% of the total project budget. Even after implementing a 3 year project schedule, delays in the construction phase of multiple projects have been experienced. This pushes the construction phase and majority of the forecasted budget out of the current year and into later years, which fall on top of other projects currently in flight and scheduled for construction in the same year.
- Large projects like Alvey-Fairview (97 miles) have to be constructed over a two year period, and the location of the dividing point is outage driven and determined by substation or tap locations. These locations are not centered in the line, so the forecasted spend is not split evenly. This adds to the variation in budget from year to year.

#### FY2014-FY2023 Expense Forecast – Transmission Line Maintenance (Includes Wood Pole Lines and Steel Lines)

Nominal Dollars in '000

| Maintenance Program     | FY14     | FY15     | FY16     | FY17     | FY18     | FY19     | FY20     | FY21     | FY22     | FY23     | Total            |
|-------------------------|----------|----------|----------|----------|----------|----------|----------|----------|----------|----------|------------------|
| Transmisn Line Maintnce | \$26,361 | \$26,820 | \$27,758 | \$28,730 | \$29,735 | \$30,776 | \$31,853 | \$32,968 | \$34,122 | \$35,316 | <b>\$304,440</b> |

#### Caveats

Forecast is currently under review as part of the 2014 Integrated Program Review (IPR) process and will be updated in conjunction with the IPR timeline.

# **STEEL LINES**

## **SUSTAIN ASSET MANAGEMENT STRATEGY**

Corinn Castro, Program Manager  
December 2013

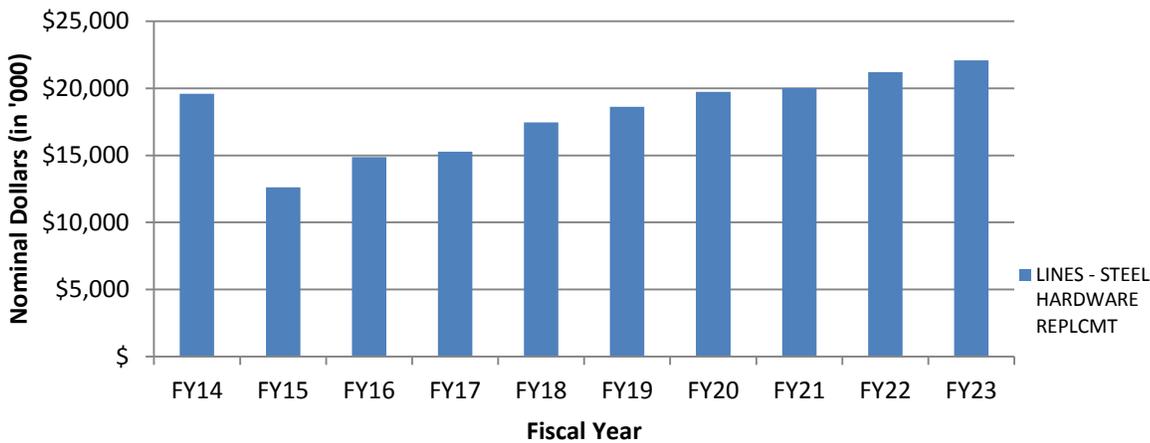
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## EXECUTIVE SUMMARY

### Steel lines program overview

- Over 10,300 circuit miles on approximately 43,500 steel and aluminum lattice towers, steel lattice poles and engineered steel poles.
- Assets:
  - ◆ Lattice Steel and Engineered Steel pole transmission lines and all associated towers, hardware and components

**Steel Lines Capital Forecast FY2014-2023**



### Key risks to be addressed

- Components which are approaching or have reached their end-of-life begin to fail and continue to fail in increasing numbers, resulting in an increased likelihood of unplanned outages
- The anticipated increase of replacement work will lead to an increasing frequency of planned outages resulting in decreased transmission line availability
- Being found out of compliance with NERC/WECC standard PRC-STD-005-1 through self report or during NERC/WECC audit leads to mandatory emergency remediation with possible financial penalties that results in increased expense costs and loss of reputation
- Age-related deterioration of line components results in component failure during maintenance activities, storm events etc., leading to injury or death

### Strategy Elements

- Standard metrics for collecting and retaining asset condition data, granular enough to: 1) identify condition trends, 2) target and pace replacement efforts, 3) manage components over time, and 4) better predict remaining service life.
- A standardized process for sampling and testing retired components, analyzing results and drawing conclusions that will assist in pacing and targeting the replacement strategies.
- A long term strategy for evaluating and mitigating the risks associated with a continuously aging asset.
- Adequate data quality and reporting in TAS and TLDD (Transmission Line Design Data) to serve in effectively tracking and evaluating the overhead asset.
- Document and continually share lessons learned so that every cost-effective effort is made to ensure that new projects are assembled with the best chance for a long and reliable service life.

- Standardize components and appropriately incorporate technology innovations into replacement efforts.

In the long run, this strategy helps:

- Restore the health of all overhead transmission system components to a state of long-term functionality and reliability while instituting a proactive, economical, and dynamic strategy for tracking, assessing and mitigating its aging overhead asset over time
- BPA continue to fulfill its commitment to the region to provide an adequate, economical, safe and reliable power supply

## 1.0 STRATEGY BACKGROUND

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### 1.1. *Business Environment*

#### Products and Services

- Network service
- Generation integration
- Point to Point Service
- Intertie Service
- Communications services for operations of the transmission system and private networks.

#### Customers and Stakeholders Served

- NW Utility Customers
- Regulatory Agencies: WECC, NERC, FERC
- Independent Power Producers, wind generation integration
- Tribes
- Private communication network service providers
- Extra Regional Customers

### 1.2 *Assets, Asset Systems and Criticality*

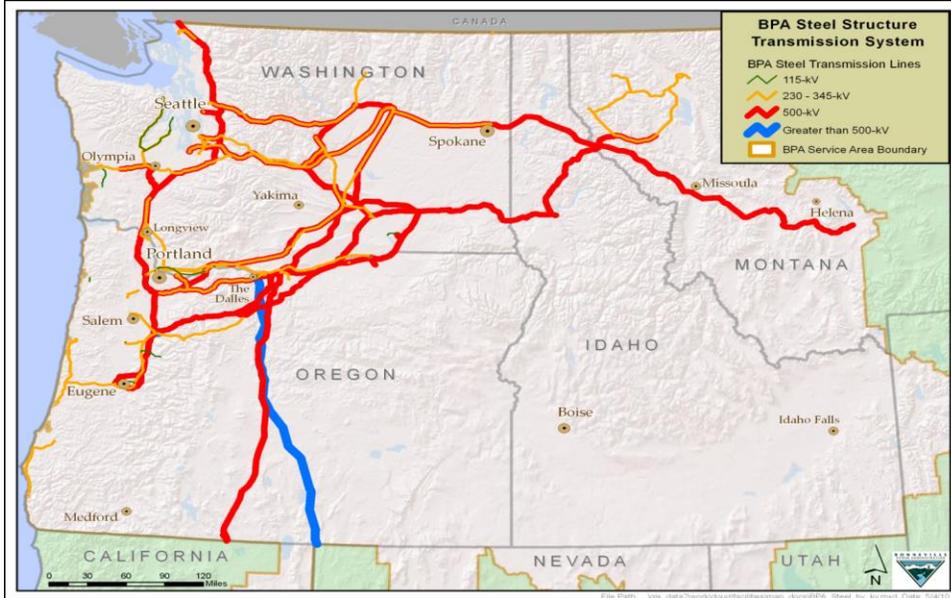
BPA's Steel transmission lines consists of about 10,300 circuit miles on approximately 43,500 steel and aluminum lattice towers, steel lattice poles and engineered steel poles. This includes the Direct Current intertie (~260 circuit miles,) all of the 500kV grid (~4670 circuit miles including the AC interties,) along with about 80 percent of the 230-345kV system (~4900 circuit miles) and about 13 percent of the 115kV system (~470 circuit miles).

**Steel lines assets consist of:** All lattice steel and aluminum and engineered pole lines and line sections and all associated hardware and components.

- Lattice Towers
- Lattice Poles
- Engineered Steel Poles
- Footings: concrete pier, rock, grillage, plate, pile
- Guying Systems: guy anchors, rods, guy strands, guy insulators
- Conductor: numerous all aluminum, aluminum with steel core, and copper conductor
- Insulator assemblies and hardware: insulator string (ceramic, glass, polymer), suspension shoes, armor rod, dampers, jumper assemblies, shunts
- Spacers and Spacer Dampers
- Ground Wire and Associated Hardware
- Obstruction Marking: airway lighting, marker balls

**Steel line asset systems consist of:**

- Network critical transmission lines
- Interties
- Key points of interconnection with many of BPA’s load serving wholesale full and partial requirements customers



**Line Criticality and Prioritization**

A combination of the following will be used to determine the likelihood, magnitude and consequence of a line outage for purposes of assessing risk and prioritizing lines for sustain program work.

- 500kV and 230kV steel lines are of importance rank 1: main grid lines many of which are on the critical outage list and 2: secondary grid and powerhouse lines. 115kV steel lines are mostly of importance rank 3: radial feed and some generation integration or 4: lower voltage lines with parallel service routes.
- Line criticality and how it will be used in prioritizing line sections for sustain work will be refined over time using Transmission's project prioritization and line criticality criteria.
- Currently line age, outage history, and Transmission Line Maintenance (TLM) observation is being used as the basis for characterizing condition and the primary basis for initiating sustain work. This will be improved upon when the TAS database for lines components is completed and information resulting from retired component testing efforts is collected.

**2.0 THE STRATEGY**

**2.1 Current State**

- Line segments for refurbishment are selected based on TLM observation, line criticality, and theoretically based expectations about component aging.
- Discoveries of severe conductor damage on Grand Coulee-Bell No. 3 during insulator replacement resulted in re-scoping the project to a full line reconductor which began in fall of 2012. This line was not damped for vibration.

- A sampling of retired components from all component replacement projects are sent to BPA’s Mechanical lab for analysis. The results are documented and will eventually serve to refine life expectancy predictions, better target high risk lines and appropriately pace the program.
- Development of a corrosion mitigation strategy began in FY2013 and a corrosion mitigation program will be launched in FY2014.
- 14 projects to mitigate structures identified as distressed either due to impact damage or slope/bank instability were completed since FY2012.
- The first projects to mitigate for unplanned outages due to bird dung contamination were implemented.
- Engineering driven expense projects that fall under the Steel Line sustain program are being identified and estimated in order to budget for this aspect of the sustain effort.
- Currently, the Steel Line sustain program, along with the Wood Line and Rights-of-way sustain programs are undergoing the evaluation of risk-informed strategic alternatives based on total economic cost. This effort will take most of FY2014 to complete. Until a new strategic approach is selected using this method, the program strategy remains unchanged from 2012.

**2.1.1 Program Accomplishments to Date**

The Sustain Steel program completed 193 miles of program work in FY2013 for a FY2011-13 cumulative total of 382 (159% of the three year program period goal of 240 miles.) The next program period of FY2014-15 has just over 300 miles of Sustain Steel Program work planned.

The FY2008-12 spacer damper replacement program has a cumulative mileage completed of 4170 miles. This program was scheduled for completion in FY2012, however, due to weather caused delays and cancelations, there remains approximately 30 miles to complete in FY2014.

The Spacer Damper re-replacement program (FY2012-14) to replace defective material installed under the FY2008-12 spacer damper program is on track for a cumulative FY2012-13 total of 1150 miles, with about 386 total miles remaining.

**Sustain Steel Historical Actual Miles**

| <b>Component Category</b>     | <b>FY11</b> | <b>FY12</b> | <b>FY13</b> |
|-------------------------------|-------------|-------------|-------------|
| Insulator Assemblies          | 95          | 68          | 62.5        |
| Conductor/Groundwire          | 0           | 22          | 127.5       |
| Corrosion Capital             | 0           | 0           | 0           |
| Misc. Capital                 | 4           | 2           | 3.5         |
| <b>Total Miles</b>            | <b>99</b>   | <b>92</b>   | <b>193</b>  |
| <b>Spacer Damper Program</b>  |             |             |             |
| <b>Spacers/Spacer Dampers</b> | <b>FY11</b> | <b>FY12</b> | <b>FY13</b> |
| Spacers/Spacer Dampers        | 607         | 150         | 52          |
| Defective Spacer              | N/A         | 711         | 439         |

**Performance targets that drive this strategy**

Reliability: Outage frequency SAIFI (System Automatic Interruption Frequency Index [number of unplanned outages per line per year]) and duration SAIDI (System Automatic Interruption Duration Index [total duration of unplanned outages per line per year]) for transmission lines, by line importance rank, do not exceed control chart violation limits of zero control chart violations for line categories 1&2 and no more than 1 violation per year for line categories 3&4.

Availability: Minimize planned outages on the system’s most important lines (ranks 1&2) such that Availability does not fall below violation limits. Target was 98% per year for line categories 1&2.

| Fiscal Year | Line Importance Rank | Number of Lines | Status                           | Comments  |
|-------------|----------------------|-----------------|----------------------------------|---|
| FY13        | 1                    | 127             | SAIFI & SAIDI Targets <b>MET</b> | Outage frequency targets (SAIFI) for all line importance ranks were met for the fiscal year. Lines of Rank 3 finished very close to the "Warning Zone", while Lines of Rank 4 finished very close to the "Superior Performance" zone.   |
|             | 2                    | 100             | SAIFI & SAIDI Targets <b>MET</b> |   |
|             | 3                    | 46              | SAIFI & SAIDI Targets <b>MET</b> |   |
|             | 4                    | 76              | SAIFI & SAIDI Targets <b>MET</b> |   |
|             | 1&2                  | 227             | Availability <b>NOT Met</b>      | AVAILABILITY of BPA's "most important" (rank 1 & 2) lines ended FY 2013 at 97.98 %, just missing the 98.00 % threshold, and thus is recorded as "target not met". A very active construction season in late summer/early fall led to a higher-than-recent-average rate of Construction outages. This complemented an already somewhat higher-than-average rate of planned outages earlier in the fiscal year, and moved this measure below the target control limit for the full fiscal year. |

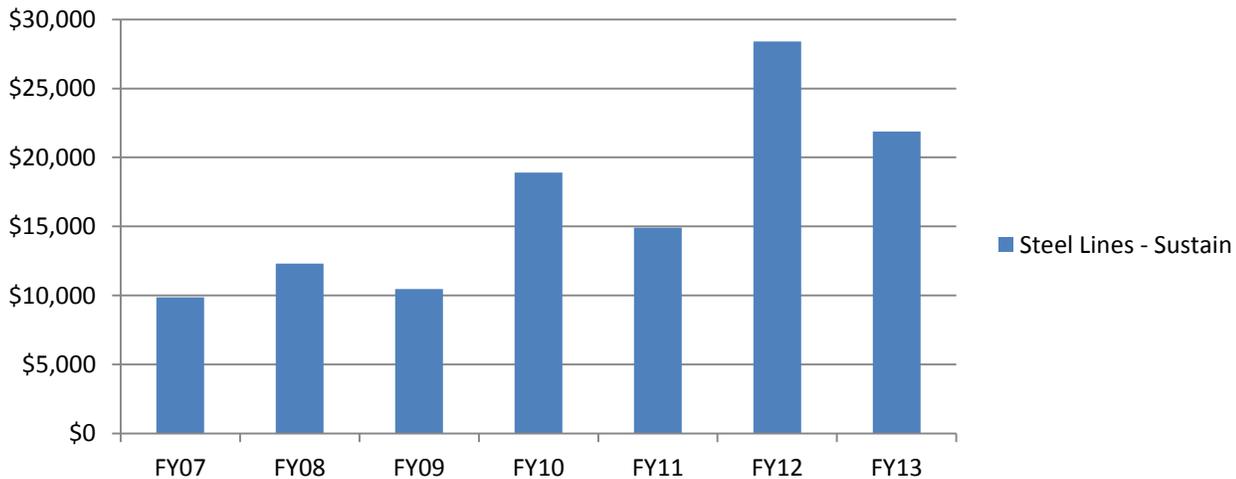
|      |     |     |                                  |  |
|------|-----|-----|----------------------------------|--|
| FY12 | 1   | 124 | SAIFI & SAIDI Targets <b>MET</b> | Fiscal Year 2012 ended with all eight reliability target measures met. All were within control limits. |
|      | 2   | 99  | SAIFI & SAIDI Targets <b>MET</b> |  |
|      | 3   | 47  | SAIFI & SAIDI Targets <b>MET</b> |  |
|      | 4   | 78  | SAIFI & SAIDI Targets <b>MET</b> |  |
|      | 1&2 | 223 | Availability <b>Met</b>          |  |

|      |     |     |                                  |   |
|------|-----|-----|----------------------------------|---|
| FY11 | 1   | 125 | SAIFI & SAIDI Targets <b>MET</b> | In general, FY11 (Oct-Sep 2011) continues a trend of a modest number of unplanned outages. All eight target measures, four for outage duration and four for outage frequency, were met. |
|      | 2   | 97  | SAIFI & SAIDI Targets <b>MET</b> |   |
|      | 3   | 44  | SAIFI & SAIDI Targets <b>MET</b> |   |
|      | 4   | 76  | SAIFI & SAIDI Targets <b>MET</b> |   |
|      | 1&2 | 222 | Availability <b>Met</b>          |   |

Please refer to Appendix D for more information about these targets.

### 2.1.2 Cost History

Historical Actuals -Capital



Historical Actuals - Capital

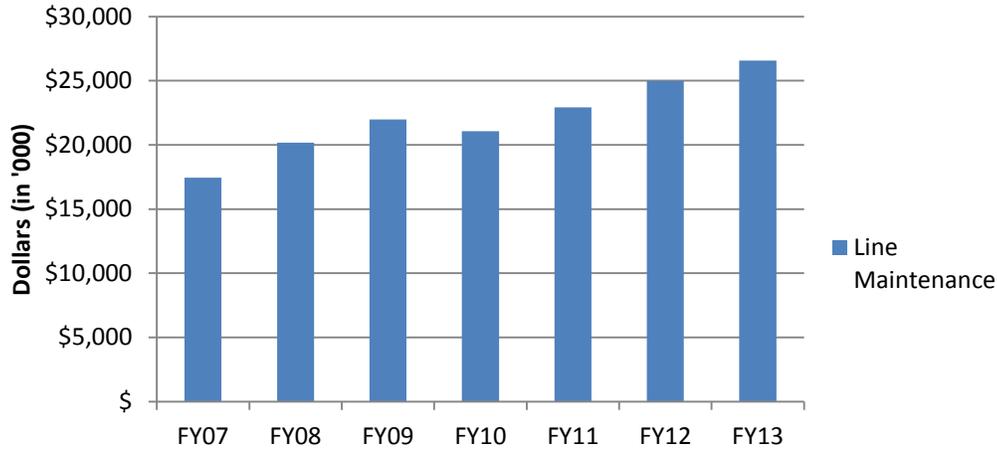
Dollars in '000

| Program               | FY07    | FY08     | FY09     | FY10     | FY11     | FY12     | FY13     | Total     |
|-----------------------|---------|----------|----------|----------|----------|----------|----------|-----------|
| Steel Lines - Sustain | \$9,866 | \$12,307 | \$10,471 | \$18,913 | \$14,918 | \$28,407 | \$21,881 | \$116,763 |

**FY2007-2013 Capital Costs for Replacement Projects:**

- Spacer Damper Replacement: \$58.3 million
- Defective Spacer Damper Replacement: \$22.7 million
- Sustain Steel program related projects: \$35.8 million

**Lines\* Historical Actuals - Expense**



\*This chart represents expense historical actuals for the Line Maintenance Program, which includes Wood Pole Line maintenance.

Historical Actuals - Expense

Dollars in '000

| Level 5 Node Name | FY07     | FY08     | FY09     | FY10     | FY11     | FY12     | FY13     | Total     |
|-------------------|----------|----------|----------|----------|----------|----------|----------|-----------|
| Line Maintenance  | \$17,442 | \$20,182 | \$21,983 | \$21,076 | \$22,921 | \$24,984 | \$26,572 | \$155,159 |

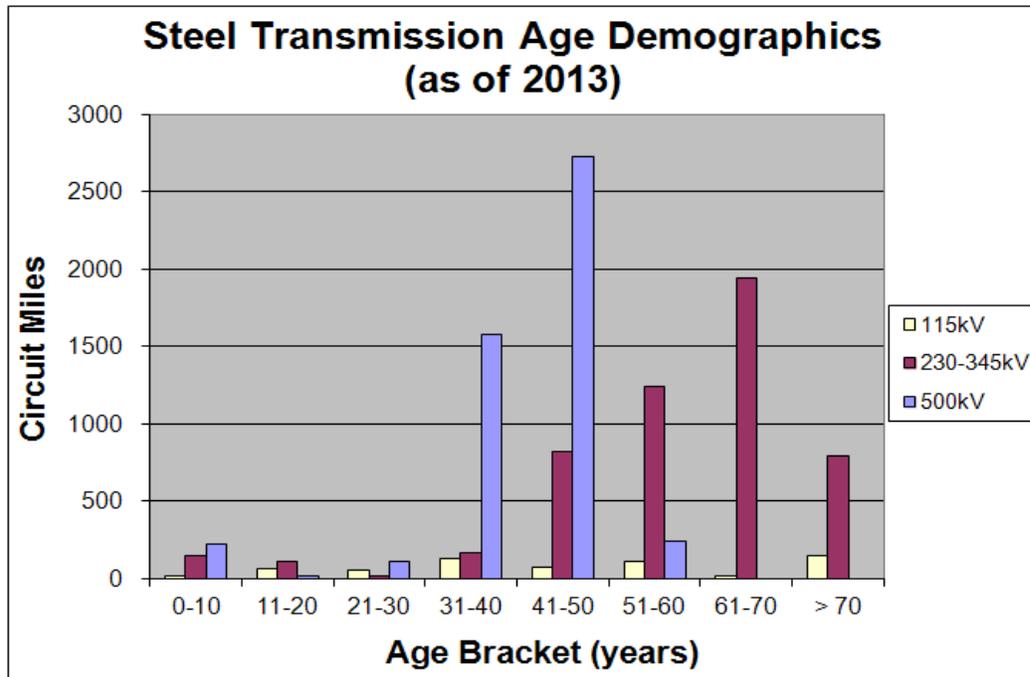
**FY2007-2013 Historic Inspections and Maintenance Expense**

- Expense does not differentiate Wood Pole Lines from Steel Lines and is listed as Line Maintenance. This is because key maintenance activities like Line Patrol are for both programs.
- As steel lines continue to age, maintenance costs will increase.
- A large component of this cost is labor hours, to inspect and maintain these lines. Costs exclude right-of-way maintenance, access roads and vegetation management.

**2.1.3 Health of Current Assets**

**Transmission Line Age**

Much of the primary loop and significant portions of the Southern Intertie exceed 40 years of service life. With the average age of all 10,300 circuit miles being 49 years, the 2007 Aging Asset Report concluded key components were approaching theoretical end-of-life on 60% of BPA's installed asset.



**Performance**

In the period from 2005 through September 2013, BPA experienced 53 outages in excess of 240 minutes that were likely due to material failure. As a proxy for deteriorating condition, the increasingly advanced age of components is assumed to increase their likelihood of failure, especially during severe weather. BPA’s steel lines are not crumbling to the ground, however the transmission system is experiencing material failures that clearly indicate that active components have a finite lifespan and are approaching that limit.

- Ground wire failures on Fairview-Rogue, Buckley-Marion and John Day Grizzly.
- Insulator failures on Olympia-Grand Coulee and Grand Coulee-Bell.
- TLM observations on North Bonneville-Troutdale and Bonneville-Hood River that tower attachment points for jumper strings have worn thin.
- Transmission Line Engineering’s concerns about fittings on copper and 2.5” expanded experiencing thermal failure
- Excessive and widespread footing corrosion at and below ground level in the Paul-Allston and Santiam-Alvey corridors.

**Steel Line Condition Data**

Currently the only overhead asset component for which condition has been consistently assessed and documented over time is wood poles. Data on steel line component health is sparse, making the data documenting efforts presently underway crucial to the success of the steel sustain program. Three key elements necessary to adequately document BPA's transmission line assets and its condition are:

- TLDD- Transmission Line Design Data
  - ◆ To understand the makeup of the population as it changes over time
  - ◆ To understand a specific line’s design parameters
  - ◆ To analyze line physical and electrical capacities
- TAS – Transmission Asset System (for asset health data)
  - ◆ For recording, retaining and managing comprehensive asset health assessment data in order to properly manage and assess the overhead asset

- ◆ To give better visibility to and manage the corrective maintenance queue in order to cost-effectively manage asset longevity
- Comprehensive metrics for regularly and consistently collecting, retaining and analyzing asset condition data
  - ◆ To identify trends
  - ◆ To assist in targeting and timing replacement programs
  - ◆ To facilitate effective management over time
  - ◆ To assist in refining predictions on component service life as impacted by site conditions

In order to facilitate efficient health and risk assessments, while recognizing that major line components will age at different rates, the steel transmission system is separated into 9 major components organized into the following two categories.

- Active Components age faster, usually have lower replacement cost and often serve a critical or protective function (connectors, insulators, dampers, spacers, obstruction marking)
- Passive Components, last longer, usually have higher replacement costs and assessment can be more difficult (towers, footings, conductors, counterpoise)

**Component Risk of Failure by Voltage** (See Appendix E for data tables)

The following bubble charts are based purely on asset age and what is currently known about equipment lifespan. As more condition data is collected, this will provide the ability to more accurately characterize the population and better predict failure and these charts will almost certainly change.

Over 60 percent of BPA’s steel line assets are approaching theoretical end of life, and although some components are failing, the rate of failure is not yet alarming, nor does it appear to indicate having reached end of life on a majority of Steel line asset components.

In the context of the following sustain steel bubble charts, “Consequence” means the impact of a specific asset component failure on the operation of its transmission line. It does not address the impact of component failure on

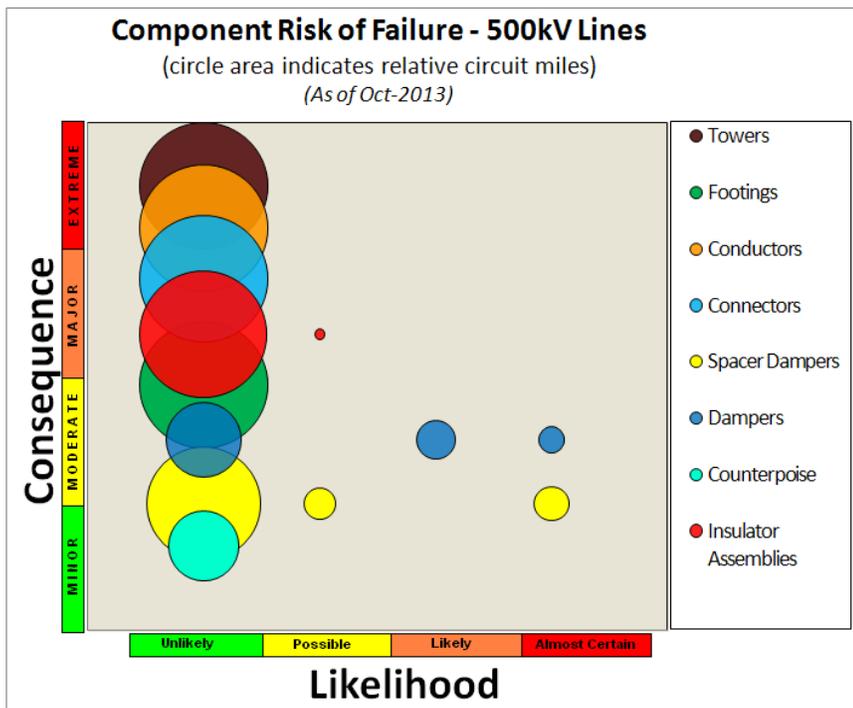
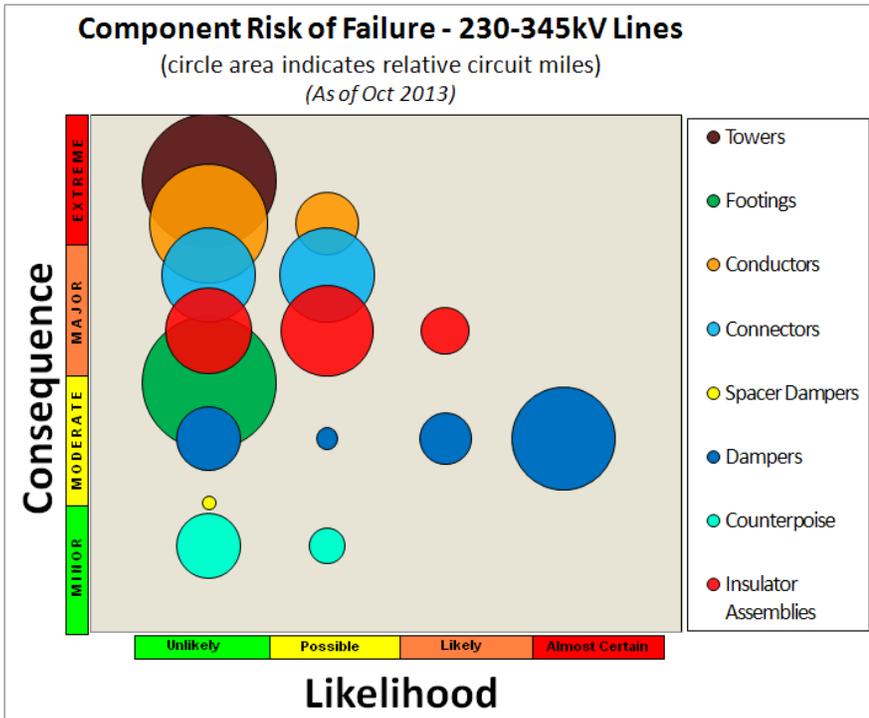


Figure A

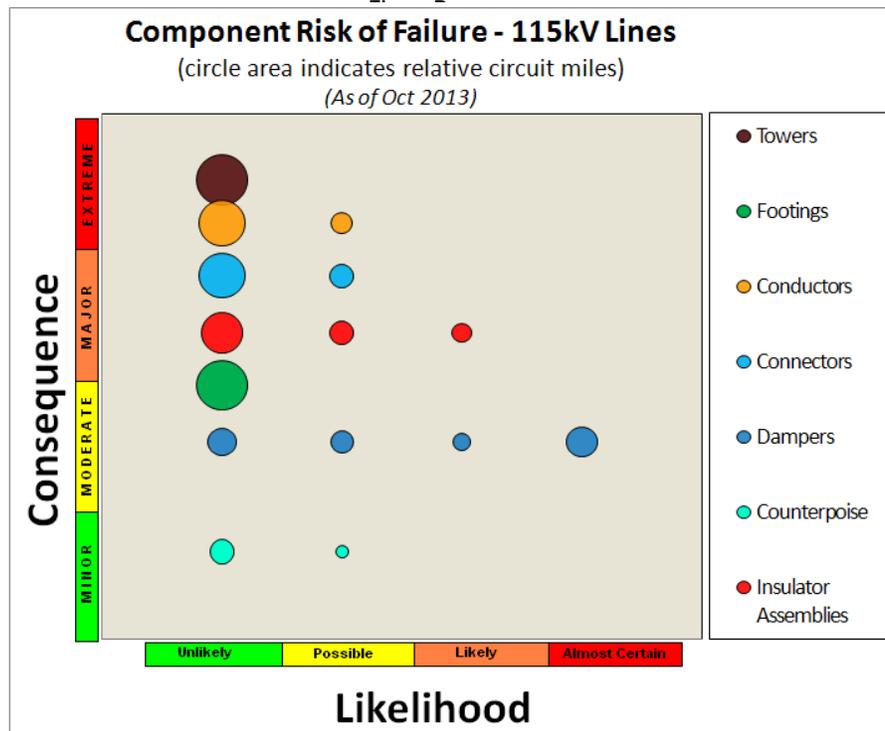
the transmission system as a whole. The severity of the consequence is based on whether or not failure causes a line outage and the time and effort require fixing the failure and restoring the line to service. Refer to Appendix E for associated data tables and Appendix F for details on likelihood and consequence scales.

As shown in Figure A there is a small population of failing dampers on the 500kV system. These are on obsolete 2.5” expanded conductor, for which getting replacement parts will continue to be problematic. The 350 miles of 2.5” expanded conductor will be replaced over the next 14 years, and interim solutions to the damper issues are being considered. There is also a small population of spacer dampers in the

“almost certain to fail” category, which represents the remaining population of defective spacers to be replaced in 2014.



On the 230kV and 115kV lines, Figures B and C, where the population is much older, dampers are a significant concern. It has only been over the last couple years that the importance of replacing failed vibration dampers has been emphasized in TLM’s line maintenance priorities.



Until the lines portion of TAS is fully functional, it will be difficult to quantify the number of dampers that are replaced annually under maintenance. As a result, these charts do not yet reflect the number of failed units being replaced during routine maintenance.

Figure C

## 2.2 Future State

**Asset Vision:** By 2027, BPA has restored the health of all overhead transmission system components to a state of long-term functionality and reliability and has instituted a proactive, economical, and dynamic strategy for tracking, assessing and mitigating its aging overhead asset over time. In doing this, BPA continues to fulfill its commitment to the region to provide an adequate, economical, safe and reliable power supply.

**Mission:** To expand, mature and refine this proactive plan to replace vital overhead system components nearing end of life and implement a sustainable strategy for doing this into the future.

### 2.2.1 Key asset performance objectives, measures and targets

These are the program’s principal drivers:

| Category  | Performance Objective  | Measure  | End Stage Target  |
|---|--|--|---|
| <b>Long Term Transmission Line Reliability</b>  | Reduce or avoid unplanned outages on BPA’s most important steel transmission lines (category 1 and 2) due to equipment condition or age related failures.  | Outage frequency (SAIFI) and duration (SAIDI) due to equipment condition or age related failure  | Maintain SAIDI and SAIFI at or below historic averages: <ul style="list-style-type: none"> <li>▪ Zero Control Chart Violations for SAIDI and SAIFI for category 1 &amp; 2 lines</li> <li>▪ No more than one control chart violation per year for line categories 3 &amp; 4</li> </ul> |
| <b>Long Term Transmission Line Availability</b> | Ensure BPA’s steel transmission lines meet availability targets.   | Duration of planned outages for maintenance  | BPA's most important transmission lines (Category 1 and 2) are available for service at least 97.39% of the time.   |
| <b>Long Term Transmission Line Safety</b>       | BPA transmission lines are maintained and operated in a way that limits risk to health and safety of employees working on the lines and to the public  | Frequency of lost-time accidents and near misses   | Lost-time accident frequency rate ≤ 1.5 per 100,000 hours worked, No fatalities occur to BPA employees or contract employees working on BPA facilities  |
| <b>Long Term Transmission Line Compliance</b>   | BPA is adequately inspecting, assessing, documenting and maintaining its transmission lines in accordance to WECC Standard FAC-501-WECC-1 (A Regional Reliability Standard to ensure the Transmission Operator or Owner of a WECC transmission path performs maintenance and inspection on identified paths as described by its transmission maintenance plan) | NERC/WECC requirements from to BPA: <ul style="list-style-type: none"> <li>▪ Transmission Maintenance &amp; Inspection Plan (TMIP) is developed, documented and reviewed annually</li> <li>▪ Maintenance is performed in accordance with the TMIP</li> <li>▪ Maintenance records are maintained as required by this Standard (documentation exists that the Transmission Lines have been regularly inspected, conditions have been noted and corrected in a timely fashion)</li> </ul> | There are no violations to NERC/WECC maintenance and inspection standards   |

**Strategic Enablers**

This is what must be focused on in order to achieve the vision

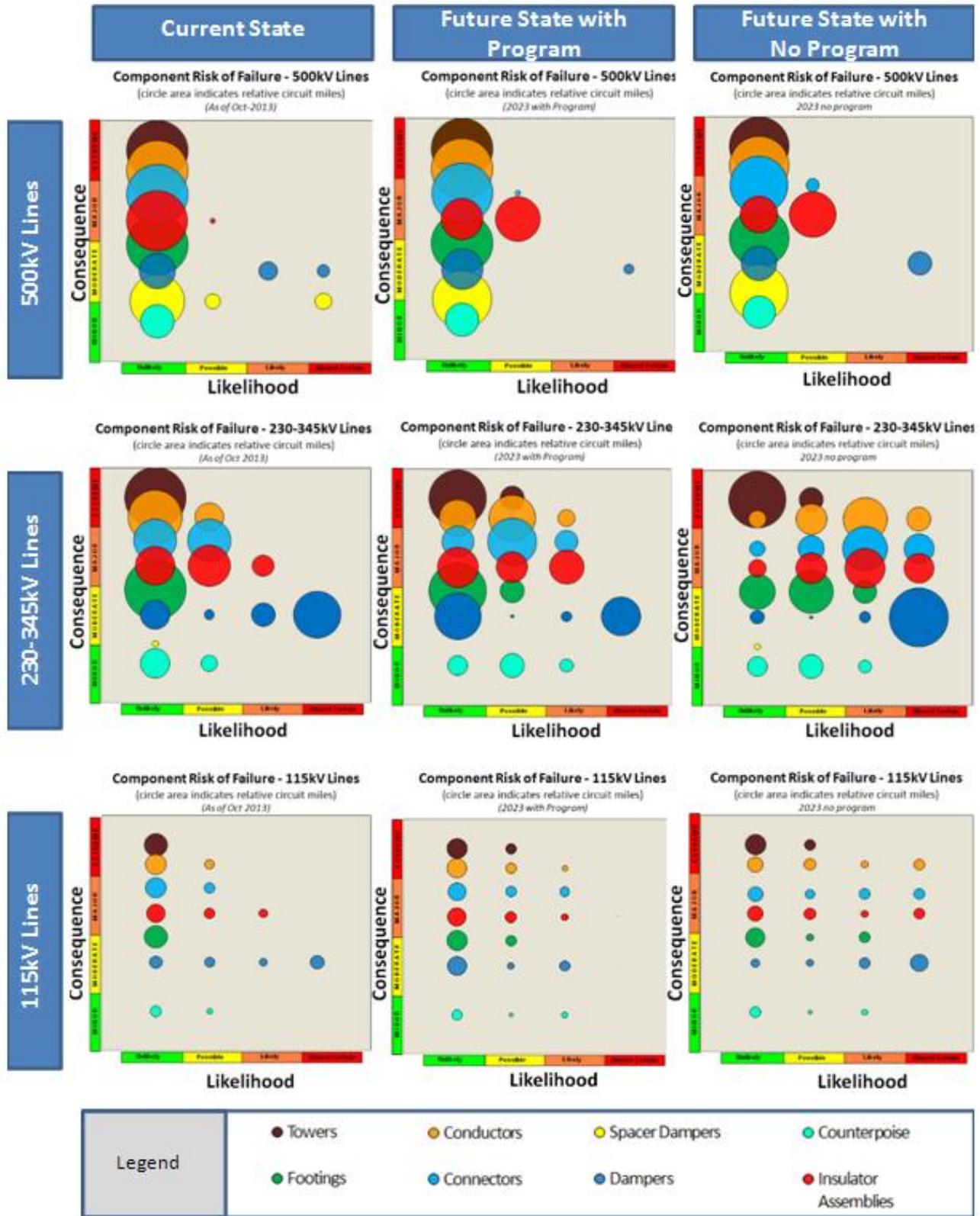
| Category  | Performance Objective  | Measure  | End Stage Target   |
|---|--|--|--|
| <b>Transmission Asset Data Adequacy and Availability</b>        | As lines are inspected on a scheduled basis, information on transmission asset component attributes and condition is complete, accurate and readily accessible in TAS.   | <ul style="list-style-type: none"> <li>Extent to which a framework for collecting and retaining program critical component condition data is provided for in TAS</li> <li>Availability of complete, accurate and readily accessible asset attribute information in TAS</li> </ul>  | <ul style="list-style-type: none"> <li>As part of lines inspections process, 95% of program critical asset data is being collected and managed after the inception of TAS</li> <li>90% of asset attributes and condition data for 99% of steel line assets inspected after the inception of TAS is available through that system.</li> </ul>                                     |
| <b>Assets are proactively assessed, maintained and replaced</b> | <p>Assets are proactively assessed, maintained and replaced</p> <ul style="list-style-type: none"> <li>Priority is given to critical assets at greatest risk of failure</li> <li>Reliability, availability, and other standards are met at least life cycle cost</li> <li>Maintenance is reliability-centered and condition-based</li> <li>Maintenance, replacements and sparing planning is integrated</li> <li>Reduce the risk of unplanned outages</li> </ul> | <ul style="list-style-type: none"> <li>Percent of critical assets at high risk of failure</li> <li>Percent of asset classes that have condition-based maintenance standards</li> <li>Extent to which sparing strategies are in place to assure that a supply of critical spare parts is geographically situated to enable timely restoration of service</li> </ul> | <ul style="list-style-type: none"> <li>Risk assessments are updated every 6 years</li> <li>The number of circuit miles for active components in the high risk category has decreased by ten percent from the last update period</li> <li>Condition-based standards are in place for 80% of asset classes after the Lines portion of TAS goes live by close of FY2014.</li> </ul> |

**Comparison of risks associated with current and future state**

The following series of bubble charts is a comparison between current state and two future states (future state with program and future state without program). An indication that the program is heading in the right direction at an appropriate pace would be the absence or shrinking of component population in the upper right quadrants of each chart. The following should be kept in mind when interpreting these bubble charts:

- Age is the primary indicator of likelihood of failure.
- As actual condition data is accumulated and failed and retired components for critical indicators of end-of-life is evaluated, these charts will be adjusted to better reflect likelihood of failure.
- Lifespan has been adjusted down in the non-program view for conductor, connectors, hardware and footings to account for the impact of not replacing dampers and not mitigating for corrosion.

Until TAS is fully functional, it is not feasible to account for components that are being replaced during routine maintenance. TLM has been replacing some number of failed dampers, however, the assumption in this data is zero.



## 2.3 Asset Condition/ Performance Gaps

Several gaps to delivering a fully informed Steel Lines program exist and have been discussed throughout this document. The following must be addressed to mature the program in order to plan and implement the proactive strategy.

- standard metrics for collecting asset condition data
- standardized process for sampling and testing retired components
- long term strategy for evaluating risks of aging assets
- accurate and useable asset condition data
- leveraging lessons learned
- standardizing replacement components and incorporating innovations

The asset condition and performance gaps are illustrated by the current state risk bubble charts in section 2.2.3 above. The following describes the risks to the objectives established for the transmission system if the strategy is not implemented and the health of the assets are not improved upon.

### 2.3.1 Risks to Meeting Key Asset Performance Objectives

- **Transmission Reliability Performance Objective:** Reduce or avoid unplanned outages on BPA's most important steel transmission lines (category 1 and 2) due to equipment condition or age related failures
  - ◆ **Risk:** Components which are approaching or have reached their end-of-life begin to fail and continue to fail in increasing numbers, resulting in an increased likelihood of unplanned outages.
  - ◆ **Likelihood:** Possible to Likely. Line components that experience mechanical load cycles have a finite lifespan; eventual failure is inevitable, even more so for those components considered to be a high risk of failure. A high rate of vibration damper failure on single conductor lines is already being seen
  - ◆ **Consequence:** Moderate to Major
    - Reliability of the operating line will decrease
    - SAIFI and SAIDI end-stage targets will increasingly not be met
    - Failing components could result in extended line outages
    - In some cases, maintenance costs to repair or replace failing components in a piece meal fashion will be less cost effective than a proactive whole line component replacement approach, however not keeping up with maintenance on components that serve a protective function, like dampers and cathodic protection will lead to much costlier premature replacements of hardware and conductor.
    - Station equipment will experience increased duty with increasing automatic outages
    - Staff will be diverted from implementing planned program work
  - ◆ **Mitigation:** An effort to more accurately determine the health of BPA overhead assets and at the same time replace the most likely candidates for near term failure is currently underway. This is being done in conjunction with a program that includes extensive sampling and testing of retired components coupled with a program that has the flexibility to refocus on critical situations as they are uncovered.
- **Transmission Availability Performance Objective:** Ensure BPA's steel transmission lines meet availability targets.
  - ◆ **Risk:** The anticipated increase of replacement work will lead to an increasing frequency of planned outages resulting in decreased transmission line availability.

- ◆ **Likelihood:** Likely. Line components that experience mechanical load cycles have a finite life expectancy; eventual failure is inevitable and without a systematic approach to preemptive replacement, the failure rate will likely be unmanageable from a maintenance perspective.
  - ◆ **Consequence:** Significant
    - Maintenance backlog will increase to an unsustainable level.
    - Depending on the component and its function, maintenance costs to repair or replace failing components in a piece meal fashion will be less cost effective than a proactive whole line component replacement approach.
    - Availability of the operating line will decrease overtime, until enough hardware has been replaced to move the line out of a high maintenance category.
  - ◆ **Mitigation:** An effort to more accurately determine the health of BPA overhead assets and at the same time replace the most likely candidates for near term failure is currently underway. This is being done in conjunction with a program that includes extensive sampling and testing of retired components coupled with a program that has the flexibility to refocus on critical situations as they are uncovered. Sustain program priorities are also being heavily driven by maintenance frequency and issue identification from the field with the goal of intercepting the poorest performers before they become unmanageable.
- **Safety Performance Objective:** BPA transmission lines are maintained and operated in a way that limits risk to health and safety of maintenance employees and the public.
    - ◆ **Risk:** Age-related deterioration of line components results in component failure during maintenance activities, storm events, etc, leading to injury or death.
    - ◆ **Likelihood:** Low. Depending on the failure mechanism, it may be difficult for field personnel to readily identify materials, like insulators, that have severely deteriorated strength capacity.
    - ◆ **Consequence:** Significant – Potential injury or loss of human life
    - ◆ **Mitigation:** Safety is a compelling driver. When there is a safety concern about a specific line or equipment category, addressing that issue becomes a high priority for the sustain program and for transmission engineering.
  - **NERC/WECC Management and Compliance Criteria Performance Objective:** BPA is inspecting, assessing, documenting and maintaining transmission lines in accordance to WECC Standard PRC-STD-005-1
    - ◆ **Risk:** Being found not in compliance with NERC/WECC standard PRC-STD-005-1 through self-report or during NERC/WECC audit leads to mandatory emergency remediation with possible financial penalties that results in increased expense costs and loss of reputation.
    - ◆ **Likelihood:** Low
      - BPA currently has a Transmission Maintenance and Inspection Plan (TMIP) in place,
      - Maintenance is performed in accordance with the TMIP
      - Maintenance records are maintained as required by this Standard
    - ◆ **Consequence:** Moderate – There are possible fines for non-compliance and BPA could be ordered to take expensive corrective actions within a short time frame.
    - ◆ **Mitigation:** TAS will greatly facilitate compliance by providing a system with which to accurately track and report on regulatory driven metrics.

#### Risks to Implementing Strategic Enablers

- **Transmission Asset Data Adequacy and Availability:** As lines are inspected on a scheduled basis, information on active and passive component attributes and condition is complete, accurate and readily accessible in TAS.

- ◆ **Risk:** BPA does not have the information available to help identify condition trends or to predict service life, making it difficult to effectively target, pace and manage replacement and maintenance programs.
  - ◆ **Likelihood:** Possible
    - Transmission Engineering is engaged in the systematic testing and assessment of a statistically significant sampling of aging component populations.
    - TAS development is moving forward and expected to be ready to begin collecting data by the end of FY2014
  - ◆ **Consequence:** Significant
    - Replacement and maintenance decisions based on inadequate asset condition information can potentially lead to significant over or under spending within the program and inefficient program targeting and pacing.
  - ◆ **Mitigation:** Sustain Program Managers are working very closely with TAS development team to ensure that program critical data is adequate and available.
- **Assets are proactively assessed, maintained and replaced:** Processes are developed to ensure that assets are proactively assessed, maintained and replaced
    - ◆ **Risk:** The anticipated backlog of maintenance work cannot be met, material for restoring service is not readily available, or BPA is not gathering and tracking adequate data to make well informed maintenance decisions.
    - ◆ **Likelihood:** Low
    - ◆ **Consequence:** Significant – Decreased reliability due to increasing frequency of unplanned outages. Reactionary replacement efforts to keep up with failures results in increased overall program costs.
    - ◆ **Mitigation:** Sustain Program Managers are working very closely with TAS development team to ensure that program critical data is adequate and available to make decisions. Reliability Centered Maintenance has been identified as being a critical function in the success of the Sustain Programs and steps are being taken to develop those skills sets within Transmission Planning and Asset Management.

## Other Constraints and Uncertainties

### Material Constraints

- Major materials to support BPA expansions and sustain programs are currently procured through long-term master contracts or on a first come first served basis
- Materials suppliers are less capable/flexible in meeting BPA requirements and last minutes demands
- In order to meet program schedules, critical elements must be communicated to Supply Chain – Sourcing Services in advance

*Mitigation:* 1) Continue to explore utilizing commercial off-the-shelf items by adopting industry standards, where it makes sense. 2) Hold quarterly material summits to continually check in on forecasting, emerging issues and lessons learned.

### Evolving Regulatory Standards

- NESC – replacement components must meet current standards for quality and electrical functionality

*Mitigation:* Continue to have a robust QA/QC function in Transmission Engineering so that the work is done correctly, with quality materials the first time.

### Other Constraints

Proposed initiatives to address the issues associated with staffing constraints and outage management were addressed in the Transmission Asset Management overarching strategy.

## **2.4 Strategic Approach to Closing Gaps**

### **Insulator Assemblies and Associated Hardware Replacement (Capital)**

- **Background:** The condition of the insulator assemblies and associated hardware is not always obvious and can be difficult to ascertain by field observation alone. An on-going strategy for testing retired components will provide the data necessary to appropriately target and pace the program.
- **First Five Years (Phase One)**
  - ◆ Replace insulator assemblies and associated hardware on discrete line sections based on age of asset, field observation of condition, weather exposure, frequency of material caused outages, line criticality and outage availability
  - ◆ Shunt compression fittings at deadends as necessary
  - ◆ Determine construction resources available and skill enhancement necessary to address hard to take out lines, which are often the most critical.
  - ◆ Review and revise replacement assemblies to meet current policy to standardize hardware components whenever possible.
  - ◆ As insulator assemblies and associated hardware are replaced, a sampling of the retired population will be evaluated to determine actual component condition, help refine service life predictions and critical indicators of end-of-life.
  - ◆ These evaluations will provide the data necessary to determine the pace at which this effort should move forward over the long term.
  - ◆ Continue to refine condition data collection efforts to best meet asset management needs
- **Five Years and Beyond (on-going:)**
  - ◆ Reevaluate the strategy for insulator assembly and associated hardware replacement for the next multi-year program period based on retired component analysis and other phase one program lessons learned.
  - ◆ Structure the next three to five year program period according to urgency and any critical indicators uncovered in phase one.
  - ◆ Continue to refine condition data collection efforts to best meet asset management needs

### **2.5" Expanded Reconductor (Capital)**

- Program starts in FY2014
- 2.5" expanded conductor is obsolete and BPA is not equipped to restore a 2.5" expanded line in the event of a major failure. Fittings for this conductor are no longer available.
- All the connectors have been shunted, in order to reduce the thermal stresses, but ultimately this conductor must be eliminated from the system before it starts to fail, since this is on some of BPA's most critical lines.
- There is approximately 350 circuit miles of 2.5" expanded conductor on BPA's system. Based on a feasible ability to execute, reconductoring about 25 miles per year over the next 14 years would be a manageable pace.
- As line sections are reconducted, sampling and testing of retired wire and connectors will be performed in order to better gage the pace with which this program should be implemented. If critical indicators of imminent failure are discovered, the program will likely have to be accelerated to minimize risk to system reliability.

**Obstruction Marking and Lighting (currently underway) Expense**

- Program started in FY2004
- Theoretical lifespan is 10 years for the fixture and 2-4 years for the flashtube.
- Region expense budgets may allow between two and six towers per year (between \$5K-\$60K)
- Program cost to date is about \$3 million
- Replacements prioritized based on criticality, condition and maintenance frequency and complexity
- Standardizing around low maintenance, self-contained fixtures
- Replace marker balls in conjunction with spacer replacement when possible. There has been no viable marker ball replacement for over a year. Transmission line engineering is currently testing a new prototype and hopes to be in production with it by summer of FY2014.
- Program tracking of work performed is currently done by the project manager on locally maintained lists, TAS and TLDD will be taking over this function eventually.

**Tower Footing Corrosion Mitigation Expense/Capital**

- Program starts in FY2014
- A steel transmission tower has a theoretical lifespan of 100 years or more, and footings up to 80 years.
- Ground level and belowground components may have corrosion issues that significantly shorten this lifespan and can often be easily and inexpensively prevented or mitigated.
- \$400K of expense funding has been secured through the TLM maintenance program to fund a service contract to perform footing corrosion assessment and mitigation in FY2014 on Longview-Chehalis No 3, a line where severe corrosion has been eating away foot stub angles for over a decade.
- This would be the first year of an on-going effort that would be paced and funded according to actual condition, as that information becomes available through TAS.
- About 20% of this corrosion mitigation program will be eligible for capital funding, primarily the installation of cathodic protection, as well as an occasional full footing replacement.
- Develop a systematic way to assess, document and track over time the condition of these passive components and their more vulnerable subparts. The goal is that TAS will provide the means for collecting, storing and tracking this information.

**Other Components of the Steel Sustain Program:**

Developing and implementing assessment strategies for all transmission line components.

- Working with utility partners to share information, the entire industry is facing this issue
- Developing and validating various testing and assessment methods
- Determining what parameters should be documented by TLM in TAS
- Determining condition thresholds that will guide program priorities and pace.
- Retired component testing, assessment and tracking

**Other replacement and maintenance activities**

- Tower steel repair, especially at insulator attachment points
- Guying repair or replacement
  - ◆ Conductor splice reinforcement – shunting

**Program delivery improvements:**

- Use standard metrics for collecting and retaining asset condition data, granular enough to: 1) identify condition trends 2) target and pace replacement efforts 3) manage components over time and 4) better predict remaining service life.
  - ◆ **Status:** This is being aggressively developed and fine-tuned as part of the Lines portion of TAS.

- Continue to develop a standardized process for sampling and testing retired components, analyzing results and drawing conclusions that will assist in pacing and targeting the replacement strategies.
  - ◆ **Status:** The Transmission Line Engineering organization is engaged in this sampling and testing effort with the goal of making it more systematic and to ensure that the data collected will inform strategy decisions.
- Develop a long term strategy for evaluating and mitigating the risks associated with a continuously aging asset.
  - ◆ **Status:** The near-term strategy is similar to strategies adopted by other utilities, in that it relies heavily on sampling and testing retired components, as a barometer of population condition and lifecycle trending. The long-term strategy will be developed as a better understanding is gained of actual condition, lifespan, critical indicators of failure and the impact to total economic cost.
- Ensure that data quality and reporting is adequate in TAS and TLDD (Transmission Line Design Data) to serve in effectively tracking and evaluating the overhead asset.
  - ◆ **Status:** Line Sustain Program Managers are working closely with TLDD data stewards and the TAS development team to ensure that sustain program data needs will be met.
- Document and continually share lessons learned so that every cost-effective effort is made to ensure that new projects are assembled with the best chance for a long and reliable service life.
  - ◆ **Status:** Lesson learned are being documented and regularly discussed with SME's and the implementation team.
- Standardize components and appropriately incorporate technology innovations into replacement efforts.
  - ◆ **Status:** The Line Sustain Program Managers meet with a team of Transmission Engineering subject matter experts, twice month to discuss and make decisions about issues relating to standardization, compatibility, new technologies, prioritization, criticality, lessons learned and emerging issues.
- Decisions will have to be made within the next 20 years about next steps for maintaining the aging transmission system as passive components begin to reach the end of their service life. This will warrant close examination of BPA's long term capacity and network needs for specific corridors as BPA is faced with decisions on replacing passive components, such as towers, footing and conductor.

### 3.0 IMPLEMENTATION PLAN

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Proactive Condition Based Replacement of Active Components beginning with an age-based approach, discrete line segments will be targeted for replacement. A sampling of retired components will be evaluated and results will be documented along with factors like age, manufacturer, geographic location, weather exposure etc. in order to refine life expectancy predictions, better target high risk lines and appropriately pace the program.

#### Implementation considerations

Load growth and long term reliability

- In targeting lines for refurbishment, a feedback loop with expansion planning has been established to ensure a thoughtful and coordinated line specific strategy that is long-term, proactive, and regional in scope.

Population Condition Assessment and Priority

- While 500kV lines are the most critical they are also younger and tend to be in better condition
- Whereas the 115kV and some 230kV lines are less critical, they are older and appear to be at greater risk of failure. Effort will be put toward restoring the health of these lower voltage lines.
- Proper management of the overhead asset is critically dependent on the reliability and availability of condition assessment data, related analysis, and timing of replacement efforts.

### 3.1 10 year Implementation Plan

| Component Category    | Ramp to get to Steady State |            |            |            |            |            |            |            |            |            |
|-----------------------|-----------------------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|
|                       | FY14                        | FY15       | FY16       | FY17       | FY18       | FY19       | FY20       | FY21       | FY22       | FY23       |
| Insulator Replacement | 119                         | 113        | 138        | 88         | 138        | 131        | 193        | 193        | 241        | 203        |
| Reconductor           | 22                          | 33         | 28         | 26         | 26         | 28         | 26         | 28         | 26         | 30         |
| Dampers               | 67                          | 3          | 2          | 2          | 2          | 2          | 2          | 2          | 2          | 2          |
| Spacers               | 31                          |            |            |            |            |            |            |            |            |            |
| PPI Spacers           | 342                         | 59         |            |            |            |            |            |            |            |            |
| Annodes               | 4                           | 3          | 3          | 3          | 3          | 3          | 3          | 3          | 3          | 3          |
| <b>Total Miles</b>    | <b>585</b>                  | <b>211</b> | <b>171</b> | <b>119</b> | <b>168</b> | <b>165</b> | <b>225</b> | <b>226</b> | <b>273</b> | <b>238</b> |

| Component Category   | Expense    |            |            |            |            |            |            |            |            |            |
|----------------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|
|                      | FY14       | FY15       | FY16       | FY17       | FY18       | FY19       | FY20       | FY21       | FY22       | FY23       |
| Dampers              | 100        | 110        | 120        | 130        | 140        | 150        | 160        | 170        | 180        | 190        |
| Corrosion            | 15         | 15         | 15         | 15         | 15         | 15         | 15         | 15         | 15         | 15         |
| Sign Replacement     | 500        | 500        | 500        | 500        | 500        | 500        | 500        | 500        | 500        | 500        |
| Obstruction Lighting | 4          | 4          | 4          | 4          | 4          | 4          | 4          | 4          | 4          | 4          |
| Obstruction Marking  | 1          | 1          | 1          | 1          | 1          | 1          | 1          | 1          | 1          | 1          |
| Interphase Spacers   | 46         | N/A        |
| <b>Total Miles</b>   | <b>666</b> | <b>630</b> | <b>640</b> | <b>650</b> | <b>660</b> | <b>670</b> | <b>680</b> | <b>690</b> | <b>700</b> | <b>710</b> |

### 3.2 Program Forecast Planning

#### FY2014-2023 Capital Forecast – Steel Lines

Direct Capital only, Nominal Dollars in '000

| Program Category | FY14     | FY15     | FY16     | FY17     | FY18     | FY19     | FY20     | FY21     | FY22     | FY23     | Total     |
|------------------|----------|----------|----------|----------|----------|----------|----------|----------|----------|----------|-----------|
| Steel Lines      | \$19,603 | \$12,625 | \$14,865 | \$15,276 | \$17,449 | \$18,623 | \$19,741 | \$20,024 | \$21,200 | \$22,074 | \$181,479 |

#### Capital Program

- The FY2014 –FY2015 capital program reflects planned work as well as projects that had been deferred from previous years for various reasons. The construction program will be managed within the current forecast. Design will continue as planned in order to have shovel ready projects on the shelf.
- This strategy update also includes the necessary ramp up to steady state that will increase the likelihood of accomplishing the strategy goals.
- Roads and associated environmental work will be programmed by the Access Road Program Manager

- Given 10,300 circuit miles of line, at the steady state refurbishing rate of 210 per year, it will take about 49 years to complete the first round of a perpetual cycle. Although between 40 and 60 percent of BPA's system is approaching theoretical end of life, program focus and pace will be adjusted based on actual condition and refined condition thresholds, critical indicators failure, and identified trends.
- To be determined is the actual longevity of the steel towers and footings. The wholesale replacement of these passive assets will require a much greater capital investment than the active components.

**FY2014-FY2023 Expense Forecast – Transmission Line Maintenance** (Includes Steel Lines and Wood Pole Lines)

Nominal Dollars in '000

| Maintenance Program      | FY14     | FY15     | FY16     | FY17     | FY18     | FY19     | FY20     | FY21     | FY22     | FY23     | Total            |
|--------------------------|----------|----------|----------|----------|----------|----------|----------|----------|----------|----------|------------------|
| Transmissn Line Maintnce | \$26,361 | \$26,820 | \$27,758 | \$28,730 | \$29,735 | \$30,776 | \$31,853 | \$32,968 | \$34,122 | \$35,316 | <b>\$304,440</b> |

**Caveats**

*Forecast is currently under review as part of the 2014 Integrated Program Review (IPR) process and will be updated in conjunction with the IPR timeline.*

- Aside from the routine maintenance performed by line crews, there is an expense component to this program of about \$1 million per year that is not included in this forecast. Discussions are underway to determine if these funding requirements should either be managed at the Sustain program level or in Transmission Line Engineering, the primary driver of the work.
- Opportunities for bundling expense activities should be thoughtfully used, in order to maximize the efficiency of each construction crew mobilization and line outage.
- Some expense activities may already be at least partially undertaken by the district maintenance crew.

# **LOAD SERVICE**

## ASSET MANAGEMENT STRATEGY

Jim Hallar, Program Manager  
December 2013

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## EXECUTIVE SUMMARY

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The Load Service Asset Management Strategy represents the capital plan for projects to expand the transmission system in response to load service obligations. The NOS (Network Open Season) process will be discussed as well.

The expand program also includes upgrades to some existing assets. Those requirements are addressed within the following strategies:

- System telecommunications/Power System Control (PSC) Asset Strategy
- Generation and Line/Load Interconnection Asset Strategy
- Control Centers Strategy

Customer requirements as well as regulatory compliance play a major role in determining the level of investment necessary for expansion projects. Attempts are made to forecast anticipated future projects to give financial and resource visibility, as well as ensuring appropriate projects are considered in the BPA Capital Prioritization Process for expansion projects.

The future state of the load service program takes into account evolving regulatory standards and energy policies, emerging alternative approaches, and the current and anticipated future economic environment when responding to load service needs. To do this, the regional planning process must be reformed. Efforts are underway to do this for Generation Interconnection (GI) and NOS projects, which will improve the ability to plan for load service projects as well. In the meantime, internal efforts in regards to grid transformation, regional collaboration, and non-wires solutions will lead to proposed projects that meet more regional needs.

## 1.0 STRATEGY BACKGROUND

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### 1.1. *Business Environment*

The Load Service Asset Management Strategy specifically covers BPA's response to load service obligations within its service area. While the NOS (Network Open Season) process is included in this strategy, it is more of a response to commercial expansion needs than it is to load service.

It is BPA's intention that load service obligations and customer service requests are met with solutions that are directed at meeting reliability and other standards at the least cost, based on asset lifecycle. Long-term expansion plans are developed for BPA's load service areas where system reinforcement is necessary.

The majority of BPA's customers are seeking what BPA was first established to provide: reliable service to loads at the lowest rates. In addition, power marketers are seeking low cost access to transmission in order to market their power to other consumers. Along with these primary functions, BPA also provides a number of ancillary services including reactive reserves, and serving as a balancing authority for several customers.

In order to maximize value for the region, it is of significant importance to preserve BPA capital for necessary system reliability upgrades and commercial expansion. The BPA Capital Project Prioritization process has been initiated in order to respond to this need and applies also to load service projects. Load service projects likely to be initiated within the prioritization window, FY2015-FY2017, have been nominated as either compliance or discretionary projects.

## 1.2 Assets, Asset Systems and Criticality

### Asset Sub-Categories

Assets are grouped into categories when they serve common functional and business purposes. The load service strategy relates to assets in the following sub-categories:

- **Inter-Regional Paths** – This asset sub-category consists of 500 kV and some lower voltage lines and facilities that interconnect with other transmission providers and generating resources outside the Pacific Northwest. These are also commonly referred to as interties. The primary inter-regional paths on BPA’s system are California-Oregon Intertie (COI AC), Pacific Direct Current Intertie (PDCI), Montana-Northwest, Idaho-Northwest, and the Northern Intertie.
- **Main Grid** – This asset sub-category consists of 500 kV transmission and substation facilities as well as some 345 kV and a few 230 kV facilities. These facilities serve the large load areas in BPA’s system. This category can be further sub-divided into geographic areas.
- **Area and Customer Service** – This asset sub-category consists of facilities, typically 230 kV and below, which function primarily to serve customer loads. This category can be further sub-divided into geographic areas.

## 2.0 THE STRATEGY

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### 2.1 Current State

- Loads throughout the Northwest continue to grow, although at a somewhat slower rate than in previous years, due to the present economic downturn/situation. This economic slowdown may result in temporary deferrals of projects intended to serve additional loads. Projects in this category are reviewed annually and adjustments made to their schedule if necessary.
- Historically, the Pacific Northwest has been a winter peaking system. This means that the highest loads typically occur during the winter when cold weather causes increased usage of electric heating equipment.
- Over time, however, in many parts of the Northwest, peak summer load levels are catching up with the winter levels. This is primarily due to a greater percentage of air conditioning being installed in homes and businesses.
- This shift presents new challenges: because equipment typically has lower capacity under warm summer conditions, and air conditioners have different load characteristics than heaters, which affects the models used for expansion planning.

### REGULATORY STANDARDS

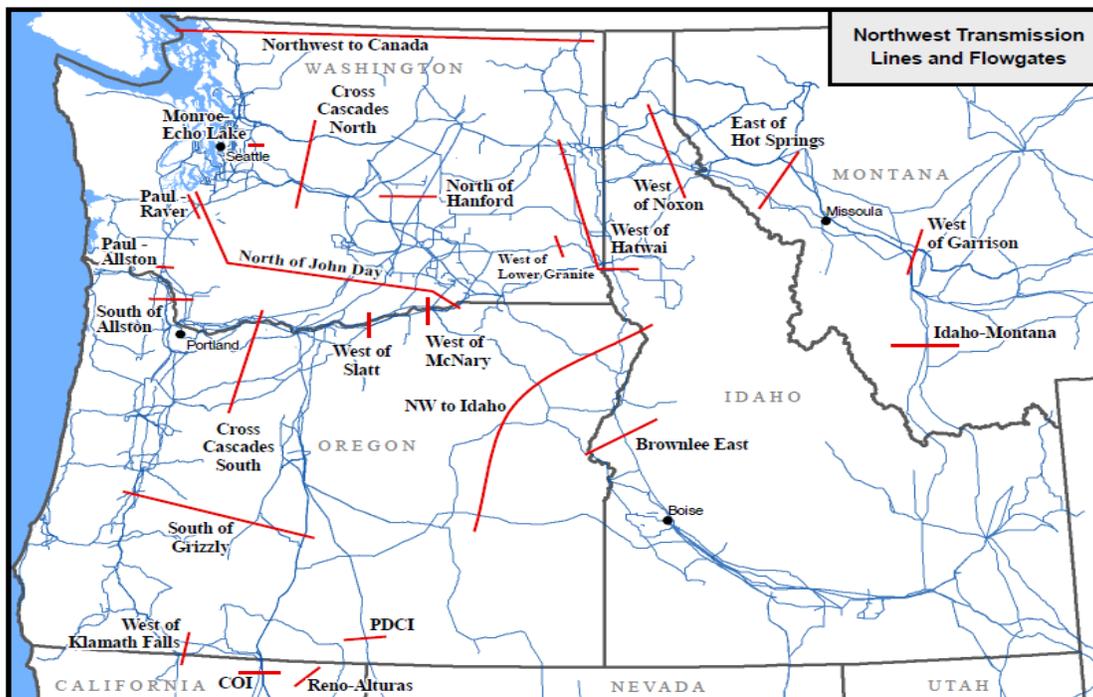
- BPA plans the grid to comply with North American Electric Regulatory Commission (NERC) and Western Electricity Coordinating Council (WECC) Reliability Standards.
- Over time, the NERC standards have evolved to cover a wider range of contingencies than the system was originally planned for.
- Compliance with these standards requires significant remediation costs.
- Keeping the existing transmission system up to the present reliability standards and ensuring that all new facilities are also in compliance, drives significant investments.

### OTHER FACTORS

- Other factors that drive investments for system expansion include efforts to meet customer expectations, NOS commitments, and Transmission Adequacy Guidelines when appropriate.
- BPA must also meet the requirements of the Biological Opinion, which restricts the operation of the Federal Columbia River Power System (hydroelectric plants). All of these factors increase the complexity of expansion planning.

**CONGESTION**

- Similar to a busy freeway, there are sections of BPA’s transmission system which have bottlenecks due to limited capacity and heavy usage.
- A transmission path consists of a single line or multiple facilities used to transport bulk electric power through the system.
- On BPA’s system, several paths are at or near their capacity limits and these are often referred to as congested paths. This congestion typically occurs during certain seasons or operating conditions, which limits transmission inventory (Available Transmission Capacity - ATC).
- BPA monitors congestion on major paths by means of metrics that show the total time that transmission flows are close to reaching System Operating Limits (SOL). Among other effects, congestion can force a change in the optimal dispatch of generating resources which can lead to higher costs for delivered power.
- Congestion also affects the ability to move power from the sources (especially renewable) to serve the loads. Therefore, it is a key consideration in the load service strategy.



BPA is currently in the middle of the NOS process for 2013. NOS is a process to manage and respond to long-term firm transmission service requests on the BPA network. For 2013 there were 49 requests for transmission service with a total demand of 3,973 MW. BPA performs a cluster study to evaluate these transmission service requests (TSRs). The objective of the NOS cluster study is to identify which parts of the transmission system require expansion and to identify projects that will allow BPA to accommodate the requested transmission service. Once the cluster study has been completed and any necessary expansion projects are identified, there will be further financial analysis to determine whether any of the projects would proceed with preliminary engineering and environmental review prior to final budgeting and implementation.

NOS for 2013 differs from the 2010 NOS in several ways. In 2010, all customers that applied for transmission service on the BPA network (interties excluded) received a Precedent Transmission Service Agreement (PTSA). If the customer met the terms of the PTSA (i.e. customer agrees to take service if offered at a rolled-in rate and provided

performance assurance), BPA would (1) study all requests and determine the requirements for transmission service, (2) perform required environmental studies and NEPA, and (3) arrange financing, plan, design, and construct the required facilities.

For the 2013 NOS, customers are required to submit data in accordance with the BPA Tariff. Only transmission service requests with valid data exhibits will be tendered a cluster study agreement. Customers are not required to commit to take service if offered at a rolled-in rate. Customers are required to advance funds, an estimated pro rata share of the cluster study costs, which will be trued up following completion of the cluster study.

The 2013 NOS cluster study began in September 2013 and is scheduled to be completed at the end of December 2013. This will be followed by the financial analysis leading to a recommendation of which projects BPA would proceed with preliminary engineering and environmental review. Projects identified through the NOS process will be submitted into the BPA Capital Project Prioritization and may affect other projects in flight.

### 2.1.1 Program Accomplishments to Date

The load service program has responded to needs across the system with the following projects currently in progress:

- McNary Substation- Additional 500 kV Transformer to handle increased loading
- McNary Substation- Install shunt capacitors to resolve low voltage issues
- Kalispell 115 kV Capacitor Bank Additions to resolve low voltage issues
- Lower Valley NEPA (Hooper Springs)
- Monroe 500 kV Shunt Capacitor- Add a shunt capacitor for voltage support
- Puget Sound Area Northern Intertie (PSANI) Memorandum of Agreement- Add a transformer bank at Raver Substation and implement Northern Intertie RAS upgrades

The NOS process of 2008 has resulted in the following projects currently in progress:

- I-5 Corridor Reinforcement NEPA
- Montana to Washington Transmission System Upgrade NEPA
- Big Eddy-Knight – West of McNary Reinforcement Group 2
- Central Ferry-Lower Monumental

Recent completed projects include:

- Ashe 500 kV New Bay - Addition for Columbia Generating Station (CGS) interconnection reliability
- Central Oregon Transformer Addition - Second 500/230 kV transformer bank at BPA's Ponderosa substation

## 2.1.2 Cost History

### Historical Actuals – Capital

#### Main Grid Projects

Dollars in '000

| Level 5 Node Name                  | FY07     | FY08    | FY09     | FY10     | FY11      | FY12      | FY13     | Total     |
|------------------------------------|----------|---------|----------|----------|-----------|-----------|----------|-----------|
| West of McNary Integration Project |          | \$288   | \$25,264 | \$62,228 | \$50,804  | \$4,102   | \$2,023  | \$144,709 |
| Olympic Peninsula Reinforcement    | \$636    | \$4,518 | \$20,424 | \$2,569  | \$15      | \$94      | \$728    | \$28,984  |
| I-5 Corridor Upgrade Project       |          | \$105   | \$780    | \$6,553  | \$9,261   | \$10,611  | \$7,414  | \$34,724  |
| Libby-Troy Line Rebuild            | \$3,538  | \$1,324 | \$9,354  | \$2,653  | \$423     | -\$116    |          | \$17,176  |
| Misc. Main Grid Projects           | \$9,078  | -\$210  | \$536    | \$755    | \$927     | \$2,238   | \$9,045  | \$22,369  |
| Mid-Columbia Reinforcement         |          |         | \$65     | \$4,247  | \$7,282   | \$909     | \$23     | \$12,526  |
| Big Eddy-Knight 500kv Project      |          |         |          | \$5,698  | \$11,423  | \$105,066 | \$24,358 | \$146,545 |
| Central Ferry-Lower Monumental     |          |         |          | \$3,231  | \$3,641   | \$11,390  | \$993    | \$19,255  |
| Central Orgeon Reinforcement       |          |         | \$150    | \$4,484  | \$10,104  | \$27,863  | \$4,267  | \$46,868  |
| Seattle-Pudget Sound Area          |          |         |          |          |           |           | \$478    | \$478     |
| Portland-Vancouver                 |          |         |          | \$448    | \$23,956  | \$10,753  | \$4,183  | \$39,340  |
| West of Cascades North             |          |         |          |          |           |           | \$685    | \$685     |
| Northern Intertie                  |          |         |          |          |           | \$43      | \$25     | \$68      |
| Salem-Albany-Eugene Area           |          |         | \$13     | \$355    | \$415     | \$4,588   | \$66     | \$5,437   |
| Tri-Cities Area                    |          |         | \$22     | \$1,372  | \$9       | \$711     | \$5,105  | \$7,219   |
| Montana-West of Hatwai             | \$4      | -\$210  | \$59     | \$9      | -\$81     | \$398     | \$105    | \$284     |
| Total                              | \$13,256 | \$5,815 | \$56,667 | \$94,602 | \$118,179 | \$178,650 | \$59,498 | \$526,667 |

### Historical Actuals - Capital

#### Area & Customer Service

Dollars in '000

| Level 5 Node Name             | FY07    | FY08     | FY09     | FY10     | FY11     | FY12    | FY13    | Total    |
|-------------------------------|---------|----------|----------|----------|----------|---------|---------|----------|
| City of Centralia Project     | \$61    | \$2,886  | \$4,301  | \$2,928  | -\$3     | \$5     |         | \$10,178 |
| Southern Idaho-Lower Valley   | \$75    | \$109    | \$1,971  | \$8,279  | \$5,394  | \$4,423 | \$2,930 | \$23,181 |
| Misc. Area & Customer Service | \$2,102 | \$6,499  | \$3,248  | \$6,359  | \$4,894  | \$2,127 | \$2,754 | \$27,983 |
| Rouge SVC Addition            | \$25    | \$3,672  | \$1,078  | \$3,910  | \$1,224  | \$144   | \$243   | \$10,296 |
| Longview Area Reinforcement   |         |          |          | \$883    | \$1,229  | \$2,253 | \$265   | \$4,630  |
| Kalispell-Flathead Valley     |         |          | \$12     | \$1,376  | \$209    | \$181   | \$3,311 | \$5,089  |
|                               | \$2,263 | \$13,166 | \$10,610 | \$23,735 | \$12,947 | \$9,133 | \$9,503 | \$81,357 |

**Historical Actuals - Capital**

**Upgrades & Additions**

Dollars in '000

| <b>Level 5 Node Name</b>   | <b>FY07</b> | <b>FY08</b> | <b>FY09</b> | <b>FY10</b> | <b>FY11</b> | <b>FY12</b> | <b>FY13</b> | <b>Total</b> |
|----------------------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|--------------|
| Celilo Upgrades Project    |             | \$11        | \$572       | \$1,050     | \$616       | \$2,380     | \$38,178    | \$42,807     |
| Misc. Upgrades & Additions | \$18,229    | \$29,539    | \$21,582    | \$18,095    | \$20,125    | \$34,035    | \$39,955    | \$181,560    |
| Line Capacity Upgrades     | \$4         |             |             |             | \$1         | \$162       | \$1,031     | \$1,198      |
| Line Switch Upgrades       | \$180       | \$172       | \$153       | \$33        | \$90        | \$1         |             | \$629        |
| Substation Upgrades        |             |             | \$473       | \$5,410     | \$33,650    | \$15,132    | \$11,559    | \$66,224     |
|                            | \$18,413    | \$29,722    | \$22,780    | \$24,588    | \$54,482    | \$51,710    | \$90,723    | \$292,418    |

**2.2 Future State**

The future state of the load service program will take into account evolving regulatory standards and energy policies, emerging alternative approaches, and the current and anticipated future economic environment when responding to load service needs. Reforming the regional planning process will improve the ability to plan for load service projects.

In identifying infrastructure investments, BPA will seek to meet regional needs while maximizing value. Fluctuations in the economy are unpredictable yet drive the demand for power thereby affecting load forecasts. This program aims to position BPA to be able to accelerate or defer load service projects based on changes in the load forecasts, thereby minimizing the risk of underutilized assets. By strategically investing based on BPA and regional priorities, the load service program will remain able to provide value for rate-payers even when confronted with a continually evolving future state.

**2.2.1 Key program objectives, measures and targets**

A primary objective for the load service strategy is to implement a regional expansion planning process that is long term, integrated with resource planning and directed at minimizing total system costs. Load service needs are considered for the current state as well as for future anticipated system conditions, including possible NOS or generation interconnection projects. Thorough planning leads to executable projects that can be completed at timelines and costs consistent with strategic or compliance drivers.

## 2.3 Program Gaps

### 2.3.1 Risks to meeting the objectives

The following risks are the most important risks relevant to the Load Service strategy.

| Risk   | Risk Description  |
|--|---|
| Evolving NERC/WECC reliability standards                               | Evolving NERC/WECC reliability standards leads to the need to revise plans of service, delays in developing plans, or scope/cost increases in the plans to meet the new standards.        |
| Load forecast uncertainty  | Uncertainty or inconsistency in load forecasts leads to an inability to develop accurate long-term plans for BPA's load service areas   |
| Unexpected changes in renewable portfolio standards and tax incentives | Unexpected changes in renewable portfolio requirements leads to abrupt changes in renewable resource generator development patterns and transmission service demands                      |
| Outage scheduling  | Outage constraints due to high wind-high water scenarios, congested paths, and efforts to maximize usage of the transmission system, create difficulties for competing expansion projects |
| Internal resource constraints  | Lack of staffing (BFTE & CFTE) compared to staffing needs leads to delays or errors in work products.   |

The above are risks to meeting the objective of implementing a long term regional planning process. Evolving NERC/WECC reliability standards, load forecast uncertainty, and a dynamic market with respect to renewable portfolio standards all mean that a long term process must be more complex, and must take into account many unknowns. Outage scheduling is similarly dynamic, and is subject to a variety of constraints. A regional planning process solution must be sophisticated enough to take into account many variables while also meeting customer and regulatory needs.

NOS and GI process reforms are currently underway to implement sustainable processes to 1) integrate renewable and other generation, 2) process long-term transmission service requests, and 3) efficiently plan transmission system expansion in a cost effective manner. These reforms will help to address the risks facing the load service program because all future expansion must be considered together in planning studies. Having a clearer picture of future system needs will enable planners to identify load service needs with adequate lead time to consider collaborative approaches and non-wires approaches.

In response to access to capital constraints, BPA has initiated the BPA Capital Project Prioritization Process in order to weigh investments with diverse costs and benefits and create a level playing field. Load service projects are nominated through the process and must be prioritized against sustain, compliance, policy, and discretionary investments across all business lines. In the event that a load service project was not prioritized in any given prioritization window, the investment would need to be re-nominated in the next prioritization cycle. This has the potential to create some uncertainty in project schedules.

## 2.4 Strategic Approach to Closing Gaps

### 2.4.1 Strategic Approach

The load service strategy is based on retaining the flexibility necessary for BPA to react to changing landscapes in the future. NERC and WECC reliability standards are evolving and changes are expected to continue. Changes to the standards will continue to drive investments in the load service program. In addition, climate change and the resulting new initiatives places pressure on Operations as well as the transmission infrastructure to maintain reliable load service. Alternative approaches are being evaluated and put into practice for everything from transmission planning to construction.

In an era of economic uncertainty, it is increasingly important to manage system expansion prudently to ensure the region is not investing in under-utilized assets. To this end, BPA is exploring new approaches to meeting current system demands and future expansion needs. Grid transformation is one evolving approach to planning that would look at different scenarios and enable planners to come up with a solution that responds well to many different futures. This minimizes the risk of an in-service asset built to respond to load growth that never materializes.

Collaborative projects are another approach to maximizing value for the region while minimizing costs. BPA is currently exploring joint participation in multiple regional transmission projects with other utilities. BPA is a signatory to the Columbia Grid Planning and Expansion Functional Agreement. This planning process provides an open stakeholder forum to recommend what should be built, who should build it and who should pay for it. The Puget Sound Area Study Team project is an example of a recent joint project developed through the process.

Non-wires alternatives can also be a way to meet system needs without building or expanding transmission lines. Possible non-wires alternatives include local generation, enhanced energy efficiency, demand management, and generation re-dispatch. Non-wires analysis needs to be incorporated relatively early in the planning process. When non-wires alternatives for future proposed transmission projects are considered, BPA will need to make informed decisions regarding which areas might provide more viable non-wires alternatives and award a contract for non-wires analysis in a timely manner so that the non-wires option can be seamlessly integrated into the transmission plan of service for that area. BPA will need to make decisions on whether to fund development activities such as permitting and preliminary engineering on both non-wires and wires alternatives while knowing that there could be some sunk costs related to the option that is not selected.

These different options will lead to proposed projects that meet more regional needs. Analytics behind decision making will be clearer and more transparent, enabling BPA to invest in priority load service and other investments while preserving capital and minimizing rates.

## 3.0 STRATEGY IMPLEMENTATION PLAN

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### 3.1 10 year Implementation Plan

The following load service projects have been nominated into the BPA Capital Prioritization Process for the FY2015-FY2017 window:

- L0322 Klondike-Blalock Reinforcement
- Monroe 500 kV Line Retermination
- Walla Walla Reinforcement
- Transmission Aggregated Projects (bundled projects, each under \$3M)

Boardman to Hemingway has been nominated and is an example of a collaborative project currently being considered.

Additionally, projects originating from NOS processes have been nominated:

- I-5 Corridor Reinforcement Project
- Montana to Washington
- Northern Intertie
- Colstrip Upgrade Project (CUP) East
- Lower Valley Reinforcement

### ***3.2 Program Forecast Planning***

The program plan will be developed once results from the prioritization process are evaluated and approved.

# **GENERATION INTERCONNECTION ASSET MANAGEMENT STRATEGY**

Jim Hallar, Program Manager  
December 2013

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## EXECUTIVE SUMMARY

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The Generation Interconnection (GI) Asset Management Strategy specifically covers BPA's approach in regard to large and small generation interconnection requests as prescribed in the Open Access Transmission Tariff (OATT) as well as to line/load interconnection requests. Other expansion type work, including the Network Open Season (NOS) process, is included in the Load Service Asset Management Strategy.

GI projects are customer requests to interconnect to the BPA system, resulting in network additions and/or interconnection facilities. In 2005, with the Congressional approval of new wind tax credits, there was a steep rise in requests for GI projects. By FY2013, BPA has constructed five substations and connected almost 6,000 MW, including thermal, wind, solar, and biomass. More than 10,000 MW requests remain in the queue with over 6,000 MW with completed studies. There has been a lull in new requests for FY2013 and 2014. There is approximately 800 MW of natural gas, solar, bio-mass and geothermal fueled generation proposed for connection between FY2014 and 2020.

Much of the wind generation demand is a result of the Renewable Portfolio Standards (RPS) enacted by Oregon and Washington that require an estimated 8,500 MW of renewable generation by 2025. Exporting to California could add another 2,000 MW during the same time period. BPA anticipates a total of 8,000 MW by FY2025 connected to BPA grid as part of the Northwest and CA RPS requirements.

A key objective of the generation interconnection strategy is to interconnect customer projects as efficiently as possible to meet customer timelines. In doing this, BPA continues to fulfill its commitment to the region to provide an adequate, efficient, economical and reliable power supply.

Risks to the objective include environmental constraints on siting, unexpected changes in renewable portfolio standards and tax incentives, evolving North American Electric Reliability Corporation (NERC)/Western Electricity Coordinating Council (WECC) reliability standards, and incomplete internal review of plans of service. An additional complexity facing the program is that GI projects must be prioritized against sustain, compliance, and discretionary investments for authorization and resource commitments. This means that in order to meet customer timelines, projects must be forecasted as part of the capital program before the customer is ready to proceed. There are two primary approaches to addressing these risks and closing program gaps. One is to pursue GI reforms which will address the backlog of completed studies, among other improvements. The other is to sync up the internal capital approval process with customer timeframes.

GI projects have been nominated as part of BPA's Capital Project Prioritization process for the FY2015-FY2017 window. Additional projects have been identified, but are outside of the prioritization window. In the event that additional projects come forward, they can be submitted for consideration in the prioritization cycle.

## 1.0 STRATEGY BACKGROUND

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### 1.1. *Business Environment*

The GI program serves developers and independent power producers, purchasers of generation connected to BPA-Transmission Services, federal and state stakeholders, and traditional load service customers (northwest utility customers, intertie utility customers, and large load customers). BPA seeks to interconnect projects that will help deliver the region's future power needs while maximizing economic value for current and future ratepayers.

GI projects are funded in advance by the customer, with BPA providing transmission credits for related transmission service of the portion that is deemed network facilities. An account is established for each project for the transmission credits with interest applied to the balance. After 20 years, BPA makes a lump sum "balloon payment" for any remaining balance. There are concerns about potential future upward rate pressure as a result of repayment of credits and interest. Accordingly, BPA is exploring potential alternatives to reduce long-term network rate impacts associated with future Large Generator Interconnection Agreements (LGIAs). Projects can also be funded by BPA, such as in the case where the upgrade is necessary to support a network customer request.

BPA has now constructed five large substations to meet these interconnection requests with a combined capacity of 5,600 MW. Facilities are currently being constructed to add another 1,500 MW with more requests in the queue, some with completed studies.

The results of the Renewable Portfolio Standards (RPS) enacted by Oregon and Washington and the exports to California will make the Northwest total over 10,000 MW in renewable generation. BPA anticipates their share to be over 8,000 MW connected to the BPA system and expects to add 300-500 MW per year on average until 2025.

In recent years, requests for interconnection have stalled due to market uncertainty with respect to production tax credits, state RPS, and uncertain economic/load growth. However, significant numbers of projects have remained in the interconnection request queue, which has impacted projects that desire to move forward in the nearer term. This is because projects must be considered according to their position in the queue, even if a project higher in the queue has stalled. A GI reform effort is currently underway that would help address the backlog issue due to stalled site permitting, enabling projects that are not delayed to proceed forward more quickly.

In order to maximize value for the region, it is of significant importance to preserve BPA capital for necessary system reliability upgrades and commercial expansion. The BPA Capital Prioritization Process has been initiated in order to respond to this need and applies to GI projects. GI projects likely to be initiated within the prioritization window, FY2015-FY2017, have been characterized as policy commitments but assessed as if they were compliance investments. Compliance investments are funded before policy and discretionary investments.

### 1.2 *Assets, Asset Systems and Criticality*

Generation and Line/Load Interconnection Assets

- **FERC Definitions:**
  - ◆ Network Additions – Additions to the BPA system BPA funded or Customer financed (up-front capital provided by customer, with transmission service credits)

- ◆ Interconnection Facilities – BPA-owned assets at a customer facility or as otherwise deemed not to qualify as network additions. Customer funds and receives no credits.
- ◆ Direct Assigned Facilities – Customer-owned facilities constructed by BPA, funded by the customer.
- **Generation projects (LGIP and SGIP) usually have 2 types of asset additions:**
  - ◆ Network Additions - New network facilities (substations, line additions, etc) and upgrades (line upgrades, communications system additions, control center additions, etc)
  - ◆ Interconnection Facilities – control, meters and communications equipment additions at the customer facilities.
- **Integration projects** - can include the same asset classes, but also involve BPA customer (intervening host utility) upgrades (not a BPA asset).
- **Line / Load projects**
  - ◆ Line additions can be a customer owned line terminated in a BPA facility where the BPA facility upgrades are treated as network assets, but the line itself is customer owned
  - ◆ Line built as a network addition between BPA and another utility that is then a network addition
  - ◆ Connections to new load service facilities owned by the customer (BPA portion is treated as Interconnection Facilities)
  - ◆ Miscellaneous line and equipment upgrades to support increased load service (Network Addition)
- **Control Center Additions (covered in the Control Center program strategy)**
  - ◆ Generation projects, whether large or small, interconnection or integration impact operating systems with limited outage windows – both Dittmer and Munro
  - ◆ Dittmer Control Center (with Munro CC as back-up) handles all of the generation dispatch duties, including AGC, Voltage support.
  - ◆ Dittmer and Munro each integrate the generation project into transmission system Dispatch control (SCADA) and related monitoring systems (Sequential Events Recorder (SER) and Phasor Measurement Units )
  - ◆ Remedial Action Scheme (RAS) system revisions are required for most generation projects
  - ◆ Wind projects include the variable generation control system (VELMA) interface and control
  - ◆ Generation additions to the control centers require detailed scheduling plans to address the many systems impacted with limited outage windows while maintaining operations.
- **Communications Additions (covered in the PSC/System Telecommunication strategy)**
  - ◆ Communication additions are required for all generation projects and many customer facilities additions.
  - ◆ Several sites and systems may be impacted for each project.
- **Scheduling System (Commercial Accounts):**
  - ◆ Generation projects are required to set-up generation accounts
  - ◆ All loads and generation must set-up scheduling system accounts for generation estimate and transmission service
  - ◆ All new loads and generation accounts are linked to metering, impacting metering services and billing systems
- **Miscellaneous Upgrades and Additions**
  - ◆ System upgrades or additions required in order to enhance the grid because of load service or generation needs. Can include line upgrades, substation upgrades, and substation additions. These types of investments are not included in sustain program strategies but are instead addressed as part of the expansion program.

## 2.0 THE STRATEGY

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### 2.1 Current State

#### Status of Generation Interconnection Expand Program

Generation interconnection projects and line load requests are accepted into the queue and posted on OASIS, per FERC order 2003A (revised in 2005). Large Generation Interconnection Project study procedures have been in place for seven years, and Small Generation Interconnection Project study procedures have been in place for five years. The number of new GI requests has slowed in 2013 and 2014. Study backlog continues to be a problem, but is expected to be addressed as part of GI reform currently underway.

BPA has completed GI-Reform review with customers and management, and tariff revisions are almost ready to submit. The main issue addressed was the backlog due to stalled site permitting. Local permitting (by Developer) must be completed before the NEPA study can be completed, and the NEPA study must be completed prior to BPA offering a final plan of service, as well as the subsequent LGIA and construction. Studies have been completed for over 12,000 MW (not including over 5000 MW withdrawn) and 6,000 MW stalled for lack of site permits.

Once a project has been added to the queue, it must follow the high level process below to proceed to construction:

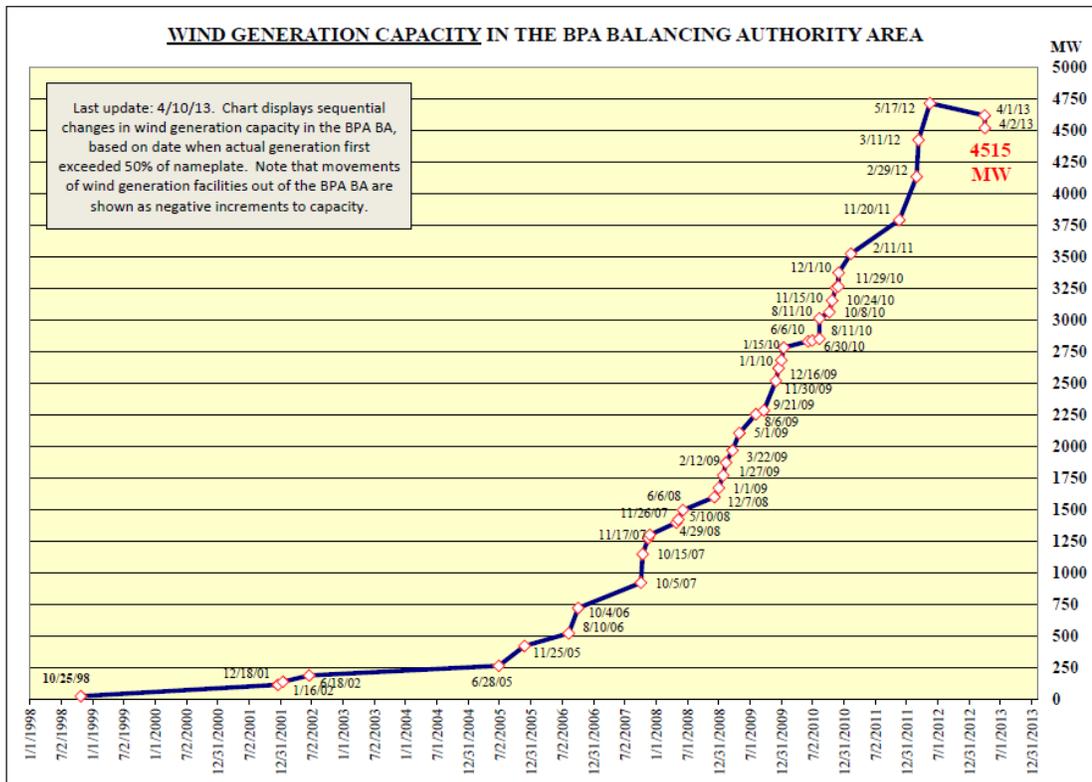
- System studies
  - ◆ Feasibility Study (FES)
  - ◆ Interconnection System Impact Study (ISIS)
  - ◆ Facility Study (FAS)
- National Environmental Protection Act (NEPA) Study
  - ◆ Completion required before the LGIA can be offered and any construction can begin.
- Project Requirements Diagram (PRD) and Estimates
  - ◆ After FAS report is issued, Planning prepares the PRD and requests estimates based on the plan of service defined in the PRD's. Typically requires 2-4 months.
- Capital Approval Project Authorization
  - ◆ Project has been nominated in the BPA Capital Prioritization process and has been assessed based on the project scope in order to provide an assessment of economic value associated with the project.
- Project is authorized within Transmission if total cost is less than \$3M, or by BPA if the cost exceeds \$3M.
- Engineering and Procurement (E&P) agreement
  - ◆ Can be initiated for large projects to the customer after the capital authorization process is complete. E&P funding is at customer's risk – if project does not execute an LGIA.
- LGIA offered and executed
  - ◆ The final Interconnection Agreement (LGIA) cannot be executed until Capital Project Authorization process and the NEPA review (ROD signed) have been completed.
  - ◆ With Executed LGIA, remaining funds are committed and construction of the project is allowed
- Timeline –
  - ◆ The FERC LGIP timeline is 14 months for the study phase taking into account all steps in the process outlined. (SGIP is 6-12 months, assuming no main grid impacts)
  - ◆ The studies are averaging 2 years with BPA study delays and extensions.
  - ◆ BPA advises customers that two years are typical to complete studies and execute a contract to initiate design (fund and list the project in the work plan).

- ◆ Impacts of huge work load and added capital authorization processes may result in longer schedules to complete projects
- ◆ An Owner-Engineer project may require additional time to initiate project.

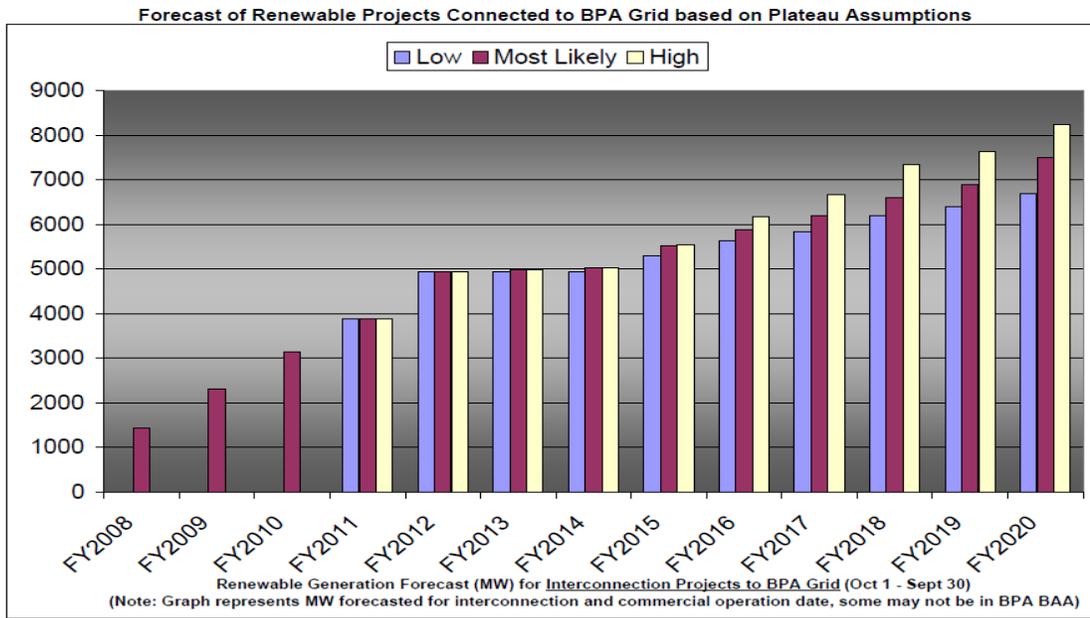
### 2.1.1 Program Accomplishments to date

Large generation projects underway such as PGE Tucannon River Wind (LSR2) and Summit Ridge Wind will be completed in FY2015. FY2013 new starts have signed LGIA’s or Engineering & Procurement Agreements, and FY2014 projects are currently progressing through capital authorization. Projects slated to go forward between FY2015 and FY2017 have been nominated through the capital prioritization process. As new requests progress forward to construction, BPA coordinates with the customer schedule. The customer project is usually one or more orders of magnitude more costly. Example: A 200 MW wind project may require a new 230 kV substation at \$12M, but the wind project cost is about \$400M.

The graph below shows the rapid completion of wind projects onto the grid in recent years.



Below is the longer range outlook for wind development in the NW that is likely to connect to the BPA grid.



NOTES:

S. Enyeart As of: 9/5/2013

## 2.1.2 Cost History

### Historical Actuals - Capital

#### Projects Funded in Advance (PFIA)

Real Dollars in '000

| Level 5 Node Name         | FY07            | FY08            | FY09            | FY10            | FY11            | FY12            | FY13           | Total            |
|---------------------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|----------------|------------------|
| Spectrum Relocation       | \$173           | \$5,843         | \$7,188         | \$5,445         | \$5,605         | \$5,364         | \$807          | \$30,425         |
| Generator Interconnection | \$53,074        | \$2,589         | \$12,831        | \$41,992        | \$62,056        | \$17,391        | -\$6           | \$189,927        |
| COI Addition Project      |                 | \$56            | \$11,121        | \$29,700        | \$9,580         | \$215           |                | \$50,672         |
| Misc PFIA Projects        | \$6,850         | \$8,826         | \$6,427         | \$6,036         | \$4,105         | \$4,657         | \$7,938        | \$44,839         |
| <b>Total</b>              | <b>\$60,097</b> | <b>\$17,314</b> | <b>\$37,567</b> | <b>\$83,173</b> | <b>\$81,346</b> | <b>\$27,627</b> | <b>\$8,739</b> | <b>\$315,863</b> |

## 2.2 Future State

GI reforms are underway that will implement sustainable processes to integrate renewable and other generation. By addressing the issue of stalled site permitting, customers desiring to move forward may interconnect within an appropriate timeline. The interconnection queue backlog will be reduced or eliminated.

### 2.2.1 Key program objectives, measures and targets

A key objective of the generation interconnection strategy is to interconnect customer projects as efficiently as possible to meet customer timelines. In doing this, BPA continues to fulfill its commitment to the region to provide an adequate, efficient, economical and reliable power supply.

BPA interconnects all customer projects that have gone through the high level process discussed in section 2.1. Customer projects will continue to be nominated in the prioritization process, but because they are considered as compliance investments, it is expected that all customer projects will be pursued.

## 2.3 Program Gaps

### 2.3.1 Risks to meeting the objectives

The risks below are the most important risks relevant to the Generation and Line/Load Interconnection program.

| Risk   | Risk Description   |
|--|--|
| Environmental constraints on siting                                    | Environmental constraints on transmission facility siting leads to unexpected project delays and cost over runs  |
| Unexpected changes in renewable portfolio standards and tax incentives | Unexpected changes in renewable portfolio requirements leads to abrupt changes in renewable resource generator development patterns and transmission service demands. Uncertainty in Production Tax Credits leads to uneven development. |
| Evolving NERC/WECC reliability standards                               | Evolving NERC/WECC reliability standards leads to the need to revise plans of service, delays in developing plans, or scope/cost increases in the plans to meet the new standards.   |
| Lack of clarity around project requirements and scope                  | Lack of clarity around project requirements and scope leads to evolving plans of service, delays in final development, potential rework and confusion, and increased costs.  |

Customer projects are included as part of the internal BPA work plan and must be prioritized against sustain and compliance projects. Projects must be included as part of the capital plan as far in advance as possible so that they may be prioritized. Customers must consider BPA timelines in their decision process/timelines. BPA must work with customers to include customer projects in planning processes to improve visibility of customer projects.

## 2.4 Strategic Approach to Closing Gaps

### 2.4.1 Strategic Approach

There are two primary approaches to closing program gaps. One is to pursue GI reforms. The other is to sync up the internal capital approval process with customer timeframes.

GI reforms will contribute most to addressing the risks and closing the gaps in the GI program. Environmental constraints on siting currently result in stalled site permits and the projects remain in the study queue, sometimes for years. Projects in the queue behind the stalled projects must face a higher level of uncertainty in their plan of service until it is known whether projects earlier in the queue will proceed.

If the GI reforms are approved, customers with stalled site permits will be offered another place in the queue, while projects with site permits will be able to go forward. Customers will have a higher level of confidence in their expected plan of service, including the financial impacts of the plan of service.

In addition to GI reform, BPA must work to sync up the internal capital approval process with customer timeframes. Customer projects must be included in the BPA Capital Project Prioritization Process and must be included in resource planning efforts so that needed resources are available to support customer projects and also to support a growing sustain program. A system is needed to manage all projects, including interconnection projects, in a timely manner. Present systems are focused on internal BPA projects.

## 3.0 STRATEGY IMPLEMENTATION PLAN

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### 3.1 10 year Implementation Plan

The following generation interconnection projects have been nominated into the BPA Capital Prioritization Process for FY2015-FY2017:

- G0314 Interconnection of Thompson Falls Hydroelectric Project
- G0361 Invenergy's Heppner Wind Stanfield Substation
- G0105 enXco's Desert Claim Wind Project
- Transmission Aggregated PFIA (bundled projects, each under \$3M)

If other projects come forward and should be considered for authorization between FY2015 and FY2017, they will be nominated and assessed through the prioritization process at that time.

Additional projects were nominated, but have since been deferred beyond the prioritization window based on the anticipated likelihood of the customer being ready to move forward:

- G0255 Invenergy (Horn Butte) Willow Creek Phase 2
- G0235 BP Alternative Energy's Golden Hills 2 Wind Project
- G0309-12 Horizon Energy-East Klickitat
- G0099-2 Golden Hills (John Day-Biglow 230 kV Substation)
- G0367 Iberdrola Renewables Inc, Bakeoven 1 Wind Project
- G0388 Exergy Development Group, LLC Badger Peak Wind
- G0389 and G0390 Swaggart Wind

### 3.2 Program Forecast Planning

The program plan will be developed once results from the prioritization process are evaluated and approved.

## **APPENDIX**

## Rights of Way

### Glossary of Terms

- Encroachments: Activities, uses, or vegetation on the rights-of-way (ROW) that intrude, invade or interfere, now or in the future, with BPA’s ability to safely access, construct, operate or maintain its facilities
- Rights-of-Way (ROW): Strips of land that have rights granted, through an easement or other mechanism, for purposes such as an electric transmission line, highways, railroad, gas line, etc.
- Easement: An interest in land owned by another that entitles its holder to a specific limited use or enjoyment.
- eGIS: BPA’s Enterprise Geographical Information System.
- ARMS: The Access Road Maintenance System is a GIS database that identifies roads that BPA uses to access BPA facilities. This database includes roads with legal land rights and roads without legal land rights.
- Danger Brush: Any vegetation located on the transmission line Right-of-Way (ROW), extending into the minimum clearance distance from the conductor as identified in Table 1 for Danger Brush.
- High Brush: Any vegetation located on the transmission line ROW extending into the minimum clearance distance from the conductor as identified in Table 1 for High Brush.
- Forbs: Herbaceous flowering plants that are not (grasses, sedges or rushes).
- License: Temporary (typically 1 year with renewal option) easement to access private property.
- Approach Permit: Land right obtained from City, County, State, and Federal agencies for the right to access a private road from a public one. These are sometimes fixed term permits that must be renewed.
- Fee: Property to which the Federal Government owns and has title to. BPA facilities and substation sites are typically owned in Fee.
- Permission to Enter Property (PEP): Written permission for BPA resources to access a specified property.
- Road Prism: the full structure of a road consisting of the driving surface, shoulders, ditches, and any cut slope and road embankment.

## Appendix A

### Access Roads Consequence Definition

|              |   |
|--------------|---|
| 4 = Extreme  | <p>*<u>Isolated Structures</u>: Outage duration &gt; 3 days</p> <p>*<u>Env. Degradation/Storm Events</u>: Lawsuits/negative press with stakeholder landowners/agencies due to catastrophic environmental damage from un-maintained roads, extensive repeated violations of the Clean Water Act.</p> <p>*<u>Safety</u>: Loss of life due to AR condition</p> |
| 3 = Major    | <p>*<u>Isolated Structures</u>: Outage duration &gt; 1 day</p> <p>*<u>Env. Degradation/Storm Events</u>: Broken relationships with stakeholder landowners/agencies, loss of trust, due to environmental damage from un-maintained roads, extensive violations of the Clean Water Act.</p> <p>*<u>Safety</u>: Serious injury due to AR condition</p>         |
| 2 = Moderate | <p>*<u>Isolated Structures</u>: Outage duration &gt; 8 hours</p> <p>*<u>Env. Degradation/Storm Events</u>: Deteriorating relationships with stakeholder landowners/agencies, due to ongoing environmental degradation from un-maintained roads, frequent violations of the Clean Water Act</p> <p>*<u>Safety</u>: Vehicle/equipment accidents</p>           |
| 1 = Minor    | <p>*<u>Isolated Structures</u>: Outage duration &lt; 4 hours</p> <p>*<u>Env. Degradation/Storm Events</u>: Strained relationships with stakeholder landowners/agencies, due to ongoing environmental degradation from un-maintained</p>   |

|  |   |
|--|---|
|  | roads, infrequent violations of the Clean Water Act |
|  | <b>*Safety:</b> Vehicle damage due to AR conditions |

NOTE: Consequence descriptions for Environmental Degradation and Storm Events are the same.

## Wood Poles

### Appendix B

#### Probability scale

| Probability Scales  |   |   |   |   |   |               |
|---|---|---|---|---|---|---------------|
| Level   | Rare<br>(<2)  | Unlikely<br>(Score 2 to 4)  | Possible<br>(Score 4 to 6)  | Likely<br>(Score 6 to 8)  | Almost Certain<br>(Score 8 to 10)   |               |
|   | Very rare to have a line outage as a result of component failures in the next 10 years (1 in 100 chance). | Unlikely to have a line outage as a result of component failures in the next 10 years (1 in 20 chance). | Possible to have a line outage as a result of component failures in the next 10 years (1 in 10 chance). | Likely to have a line outage as a result of component failures in the next 5 years (1 in 5 chance). | Almost certain to have a line outage as a result of component failures in the next 2 years (1 in 2 chance). |               |
| <b>Likelihood</b>   | <b>Excellent</b>  | <b>Good</b>   | <b>Fair</b>   | <b>Marginal</b>   | <b>Poor</b>   |               |
| <b>Rating Scale</b>   | <b>&lt;2</b>  | <b>2-3</b>  | <b>4-6</b>  | <b>7-8</b>  | <b>9-10</b>   | <b>Weight</b> |
| <b>Wood Pole Structures incl hardware</b>                                   | No condition 1, 2 or 3 poles on line  | Less than 10% condition 1, 2, or 3  | 10% to 20% of poles are rated 1,2 or 3  | More than 20% of poles rated 1, 2, or 3   | More than 50% are rated 1,2 or 3  | <b>50%</b>    |
| <b>Conductor</b>  | ACSR/TW and no known issues   | ACSR  | Non-standard conductor  | Conductor is obsolete and original to a line over 50 years  | Copper conductor and other conductor with known performance issues  | <b>20%</b>    |
| <b>Insulator &amp; Assemblies</b>   | Line <20 years, SW/Ceramic insulators   | Non-ceramic insulator <10 years old   | Ceramic between 20 and 40 years<br>Non-ceramic between 10 and 20 years                                  | Ceramic between 40 and 50 years   | Non-ceramic > 20 years<br>Ceramic > 50 years  | <b>10%</b>    |
| <b>Performance (SAIDI average over past 10 years and number of outages)</b> | No line outages in the last 10 years related to line components<br>SAIDI 0                                | one or fewer line outages related to components<br>SAIDI <100   | More than one line outage related to components<br>SAIDI 100 to 300                                     | 2-5 line component outages in last 10 years<br>SAIDI 300 to 500                                     | More than five in last 10 years<br>SAIDI greater than 500   | <b>20%</b>    |
|   |   |   |   |   |   | <b>100%</b>   |

### Appendix C

#### Consequence Scale

| Consequence Scales   |   |  |   |  |   |               |
|--|---|--|---|--|---|---------------|
| Level  | Insignificant<br>(Score <2)   | Minor<br>(Score 2 to 4)  | Moderate<br>(Score 4 to 6)  | Major<br>(Score 6 to 8)  | Extreme<br>(Score 8 to 10)  |               |
| <b>Reliability of Transmission Line in service</b>             | A failure to the transmission line occurs, but no customers lose power. | If a failure to the transmission line occurs, then there is a momentary outage, customers lose power but are not adversely impacted by the outage. | If a failure to the transmission line occurs, then there is an outage of short duration (less than 120 minutes), customers lose power and are inconvenienced by the outage. | If a failure to the transmission line occurs, then there is an outage of long duration (2 to 12 hours), customers lose power and are impacted by the outage. | If a failure to the transmission line occurs, then there is an outage of extended duration (over 24 hours), more than one BPA customer community is blacked out and results in significant financial losses for businesses and customers served by BPA. |               |
| <b>Consequence</b>   | <b>Insignificant (1-2)</b>  | <b>Minor (2 to 4)</b>  | <b>Moderate (4 to 6)</b>  | <b>Major (6 to 8)</b>  | <b>Extreme (8-10)</b>   | <b>Weight</b> |
| Line Category (1-4)  | 4   | 4  | 3   | 3  | 2   | <b>30%</b>    |
| Priority Pathways ranking                                      | Last Quartile   | Last Quartile  | 3rd Quartile  | 2nd Quartile   | 1st Quartile  | <b>60%</b>    |
| Number of taps on line   | No taps and line is not radial feed                                     | one tap and line is not radial feed  | Multiple taps and line is not radial feed   | Line is a radial feed  | Line is a radial feed with one or more taps   | <b>10%</b>    |
|  |   |  |   |  |   | <b>100%</b>   |
| <i>This scale only applies to Wood Pole Transmission Lines</i> |   |  |   |  |   |               |
| <b>Safety - Employee and Public</b>                            | No or minor injury, first aid   | Injury requiring treatment by medical professional   | Injury resulting in hospitalization   | Injury resulting in permanent disability   | fatality  | <b>0%</b>     |

## Steel Lines

### Appendix D

#### BPA Transmission Reliability (FY2013)

##### Summary

- SAIFI = System Average Interruption *Frequency* Index
- Addresses the frequency of automatic (unplanned) outages
- Measures the average number of automatic outages, per line, per year
- Applies to lines as grouped by the four Importance Ranks (345 total lines in FY2008)
  
- SAIDI = System Average Interruption *Duration* Index
- Addresses the duration of automatic (unplanned) outages, i.e., restoration time
- Measures the average total duration, in minutes, of automatic outages, per line, per year
- Applies to lines as grouped by the four Importance Ranks (345 total lines in FY2008)

|              |  |
|--------------|--|
| Description: | Outage frequency SAIFI (System Automatic Interruption Frequency Index [number of unplanned outages per line per year]) and duration SAIDI (System Automatic Interruption Duration Index [total duration of unplanned outages per line per year]) for transmission lines, by line importance rank, do not exceed control chart violation limits.  |
| Background:  | Maintaining system reliability is a critical BPA responsibility. Reliability measures are monitored to help minimize both the frequency and duration of automatic (unplanned) line outages on the BPA system. SAIFI and SAIDI data are used in Transmission’s capital and expense planning, maintenance, and operations processes.   |
| Methodology: | <p>Reliability assessment is based on IEEE-standard measures of outage frequency (SAIFI) and duration (SAIDI). Control chart techniques, closely mirroring transmission reliability methodology adopted by the California ISO, are used to establish allowable performance levels for each line importance category (1-4). Control charts are statistically-based graphs which illustrate the natural range of variability in performance, based on the most recent 10 years of historical data (FY2003-2012). In general, the Control Limit is calculated as the 3-standard deviation band, and the Warning Limit as the 2-standard deviation band, based on historical line performance. Actual SAIFI and SAIDI measures in FY2013 are then compared to the control chart limits to gauge the adequacy of system reliability. The goal is to have no control chart violations for line importance categories 1 &amp; 2, and not more than one violation for line importance categories 3 &amp; 4.</p> <p>Control chart violations are defined as follows:</p> <ul style="list-style-type: none"> <li>• Latest FY above the Upper Control Limit (short-term degradation)</li> <li>• 2 of last 3 FYs above the Upper Warning Limit (mid-term degradation)</li> <li>• Continuous worsening trend in the last six FYs (long-term degradation)</li> </ul> |
| Remarks:     | The following outage inclusion/exclusion rules apply for FY2013:   |

|               |   |                      |              |               |
|---------------|---|----------------------|--------------|---------------|
|               | <ul style="list-style-type: none"> <li>Reliability monitoring is based on automatic (unplanned) outages to transmission lines (not points-of-delivery)</li> <li>Duration of any single outage is capped at 4,320 minutes (72 hours)</li> <li>Momentary outages are excluded</li> <li>Outages to lines with all or part non-federal ownership are excluded</li> <li>Outages in the year in which a line may have been energized or retired are excluded (i.e., line must have “full year” availability)</li> <li>Outages with a cause attributed to a foreign utility are excluded</li> <li>Overlapping outages to the same line, due to multiple section or tap outages, are compressed to eliminate double-counting of outage duration (starting with FY2011 targets and reports)</li> </ul> |                      |              |               |
| Targets:      | <b>Line Rank</b>  | <b>Limit</b>         | <b>SAIFI</b> | <b>SAIDI</b>  |
|               | 1   | <b>Upper Control</b> | <b>1.00</b>  | <b>460.31</b> |
|               |   | <b>Upper Warning</b> | <b>0.89</b>  | <b>371.61</b> |
|               |   | Lower Warning        | 0.46         | 85.47         |
|               |   | Lower Control        | 0.39         | 49.17         |
|               | 2   | <b>Upper Control</b> | <b>1.04</b>  | <b>267.81</b> |
|               |   | <b>Upper Warning</b> | <b>0.81</b>  | <b>208.52</b> |
|               |   | Lower Warning        | 0.22         | 22.63         |
|               |   | Lower Control        | 0.16         | 9.29          |
|               | 3   | <b>Upper Control</b> | <b>0.85</b>  | <b>668.76</b> |
|               |   | <b>Upper Warning</b> | <b>0.70</b>  | <b>485.87</b> |
|               |   | Lower Warning        | .20          | 37.37         |
|               |   | Lower Control        | .13          | 12.48         |
|               | 4   | <b>Upper Control</b> | <b>.88</b>   | <b>567.18</b> |
|               |   | <b>Upper Warning</b> | <b>.77</b>   | <b>457.36</b> |
|               |   | Lower Warning        | .31          | 87.73         |
| Lower Control |   | .25                  | 48.65        |               |
| Contact:      | Transmission Technical Operations/TOT   |                      |              |               |

### BPA Transmission Availability FY2013

|              |   |
|--------------|---|
| Description: | Minimize <i>Planned</i> outages on the system’s most important lines (ranks 1&2) such that Availability does not fall below violation limits. Transmission Availability for line ranks 1&2 represents a key agency target (KAT) for BPA.  |
| Background:  | Maintaining system availability is a critical BPA responsibility. Availability measures are monitored to help minimize the amount of time the most important lines on the system are out of service for maintenance, construction, and related “planned” activities, thus maximizing the commercial availability of the grid. Availability data are used in Transmission’s capital and expense planning, maintenance, and operations processes. |

|              |   |
|--------------|---|
| Definition:  | Percentage of time lines are available for service.   |
| Calculation: | Availability = $\frac{\text{Total Time} - \text{Outage Time}}{\text{Total Time}}$   |
| Methodology: | <p>Control chart techniques are used to establish allowable performance levels for system availability. Control charts are statistically-based graphs which illustrate the natural range of variability in performance, based on the most recent 5 years of historical data (FY2008-FY2012). In general, the Control Limit is calculated as the 3-standard deviation band, and the Warning Limit as the 2-standard deviation band, based on historical line availability, for lines of importance ranks 1 &amp; 2 only. Actual Availability in FY2013 is then compared to the limits. The availability goal is to have no control chart violations.</p> <p>Control chart violations are defined as follows:</p> <ul style="list-style-type: none"> <li>• Latest FY below the Lower Control Limit (short-term degradation)</li> <li>• 2 of last 3 FYs below the Lower Warning Limit (mid-term degradation)</li> <li>• Continuous worsening trend in the last six FYs (long-term degradation)</li> </ul>  |
| Targets:     | <ul style="list-style-type: none"> <li>• Run at the beginning of each fiscal year (e.g. October)</li> <li>• Timeframe most recent five completed fiscal years</li> <li>• One set of targets produced for the entire period</li> </ul>   |
| Reports:     | <ul style="list-style-type: none"> <li>• Run at the end of each quarter (e.g. beginning of Jan, Apr, Jul, Oct)</li> <li>• Timeframe most recent ten completed fiscal years</li> <li>• Reports compare the portion of the fiscal year completed to like portions of prior fiscal years (e.g. first quarter this FY compared with first quarter prior FYs)</li> <li>• Availability of individual lines reported from lowest availability to highest availability</li> <li>• Line Importance Rank 1&amp;2 combined into a single report</li> </ul>   |
| Assumptions: | <ul style="list-style-type: none"> <li>• Planned outages only, excludes automatic outages</li> <li>• Transmission line outages only, excludes customer point of delivery outages</li> <li>• Momentary outages (minutes duration = 0) excluded</li> <li>• Includes Line Ownership 1-“All BPA” and 2-“Foreign Federal (all or part)”, excludes 3-“Foreign Non-Federal (all or part)”</li> <li>• Outages in the year in which a line may have been energized or retired are excluded (i.e., line must have “full year” availability)</li> <li>• Outages to the four Big Eddy-Celilo feeder lines are excluded: <ul style="list-style-type: none"> <li>• Big Eddy-Celilo No 1 500kV line</li> <li>• Big Eddy-Celilo No 2 500kV line</li> <li>• Big Eddy-Celilo No 3 230kV line</li> <li>• Big Eddy-Celilo No 4 230kV line</li> </ul> </li> <li>• Outages with causes Maintenance – TOp, Voltage Control, Foreign Request, and Normally Out are excluded</li> <li>• Tap outages excluded (generated flag = “T”)</li> <li>• Overlapping outages to the same line, due to multiple section outages, are</li> </ul> |

|          |   |               |  |
|----------|---|---------------|--|
|          | compressed to eliminate double-counting of outage duration (starting with FY2011 targets and reports) |               |  |
| Targets: | <b>Line Rank</b>  | <b>Limit</b>  | <b>Percentage</b>                          |
|          | <b>1 &amp; 2</b>  | Upper Control | 99.16 %                                    |
|          |   | Upper Warning | 99.03 %                                    |
|          |   | Lower Warning | 98.05 %                                    |
|          |   | Lower Control | 98.00 % (managerially adjusted from 97.72) |
| Contact: | Transmission Technical Operations/TOT   |               |  |

**Appendix E**

**Steel Lines Data Tables for Current State Bubble Charts**

Component Condition Characterization Parameters for 500kV Lines (as of 10-2013)

| Likelihood of Failure |                               | UNLIKELY    |               |      | POSSIBLE          |      |               |    | LIKELY            |     |               |     | ALMOST CERTAIN |               |    |
|-----------------------|-------------------------------|-------------|---------------|------|-------------------|------|---------------|----|-------------------|-----|---------------|-----|----------------|---------------|----|
| Component             | Average Theoretical Life Span | Age Range ≤ | Circuit Miles |      | Age Range Between |      | Circuit Miles |    | Age Range Between |     | Circuit Miles |     | Age Range >    | Circuit Miles |    |
|                       |                               |             | Towers        | 100  | 81                | 4887 | 100%          | 80 | 111               | 0   | 0%            | 110 |                | 131           | 0  |
| Conductors            | 70                            | 66          | 4887          | 100% | 65                | 86   | 0             | 0% | 85                | 106 | 0             | 0%  | 105            | 0             | 0% |
| Insulator Assemblies  | 40                            | 51          | 4855          | 99%  | 50                | 66   | 32            | 1% | 65                | 81  | 0             | 0%  | 80             | 0             | 0% |
| Connectors            | 60                            | 61          | 4887          | 100% | 60                | 81   | 0             | 0% | 80                | 101 | 0             | 0%  | 100            | 0             | 0% |
| Spacer Dampers        | 40                            | 41          | 3883          | 86%  | 40                | 51   | 304           | 7% | 50                | 61  | 0             | 0%  | 60             | 353           | 8% |
| Dampers               | 40                            | 31          | 1686          | 72%  | 30                | 41   | 0             | 0% | 40                | 51  | 444           | 19% | 50             | 207           | 9% |
| Footings              | 80                            | 81          | 4887          | 100% | 80                | 111  | 0             | 0% | 110               | 131 | 0             | 0%  | 130            | 0             | 0% |
| Counterpoise          | 80                            | 66          | 1466          | 100% | 65                | 81   | 0             | 0% | 80                | 101 | 0             | 0%  | 100            | 0             | 0% |

Component Condition Characterization Parameters for 230-345kV Lines (as of 10-2013)

| Likelihood of Failure |                               | UNLIKELY    |               |      | POSSIBLE          |      |               |     | LIKELY            |     |               |     | ALMOST CERTAIN |               |     |
|-----------------------|-------------------------------|-------------|---------------|------|-------------------|------|---------------|-----|-------------------|-----|---------------|-----|----------------|---------------|-----|
| Component             | Average Theoretical Life Span | Age Range ≤ | Circuit Miles |      | Age Range Between |      | Circuit Miles |     | Age Range Between |     | Circuit Miles |     | Age Range >    | Circuit Miles |     |
|                       |                               |             | Towers        | 100  | 81                | 5230 | 100%          | 80  | 111               | 0   | 0%            | 110 |                | 131           | 0   |
| Conductors            | 70                            | 66          | 4091          | 78%  | 65                | 86   | 1139          | 22% | 85                | 106 | 0             | 0%  | 105            | 0             | 0%  |
| Insulator Assemblies  | 40                            | 51          | 2139          | 41%  | 50                | 66   | 2429          | 46% | 65                | 81  | 662           | 13% | 80             | 0             | 0%  |
| Connectors            | 60                            | 61          | 2580          | 49%  | 60                | 81   | 2651          | 51% | 80                | 101 | 0             | 0%  | 100            | 0             | 0%  |
| Spacer Dampers        | 40                            | 41          | 52            | 100% | 40                | 51   | 0             | 0%  | 50                | 61  | 0             | 0%  | 60             | 0             | 0%  |
| Dampers               | 40                            | 31          | 524           | 10%  | 30                | 41   | 139           | 3%  | 40                | 51  | 789           | 15% | 50             | 3777          | 72% |
| Footings              | 80                            | 81          | 5230          | 100% | 80                | 111  | 0             | 0%  | 110               | 131 | 0             | 0%  | 130            | 0             | 0%  |
| Counterpoise          | 80                            | 66          | 1203          | 77%  | 65                | 81   | 367           | 23% | 80                | 101 | 0             | 0%  | 100            | 0             | 0%  |

Component Condition Characterization Parameters for 115kV Lines (as of 10-2013)

| Likelihood of Failure |                               | UNLIKELY    |               |      | POSSIBLE          |     |               |     | LIKELY            |     |               |     | ALMOST CERTAIN |               |     |
|-----------------------|-------------------------------|-------------|---------------|------|-------------------|-----|---------------|-----|-------------------|-----|---------------|-----|----------------|---------------|-----|
| Component             | Average Theoretical Life Span | Age Range ≤ | Circuit Miles |      | Age Range Between |     | Circuit Miles |     | Age Range Between |     | Circuit Miles |     | Age Range >    | Circuit Miles |     |
|                       |                               |             | Towers        | 100  | 81                | 605 | 100%          | 80  | 111               | 0   | 0%            | 110 |                | 131           | 0   |
| Conductors            | 70                            | 66          | 481           | 79%  | 65                | 86  | 124           | 21% | 85                | 106 | 0             | 0%  | 105            | 0             | 0%  |
| Insulator Assemblies  | 40                            | 51          | 373           | 62%  | 50                | 66  | 127           | 21% | 65                | 81  | 106           | 17% | 80             | 0             | 0%  |
| Connectors            | 60                            | 61          | 461           | 76%  | 60                | 81  | 144           | 24% | 80                | 101 | 0             | 0%  | 100            | 0             | 0%  |
| Dampers               | 40                            | 31          | 177           | 29%  | 30                | 41  | 123           | 20% | 40                | 51  | 73            | 12% | 50             | 233           | 38% |
| Footings              | 80                            | 81          | 605           | 100% | 80                | 111 | 0             | 0%  | 110               | 131 | 0             | 0%  | 130            | 0             | 0%  |
| Counterpoise          | 80                            | 66          | 138           | 76%  | 65                | 81  | 44            | 24% | 80                | 101 | 0             | 0%  | 100            | 0             | 0%  |

Appendix F

**Likelihood and Consequence Definitions for Steel Lines Program**

Likelihood:

|                |   |
|----------------|---|
| Unlikely       | Like new condition, failure extremely rare            |
| Possible       | Possible but not probable                             |
| Likely         | The occasional failure is happening                   |
| Almost Certain | Component failures are happening with some regularity |

Consequence:

|          |  |
|----------|--|
| Minor    | If component fails, will not cause an immediate outage, however, may accelerate deterioration of other more costly components over time  |
| Moderate | If component fails, and is not repaired, it may damage other more costly components and cause an outage or if this component fails, it may not cause an outage but could be costly to repair |
| Major    | If component fails, it will likely drop conductor and cause an outage. High public safety risk.  |
| Extreme  | If component fails, it will almost certainly cause an outage, be a high public safety risk and be costly to repair   |

**Appendix G**

Likelihood and Consequence Definitions for PSC Program

| <b>PSC Consequence Definition</b> |   |
|-----------------------------------|---|
| 6-7 = Extreme                     | Violations resulting from multiple contingencies even after load shedding over 300 MW has been applied          |
| 4-5 = Major                       | Violations resulting from multiple contingencies even after load shedding of 100 MW to 300 MW have been applied |
| 2-3= Moderate                     | Load loss of 50 to 100 MW   |
| 0-1 = Minor                       | Load loss of up to 50 MW  |

| <b>PSC Probability Scale</b> |                |  |
|------------------------------|----------------|--|
| Level                        | Descriptor     | Frequency  |
| 5                            | Almost Certain | Once a year or more frequently   |
| 4                            | Likely         | The event will probably happen in most conditions (~once in every 2 years) |
| 3                            | Possible       | The event should happen at some time (~once in every 5 years)              |
| 2                            | Unlikely       | The event could happen at some time (~once in every 10 years)              |
| 1                            | Rare           | This event could happen once every 30 years                                |

Appendix H

**Risk Table Definitions**

|              |  |
|--------------|--|
| 4 = Extreme  | * <u>Acquisition of Permanent or Temporary Land Rights Prior to Construction</u> - Without legal access we cannot perform any maintenance or construction activities.  |
| 3 = Major    | NA   |
| 2 = Moderate | * <u>Acquisition of Permanent Land Rights Prior to Construction Date</u> - Without legal access we cannot perform maintenance or construction activities. Risk is moderate as we can construct using temporary licenses. |
| 1 = Minor    | NA   |

## **FINANCIAL DISCLOSURE**

This information has been made publicly available by BPA on February 18, 2014 and contains information not reported in BPA financials statements.