TRANSMISSION ASSET STRATEGY

EXECUTIVE SUMMARY
1 Transmission

1.1 Purpose and Scope

The Bonneville Power Administration owns and manages about three-fourths of the region’s high voltage transmission assets. BPA’s transmission system is the largest of 17 balancing authorities in the Pacific Northwest. This system spans approximately 300,000 square miles and much of four states (with service to four others) and includes more than 15,000 circuit miles of transmission lines and 251 substations. These assets deliver electric power, directly or indirectly, to a Northwest 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

Transmission Services’ Asset Management Strategy provides the roadmap for managing the health, performance, costs and risks of transmission assets owned or leased by BPA. Its strategic ambition is two-fold and ensures

- that critical existing assets, including transmission lines, substations, control center equipment and other facilities and equipment are sustained to meet reliability and availability requirements; and
- that expansion of the system provides the needed transmission capacity and flexibility into the future.

These objectives are to be accomplished while minimizing long-term costs.

1.2 BPA’s Transmission Programs

Sustain existing assets

Because of the age of the transmission system, the deteriorating condition of some equipment and facilities, and years of underinvestment, serious backlogs of needed replacements have developed. BPA has spent the past two years refining its transmission sustain programs and creating long-term asset strategies to overcome the backlogs and determine an optimized replacement plan. Strategies are developed for:

- Alternating and direct current substations
- Control centers
- Power system control/telecommunications
- System protection and control
- Rights-of-way
- Steel lines
- Wood 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 now contains an evaluation of asset health and risk of failure to the system along with a strategy for mitigating the risks. The strategies provide the direction for replacing the most critical assets first.

The challenges facing BPA’s transmission sustain programs include managing the risks of an aging infrastructure, including equipment failure and technological obsolescence risks, and managing funding, labor, outage 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 communications 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. The capital plan includes investments in each of these programs in order to regain and maintain asset health over the long term and thereby assure the system will perform with the required reliability and availability.

The sustain program strategies, specify an implementation plan to mitigate risks, slow down or eliminate growing backlogs, and reach the optimal steady state of replacements.

**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 also 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 (project funded in advance).

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. These include modernization and upgrades to the Celilo Converter Station and the Pacific Direct Current Intertie north of the California-Oregon border.

The expand load service strategy proposes a set of investments to meet expansion requirements as well as to upgrade and modernize a system that is over 70 years old. 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 agency’s ability to schedule outage time for
needed maintenance, repairs and replacements. The generation interconnection strategy fulfills the need to incorporate and integrate the ramp up in wind and other generating resources. 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.

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

### 1.3 Transmission Assets Covered

**Alternating Current Substations:** 251 Substations and 32,000 major voltage equipments

- 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, Seismic Hardening, Substation Grounding, Substation Bus and Structures, Low Voltage Station Auxiliary

**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 65 + 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 support systems; Commercial Business Systems/facilities

**Power System Control / Telecommunications:** 732 sites and 11,250 pieces of equipment, 3,000 miles of fiber optic cable

- RAS, Transfer Trip, SCADA, Fiber cable, Comm batteries/chargers, SONET/MW Radios, VHF/mobile/portable radios, UHF, DATS, Multiplex, Power Line Carrier, Telemetering, Operational Networks/NMS, Engine Generators, Supervisory Control Systems, UPS, Telephone systems, Telephone protection, FIN network, Misc support systems

**Rights of Way:** 266,600 acres of BPA maintained ROW corridors, 295 corridors, 423 transmission lines, 289 substations, 368 communication sites, 11,858 miles of access roads, approx. 80,000 tracts of easement

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

**System Protection and Control:** 950 locations, 28,391 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

**Steel Lines:** 10,660 circuit miles with 43,000 steel lattice towers

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

**Wood Lines:** Approx. 5,000 miles, 336 separate transmission lines with 75,000 wood poles

- Poles, Conductors, Insulator assemblies, Guy assemblies, Fiber optic cable, Line disconnect switches, Ground wire, Counterpoise
1.4 Key accomplishments

During the 2010 IPR, Transmission Services laid out a set of objectives for enhancing its asset management program. Key objectives included developing asset strategies for sustain programs that were not included in the 2010 IPR and making process improvements in resource planning and project management processes.

Asset strategy development

In addition to the asset strategies presented at the 2010 IPR, strategies have now been developed for rights-of-way, AC substations and power system control/telecom assets. During the past two years, Transmission Services has begun implementing an economic value-based method to better determine the level of effort that is needed for each sustain program and the priority that should be assigned when replacing equipment. This new, leading-practice method 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. Application of the method has been completed for power system control assets, and the project to apply the method to all control system assets is currently in implementation planning. A remedial action scheme strategy is also in development and is expected to be complete by the end of calendar year 2012. The method will be extended to the rest of the sustain program assets in FY 2013-2014.

Resource planning

As a result of a greatly expanded capital program, Transmission Services determined it needed a strategic staffing approach for project execution. The Strategic Capability Planning team was formed in 2011 to increase efficiency in project execution through more effective forecasting and use of staffing resources. An extensive evaluation of the personnel required for implementing various work was conducted and analyzed to determine where capacity exists and where there are constraints. The knowledge gained from this evaluation will drive the development of a staffing strategy based on the availability of key resources required to execute the work plans identified in the asset strategies.

Contract Management Office (CMO)

At the 2010 IPR, the CMO introduced use of an owner’s engineer; a pool of engineers, procure and construct firms; and other contracting approaches to complete additional capital projects without increasing federal employee levels. Using these methods, BPA completed over $171 million of projects in FY 2011 through the CMO and over $247 million in projects in FY 2012. Further, BPA has initiated a construction administration and inspection contract that has enabled much better coverage of contracted construction and higher quality results. The flexibility the CMO provides to match the need to deliver the capital program is establishing BPA’s credibility with the region. The CMO will continue to assess, improve and expand these approaches to deliver the capital program well into the foreseeable future.
Project and program accomplishments

As a result of significant improvement in project management processes, training and operating procedures, as well as the increased use of CMO-administered owner’s engineer contracts, BPA executed 95 percent of its direct capital spending in 2011 as compared to 72 percent in 2010.

Sustain programs

In FY 2010 and FY 2011, the sustain programs met many key targets toward replacing at-risk assets. In general, the programs achieved what was planned. Some of the accomplishments are noted below.

During the past two years, BPA replaced a total of 2,130 wood poles as part of the life extension portion of the transmission wood line strategy – 1,278 poles in FY 2010 and 852 poles in FY 2011 – in nine wood pole line rebuild projects. As of the end of calendar year 2011, approximately 146 miles of wood pole transmission lines have been rebuilt using owner’s engineer contracts.

In FY 2009, Transmission Services discovered that the spacer damper materials installed on approximately 1,700 miles of BPA’s system from 2001 to 2008 were defective. After extensive analysis, Transmission Services initiated an aggressive three-year program in FY 2012 to replace all defective units and renewed its commitment to a robust quality assurance/quality control program to minimize this risk in the future. In FY 2010-2011 the steel lines sustain program successfully replaced over 1,500 miles of spacer dampers and replaced 87 miles of insulators while installing bird dung deflectors on 11 towers in 2011.

Support from the right-of-way program is essential to the success of the lines programs. In FY 2010-2011, the right-of-way program successfully completed 97 percent of the access road projects planned in support of the wood and steel lines programs on schedule and within budget. The Vegetation Management Right of Way Asset management plan established program health metrics, and implemented project management principles including the use of earned value management for scheduled maintenance projects. Since 2010 the program has reduced the number of corrective maintenance locations (Hot Spots) from over 12,000 to under 4,000 for FY 2013. The Vegetation Management strategy is continuing to pursue the development of a vegetation management software solution to enhance the work management process.

The 2010 control center strategy identified nine projects to address critical asset risks. Five have been completed – the remaining four will be completed between FY 2012 and FY 2014. Transmission Services made significant improvements in control center program project portfolio management, including project standards and oversight processes, in FY 2011, which will improve program and project visibility and execution performance.

The AC substations program made great progress in replacing key equipment such as circuit breakers, circuit switchers, disconnect switches, transformers, reactors and low voltage auxiliary equipment such as DC control batteries and chargers. The program met all targets
while addressing multiple emergency replacements of various equipment including control batteries, instrument transformers, bus risers, switchgear and transformers.

**Expand program**

The expansion program efforts have been focused on developing and constructing numerous large projects, many of which were identified during the 2010 IPR process.

**Main Grid:**

*Completed*

- Big Eddy-Knight – a new 500-kV substation (Knight)
- Central Oregon Reinforcement – a new 500/230 kV bay at Ponderosa Substation.
- Puget Sound Area Northern Intertie (PSANI) Memorandum of Agreement – a new 500/230-kV bank at BPA’s Raver Substation and improved remedial action scheme for the Northern Intertie.
- Lower Mid-Columbia – line and substation upgrade to increase peak rating.
- Forest Grove – addition of 115-kV bay.
- Ostrander – new 500/230-kV transformer.

*In progress*

- Big Eddy-Knight – a new 28-mile, 500-kV transmission line connecting BPA’s Big Eddy 500-kV substation to the Knight substation.
- Pearl Substation – new 500kV Bay addition
- PSANI project – major upgrades at Raver substation and surrounding area
- Alvey Substation – addition of new shunt capacitors

**Upgrades and Additions:**

*Completed*

- Purchased and installed 500-kV single phase spare transformers at five key substations.
- California-Oregon Intertie Series Capacitor Control and Protection System Upgrade – replaced existing analog controls with new modern digital controls for the series capacitors at Sand Springs, Fort Rock, Sycan, Captain Jack and Alvey substations.
- Pacific Direct Current Intertie Modernization and Upgrade (Celilo) – completed phase 1 work including a technical analysis that defined the scope and performance requirements, a risk analysis and mitigation study, a preliminary design, a refined project cost estimate and a high voltage direct current market analysis.
- The COI communication upgrade migrated from analog microwave to fiber and digital radio communication. Also completed a joint fiber ring in the Puget Sound area with Puget Sound Energy.
In progress
- Pacific Direct Current Intertie Modernization and Upgrade (Celilo) – As of the fall of FY2012, bids on this project have been received and are in the process of being evaluated. The project will extend through FY16.
- Significant improvements are underway to replace the analog controls for the Series Capacitors on the third alternating current line. This work should be completed in FY2014.

Customer Requested Projects (Projects Funded in Advance):

Completed
- Generator interconnection projects at numerous sites (e.g., Lower Snake River and Shepards Flat)
- Miscellaneous customer requested projects – numerous smaller wind and customer projects.

In progress
- Spectrum Relocation project – multiyear project will be finished in FY 2013.
- COI addition project – wrapping up work on COI 4800 project.
- Six large generation interconnection projects approved.

1.5 Asset Management Objectives

BPA’s transmission asset management vision and strategic objectives are derived from BPA’s mission, vision and agency-level strategic business objectives.¹ Seven of the strategic objectives are important drivers of this asset management strategy and are detailed in Appendix A in the Transmission Asset Strategy Appendices found online. These strategic objectives drive important long-term goals for managing assets and together with a number of strategic initiatives, form the foundation of Transmission’s long-term approach for improving and optimizing its asset management program.

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.

Long-term goals
for improving asset management practices:

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<td>G1</td>
<td>Transmission asset management practices conform to leading practices.</td>
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<td>G2</td>
<td>Expansion, replacements, and maintenance are integrated, prioritized in terms of asset criticality and risk, and directed at</td>
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¹ BPA’s mission statement and strategic objectives are available at: http://www.bpa.gov/corporate/About_BPA/
meeting reliability and other standards at least life cycle cost.

G3 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:**

- **G4** Load service obligations and customer service requests meet standards and tariff requirements.
- **G5** An integrated regional expansion planning process is implemented
- **G6** A robust grid that effectively and efficiently integrates diverse energy resources
- **G7** Inter-regional transfer capacity meets reliability standards and commercial needs
- **G8** Fuller, more optimal use is made of existing transmission capacity through technological, policy and process change

**for sustaining assets:**

- **G9** Information on asset attributes (condition, performance, and costs) is complete, accurate, and readily accessible
- **G10** 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 least life cycle cost
- **G11** Maintenance is reliability-centered (condition-based)

**Strategic initiatives**

Transmission Services approved a set of 18 robust and aggressive strategic initiatives to assure it is on track to meet its long-term goals. The complete list of initiatives can be found in Appendix B.

**System performance measures and targets**

Transmission Services has adopted system performance measures, or metrics, to monitor the overall reliability, adequacy and availability of BPA’s transmission system (shown in Figure 1). Most of these measures are included in Transmission Services’ annual balanced scorecard for managing performance. The methodology for tracking and documenting the progress on these measures are in Appendix C.

End-stage targets are defined as the “future state” level of performance to be achieved for each metric over time. These system performance measures and targets are supplemented with asset program-specific metrics and targets contained in the sustain and expand program strategies. Reports on BPA’s transmission system FY2012 performance results can be found in Appendix D.
### System Performance Measures

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<th>System Performance Measures</th>
<th>End-stage Targets</th>
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<td><strong>System Average Interruption Duration Index (SAIDI)</strong> - Average duration of automatic outage minutes by BPA line category.</td>
<td>No control chart violations per year for line importance categories 1-2.</td>
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<td>Provides an indication of BPA’s success at minimizing the duration of unplanned transmission line outages.</td>
<td>No more than 1 control chart violation per year for line importance categories 3-4.</td>
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<td>Included in Transmission Services FY 2012 balanced scorecard.</td>
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| **System Average Interruption Frequency Index (SAIFI)** - Average number of automatic outages by BPA line category. | No control violations per year for line importance categories 1-2. |
| Provides an indication of BPA’s success at minimizing the number of unplanned transmission line outages. | No more than 1 control chart violation per year for line importance categories 3-4. |
| Included in Transmission Services FY 2012 balanced scorecard. | |

| **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) | No outages to transmission lines of all voltage levels caused by vegetation growth. |
| | No end-stage target will be set for this metric during this planning cycle. |

| **System Operating Limits (SOL) for BPA Paths, Interties, & Flowgates.** | |
| Number of minutes that actual path flows are near, at or above System Operating Limits. Indicates congested areas for which capacity expansion may merit consideration. | |

| **Availability for service of BPA’s most important transmission lines (Category 1 and 2)** | BPA’s most important transmission lines (Category 1 and 2) are available for service at least 98.0% of the time. |
| Included in Transmission Services FY 2012 balanced scorecard. | |
1.6 **KEY DRIVERS AND RISK**

*Existing infrastructure*

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.

Transmission assets generally have long expected lives. On BPA’s system, it’s not unusual to encounter transformers, poles 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 2 indicates that 40 percent of AC power transformers with an expected life of 45 years are over 50 years old. 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 agency’s rate of replacement is lower than most other utilities benchmarked.

Prior years of underinvestment created issues in most of the sustain programs. Although progress has been made, replacement has lagged behind expansion projects, and investment in sustaining the existing infrastructure has not kept up with depreciation. For example, based on system requirements, the power system and control program replacement investments should be approximately $20 million annually. Historically, only $3 million to $4 million has been spent each year on replacements, which has created a perpetual problem of emergency replacements and high maintenance costs.

As a result, failures occur that regularly require costly outages with accompanying high emergency response costs. Failures lead to unplanned transmission and customer outages that put the system’s reliability at risk (see Figure 3). As part of the integrated control system strategy underway this year, reliability risks from equipment failures and line outages are being monetized and are considered to be a key factor for determining an optimized replacement plan based on total economic cost. While the strategies lay out the plans to address the backlog of repair and replacements, an effort to extend the economic evaluation method beyond the control system assets to line and substations is in the works to fully account for the cost associated with reliability risks. This is paramount to developing a work plan that best mitigates risks at the lowest total economic cost.

**Technological Obsolescence**

A major challenge facing Transmission Services is the rapid evolution of technology in areas such as communications. The system currently is a mix of analog microwave and Synchronous Optical Network (SONET) digital communications equipment. Migration to a fully digital system is underway but will take approximately eight years to complete. BPA has lagged behind the industry and is feeling the effects of this delay on system reliability. 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.

**New Transmission**

BPA has recently relied on increasing the capability of existing lines through the addition of remedial action schemes, reactive power support and dynamic operating limits. These systems have added to the complexity of operating and maintaining a reliable transmission system.

As utilization of the existing assets increases, operational flexibility can be reduced because planned outages for required maintenance become more difficult to obtain and unplanned outages cause greater disruptions. BPA currently monitors 10 flowgates for transmission congestion. Transmission congestion in real time or on a long-term firm basis may lead to suboptimal dispatch and generation resource development. Present tools for managing congestion are generally limited to actions within the BPA balancing authority.

**Collaborative projects**

Transmission lines are often discrete investments available in a limited number because of standard designs and operating voltages. The capacity that a single utility needs may be less than the standard increment available. Regional transmission investments can be optimized if multiple utilities partner on a project and share capacity. For example, opportunities to build a more efficient line with a higher operating voltage or a double-circuit configuration may exist in some instances. Therefore, BPA is currently exploring joint participation in multiple regional transmission projects with other utilities.

BPA is a signatory to the ColumbiaGrid 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 this process.

The timelines for investment decisions on collaborative regional projects and external project proposals may not always align closely with BPA's present budgeting cycles. BPA risks lost opportunities if it is unable to respond to the schedule requirements of potential partners.

**FERC Order 1000**

FERC Order 1000\(^2\) establishes the following requirements for transmission planning and transmission cost allocation:

- Each transmission provider must participate in a regional transmission planning process that produces a single regional transmission plan and satisfies the principles under Order No. 890.
- Each transmission planning process at the local and regional level must consider transmission needs driven by federal or state laws or regulations.

\(^2\) Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities
Transmission providers in neighboring transmission planning regions must coordinate concerning more efficient or cost-effective solutions.

Each transmission provider must participate in a regional transmission planning process that has a regional cost allocation method for new transmission facilities that satisfies six regional cost allocation principles.

Transmission providers in neighboring planning regions must have a common interregional cost allocation method for new interregional transmission facilities that satisfies six regional cost allocation principles.

Participant funding of new transmission facilities is permitted but not as part of the regional or interregional cost allocation method.

These principles apply only to FERC jurisdicational utilities. BPA being a non-jurisdictional utility does not have participate but it is BPA’s intention to satisfy FERC and comply with statutory obligations.

With that in mind, FERC Order 1000 is likely to be another driver toward increased coordinated and collaborative regional transmission planning. The outcome of future regional planning processes is expected to affect the timing of BPA investment decisions more than it has in the past. BPA is currently working with other ColumbiaGrid members on a compliance filing to resolve the implementation details.

**Non-wires alternatives**

BPA evaluates non-wires alternatives to building or expanding transmission lines to determine if measures such as local generation, enhanced energy efficiency or demand management could meet BPA’s reliability and commercial objectives and, thereby, defer construction. Transmission Services determines the preferred alternative from a least-cost and risk-management perspective. BPA has reconvened the Non-Wires Roundtable to review the I-5 Corridor Reinforcement and Hooper Springs projects to evaluate the feasibility of deferral alternatives to the transmission build proposals. Established in 2003, this Roundtable consists of an independent group of energy experts and utility leaders to provide knowledgeable and authoritative input on alternatives to constructing new transmission lines.

Recent experience has shown non-wires analysis needs to be incorporated relatively early in the planning process. When BPA considers non-wires alternatives for future proposed transmission projects, the agency will need to make informed 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.

**Operational complexities of integrating renewables on the grid**

BPA plays a pivotal role in integrating renewable generation in the Northwest. On a percent of load basis, the BPA balancing authority has one of the nation’s highest levels of wind penetration. To date, BPA has interconnected 41 renewables projects totaling approximately 4,700 MW into the transmission grid while building eight substations and seven tap lines. BPA is building or proposing to build three new transmission lines to increase the capacity of the BPA system to meet increased loads and reliability needs and to accommodate new generation.
sources including wind projects. As shown in Figure 4, the wind resources are geographically concentrated along the Columbia River east of the Columbia River Gorge.

Figure 4

For BPA’s grid, higher penetration of wind resources has required new operating procedures (for example, DSO-216) to assure reliability is maintained and to address the nondispatchable variability of wind and solar generation. This is particularly challenging during high spring runoff when BPA has limited flexibility with hydro spill levels due to migratory fish passage requirements. Low load conditions and mandatory fish flows (releases of water to increase flows between dams) has become another operational issue for wind projects that is being addressed within BPA. BPA has also initiated several new wind integration efforts to find ways to reduce the operational issues associated with wind generation. Several of these initiatives are now becoming models for other regions as wind generation penetration increases in their areas. Although regional diversity would be beneficial, the cost of new transmission lines far exceeds the costs associated to implement many of the wind integration projects. BPA has developed new rate products as well to assure that those benefiting bear the costs of integrating firmed Pacific Northwest renewable power and maintaining system reliability standards. BPA continues to look for alternatives to reduce the impact of variable generation on the FCRPS’s Pacific Northwest preference customers.

The wind resources being added to the BPA control area are greater than the Northwest renewable portfolio standards requirement at this time. Much of the renewable generation is being exported to California under short-term sales to offset the initial cost of the investments Northwest utilities made in wind developments. Some longer term sales are to meet the
California renewable portfolio standard. Recent changes in the economic outlook and California RPS policies will slow the rapid growth after this year, but, long term, utilities in Oregon and Washington will need as much as 10,000 MW of qualified renewable generation to meet the higher renewable portfolio requirements that take effect in 2020. The forecast for wind/renewable generation is shown online.

**Dynamic transfer capability**

The significant increase in the number of wind projects interconnected to BPA’s system has created a need to manage within-hour variability associated with wind resources. To keep the system balanced, BPA must move generation inversely to changes in wind power output. In some instances, BPA customers use BPA’s system to balance their wind resources with their own generation. To accomplish this, these customers seek dynamic transfer capability from BPA. Dynamic transfer capability is a transmission system’s ability to accommodate dynamic movement of a generating resource within the delivery hour in response to a signal from some other generator (for example, a wind resource) or load.

The dynamic transfers have been relatively easy to accommodate. They have been limited to allowing load service entities to supply regulation or load following service using generating resources that are remote. The generation from the remote resources is transmitted through BPA’s system in response to load signals. Such historic uses are characterized by small movements in generation in response to relatively predictable changes in load.

By contrast, movements by generators to balance wind output are significantly larger than movements to balance load variation and are often more rapid as winds pick up or drop off. Accommodating these large, rapid swings in power flows on BPA’s system is possible but challenging, particularly with respect to keeping voltage excursions caused by these variations in flow within acceptable limits. In some instances, customers have asked BPA to change its policies from the current limit of dynamic transfer capability awards of two years’ duration to awards of perhaps 20 years. Such change in policy may require capital investments in equipment.

Over the next five years, BPA expects the demand for dynamic transfers to increase as more wind is interconnected to BPA’s system. To address a regional need for ancillary services to accommodate a large wind fleet, BPA, other balancing authorities and customers are considering creating a regional imbalance market that would facilitate the use of regional generators to supply within-hour imbalance energy to help balancing authorities and others balance wind and other resources as well as load.

A regional imbalance market may create a demand to invest capital in regional transmission systems, including BPA’s system, to increase dynamic transfer capability to allow more resources to be moved within-hour. This also would increase BPA’s need for capital to invest in growing dynamic transfer capability on its system.

**Optimizing the use of assets**

As with most other electric grids, the BPA grid was built gradually over 70 years. The system was built to deliver power to fairly predictable loads from very stable and controllable
generation resources, primarily hydro based. Today, however, approximately 4,700 MW of wind generation has been installed on the system with a considerably larger amount in the queue that may be installed over the next several years. This variable resource, as well as substantial changes in policy and regulation, has forced the system to be operated in ways that were not envisioned even 20 years ago.

Today's environment contains far more constraints in outage planning because of the increasing requirements of customers, both direct service and public, and the need to abide by regulations such as recent biological opinions. All these items make the system far more complex and require increasing amounts of real-time data and sophisticated solutions to properly manage the grid. Add to this the amount of time it takes today to plan, perform environmental studies, permit, finance and construct transmission lines, and it becomes imperative to wring the most capacity possible from the existing assets.

**Increasing compliance requirements**

Each year, BPA is challenged to address changes in regulatory requirements (Federal Energy Regulatory Commission, North American Electric Reliability Corporation and Western Electricity Coordinating Council) that affect operations and reliability. At the same time, it is incumbent upon BPA to meet statutory requirements, comply with open access and stay competitive in an ever changing energy market.

Today, BPA is subject to over 120 mandatory reliability standards, and FERC, NERC and the regional regulatory authorities are actively engaged in auditing entities for compliance and enforcing noncompliance. Enforcement actions typically result in assessment of monetary and nonmonetary sanctions.

Recent FERC changes (and subsequent NERC and WECC changes) in requirements, as well as the growth in new generation, has required significantly more system studies to ensure system integrity and stability. Because of these studies and changes in the loading of various paths throughout the system, Transmission Services has had to replace fault duty breakers, install additional system spares, upgrade transformers and install increased monitoring and control hardware and software.

State and regional requirements also significantly influence operations and maintenance of transmission assets. This includes conforming to environmental standards for handling and disposing material and limiting noise and electrical field strength. Contractual obligations for open access and interconnection responsibilities greatly affect system operations.

**Technological advances**

Increasingly, technological advances are influencing electric industry asset strategies. These advances allow BPA to pursue opportunities to improve available transfer capacity. Good examples of the technology include:

- Synchrophasor-based remedial action schemes. This project is scheduled for deployment in 2015. It will be used initially as a safety net, providing voltage and transient stability margin for the AC intertie and the Portland metro area. If it is successful, the scheme could be used
to maximize short-term available transfer capability during forced or planned system outages.

- Grid-friendly appliances that use information available at the plug to make useful contributions to grid stability.
- Flexible AC transmission system elements: power electronic-based devices that provide dynamic reactive compensation to the transmission network. Examples include static VAR compensation systems and thyristor controlled series capacitors.

At BPA, new technology and its viable application to BPA’s transmission system is evaluated through a Technology Innovation program that invests 0.5 percent of revenues (approximately $15 million annually) in a disciplined program of research, demonstration and development focused on BPA’s business challenges.

**Business continuity**

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 (see Figure 5). 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.

A business continuity program for transmission assets is being implemented in the areas of critical business function redundancy, critical equipment anchoring, rigid bus riser replacement, river-crossing mitigation and building strengthening. The building seismic strengthening program is included in the Facilities Asset Management Strategy.

**Availability risk**

The growing backlog of age-related replacement work will require an increasing number of planned outages. This, in turn, will reduce transmission line availability. Efforts are underway to create a portfolio management system that enables the sustain programs to better coordinate work during outages to help minimize this availability risk. This project is currently identified as a priority. It was launched in FY 2012 and is anticipated to take two to three years to complete.
1.7 Strategy Proposal

BPA’s 2012-2021 asset management strategy for transmission assets is a prioritized set of sustain and expand investments to meet the objectives and drivers identified in this document. Over the past year, the proposed forecast has been updated and reshaped to keep within the total and annual capital investment level presented during the 2011 Strategic Capital Discussions. The current expansion strategy is limited by the availability of capital funding. Decisions to implement or defer key projects are driven by priority and limited by affordability. During the 2012 IPR process, Transmission Services presented an alternative scenario that proposed the retention of the originally proposed timelines for major expansion projects such as the I-5 Reinforcement and Northern Intertie projects. While this alternative exceeded the established investment level presented to customers in the 2011 Strategic Capital Discussions, in general, customer response was supportive of this proposal and the decision was made to accept the alternative as the preferred strategy.

In July 2012, BPA developed the FY2013 start of year budget. During this process, the forecasted timelines for the I-5 and Northern Intertie projects were evaluated based on current project status. The investment forecast was updated to account for the shifts in expansion project timelines and in August 2012, this forecast was approved as the final IPR budget and is presented in this document. Understanding that changes can occur in the timing of projects for various reasons, Transmission Services is committed to managing to the annual capital budget and total 10 year forecast while still meeting the objectives of the asset management strategy.

The 10-year investment forecast equals $3.9 billion in direct capital costs, with 47 percent of the direct capital being allocated to sustain projects, 45 percent to expand projects and 8 percent to the Celilo upgrade project. The Celilo upgrade project is estimated at $326 million direct capital costs, an increase of $218 million since the 2010 IPR. With AFUDC and overheads, the total capital cost is approximately $428.1 million. Given its criticality, the Celilo project was treated separately from other forecast spending estimates due to the large capital outlay required. If included in the initial CIR capital forecast, it would have squeezed out many other necessary projects. In addition, the project can be funded primarily from non-Treasury sources and costs will be recovered only from parties benefiting from the California-Oregon intertie.

The transmission 10-year capital program also includes $316 million for customer requested projects (PFIA) and $486 million of capitalized indirect costs. This brings the total capital requirement to $4.7 billion for the 10-year planning period.

In addition, it should be noted that for various reasons the following projects and initiatives are not represented in the current proposed 10-year capital forecast:

- Network Open Season beyond 2010 solicitation
- Boardman-to-Hemingway/MISTI (estimated $300-400 million)
- Boardman Substation – Morrow County server load (estimated $30 million)

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3 Does not include investments for fleet, environment, information technology, nonelectric facilities and security enhancements, all covered through separate strategies.
• Post study work on Southern Idaho to Lower Valley (Caribou Substation/Hooper Springs estimated $50 million)
• Pending Central Ferry-Lower Monumental decision (could result in schedule shift affecting implementation of other projects)
• Regional energy imbalance market (EIM)

Sustain

To meet transmission asset management objectives and respond to the drivers outlined earlier, Transmission Services has developed specific strategies for sustaining the existing transmission infrastructure. Highlights from each of the sustain strategies are included below to provide context to the capital investment levels being forecast for FY 2012-2021. Detailed strategies and supporting asset information can be found in the individual strategy documents.

AC substations

• A long-term strategic approach proactively maintains assets and evaluates them based on evolving reliability centered maintenance principles. Assets will be replaced based on their effective life cycle. Strategic drivers for asset replacement are based on technical obsolescence, limited long-term vendor support, spare parts availability and cost, decreasing equipment operating margins and skilled workforce shortages.
• The strategy is focused on four key areas for all major equipment groups.
  - Performance monitoring and data analysis
  - Maintenance and operations approaches
  - Equipment standardization
  - A proper level of equipment spares
• Assets are targeted for replacement based on three key drivers.
  - Asset condition assessment
  - System upgrade (capability/capacity)
  - Asset risk (failure and consequence)

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 OpenVMS-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;
  - conducting annual asset risk assessments; and
  - developing a two-to-three-year rolling resource plan and sourcing strategies to support sufficiently maintaining and replacing risk assets.
• Asset management improvement strategies include
  - identifying a plan for completing condition-based standards refinements and assessment methodology;
- identifying availability targets for other assets as appropriate and implementing processes to manage tracking, reporting and responding to them;
- identifying control center asset management requirements and establishing a plan to address them; and
- adopting an integrated investment planning process with power system control and system protection and control to address related and dependent assets.

**Power system control**

- The strategy is aimed at aggressively 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; and
  - technological obsolescence by developing and implementing a long-term strategy for moving off SONET.
- PSC and telecommunication equipment is upgraded and replaced to enable the agency to deliver on its strategic initiatives, including possible regional imbalance market formation, greater use of dynamic transfer capacity and demand response resources, and changes in scheduling.
- Documentation activities are improved to address backlogs and reduce rework.
- Replacement plans are integrated with system protection and control and associated control center assets.

**Rights-of-way**

- Vegetation management
  - Implement an integrated vegetative 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 vegetative 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 line 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 poles/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.

**System protection and control**

- Over the next 10 years, replace specific populations of equipment groups that are at highest risk of failure or technological obsolescence. 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 and
  - the challenge of retaining the skill set necessary to work on older equipment models.

**Steel lines**

- The strategy includes a proactive plan to replace vital overhead system components nearing end of life.
- It sets 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.
- It standardizes the process for sampling and testing retired components.
- It develops a long-term strategy for evaluating and mitigating a continuously aging asset.
- It incorporates standardized components and technology innovations into replacement efforts.

**Wood lines**

- The strategy focuses on shifting from individual components of the line, such as wood poles, to an asset life cycle strategy that combines life extension replacement of all of the aged components on the structure and systematic replacement of aged, poorly performing wood pole lines.
- It implements projects on a three-year program schedule to allow adequate time for gaining road rights, acquiring land and materials, and performing NEPA activities.
- It retires old de-energized lines to mitigate safety and liability risks and reduce maintenance responsibility.

**Expand**

The expand strategy has been developed to

- meet regulatory requirements,
- improve reliability,
- meet customer service requirements,
- deliver new generation sources and
- upgrade key transmission infrastructure.
Details on the specific expand projects can be found in the Load Service and Generation Integration strategy documents.

BPA spends about $80 million to $100 million annually on upgrades and additions of transmission assets to implement special remedial action control schemes to accommodate new generation and mitigate immediate operational and market constrained paths.

**Process improvement efforts**

While Transmission Services continues to improve its asset management practices, growth is still needed in critical areas to effectively manage assets and mitigate some of the risks mentioned above. Several improvement initiatives are underway including

- asset tracking tools and systems development,
- resource capability planning,
- outage coordination and
- standardized risk assessment methodology development.

**Asset tracking tools and systems:**

*Transmission Asset System (TAS):* Over the past two years, the TAS project development focused on substations, power system control and system protection & control asset information. This phase of the project concluded in 2011 with asset information being imported into an asset management system called Cascade.

In the meantime, Transmission Services has also been working on an approach to develop tools for capturing line asset condition information. In FY2012, the business objectives for this approach were refined and a proof of concept is being developed in Cascade to replicate how the tool would be used for lines. This evaluation will be the final step before a formal system design is created. In the meantime, until this project can be concluded, the line assets will have to rely on a more manual method of identifying condition trends or predicting service life.

*Asset Portfolio Management (“Endeavor”):* In 2012, Transmission Asset Management launched an initiative to design an integrated system and set of processes to enable real-time management of asset strategies and resultant projects.

The expected outcome from this effort, called “Endeavor,” is a solution that will provide an up-to-date integrated set of data and incorporate consistently applied business processes. It will create a holistic view of current and future projects with visibility of attributes such as location, timing, resource requirements and outage scheduling that is necessary to facilitate optimal planning. It is anticipated that this project will take at least two to three years to offer a first version of a robust planning system.

**Resource capability planning**

In order to execute on the asset strategies as designed, adequate staffing levels with the necessary skills are critical. Many of the sustain programs are experiencing implementation delays because of a lack of available labor resources. The system protection and control sustain program, for instance, has slowed the rate of replacement projects to below the strategy level.
presented at the 2010 IPR as a direct result of the need for available skilled labor. This is in part due to the increased volume of deferred replacements and repairs that Transmission Services is attempting to overcome. Until the aged infrastructure can be updated, emergency projects will continue, thereby affecting the system’s reliability, costs and staff availability to an even greater degree. To relieve this constraint, adequate funding for project staffing and maintenance, both preventative and corrective, needs to be provided.

The challenge is not only to have the right number of staff but also to have the right capabilities. The Strategic Capability Planning team is working to close this gap through in-depth analysis of the resource and capability requirements for program implementation. This will drive the creation of a comprehensive staffing strategy and implementation plan.

**Outage work coordination:** Historically, schedules for work and schedules for outages have not always been aligned, thus creating conflicts and scheduling changes that cause an ineffective use of resources and outages. Some outages are extremely difficult to schedule because of reliability, season or other issues and should/may dictate the rest of the project schedule. This situation does not always facilitate an adequate planning window for all work needing to be performed during the outage.

In order to ensure that BPA can deliver on its transmission system upgrades, improvements and replacements while continuing to maintain a reliable and compliant transmission system, there must be a cohesive process that identifies when outages are a significant constraint to accomplishing the work and a methodology that effectively enables optimized planning and scheduling around those constraints.

BPA’s outage team is evaluating these issues and developing a recommendation that will address the challenges in outage planning and coordination. During FY 2012, the team focused on developing recommendations for two areas: coordination of outages in progress and advance planning of outages needed in 45 days to 18 months. Upon approval from Transmission Services Tier 2 vice presidents, the team will then move forward on the specifics of the implementation plan. The basic approach is to develop a plan for initiating pilot projects, documenting lessons learned and creating specific processes around these learnings.

**Standardized risk assessments:** Although many of the risks identified in the asset strategies are common across programs, using a standard evaluation methodology in assessing the impact of the risks is challenging. In the risk assessments of each strategy, every program has evaluated condition assessment, the impact of failures and the age of critical equipment as it relates to expected service life. The approach taken by each program manager has been driven by the availability of adequate data, which differs greatly between programs. With the progression of the Transmission Asset System project to include asset health data on other asset groups in 2013, Transmission Services will be better positioned to create a standard approach for assessing risks across all programs.
1.8 Prioritizing projects

**Background**

Transmission Services has established a set of criteria that prioritizes its capital program toward providing the greatest benefit to BPA and its customers. This criteria should be applied to all capital projects regardless of the project size or financing source and is consistent with the agency’s strategic direction, agency policies and transmission asset strategies.

Project prioritization is focused on the *importance* of projects, as distinct from the sequencing and timing of projects. The criteria separate more important projects from less important projects so that the agency’s limited funding, staffing, planned outage time and other resources are directed to the greatest benefit over time. The actual sequencing and timing of projects and the allocating of funding and resources occur after projects have been prioritized.

Transmission investment is prioritized under separate criteria for core sustain projects, non-core sustain, and expand projects. Separate criteria are used because the business drivers for core sustain are very different from the drivers for other investments. Core sustain programs are driven by the need to manage equipment failure, obsolescence, safety, security and other risks so that the system continues to perform with the reliability, availability, and efficiency that is required. By contrast, the rest of transmission projects are driven largely by system capacity and flexibility needs, customer requests and tariff requirements to

- increase capacity to meet load growth and reliability standards,
- meet generation interconnection and customer service requests,
- provide congestion relief,
- meet requirements of the biological opinion and
- capture economic opportunities.

**Prioritization of core sustain projects**

The strategies articulate the condition of the aging transmission system. Critical equipment is at risk of operating failure and technological obsolescence and significant backlogs in upgrades, replacements and maintenance require ramp up and a sustained effort over many years.

A stable, predictable level of funding for replacements and upgrades is critical to managing asset age and health risks efficiently and effectively. To be sustainable, the level of funding should be tied to an objective measure of asset life expectancy and the size and composition of the transmission asset base. Accordingly, total annual funding for sustain investment would be set at the *sum of* two factors.

- Annual depreciation expense (that is, annual depreciation rates as established in the agency’s depreciation study *times* gross historical plant).
- Added amounts, as approved by the agency, to compensate for years of underinvestment in select asset groups and to accommodate inflation.

Total annual depreciation expense for transmission assets was $181.8 million in FY 2011. Because sustain program forecast are prepared on a direct expenditure basis, corporate and AFUDC costs estimated at $53.1 million must be removed from the total. The adjusted
transmission depreciation total is $128.7 million. Due to the specific drivers for core sustain work, BPA supports funding all core sustain investments prior to non-core sustain and expansion projects. The identification of transmission core sustain work is shown in Appendix E.

The following criteria optimizes the use of core sustain capital funding by prioritizing replacements and upgrades across the eight sustain programs.

**Prioritization principle for sustain**

Highest priority is assigned to replacing and maintaining equipment and facilities with the *highest system impact* (greatest importance) and the *poorest health condition*. These are facilities at greatest risk of

- safety mishap or health issue,
- operational failure,
- technological obsolescence,
- environmental damage or noncompliance, or security breach or noncompliance with directives and requirements.

**Determining “system impact”:**

System impact reflects the underlying importance or criticality of an asset, regardless of its health condition. It is determined in three steps:

1. *Delineate the transmission lines, substations and other facilities that are strategically and operationally more important from those that are less important.*

   Generally, the higher the voltage of the equipment, the more critical the asset is. BPA’s main grid is the 500-kV backbone of the transmission system. It moves bulk power through the system, including power to lower voltage facilities. BPA’s reliability criteria impose stricter performance requirements on these higher voltage facilities. For these reasons, Transmission Services generally ranks main grid facilities and equipment highest in terms of transmission asset criticality.

   Transmission lines are ranked based on average system loading and connected substations. Substation assets are ranked by taking into account such factors as

   - station bus voltages,
   - connection to generation,
   - load service,
   - VAR support,
   - status as transmission hub,
   - transformers,
   - remedial action schemes and
   - regional source lines.

   Control center system (cyber) assets are ranked based on the severity of the impact a software or equipment failure would have on operations if interrupted. The Federal Information Security Act Federal Information Processing Standard classification is used to
determine the system criticality based on system information integrity, availability and confidentiality. It also identifies whether the asset is a NERC critical cyber asset.

2. **Delineate components of the lines, substations and other facilities that are more important from those that are less important.**

Not all components of a highly ranked line or substation are critically important, and, conversely, not all components of a low ranked line or substation are unimportant. This step is accomplished through use of component-level ranking criteria developed by subject matter experts in each of the sustain programs. These component rankings are shown in Appendix F.

3. **Delineate components of the lines, substations, and other facilities that provide the greatest reduction to total economic cost.**

Total economic cost is defined as the sum of all BPA ongoing costs (labor, materials, cost of inventory and the like) and all costs incurred as a result of planned and unplanned outages (customer societal value losses, fines, collateral damage and the like).

Taken together, these steps delineate the more important components of critical lines, substations and other facilities from the less critical.

The **health condition** of an asset (that is, the risk of operating failure, obsolescence, environmental damage, noncompliance or other “asset health” factors) is determined through inspections, historical and projected failure rates, maintenance and repair trends, and other health assessment techniques and sources. Asset health assessments are collected in the Transmission Asset System or other applications and reflected in asset management strategies for each of the sustain programs.

System impact rankings and asset health assessments are then combined in a risk assessment, as illustrated in Figure 6. The criticality of transmission equipment and facilities is captured on the “System Impact” (Y) axis. The most critical assets are represented by the very high impact end of the axis and the least critical assets are represented by the low end of the axis. The **health** of equipment and facilities is represented on the (X) axis of the risk chart.
Core sustain projects associated with replacing assets that fall in the upper right quadrant of the risk chart (red zone) are assigned the highest priority. These projects represent the most important assets that are at greatest health risk. Projects involving the most important assets that are in marginal and deteriorating health are assigned second priority (orange zone). Projects involving assets that carry a medium criticality but are in poor health are assigned third priority (yellow zone). All other projects are assigned fourth priority.

Generally, there is no numerical scoring or subranking of projects within each of the four zones. Projects in the red zone, followed by projects in the orange zone, should receive priority attention in funding, resourcing, outage planning and materials.

**Prioritization of non-core and expand projects**

Unlike core sustain investments, there is no calculated methodology for determining the level of funding for expand projects. The capital spending for expand program investment can rise and fall year to year depending on system capacity, flexibility and other needs.

Transmission Services proposes to prioritize these investments through the application of the agency prioritization methodology currently in development. The methodology employs an approach that will provide the agency with the ability to evaluate all non-core and expansion projects using the same platform. Prioritization is determined using three tests.

1. Strategic fit - based on the agency’s strategic priorities
2. Value contribution - on a Net Economic Benefits ratio and Net Present Value basis
3. Feasibility - ability to afford and execute the project

Non-core and expansion projects that are proposed to be initiated within a rolling three year window will be evaluated in three investment categories.

- Compliance
- Policy commitment
- Discretionary

Design of the prioritization process concluded in September 2012 and was presented to customers as promised. The next phase of the effort will be testing the methodology and preparing for implementation. This is expected to be complete by March 2013.

**Sequencing projects**

The highest priority projects are not always the first projects to be implemented. The actual sequencing and timing of projects is based not only on their prioritization but also on such “real world” factors as

- availability of skilled FTE;
- availability of outage time;
- procurement timelines;
- NEPA process timelines;
- contractual commitments;
- efficiencies in making replacements on a combined basis, such as a full line rebuild,
- regulatory directives (with hard deadlines); and
- funding availability and agency affordability.

Emergency or urgent situations take precedence. Emergency or urgent situations are caused by severe weather, sudden equipment failure or other unforeseen events for which investment must be made without delay in order to

- restore load service,
- avoid imminent unplanned outage or curtailment,
- mitigate environmental emergency
- mitigate safety or security emergency or
- avoid significant financial loss to the agency.

In no case will projects be canceled or deferred if the cancelation or deferral would cause a significant violation of reliability, security or other industry standards; tariff requirements; or other legal commitments and requirements.

1.9 Costs

Historical investment costs

Historical investment in the transmission assets that are in service today totals $6,119 million, or 29 percent of cumulative total investment funded by BPA (see Figure 7). Net transmission plant, meaning historical investment less depreciation, totals $3,585 million. Of this net plant total, nearly half is attributable to station equipment and about one-third is attributable to towers, poles, conductors and other overhead line equipment.
Figure 8 includes all costs charged to the Transmission capital program, including IT, Non-electric facilities, Security, and Environment. These are loaded costs that include overheads and Allowance for Funds Used During Construction (AFUDC). Projects Funded in Advance (PFIA) are projects where BPA owns or controls the assets, but the asset or asset additions are funded by customers in advance of construction. This category includes all customer financed projects including Master Lease projects.

Over the past 10 years, BPA investment in transmission has averaged $321 million per year. Approximately $100 million (31 percent) of this average was for replacements and $221 million (69 percent) was for expansion-related purposes as shown in Figure 8. The higher replacement and maintenance costs in recent years are due to an aging infrastructure, postponed replacement and maintenance work, and the need to reduce backlogs to ensure long-term system reliability and performance.

Asset-related expenses, including depreciation and interest on capital investment and maintenance expense (shown in Figure 9), make up about 61 percent of BPA’s transmission
revenue requirement. If system operation, environmental and scheduling expenses are also factored in, this percentage increases to about 76 percent.

**Forecast capital costs**

The planning forecast presented here represents the current (as of July 2012) estimate driven by known priority expansion and replacement projects. The annual forecasts take into account constraints in capital funding availability.

<table>
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<th>Capital Costs (excluding AFUDC and Corporate Overheads)</th>
<th>Current rate</th>
<th>Next rate period</th>
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<td><strong>Transmission</strong></td>
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<td>AC Substations</td>
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<td>Power Systems Control and Telecom.</td>
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<td>Total with Indirects and PFIA</td>
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**Forecast maintenance costs**

**Figure 11**

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<th>Next rate period</th>
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Transmission Asset Management Strategy
Executive Summary
Appendices

Revised October 2012
Appendix A: Strategic direction

Transmission Services’ Asset Management vision and strategic objectives are derived from BPA’s mission, vision and agency-level strategic business objectives. 1 Seven of the strategic objectives are important drivers of this asset management strategy.

**Asset Management**: Maximize the long-term value of FCRPS power and transmission assets through integrated asset management practices (supports agency strategic objective I4)

Transmission Services will manage its assets and capital investment decisions with a comprehensive understanding of the long-term costs, benefits, risks, and strategic opportunities the region faces. In critical areas, transmission assets are aging and need increased maintenance or replacement. New capacity is needed to ensure the agency can provide adequate, efficient and reliable services. Transmission will employ a rigorous, risk-informed and transparent asset management program that applies leading practices in planning, maintaining, expanding, operating and disposing of assets.

**FCRPS Operations & Expansion**: Operate and expand FCRPS power and transmission facilities to meet availability and reliability standards in the most regionally cost-effective manner (S2, S8)

FCRPS operations are increasingly complex and challenging. The Northwest transmission grid and federal power system are now operated in ways not originally envisioned due to dramatic changes in markets, generation resources and transmission patterns. These changes are placing increasing stress and congestion on the grid and creating new requirements for flexibility and capacity in the power system. Expanding and upgrading the aging transmission infrastructure are key to sustaining reliability.

Transmission Services is committed to ensuring transmission availability and reliability through new transmission construction and upgrades that will facilitate an increase in the supply of non-federal capacity services to integrate wind and other generation resources. Likewise, with the need to integrate large amounts of variable generation into the transmission system, Transmission Services will continue to examine and adjust its system and coordination capabilities to ensure the grid continues to operate reliably.

**Renewable Energy**: Actively enable renewable resource integration and development through cost-effective, innovative solutions (S6)

Cost-effective renewable resources are second in priority only to energy efficiency for meeting future energy needs. They offer numerous advantages over other generation sources, including reduced exposure to carbon emissions and to fuel price uncertainty. Many challenges need to be addressed in order to capture the full benefit of renewables for the region and BPA’s customers. These include integrating resources with variable output into the existing system in a way that preserves reliability, protects fish recovery efforts and is cost effective.

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Transmission Asset Management Strategy

**Policy & Regional Actions** - Promote policies that result in regional actions that ensure adequate, efficient, environmentally responsible, and reliable regional transmission service (S1, S5, S7, S8)
Transmission Services develops policies and facilitates collaborative actions to produce the best outcomes for regional consumers and their requirements for adequate, efficient and reliable electricity. This reflects Transmission Service’s mandate to advance innovative regional solutions that balance diverse stakeholder interests. Transmission Services will continue its leadership, facilitation and participation in industry policy and implementation venues, including public policy and decision-making processes; state, regional and West-wide planning and resource adequacy initiatives; national reliability entities; and similar channels to ensure the best outcomes for the region.

**Transmission Access & Rates** - BPA provides open, nondiscriminatory transmission services (S4)
Transmission Services is committed to providing open access transmission services to all customers as described in the BPA tariff filed with the Federal Energy Regulatory Commission (FERC) while observing the FERC Standards of Conduct. Transmission Services will provide service at cost-based rates that are as low as possible consistent with sound business principles, while making investments to maintain reliability, manage congestion, and provide firm transmission and related services to deliver power from new resources, particularly renewable resources.

**Systems and Processes** - BPA meets the demands of business operations efficiently and effectively through standardized continuously-improved systems and processes (S1)
Transmission Services will broaden its use of disciplined, repeatable, standardized business processes and systems to deliver value in the most efficient and effective manner. We will continually improve systems and processes to meet evolving business needs and deliver high value to our customers and internal clients.

**Technology Innovation** - BPA solves business challenges and enables breakthroughs using a program of disciplined research and technology innovation that is recognized to deliver high value to the region (I5)
Transmission Services will advance research, development and adoption of technologies that improve the reliability, cost-effectiveness, efficiency and environmental sustainability of the FCRPS. Transmission Services will use an approach that is directed toward advancing its strategic objectives. It will foster a wide range of credible business-driven initiatives, continuously refocus resources on the most promising efforts, and ensure that regional stakeholders will benefit from the lessons learned and breakthroughs achieved. Transmission Services will collaborate in this program with other utilities and regional, national and international partners.
## Appendix B: Transmission Services Asset Management Goals and Strategic Objectives

### Goals for improving asset management practices

<table>
<thead>
<tr>
<th>Goals</th>
<th>Strategic initiatives</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>G1</strong> Transmission asset management practices conform with leading practices.</td>
<td>1.1. Transmission Services employs a structured management system to evaluate, identify and prioritize areas of improvement for the Asset Management program. The gaps are validated with an independent assessment to be conducted in Q3 of FY12 against Asset Management best practices. Ongoing performance is monitored through the Asset Management operational Dashboard. (G1) (Lead: T, Support: TAMEC, AMS Sponsor Team)</td>
</tr>
<tr>
<td><strong>G2</strong> Expansion, replacements, and maintenance are:</td>
<td>Note: Strategic initiatives for G2 are shown in the Expand and Sustain sections below</td>
</tr>
<tr>
<td>• Coordinated and integrated</td>
<td>1.2. Streamline and integrate business processes and information systems and train the workforce on process changes through selected projects under the Integrated Program and Project Improvement (IPPI) program (within approved scope, schedule and spending targets) (G1, G3) (Business Sponsor: IPPI Team)</td>
</tr>
<tr>
<td>• Prioritized to give prompt attention to the most critical assets at greatest risk</td>
<td>• TAS/WPSS - Deliver the Transmission Asset System (TAS Outside-the-Fence) and the Work Planning and Scheduling System (WPSS) Information Technology projects (Lead: T, N)</td>
</tr>
<tr>
<td>• Directed at meeting reliability, adequacy, availability and other standards</td>
<td>• Project Management Implementation Plan - Improve project management processes and practices and implement the Project Management Playbook (Business Sponsor: TEP)</td>
</tr>
<tr>
<td>• Directed at minimizing life-cycle costs</td>
<td>• Asset Plan Repository/Portfolio Management - Improve processes and tools to, at a minimum, facilitate cross-program prioritization/coordination, effective sequencing/aggregation of work, IPR/OMB financial forecasting (Business Sponsor: TPW)</td>
</tr>
<tr>
<td>• Responsive to regional customer needs</td>
<td>• Asset Plan and Strategy Development - Develop a more structured, systematic, and integrated approach to formulating Asset Strategies/Plans. (Lead: TPO; Support: TPW)</td>
</tr>
<tr>
<td><strong>G3</strong> 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</td>
<td>• IPPI Change Management - Implement a robust, integrated change management strategy and plan to promote acceptance and adoption of business process changes and new systems</td>
</tr>
<tr>
<td></td>
<td>• Resource Strategies Development - the Strategic Capability Planning Team will develop resourcing strategy recommendations, the TAMEC will review and approve the recommendations for implementation.</td>
</tr>
</tbody>
</table>
### Goals for expanding transmission

#### Goals

<table>
<thead>
<tr>
<th>G4</th>
<th>Load service obligations and customer service requests are met with solutions that are:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>• Directed at meeting reliability and other standards at least life-cycle cost</td>
</tr>
<tr>
<td></td>
<td>• Implemented consistent with tariff timelines and requirements and with customer requirements</td>
</tr>
</tbody>
</table>

| G5 | Implement a regional expansion planning process that is long term, integrated with resource planning and directed at minimizing total system costs |

<table>
<thead>
<tr>
<th>G6</th>
<th>A robust grid that effectively and efficiently integrates renewable and other energy resources</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>• Promotes Department of Energy and regional energy policy objectives</td>
</tr>
<tr>
<td></td>
<td>o Enables NW customers to meet their renewable portfolio standards</td>
</tr>
<tr>
<td></td>
<td>o Fosters a geographically diverse wind fleet</td>
</tr>
<tr>
<td></td>
<td>• Provides access to cost-effective balancing reserves</td>
</tr>
<tr>
<td></td>
<td>• Complies with reliability and other standards and with tariff requirements</td>
</tr>
</tbody>
</table>

#### Strategic initiatives

| 1.3 | Improve forecasting ability, conduct screening studies for alternatives (including non-wires alternatives), and develop long-term plans for BPA’s load service areas where system reinforcement is necessary (G4) (Lead: TPP) |
|      |   • Develop metrics for customer requested screening studies to help determine resource requirements and customer service levels. |

| 1.4 | Evaluate options for providing service to transfer customers that improve reliability and reduce life-cycle costs (G4) (TPP, TPC, SR) |

| 1.5 | Implement a regional expansion plan that (1) is long term and integrated with resource planning, (2) meets reliability standards and (3) is directed at minimizing total system costs (by date) (G5) (Lead: TPL; Support: TPP, SR) |
|      |   • Support and apply established WECC expansion planning process and policies |

| 1.6 | NOS and GI Process Reform: 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 by: (G6) (Leads: TPP, TS; Support: TPL, TPC) |
|      |   • Establishing criteria to promote participation from customers committed to using the service they request; |
|      |   • Removing roadblocks that may inhibit the interconnection of generation within an appropriate timeline; |
|      |   • Reducing financial risk to BPA and rate payers; |
|      |   • Developing transmission capacity where and when needed by regional stakeholders; |
|      |   • Facilitating transmission planning that enables regional input on assumptions and sensitivities; |
|      |   • Planning to meet obligations to Network Integration Transmission Service customers; |
|      |   • Maintaining transmission system reliability when developing new generation interconnection and transmission infrastructure; |
|      |   • Study and evaluate opportunities to join other utility transmission projects that meet BPA and regional needs. |
### Goals for expanding transmission

#### G7
The need for increasing interregional transfer capability is assessed regularly in a joint planning process among transmission providers potentially affected by an increase in interregional transfer capability

- Enables interregional transfer needs to be identified and assessed regularly by those potentially affected by an increase in interregional transfer capability, including BPA
- Assures that the commercial needs of buyers and sellers of electric power between regions are met in a timely manner, including the benefits of:
  1. Importing or exporting energy or capacity into or out of the Pacific NW
  2. Strengthening dynamic scheduling capabilities between regions
  3. Maintaining reliability
- Complies with energy policy objectives, regulatory standards and tariff requirements

#### G8
Fuller, more optimal use is made of existing transmission capacity through:

- Reliable and cost-effective management of transmission congestion
- Technological innovations that enable:
  - grid operators to “see” the grid more accurately
  - intermittent generation to be forecast more accurately
  - grid operations to be controlled more precisely
- Methodological refinements that increase the availability of capacity while protecting from overselling
- Scheduling and product design innovations that increase access and enable fuller use of existing capacity
- Demand response, redispatch, power exchange and other non-wires solutions to manage transmission congestion, when more economic than wires solutions

### Strategic initiatives

**1-7.** (IOS) Develop & implement a process to facilitate expansion of interregional transfer capability by: (G7) (Lead: TSP; Support: TP, TO)

- Establishing a coordinated interregional planning process to assess proposals or respond to customer requests to increase interregional transfer capability that includes participation by transmission providers potentially affected by such proposals, whether located within or outside the region
- Assuring that any such process is consistent with Order 1000, including rules for allocating costs among project sponsors
- Assuring that any such proposal is likely to be supported by transmission providers potentially affected by such proposal both within and outside the region
- Developing a process to allocate equity, capacity or other ownership interests among project sponsors
- Assuring that enough customers are willing to commit to take service from affected transmission providers potentially affected by such proposal to justify incurring the cost, time, and effort needed to plan, design, and construct new capability
- Establishing customer financing obligations to pay for engineering or other technical studies, for NEPA or other environmental studies, and for constructing any new facilities
- Assuring that construction is approved in advance and meets BPA’s and other regulatory requirements and safety standards.
- Determining fair and equitable rate treatment that are consistent with BPA statutes and policies for the costs of any new Intertie facilities assigned to BPA

**1-8.** Select and implement operational tools and visualization techniques to give system operators critical decision-making information on wind fleet operating status, reserves availability, potential ramps and contingencies (G7) (Lead: TO; Support: TPM)

**1-9.** Improve Remedial Action Scheme (RAS) functionality and infrastructure by: (G8) (Leads: TO, TE, TP, SR)

- Replacing and upgrading antiquated RAS infrastructure
- Improving granularity of generation dropping
- Transitioning from manual to automatic arming of major schemes

**1-10.** Implement policies to optimize use of existing transmission assets (G8) (TO, SR)

- BPA ATC method made consistent with ATC reliability standards (once approved by FERC)
- Margins (TRM) set in accordance with NERC ATC reliability standards and reliable operating practices
- Federal and nonfederal generation redispatch programs put in place to mitigate operational constraints
- Innovative transmission products developed (or expanded in the case of conditional firm service) that can increase utilization of transmission
- Innovative power exchanges considered to avoid transmission build

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Revised October 2012
### Goals for expanding transmission

**Goals**

- Balancing authority consolidation (or virtual consolidation), should the region decide to consolidate

**Strategic initiatives**

1-11. Enhance grid ops and commercial systems to enable:
   - Dynamic and sub-hourly scheduling, should BPA decide to implement these changes in scheduling practices
   - Balancing authority consolidation (or virtual consolidation), should the region decide to consolidate
   - Customers to self-supply all or a portion of their wind integration balancing needs

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**Note**

Light gray text: goal and strategic initiatives that influence the management of assets, but is deemed to be outside the scope of this asset management strategy.

### Goals for sustaining transmission

**Goals**

- **G9** Information on asset attributes (condition, performance, and costs) is complete, accurate, and readily accessible

- **G10** Assets are proactively maintained and replaced
  - Maintenance, replacements and sparing planning is integrated
  - Priority is given to critical assets at greatest risk of failure or noncompliance
  - Reliability, availability, and other standards are met at least life-cycle cost

- **G11** Maintenance is reliability-centered (condition-based)

**Strategic initiatives**

1-12. Establish processes, procedures, controls, roles & responsibilities to ensure nameplate, condition assessment, outage history, maintenance costs and other asset information is accurate, complete, and readily accessible via the Transmission Asset Register (implementation to be addressed through the IPPI projects) (G9) (Lead: TPO)

1-13. Maintain or replace existing communications, control and operations infrastructure on a timely basis to ensure reliable, efficient, secure, and safe operation of the power system (G10, G11) (Lead: TPO)
   - Develop and implement policies, guidelines, and standards that ensure communications, control and operations infrastructure will comply with regulatory standards and requirements

1-14. Prioritize and manage maintenance and replacement backlogs to sustainable levels (target dates set in life-cycle strategies for each sustain program) (G10, G11) (Lead: TPO)

1-15. Develop and implement a process that ensures replacement and maintenance actions result in no more than X% of critical assets at high risk of failure or noncompliance (target percents and target dates set in life-cycle strategies for each sustain program) (G10, G11) (Lead: TPO)

1-16. Develop and implement sparing strategies to assure a supply of critical spare parts is geographically situated to enable timely restoration of service (G10) (Lead: TPO)

1-17. Establish condition-based maintenance standards and implement reliability-centered maintenance as each asset class is added to TAS (G11) (Lead: TPO)

1-18. Develop a near term process and plan for integrating asset strategies across programs where interdependent equipment drives coordinated investment decisions. Plan to include defined scope, timeline, funding, and committed resources. (Lead: TPO, Support: TPW)
Long-term Outcomes: Transmission’s future state for asset management

It is anticipated that through the successful completion of initiatives and achievement of long term goals, Transmission’s asset management program will result in asset strategies and actions that ensure critical assets operate reliably, meet availability targets, and provide adequate capacity into the future, and that life cycle costs will be prudent and economic. Asset strategies will be developed with a vision across all programs and the implementation of an integrated Transmission capital program will be driven by:

- the agency’s strategic priorities and business environment
- asset performance objectives
- assessments of asset health, performance and cost
- analysis of risks to achievement of performance objectives
- risk-informed evaluation of alternative investments

When selecting investments, highest priority is assigned to:

- Replacements and maintenance that minimize regional economic risks from equipment failure
- Upgrades and additions to effectively and efficiently:
  - Meet load service and wheeling requests
  - Integrate renewable and other energy resources
  - Ensure ongoing reliable power system operations
- Enhancements that enable fuller, more optimal use of the transmission system.
## Appendix C: Documentation of System Performance Measures and End-stage Targets

<table>
<thead>
<tr>
<th>Measure:</th>
<th>System Average Interruption Duration Index (SAIDI) – Average number of automatic outage minutes by BPA line category</th>
</tr>
</thead>
<tbody>
<tr>
<td>Background:</td>
<td>Maintaining system reliability is a critical BPA responsibility. This reliability measure is monitored to help minimize the duration of unplanned (automatic) line outages on the BPA system. SAIDI provides an indication of BPA’s success at minimizing the duration of unplanned transmission line outages. SAIDI data is used in developing Transmission’s asset management strategies and plans, and in its capital and expense planning levels.</td>
</tr>
</tbody>
</table>
| Methodology: | Reliability assessment is based on IEEE-standard measures of outage duration (SAIDI). Control chart techniques, closely mirroring transmission reliability methodology adopted by the California Independent System Operator (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 (FY 2002 - FY 2011). 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 SAIDI results from the past year are then compared to the control chart limits to gauge the adequacy of system reliability and to determine control chart violations. Control chart violations are 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) |
| End-stage Targets: |  
  No control chart violations for line importance categories 1 and 2.  
  No more than 1 control chart violations per year for line importance categories 3 and 4. |
| Inclusions/Exclusions: |  
  - Reliability monitoring is based on unplanned (automatic) outages to transmission lines (not points-of-delivery)  
  - Duration of any single outage is capped at 4,320 minutes (three days)  
  - Momentary outages are excluded  
  - Outages to lines with all or part non-federal ownership are excluded  
  - Outages in the year in which a line may have been energized or retired are excluded (i.e., line must have “full year” availability)  
  - Outages with a cause attributed to a foreign utility are excluded  
  - Overlapping outages to the same line, due to multiple section outages, are compressed to eliminate double-counting of outage duration |
<table>
<thead>
<tr>
<th>Measure:</th>
<th>System Average Interruption Frequency Index (SAIFI) – Average number of automatic outages by BPA line category</th>
</tr>
</thead>
<tbody>
<tr>
<td>Background:</td>
<td>Maintaining system reliability is a critical BPA responsibility. This reliability measure is monitored to help minimize the frequency of unplanned (automatic) line outages on the BPA system. SAIFI provides an indication of BPA’s success at minimizing the number of unplanned transmission line outages. SAIFI data is used in developing Transmission’s asset management strategies and plans, and in its capital and expense planning levels.</td>
</tr>
</tbody>
</table>
| Methodology: | Reliability assessment is based on IEEE-standard measures of outage frequency (SAIFI). Control chart techniques, closely mirroring transmission reliability methodology adopted by the California Independent System Operator (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 (FY 2002 - FY 2011). 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 results from the past year are then compared to the control chart limits to gauge the adequacy of system reliability and to determine control chart violations. Control chart violations are 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) |
| End-stage Targets: | No control chart violations for line importance categories 1 and 2.  
No more than 1 control chart violations per year for line importance categories 3 and 4. |
| Inclusions/ Exclusions: |  
- Reliability monitoring is based on unplanned (automatic) outages to transmission lines (not points-of-delivery)  
- Duration of any single outage is capped at 4,320 minutes (three days)  
- Momentary outages are excluded  
- Outages to lines with all or part non-federal ownership are excluded  
- Outages in the year in which a line may have been energized or retired are excluded (i.e., line must have “full year” availability)  
- Outages with a cause attributed to a foreign utility are excluded  
- Overlapping outages to the same line, due to multiple section outages, are compressed to eliminate double-counting of outage duration |
**Measure:**

*Frequency of Line Outages caused by Vegetation Growth* – Report the number of outages caused by vegetation growing into the conductor or within flashover distance to the conductor on transmission lines of 200 kV or higher and lower voltage lines designated by the Regional Reliability Organization (RRO) as critical lines to maintaining transmission system reliability.

WECC vegetation outage reporting classifies these as Category 1 – Grow-ins: outages caused by vegetation growing into lines from vegetation inside/or outside of the right-of-way.

**Background:**

Maintaining system availability is a critical BPA responsibility. A vegetation growth caused outage measure is monitored to help minimize the amount of time that transmission lines are out of service due to a tree related incident. Cause of outage observed in the field is documented and captured in the outage management system. Outage cause data is used in determining Transmission’s expense planning for vegetation management.

**Methodology:**

- The Outage Analysis and Reporting System (OARS) database is the repository of information related to WECC Vegetation Growth Outages.
- Outages that have a ‘TREE’ cause appearing in the Dispatcher Cause or Field Cause or Fault Location or Comment fields are investigated by TF.
- Vegetation related Transmission line outages are classified as follows:
  - Category 1 – grow-ins, from inside/or outside of the right-of-way
  - Category 2 – fall-ins, from inside the right-of-way
  - Category 3 – fall-ins, from outside the right-of-way
- Mandatory reporting to WECC of vegetation outages.

**End-stage Targets:**

No outages to transmission lines of 200 kV or greater and for RRO designated lines caused by vegetation growth.

**Inclusions/Exclusions:**

- Applies primarily to lines 200 kV or greater with the exception of lower voltage lines that are designated RRO.
- WECC reporting includes tree falling from inside and outside of the right-of-way. For purposes of this measure, only category 1 vegetation outages apply. Category 2 and 3 are excluded.
- Excludes vegetation related outages that result from natural disasters or major storm events
- Excludes vegetation related outages that are due to human or animal activity such as logging, vehicle contact, etc.

**Responsibility for Monitoring & Reporting:**

Transmission Field Services, Internal Operations, Vegetation/Access Road Management (TFBV)
**Measure:** 
*System Operating Limit (SOL) for BPA Paths, Interties, & Flowgates* – number of minutes that actual path flows are near, at or above System Operating Limit. Monitored for 21 separate directional paths, interties and flowgates.

**Background:**  
On-going monthly analysis comparing System Operating Limit (SOL) with Actual Path Flows for 24 separate directional paths, interties, & flowgates, based on 1-minute SCADA data. Selected elements are Transmission Business Key Performance Indicators and NERC/WECC Compliance reporting elements. Note terminology update from "OTC" (Operational Transfer Capacity) to "SOL" (System Operating Limit), per national standards.

**Methodology:**  
For 24 separate directional paths, compare the actual path flow to the System Operating Limit (SOL) for that path, at 1-minute increments. Calculate the number of minutes where actual flows were within 20% of SOL, 10% of SOL, and Over SOL. Report this by month, by path, in minutes and percentage of total time. For excursion periods Over SOL, compare the consecutive minutes vs. the reliability limits (30 minutes) to determine if a NERC/WECC violation occurred.

**End-stage Targets:**  
No end stage target will be set for this metric during this planning cycle.

**Inclusions/Exclusions:**  
This metric indicates:
- Utilization levels/patterns for existing line assets.
- Congestion areas for which capacity expansion may merit consideration.

**Responsibility for Monitoring & Reporting:**  
System Operations, Technical Operations (TOT)
<table>
<thead>
<tr>
<th>Measure:</th>
<th>Percent Availability for Service of BPA’s most important transmission lines = (Total Time minus Planned Outage Time)/Total Time.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Background:</td>
<td>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.</td>
</tr>
</tbody>
</table>
| Methodology: | 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 (FY2007-FY2011). 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&2. Actual Availability for the current year is then compared to the lower limit of availability to determine if it falls below the violation limits. Control chart violations are defined as follows:  
- Latest fiscal year below the Lower Control Limit (short-term degradation)  
- 2 of last 3 fiscal years below the Lower Warning Limit (mid-term degradation)  
- Continuous worsening trend in the last six fiscal years (long-term degradation) |
| End-stage Targets: | Line importance categories 1 & 2 (combined) are available for service at least 98% of the time. Line importance categories 3 & 4 (combined) are available for service at least XX% of the time. (Target to be determined.) |
| Inclusions/Exclusions: | The following outage inclusion/exclusion rules apply:  
- Momentary outages are excluded  
- Planned outages only, excludes automatic outages  
- Outages to lines with all or part non-federal ownership are excluded  
- Outages in the year in which a line may have been energized or retired are excluded (i.e., line must have “full year” availability)  
- Outages to the four Big Eddy-Celilo feeder lines are excluded  
- Outages with causes Voltage Control, Foreign Request, and Normally Out are excluded  
- Tap outages excluded  
- Overlapping outages to the same line, due to multiple section outages, are compressed to eliminate double-counting of outage duration |
| Responsibility for Monitoring & Reporting: | Transmission Technical Operations (TOT) |
Appendix D: Transmission Reliability Targets

Availability:

Availability of BPA’s “Most Important” Lines
FY03-FY12, Complete, Q1-Q4

Higher = Better

Target Met

Lower Control Limit = 98.00% (managerially adjusted from 98.14%)
Lower Warning Limit = 98.40%
Upper Warning Limit = 99.17% (superior performance)
Upper Control Limit = 99.26% (exceptional performance)

Availability = Percent of time that all transmission lines of Importance Ranks 1 and 2 were available for service, as reduced by periods of PLANNED outages; 219 lines of Importance Ranks 1 & 2 in FY12

Limits shown are for the FULL FY12, based on the five most recent full years of outage history.
SAIDI/SAIFI

Importance rank 1 lines

CONTROL CHART OF OUTAGE DURATION (SAIDI)
IMPORTANCE RANK 1 LINES ONLY (124 total)  FY03-FY12, COMPLETE, Q1-Q4

LOWER = BETTER
LIMITS ARE FOR FULL FY12

Upper Control Limit = 466.10
Upper Warning Limit = 379.09
Lower Warning Limit = 90.25 (superior performance)
Lower Control Limit = 57.54 (exceptional performance)

SAIFI (auto outages per line per year)

Fiscal Year

1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
FY03 FY04 FY05 FY06 FY07 FY08 FY09 FY10 FY11 FY12

CONTROL CHART OF OUTAGE FREQUENCY (SAIFI)
IMPORTANCE RANK 1 LINES ONLY (124 total)  FY03-FY12, COMPLETE, Q1-Q4

LOWER = BETTER
LIMITS ARE FOR FULL FY12

Upper Control Limit = 1.01
Upper Warning Limit = .90
Lower Warning Limit = .46 (superior performance)
Lower Control Limit = .38 (exceptional performance)
SAIDI/SAIFI
Importance rank 2 lines

CONTROL CHART OF OUTAGE DURATION (SAIDI)
IMPORTANCE RANK 2 LINES ONLY (99 total) FY03-FY12, COMPLETE, Q1-Q4

LOWER = BETTER
LIMITS ARE FOR FULL FY12

Upper Control Limit = 268.99
Upper Warning Limit = 208.16
Lower Control Limit = 10.26 (exceptional performance)
Lower Warning Limit = 24.29 (superior performance)
LOWER = BETTER
LIMITS ARE FOR FULL FY12

CONTROL CHART OF OUTAGE FREQUENCY (SAIFI)
IMPORTANCE RANK 2 LINES ONLY (99 total) FY03-FY12, COMPLETE, Q1-Q4

LOWER = BETTER
LIMITS ARE FOR FULL FY12

Upper Control Limit = 1.05
Upper Warning Limit = .82
Lower Control Limit = .16 (exceptional performance)
LOWER = BETTER
LIMITS ARE FOR FULL FY12
SAIDI/SAIFI
Importance rank 3 lines

CONTROL CHART OF OUTAGE DURATION (SAIDI)
IMPORTANCE RANK 3 LINES ONLY (47 total) FY03-FY12, COMPLETE, Q1-Q4

LOWER = BETTER LIMITS ARE FOR FULL FY12

Upper Control Limit = 689.55

Upper Warning Limit = 522.68

Lower Warning Limit = 35.52 (superior performance)

Lower Control Limit = 8.09 (exceptional performance)

LOWER = BETTER LIMITS ARE FOR FULL FY12

CONTROL CHART OF OUTAGE FREQUENCY (SAIFI)
IMPORTANCE RANK 3 LINES ONLY (47 total) FY03-FY12, COMPLETE, Q1-Q4

LOWER = BETTER LIMITS ARE FOR FULL FY12

Upper Control Limit = .82

Upper Warning Limit = .66

Lower Warning Limit = .18 (superior performance)

Lower Control Limit = .11 (exceptional performance)
SAIDI/SAIFI

Importance rank 4 lines

CONTROL CHART OF OUTAGE DURATION (SAIDI)
IMPORTANCE RANK 4 LINES ONLY (78 total) FY03-FY12, COMPLETE, Q1-Q4

LOWER = BETTER
LIMITS ARE FOR FULL FY12

Upper Control Limit = 597.76
Upper Warning Limit = 485.53
Lower Warning Limit = 93.82 (superior performance)
Lower Control Limit = 53.05 (exceptional performance)

LOWER = BETTER LIMITS ARE FOR FULL FY12

CONTROL CHART OF OUTAGE FREQUENCY (SAIFI)
IMPORTANCE RANK 4 LINES ONLY (78 total) FY03-FY12, COMPLETE, Q1-Q4

LOWER = BETTER
LIMITS ARE FOR FULL FY12

Upper Control Limit = .96
Upper Warning Limit = .82
Lower Warning Limit = .31 (superior performance)
Lower Control Limit = .23 (exceptional performance)
Appendix E: Core Sustain Work

Steel lines

Core sustain work: 99.5%
Comprised of replacing, refurbishing or protecting existing steel line assets or asset components in order to maintain performance and capabilities of the transmission asset.
Program activities include:
- Insulator assembly replacement
- Distressed tower mitigation
- Conductor replacement
- Vibration Mitigation (new damper installation)
- Shunt installation
- Corrosion Protection (new anode installation)
- Insulation Contamination Mitigation
- Lightening Mitigation and Grounding

Non-core sustain: .5%
For capital switch removal (removing switches that are no longer functional and no longer needed).

Wood pole

Core sustain work: 100%
Consists of priority pole replacements, and systematic replacement of wood pole transmission lines.

Rights of way

Core sustain work: 100%
Consists of upgrading the transportation system to enable line replacements and upgrading the transportation system to provide legal and environmentally compliant access to and through major transmission corridors throughout the BPA transmission system. Providing legal and environmentally compliant access is not discretionary.

Power system control

Core sustain work: 100%
Comprised of replacing aging units in currently installed base of equipment including:
- Telecom transport
- Telecom support equipment
- SCADA/Telemetry support control
- FIN/OP networks
- Transfer trip
- Telephone systems

System protection and control

Core sustain work: 100%
Covers replacement of the following equipment:
- Protective Relaying
- Sequential Events Recorders
- Fault Recorders
- Revenue and Interchange Metering
Transmission Asset Management Strategy

- Control and Indication Equipment

**Alternating current substations**

*Core sustain work: 100%*

Consists of replacements due to condition, effective life cycle, failures, technological obsolescence, and to perform seismic upgrades to increase reliability in the event of an earthquake for the following equipment:

- Transformers/Reactor/Fuses
- Circuit Breakers/Circuit Switchers/Disconnects
- Shunt Capacitors
- Instrument Transformers/Arresters
- Low Voltage Aux/Batteries/Station Service
- Bus/Structures/Seismic Upgrades

**TEAP tools**

*Core sustain work: FY13 - 90%, FY14 - 51%*

FY13- $1,032,000  
FY14- $517,000

Tools that are used in multiple work crafts, engineering, planning, and other groups that support BPA's mission. The tools are either replacement of existing tools or tools that are required for new and additional compliance/regulations.

*Non-core sustain work: FY13 - 10%, FY14 - 49%*

FY13- $115,000  
FY14- $500,000

These are tools that are not replacing tools currently used at BPA but would support BPA's mission and would increase efficiency and/or reduce cost of doing business.

**Control center**

*Core sustain work: 87-95%*

Comprised of control center infrastructure work. Includes projects that, while expanding capability or facilities, are necessary to keep up with basic management of current assets/functions and stay compliant with NERC regulations.

*Non-core sustain work: 5-13%*

Comprised of expansions, e.g., RAS due to wind expansion demands, and tools that improve dispatch decision-making (including reducing line outages).
## Appendix F: Sustain Prioritization Criteria

### Component Rankings by Sustain Program

<table>
<thead>
<tr>
<th>More Important</th>
<th>Less Important</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>AC Subs</strong></td>
<td></td>
</tr>
<tr>
<td>▪ Power Transformers</td>
<td>▪ Shunt Capacitors</td>
</tr>
<tr>
<td>▪ Power Circuit Breaker</td>
<td>▪ Current Limiting Reactors</td>
</tr>
<tr>
<td>▪ Circuit Switchers</td>
<td>▪ Instrument Transformers</td>
</tr>
<tr>
<td>▪ DC Control Batteries and chargers</td>
<td>▪ Surge arrestors</td>
</tr>
<tr>
<td>▪ Fuses</td>
<td>▪ Disconnect Switches</td>
</tr>
<tr>
<td>▪ Substation Bus and structures</td>
<td>▪ Station auxiliary exc. DC control batteries</td>
</tr>
<tr>
<td><strong>DC Subs</strong></td>
<td>▪ All components</td>
</tr>
<tr>
<td>▪ Towers</td>
<td>▪ Dampers</td>
</tr>
<tr>
<td>▪ Connectors</td>
<td></td>
</tr>
<tr>
<td>▪ Conductors</td>
<td></td>
</tr>
<tr>
<td>▪ Insulator assemblies</td>
<td></td>
</tr>
<tr>
<td>▪ Footings</td>
<td></td>
</tr>
<tr>
<td>▪ Rights of way</td>
<td></td>
</tr>
<tr>
<td><strong>Steel Lines</strong></td>
<td>▪ Countepoise</td>
</tr>
<tr>
<td>▪ Poles</td>
<td></td>
</tr>
<tr>
<td>▪ Conductors</td>
<td></td>
</tr>
<tr>
<td>▪ Insulator assemblies</td>
<td></td>
</tr>
<tr>
<td>▪ Guy assemblies</td>
<td></td>
</tr>
<tr>
<td>▪ Rights of way</td>
<td></td>
</tr>
<tr>
<td>▪ Fiber optic cable</td>
<td></td>
</tr>
<tr>
<td><strong>Wood Lines</strong></td>
<td>▪ Counterpoise</td>
</tr>
<tr>
<td>▪ Poles</td>
<td></td>
</tr>
<tr>
<td>▪ Conductors</td>
<td></td>
</tr>
<tr>
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</tr>
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<td></td>
</tr>
<tr>
<td>▪ Rights of way</td>
<td></td>
</tr>
<tr>
<td>▪ Fiber optic cable</td>
<td></td>
</tr>
<tr>
<td><strong>PSC/Telecom</strong></td>
<td>▪ Misc support systems</td>
</tr>
<tr>
<td>▪ RAS</td>
<td>▪ VHF/mobile/portable radios</td>
</tr>
<tr>
<td>▪ Transfer Trip</td>
<td>▪ UHF</td>
</tr>
<tr>
<td>▪ SCADA</td>
<td>▪ DATS</td>
</tr>
<tr>
<td>▪ Fiber cable</td>
<td>▪ Multiplex</td>
</tr>
<tr>
<td>▪ Comm batteries/chargers</td>
<td>▪ Power Line Carrier</td>
</tr>
<tr>
<td>▪ SONET/MW Radios</td>
<td>▪ Telemetering</td>
</tr>
<tr>
<td>▪ Fiber optic cable</td>
<td>▪ Operational Networks/MMS</td>
</tr>
<tr>
<td>▪ Engine Generators</td>
<td>▪ Engine Generators</td>
</tr>
<tr>
<td>▪ Supervisory Control Systems</td>
<td>▪ Surge arrestors</td>
</tr>
<tr>
<td>▪ UPS</td>
<td>▪ Surge arrestors</td>
</tr>
<tr>
<td>▪ Telephone systems</td>
<td>▪ Substation grounding</td>
</tr>
<tr>
<td>▪ Telephone protection</td>
<td></td>
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<tr>
<td>▪ FIN network</td>
<td></td>
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<tr>
<td><strong>SPC</strong></td>
<td>▪ Load shedding relays</td>
</tr>
<tr>
<td>▪ Transformer relays</td>
<td>▪ DFR</td>
</tr>
<tr>
<td>▪ Bus relays</td>
<td>▪ Control equip</td>
</tr>
<tr>
<td>▪ Line relays</td>
<td>▪ Relay Communications</td>
</tr>
<tr>
<td>▪ Breaker relays</td>
<td>▪ Load shedding relays</td>
</tr>
<tr>
<td>▪ Transformer relays</td>
<td>▪ Overcurrent relays</td>
</tr>
<tr>
<td>▪ Bus relays</td>
<td>▪ Revenue metering</td>
</tr>
<tr>
<td>▪ Line relays</td>
<td>▪ SER</td>
</tr>
<tr>
<td>▪ Breaker relays</td>
<td>▪ Control equip</td>
</tr>
<tr>
<td><strong>Control Center</strong></td>
<td>▪ Systems that support non-real-time operations decisions, processes, and analysis (Dispatch Activity Record and Tracking (DART), Plant Interface (PI), Dispatch Training Facility (DTF))</td>
</tr>
<tr>
<td>▪ Systems that control and manage the grid (SCADA Master, AGC, RAS Masters)</td>
<td>▪ Systems that support real-time operations decision-making, events response &amp; communication, and which impact field safety (PSST, Sequential Events Monitor Master/Fault Locator system, Lightning Monitoring, AVTEC)</td>
</tr>
<tr>
<td>▪ Systems &amp; cyber infrastructure that enables and protects our CC systems and network</td>
<td>▪ Systems that enable management of CC and communications networks and systems infrastructure</td>
</tr>
<tr>
<td>▪ CC Critical Power Infrastructure</td>
<td>▪ Facilities assets that support building and fire safety</td>
</tr>
<tr>
<td>▪ Systems &amp; facilities that support Commercial Business systems</td>
<td></td>
</tr>
</tbody>
</table>

This ranking occurs after the ranking based on designation of Transmission system criticality—it is independent of the overall importance of the line, sub, or facility.

Since CC assets components cannot be replaced independently, these rankings delineate types of systems by criticality of function.

The component ranking will be re-evaluated annually to capture changes in system needs and priorities.